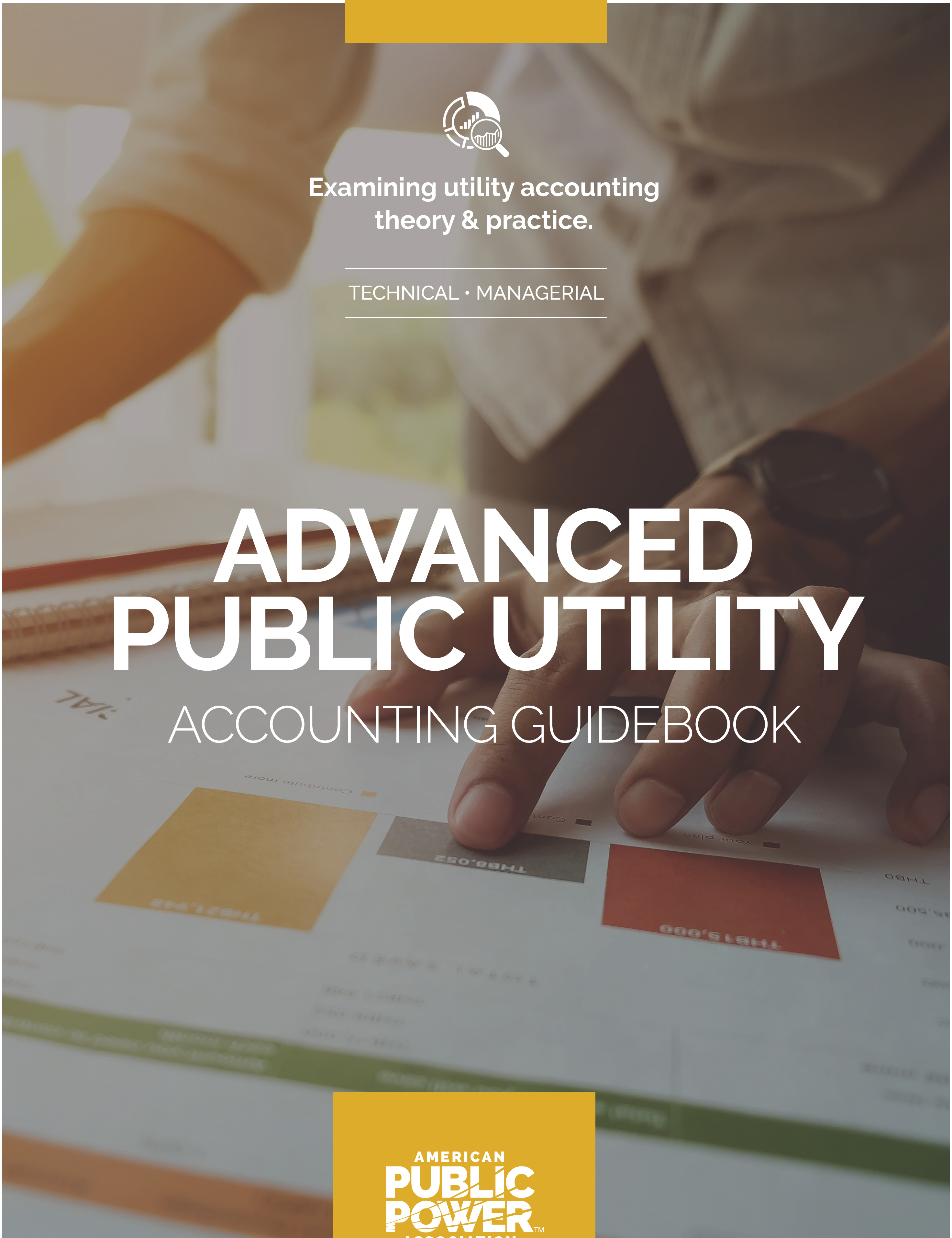

Examining utility accounting theory & practice.

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ACCOUNTING GUIDEBOOK

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ADVANCED PUBLIC UTILITY
ACCOUNTING GUIDEBOOK

PUBLISHED APRIL 2019

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The American Public Power Association is the voice of not-for-profit, community-owned utilities that power 2,000 towns and cities nationwide. We represent public power before the federal government to protect the interests of the more than 49 million people that public power utilities serve, and the 93,000 people they employ. Our association advocates and advises on electricity policy, technology, trends, training, and operations. Our members strengthen their communities by providing superior service, engaging citizens, and instilling pride in community-owned power.

TABLE OF CONTENTS

INDEX OF TABLES

INDEX OF FIGURES

ABOUT THE CONTRIBUTING TEAM

Baker Tilly Virchow Krause is proud to offer this revision to the Advanced Public Utility Accounting Guidebook. The team that worked on this issue has extensive knowledge in energy and utility accounting practices. The Baker Tilly Virchow Krause team members contributing to this book are:

Jodi Dobson, CPA
Partner, Energy & Utilities

Russ Hissom, CPA, CIA, CISA
Partner, Energy & Utilities

Dan LaHaye, CPA
Manager, Energy & Utilities

Bethany Ryers, CPA
Senior Manager, Energy & Utilities

Sarah Slaughter, CPA
Senior Manager, Energy & Utilities

Thomas Unke, CPA
Partner, Energy & Utilities

Aaron Worthman, CPA
Partner, Energy & Utilities

INTRODUCTION

The American Public Power Association is dedicated to serving the needs of its members in financial management. This guidebook examines some of the more complicated aspects of public utility accounting theory and practice. The learning outcomes that the guidebook is designed to achieve include:

Review introductory public utility accounting theory and practice and examine technically complicated public utility accounting topics

Examine topics related to public utility accounting, including cost allocation, rate design, budgeting and internal controls

Examine topics related to the analysis and interpretation of financial information

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ABOUT PREVIOUS REVISIONS

In May 2003, this guidebook was updated by Virchow, Krause & Company, LLP to address Governmental Accounting Standards and Financial Accounting Standards issued after the 1998 version of this guidebook.

In 2012, Baker Tilly Virchow Krause, LLP (Baker Tilly) completed an extensive revision to the guidebook. Updates included addressing new accounting standards issued since the 2003 version through May 31, 2012, and reformatting the guidebook to clearly segregate financial guidance from managerial guidance. In addition, Baker Tilly Virchow Krause added several chapters for topics specific to electric utilities, such as regulatory accounting and accounting for pensions and other post-employment benefits.

In 2018, Baker Tilly Virchow Krause, LLP (Baker Tilly) completed another revision to the guidebook. In the six years since the last revision GASB has issued 23 new standards. The 2018 revision updates the technical guidance for the portions of these standards relevant to public utilities. This includes significant revisions to the chapter on pensions and other post-employment benefits as well as the addition of a chapter on leases. In addition, the chapter on capital assets was revised with the upcoming issuance of a separate publication on work order accounting.

Baker Tilly Virchow Krause greatly appreciates this opportunity to update the Advanced Public Utility Accounting Guidebook that addresses current accounting issues in utility accounting. We hope readers will find this guidebook an invaluable tool in establishing sound financial control, in recording financial transactions and in the financial management of their utility operations.

TECHNICAL GUIDANCE

CHAPTER ONE
UTILITY ACCOUNTING THEORY & REGULATION

INTRODUCTION

Accounting plays a crucial role in today's public utilities. Most decisions that utility managers, lenders, regulators and other governing bodies make require extensive use of accounting and financial information. Indeed, a utility's ability to succeed is directly related to the quality of its accounting information.

This chapter provides an overview of utility accounting theory. A more detailed discussion of basic utility accounting theory can be obtained by attending the Association's Public Utility Accounting course and reading the related course manual titled *Utility Accounting*[1]. This document addresses accounting standards through June 30, 2018, and GASB No. 89.

REGULATION OF UTILITY ACCOUNTING

Utilities generally are subject to regulation, which becomes a substitute for the economic controls of competition in assuring efficient prices and adequate service. A chief objective of the regulatory process is to secure the efficiency of monopolistic operation without allowing the enterprise to take advantage of its position. Public utility regulation, as now conceived, is the consequence of many years of experimentation and change, developing with the growth and technological advancement in the utility industry and the economy.[2]

Over time, public power utilities have become subject to local, state, and national regulation. Although regulators have many powers and duties, historically their principal reason for existence has been to regulate rates. Many of their other powers are necessary adjuncts of rate regulation. In addition to rates, the areas of regulation include accounting, financing, rules of service, safety, licensing of major construction projects, sales and purchases of property, and determination of service areas.

Many utilities are subject to rate regulation by local or state commissions. Regulation of rates and revenues would affect accounting, but regulatory commissions generally have direct accounting jurisdiction as well. Some utilities are also subject to accounting regulation by federal agencies. Since most utilities frequently engage in financing, they are also subject to the requirements of lenders and in some cases the Securities and Exchange Commission.

Regulation of rates requires accounting information, and sound regulation requires sound accounting practices that in some cases are unique to regulated industries. Accounting supplies the information that is used in rate regulation and rate regulation, in turn, affects the accounting data. Because of this interaction, regulated accounting differs in certain respects from that used in other businesses, including investor-owned utilities.

Accounting generally is regarded as a tool of regulation. Historically, regulatory commissions have required substantial uniformity of accounting to assist in regulation. Directly or indirectly, accounting regulation affects published reports and financing, which in turn affects rates. The authority granted to regulators with respect to accounting is desirable when it results in comparability. It also has helped to eliminate some of the undesirable accounting practices from earlier days of the utility industry.

[1] Call APPA at 202-467-2978 for information on the Public Utility Accounting Course or the related publication (Public Utility Accounting, American Public Power Association, 2012).
[2] Deloitte Haskins and Sells, Public Utilities Manual, page 8.

When regulation began, little attention was paid to the accounting methods that public utilities used. Operating expenses were overstated, the investment in plant and equipment was impossible to ascertain, and overcapitalization was common due to the lack of reliable figures. Under these conditions, the goals of regulation were frustrated; effective regulation requires regulatory oversight of accounting procedures.[3]

Accounting control is not an end. Rather, it is a means for making data available. It does not interfere with proper managerial functions. It simply requires that management keep its books or records of accounts to give regulators information. Therefore, both state and federal laws have generally given regulatory commissions authority to require public utilities to keep certain types of records and accounts.

Since many state and federal regulations apply only to large utilities or to investor-owned utilities, some public power utilities are not required to comply with standard public utility accounting practices. However, in some cases, either state statutes or local government ordinances mandate that standard public utility accounting practices be adopted. Also, many public power bond covenants require public power utilities to adopt standard utility accounting practices.

Many utilities that are not required to adopt standard utility accounting practices do so voluntarily. The primary reason for this voluntary compliance is comparability. By using standard utility accounting practices, utilities can effectively compare their operating statistics to those of other utilities. These measurements of operating efficiency can be extremely helpful in identifying financial problems at an early stage. Voluntary compliance also facilitates the completion of standardized annual reports that are organized in a format consistent with regulated standard accounting practices.

The balance of this chapter focuses on the regulation of accounting and the uniform system of accounts. Several standard-setting bodies promulgate accounting standards for public utilities. The appropriate standards for a given utility depend primarily on the requirements of the utility's regulators, lenders, and constituents.

GENERALLY ACCEPTED ACCOUNTING PRINCIPLES (GAAP)

The public utilities this manual is written for are governmental entities, or departments of a governmental entity, for GAAP purposes. The Governmental Accounting Standards Board (GASB) sets GAAP for governmental entities. Governmental entities consist of all state and local governments, public corporations, and the bodies corporate and politic. Entities with any one of these characteristics are also considered a governmental entity for reporting purposes.

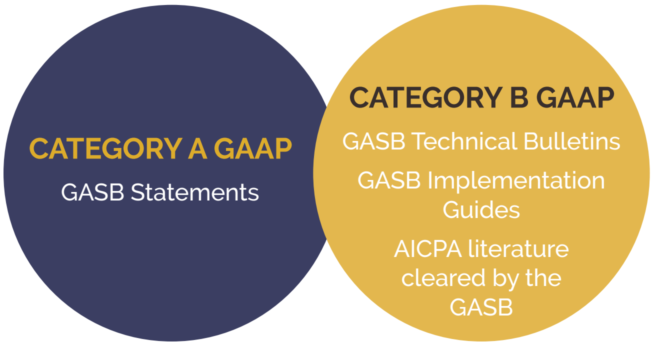
Although utilities operate as either public entities or private entities, the accounting for each type of utility is governed by different authoritative bodies. While public power utilities follow GASB pronouncements, private (investor-owned) utilities follow Financial Accounting Standards Board (FASB) pronouncements.

In March 2009, GASB released its Statement No. 55, which incorporated the GAAP hierarchy for state and local governments into GASB's authoritative literature. The goal

[3] Charles F. Phillips, The Regulation of Public Utilities, page 216.

of this statement was to make it easier for preparers of state and local government financial statements to identify and apply all relevant guidance. However, it is not expected to result in any changes in current practice. This standard was superseded by GASB No. 76 in June 2015. The intent of Statement No. 76 was to simplify the hierarchy and provide guidance for evaluating the proper treatment for transactions not addressed in GAAP.

The categories of accounting principles are as follows:



If a specific transaction or event is not addressed in the Category A or B GAAP listed above, the utility should determine whether there is a similar transaction addressed within the GAAP guidance. If there is none, the utility may consider other accounting literature, also called non-authoritative accounting literature, if it does not conflict with guidance provided within the authoritative literature. Other accounting literature would include GASB Concept Statements, guidance or pronouncements issued by the FASB, American Institute of Certified Public Accountants (AICPA) Issues Papers, international standards, guidance provided by professional associations or regulatory agencies, etc. A utility is required to consider the consistency of the non-authoritative literature with the GASB Concepts Statements as part of its evaluation of the appropriateness of the literature to the specific situation.

Historically, public utilities were required to follow FASB standards issued prior to November 30, 1989, and had the option to follow FASB standards issued after that date as long as they did not conflict with GASB standards, as outlined in GASB No. 20. In December 2010, GASB issued Statement No. 62, which incorporated pre-November 30, 1989, FASB guidance into the GASB standards. This, combined with the hierarchy discussed above, results in a simplified system in which utilities follow GASB statements unless they are silent on the accounting issue in question. FASB guidance may be followed if it is consistent with GASB guidance.

GASB establishes rules for accounting and financial reporting for certain transactions and activities, but it does not provide guidance or restrictions on the account structure that a utility uses to track activity in its general ledger. This structure is commonly referred to as a chart of accounts or system of accounts.

Uniform Accounting Systems

The control of accounting ordinarily is accomplished by uniform systems of accounts, together with interpretive orders. The uniform systems that most utilities are required to follow consist of lists of the titles and identifying numbers of accounts to be used, together with specific instructions for the use of individual accounts and general accounting instructions. There are, of course, specialized systems for different types of utilities. Since many public power utilities provide electricity and other services (water, gas, telecommunications), the most common uniform systems are discussed here.

The standard uniform accounting systems for electric and natural gas utilities are promulgated by the Federal Energy Regulatory Commission (FERC). The National Association of Regulatory Utility Commissioners (NARUC) also provides accounting standards for gas and electric utilities by issuing Interpretations of the FERC accounting standards. Accounting decisions involving compliance with the provisions of the FERC Uniform System of Accounts should consider NARUC interpretations and FERC accounting releases as though they were part of the text of the FERC Uniform System of Accounts.[4]

Water utility accounting is regulated only by state commissions or municipal bodies, many of which prescribe the NARUC Uniform System. Rural electric cooperatives and other Rural Utilities Services borrowers are subject to RUS accounting regulations. These regulations require the state systems to be used by entities subject to a state system and federal systems are to be used by others.

Since the intended audience of this manual is electric public power utilities, the FERC Uniform System of Accounts (USOA) will be the assumed accounting system. USOA basically follows generally accepted accounting principles (GAAP) and the techniques normally employed elsewhere, but accounting specifications for certain matters are designed to meet the needs peculiar to regulated utilities. The differences normally result, either directly or indirectly, from the emphasis in regulation on ratemaking objectives, and their effect on financial statements may be significant. Some of the principal differences and their relationships to generally accepted accounting principles are discussed below.

[4] AGA/EEI, Introduction to Public Utility Accounting, page 61.

Matching Costs and Revenues

Many differences between the regulated and unregulated approach to accounting for transactions result from the recognition of operating expenses in rate proceedings at a time different from that when they would be recognized by unregulated businesses. It is a common practice in the ratemaking process to defer recognition of costs considered abnormal or as having benefits applicable to future rates. In such cases, when deferred costs will be recoverable out of future revenues, accounting that follows the timing of costs used for rate purposes is considered to conform with generally accepted accounting principles. This is in accord with the matching concept, because the deferred costs are matched against future revenues. See further discussion of this in Chapter 5.

Regulators usually require that accounting treatment correspond to rate treatment, but even if they do not so require, the two treatments should ordinarily conform. It is possible to affect a proper matching of costs and revenues, unless the revenues cannot reasonably be presumed to be recoverable in the future. The matching, however, may be only approximate, since rate proceedings usually do not occur annually or guarantee exact recovery of costs.

Conflicting Regulations

Determination of proper accounting may be complicated by conflicting regulations. For example, a utility may be under the jurisdiction of the federal government and one or more state or local jurisdictions. With multiple regulatory agencies exercising overlapping authority, the potential difficulties for a utility are obvious. These conflicts have been largely minimized in the past through cooperation of these bodies.

CONFLICTS BETWEEN REGULATION AND GAAP

Complications can also arise when accounting rulings are made before ratemaking determinations. For example, regulators may order or approve an accounting treatment without having dealt adequately with the related ratemaking considerations. Other accounting practices may be dictated by regulatory requirements not related directly to ratemaking or by regulation related to aspects of ratemaking other than the timing of income and expense. Accounting practices that depart from the normal pattern but are not related solely to timing differences or ratemaking considerations must be analyzed to determine whether, for other reasons, they conform to GAAP. Some of the most common differences between FERC and GASB are as follows:

- **Capitalization policies**
  While GAAP requires the utility to establish a capitalization policy (typically based on useful life and cost) and defines capital assets, FERC provides very detailed instructions on what costs should be included as part of the cost of construction of capital assets and requires certain equipment, such as meters and transformers, to be treated as a capital asset no matter what the individual cost.
- **Contributions in Aid of Construction**
  Under FERC rules, contributions in aid of construction are not included in the plant accounts and the amount of contributions is accounted for as a reduction to gross plant. Under GAAP, contributed amounts are credited to capital contributions, which results in an increase in equity and the assets are recorded.
- **Payment in Lieu of Taxes**
  Under GAAP rules, non-exchange payments to the local government are shown as a transfer and not included in operations, but FERC considers the payment in lieu of taxes an operating expense.
- **Loss on Advance Refunding Amortization**
  While FERC allows the utility to decide if the loss will be expensed, amortized over the remaining life of the old debt, or amortized over the life of the new debt, GAAP requires these amounts to be amortized over the shorter of the life of the old or new debt.
- **Issuance Costs Related to Debt**
  FERC states that issuance costs related to debt should be amortized in a systematic and rational manner. Until the issuance of GASB No. 65, this was consistent with GAAP. For periods beginning after December 31, 2012, these costs should be expensed as incurred.
- **Bad Debt Expense**
  Under GAAP rules, revenues are to be reported net of amounts written off as uncollectible. FERC guidance reports bad debts as an operating expense.

- **Capitalized Interest**
  FERC gives us specific guidance on capitalized interest. It provides a formula that allows interest to be capitalized when two conditions are present: capital expenditures have been incurred, and activities are in progress to get the asset ready for its intended use.

  Historically, GAAP rules specified three conditions that need to be present and provided two formulas for calculating capitalized interest, one for taxable borrowings and one for tax-exempt borrowings. With the issuance of GASB No. 89, which is effective in 2020, GAAP no longer incorporates capitalized interest; rather, interest incurred during construction is expensed.
- **Gain/Loss on Asset Disposal**
  GAAP anticipates that the amount of accumulated depreciation for a specific asset is known and thus the gain or loss on disposal can be computed and recognized as a non-operating revenue/expense. FERC guidance understands that mass units of property are depreciated as a class and thus assumes that items are fully depreciated when retired, therefore not recognizing a gain or loss.
- **Equity Reporting**
  While FERC uses retained earnings, contributed capital, and stock as equity classifications, GAAP requires equity to be classified as net investment in capital assets, restricted and unrestricted.

Many of these differences can be accommodated by grouping accounts differently for regulatory reporting vs. GAAP financial statement preparation. However, there may be differences that are not so easily handled for which the utility needs either to maintain two sets of records or evaluate its external reporting needs to determine if audited financial statements under GAAP and regulatory reporting are both required.

FERC UNIFORM SYSTEM OF ACCOUNTS

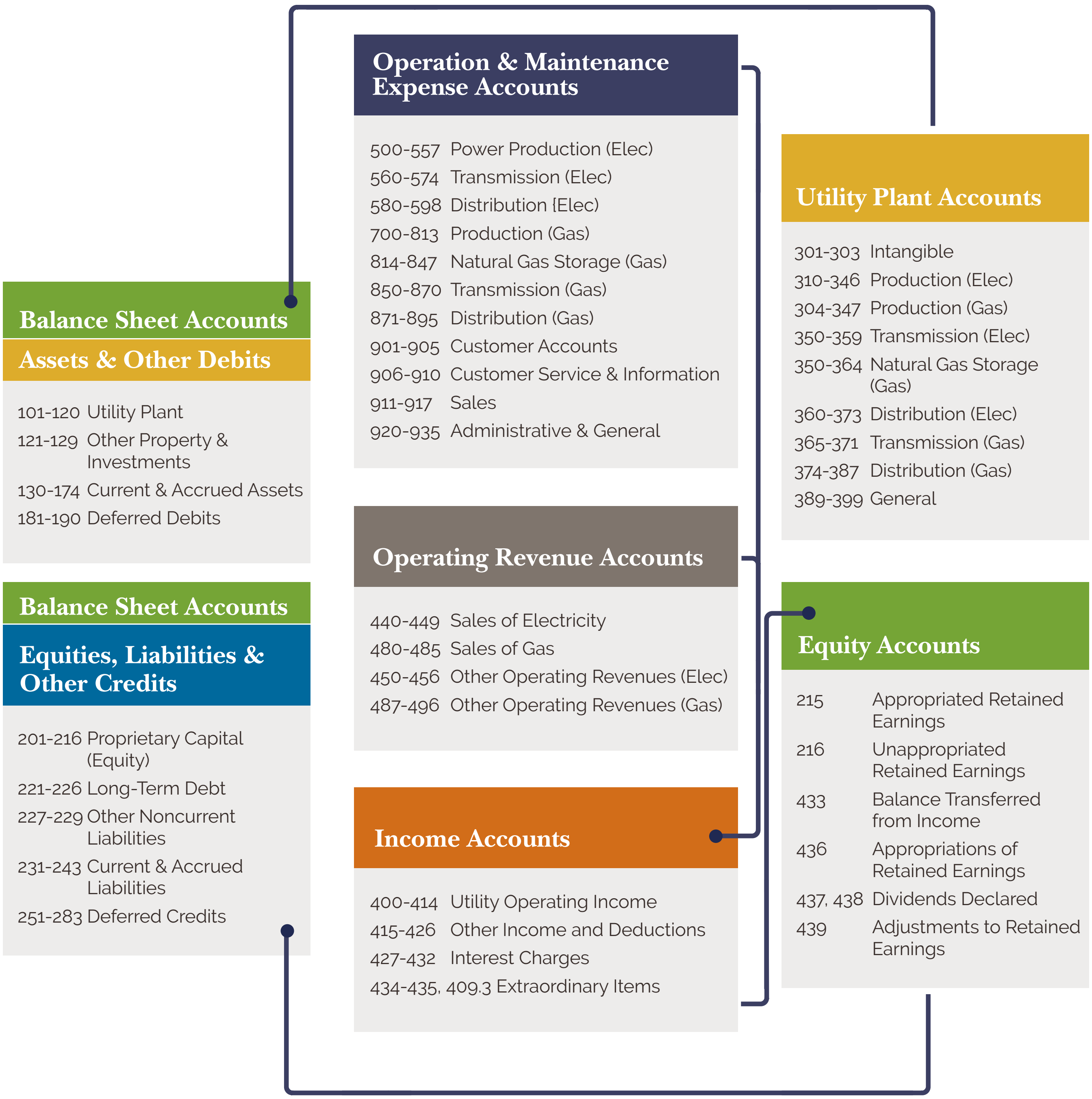
The FERC has authority under the Federal Power Act and the Natural Gas Policy Act to prescribe accounting rules and regulations, to a certain extent, for utilities that are under its jurisdiction. The FERC Uniform System of Accounts (USOA) covers many accounting matters, including those related to regulated industries. However, there are many details of accounting principles and practices that cannot be ascertained from USOA. Thus, GASB and FASB standards must also be reviewed for guidance. The complete text of USOA is published in the Code of Federal Regulations – Title 18 and can be found at www.ferc.gov.

The specific sections of the FERC Uniform System of Accounts for electric utilities are:

1. Commission Order of Applicability
2. Definitions
3. General Instructions
4. Electric Plant Instructions
5. Operating Expense Instructions
6. Balance Sheet Chart of Accounts and Descriptions
7. Electric Plant Chart of Accounts and Descriptions
8. Income Chart of Accounts and Descriptions
9. Retained Earnings Chart of Accounts and Descriptions
10. Operating Revenue Chart of Accounts and Descriptions
11. Operation and Maintenance Expense Chart of Accounts and Descriptions

Each of these sections is discussed in the Association's Public Utility Accounting course. The key to mastering the FERC Uniform System of Accounts is gaining an understanding of the interrelationships among the various account numbers shown below.

Figure 1 – Interrelationship of FERC Accounts[5]



[5] AGA/EEI, Introduction to Public Utility Accounting, page 66.

CHAPTER TWO
FINANCIAL REPORTING

INTRODUCTION

Chapter One began the discussion of public utility accounting theory and highlighted the differences between internal or regulatory accounting and external reporting under GAAP. This chapter focuses on the external financial reporting for public utilities. External financial reporting relates to a utility's audited financial statements. Public power utilities are governmental entities and thus GAAP is established by GASB.

Classification – GASB Purposes

Most public power utilities are classified for GASB purposes as enterprise funds, proprietary funds, or business-type activities. Enterprise funds are used to account for activities that charge a fee to external parties for goods or services. This classification allows utilities to use full accrual accounting, which is like for-profit business accounting.

BASIC FINANCIAL STATEMENTS

GASB No. 34, as amended by GASB No. 63, requires that governmental enterprise funds report a Statement of Net Position (like a balance sheet), Statement of Revenues, Expenses and Changes in Net Position (like an income statement), and a Statement of Cash Flows.

Statement of Net Position

The statement of net position uses a classified format to distinguish between current and non-current assets and liabilities. Items are generally reported in order of liquidity. Therefore, cash would be reported before accounts receivable, which are not as readily converted to cash. Utilities may choose to use either a net position format of assets and deferred outflows less liabilities and deferred inflows equals net position (equity) or a balance sheet format, where assets plus deferred outflows equal liabilities plus deferred inflows plus net position for reporting. Net position must be split into three components: (1) invested in capital assets net of related debt, (2) restricted and (3) unrestricted. Each of these categories is calculated as follows:

Net Investment in Capital Assets

- Plant in service
- Less accumulated depreciation
- Construction work in progress
- Less capital debt outstanding*

*This includes unamortized premiums/discounts/loss on refunding. This amount should not include unspent debt proceeds on hand (construction funds or funds borrowed to meet the reserve account requirements) nor should it include any debt outstanding that was issued for purposes other than construction of capital assets (for example debt issued to fund operating expenses or pension liabilities).

Restricted

- Assets restricted by external parties (eg., bond covenants)
- Assets restricted by law by constitutional provisions or enabling legislation
- Less liabilities payable from restricted assets

Because the current portion of capital-related debt is included in the calculation of net investment in capital assets, it is not considered payable from restricted assets. Restricted net position cannot ever be reported as a negative amount. If liabilities related to restricted assets exceed those assets, the excess should be reported as a reduction of unrestricted net position.

Unrestricted

This represents the remaining equity, which is not invested in capital or restricted.

Statement of Revenues, Expenses, and Changes in Net Position

The Statement of Revenues, Expenses, and Changes in Net Position is like an Income Statement used in private sector financial reporting. This is the correct order to present the statement:

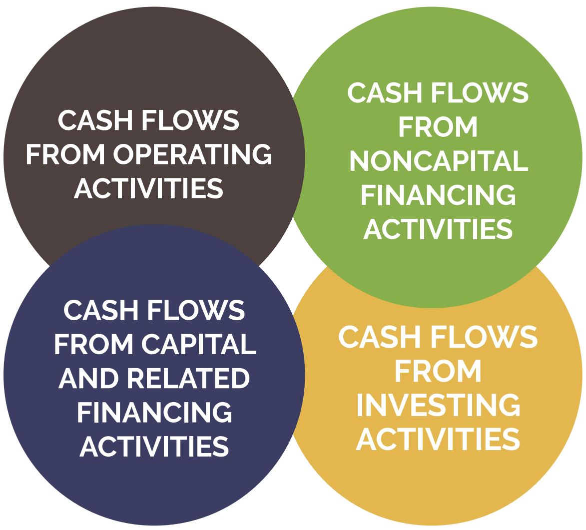
Table 1: Statement of Revenues, Expenses and Changes in Net Position

Operating Revenues
Operating Expenses
Operating Income
Non-operating Revenues and Expenses
Income before contributions, transfers, and special/extraordinary items
Capital Contributions
Transfers
Special/Extraordinary Items
Increase (decrease) in net position
Net Position–beginning of period
Net Position–end of period

Statement of Cash Flows

The last of the basic required financial statements is the Statement of Cash Flows. Again, this reflects the Statement of Cash Flows for private sector financial reporting, but there are some major differences. The first major difference is the use of four categories, whereas private sector uses only three.

The statement and related cash flows must be classified into four distinct categories:



Further, the location for reporting certain activity is different under GASB guidance than that followed by private utilities, as outlined below.

Finally, while private sector guidance allows the option of using the direct or indirect method of presenting the statement of cash flows, GASB requires the use of the direct method, meaning cash flows are shown by major classification of receipts and payments, and a reconciliation of operating income to cash flows from operations is required.

Cash flows from operating activities generally include all cash flows related to transactions and events reported as components of operating income in the statement of revenues, expenses, and changes in net position. This classification is also used to reflect cash flows that cannot be categorized into one of the other three categories. At a minimum, the following classifications within cash flows from operating activities should be used:

Cash Flows From Operating Activities

- Cash receipts from customers
- Cash receipts from services provided to other funds*
- Payments to suppliers for good or services
- Payments to employees for services
- Payment for services made to other funds*

*If the utility is a fund of a municipality, transactions for services provided to or purchased from other funds of the primary government should be segregated. This requirement does not apply if the utility is a stand-alone governmental entity.

The next category, cash flows from noncapital financing activities, includes borrowing and repayments of debt unrelated to capital improvements. Because electric utilities are capital-intensive entities, this area of the cash flow statement is not used as often as the other categories. The most common cash flow presented in this area relates to inter-fund transfers, specifically for payments in lieu of taxes (PILOT). Some other types of activities that would be recorded here are any borrowing activities that do not directly relate to capital purposes, grant proceeds (non-capital related), grant payments to other entities, and any advances made to other funds of the municipality or repayment of those advances.

Cash flows from capital financing activities include all borrowing and payments of debt directly related to capital financing. These payments include both principal and interest payments. This category is also used to report grant proceeds and other cash contributions for capital assets. Cash paid for the acquisition or construction of capital assets and cash flows from the sale of capital assets would be reported in this area as well.

The final category of cash flows is from investing activities. As the statement of cash flows focuses on cash and cash-equivalents (investments that mature within three months of acquisition) the purchase or sale of investments that do not meet the definition of cash-equivalents results in a cash flow from investment activities. A cash outflow would be recorded when purchasing non-cash equivalents (certificates of deposits, stocks, and bonds), while the proceeds from sales of non-cash equivalents are cash inflows. Investment income is also reported in this section.

In general, cash flows should be reported gross rather than net. For example, if the utility receives payment from a customer for power during portions of the year and purchases power from this same counterparty during other times, these transactions should not be net. GASB has provided an exception to allow net reporting for certain transactions, including investments not classified as cash equivalents, loans receivable, and debt, provided that the transactions are due on demand, occur in large volume, and turn over rapidly.

It is important to remember that a cash balance cannot be less than zero, therefore a negative cash position should be treated as debt and reported under cash flows from noncapital financing activities.

Any significant non-cash investing, capital, or financing activity should be disclosed on the statement. This can be presented in narrative or tabular form. Common items noted in this area include non-cash capital contributions, debt refinancing transactions, or the increase/decrease in the value of investments for unrealized market valuation adjustments.

CLASSIFICATION DECISIONS

For each of the basic financial statements discussed above, decisions must be made at the transactional level, which may determine how activity is classified for reporting. The following discusses some of the most common decisions that utilities face.

Capitalization vs. Expense

When disbursements are made to purchase equipment or construct infrastructure, it is clear that these are long-lived items and should be capitalized. When capitalized, the result is an increase in the assets on the statement of position. The only impact on the operating statement is the increase in the annual depreciation expense. There are transactions, however, that may not be so clear, such as re-roofing a building. The new roof will last more than one year and may have a significant cost, however, is it extending the life of the building or just maintaining the original value of the structure? Depending on how you answer this question, this could be capitalized or expensed. If the outlay is capitalized, the impact on the bottom line in the current year is less and the costs are recovered in rates over several years. If this is treated as routine maintenance and expensed, the current year income would be lower, but the average routine maintenance costs recovered through rates should be higher, resulting in faster recovery. Often utilities face such decisions for which there is not one right answer. In such cases, management needs to consider the local capitalization policy, the rate recovery model, and past practice to ensure that similar transactions are treated consistently over time.

Current vs. Noncurrent

Current assets and liabilities are accounts that are expected to generate or use cash within the current year. Assets and liabilities that will not generate or use cash within the current year are categorized as noncurrent. This decision is made based on the intent at the reporting date. For example, a utility may have bond anticipation notes that come due within the next year, but a decision has been made to refinance these notes with 20-year bonds. In that case, the notes can be classified as non-current because there is no intent to use cash to liquidate this liability within the next year.

Operating vs. Non-operating

While GAAP requires that the Statement of Revenues, Expenses, and Changes in Net Position segregate operating from non-operating activity, there is no specific definition provided for operating activities within the GASB standards. The underlying intent is to present the revenues generated by fees for services and the related cost to provide those services within each enterprise fund. Thus, it is reasonable to assume

Table 2: Prior and Current Format of Statement of Net Position (Formerly Statement of Net Assets)

STATEMENT OF NET POSITION	STATEMENT OF NET ASSETS
Assets	Assets
Current Assets Noncurrent Assets	Current Assets Noncurrent Assets
Deferred Outflows	
Liabilities	Liabilities
Current Liabilities Noncurrent Liabilities	Current Liabilities Noncurrent Liabilities
Deferred Inflows	
Net Position	Net Assets
Net investment in capital assets	Net assets invested in capital assets, net of related debt
Restricted	Restricted
Unrestricted	Unrestricted

that operating activities are those that relate to the principal purpose of the utility – i.e., providing electric service. It is important that each utility define its operating activities so unique transactions can be evaluated properly for their relationship to the utility's core operations.

Operating revenues would be derived from providing service from customers whereas non-operating revenues would reflect revenues that are not related to providing electric services such as investment income or gain on sale of property.

In addition, operating expenses would be those expenses necessary to earn operating revenues, like purchased power, and non-operating expenses would reflect those expenses incurred because of other activities, like interest costs from financing activities.

DEFERRED OUTFLOWS OF RESOURCES AND DEFERRED INFLOWS OF RESOURCES

In 1999, GASB issued Statement No. 34, which made significant changes to the basic financial statements. In 2011 and 2012, GASB issued Statements No. 63 and No. 65, which discuss the presentation of deferred outflows of resources and deferred inflows of resources. Neither of these financial statement elements is new; they were defined in GASB Concepts Statement No. 4. However, until these new standards were issued, there was no guidance on the use of these reporting categories.

GASB No. 63 begins by adding to and changing the structure of the Statement of Net Position (formerly Statement of Net Assets). The new format displays categories of assets, deferred outflows of resources, liabilities, deferred inflows of resources, and the difference of these accounts totaling net position. See the differences and the formats of each in Table 2.

Deferred outflows of resources exist when the utility uses resources in the current period to benefit a future reporting period. They have a positive effect on net position, like assets. Meanwhile, deferred inflows of resources are the result of transactions in the current period that will be earned in a future period and have a negative effect on net position, like liabilities. Only balances that GASB designates as deferred outflows or inflows of resources in other standards are to be shown in these new categories.

Additional disclosures in the footnotes are required if the significant components of the total deferred amounts are not presented separately on the face of the Statement of Net Position.

GASB No. 65 provided additional guidance on items to be classified as deferred outflows and deferred inflows in the future. This guidebook emphasizes items that affect many electric utilities.

In Chapter 7, we address the details of a debt-refunding transaction. However, when outstanding debt is refunded, a loss on advance refunding is often recognized. Historically this was reported as a component of long-term debt, but GASB No. 65 specifies that the unamortized loss on advance refunding be classified as a deferred outflow of resources.

If a utility sells property and subsequently leases that property back, the gain or loss on the sale should be reported as a deferred inflow or deferred outflow of resources and amortized over the life of the lease.

Chapter 5 provides an in-depth discussion of regulatory accounting. If a utility's rates are designed to recover current period costs that are anticipated to be incurred in a future period, the regulatory deferral should be reported as a deferred inflow of resources, rather than a liability. Similarly, if a utility has a gain in the current period that will be used to offset expenses in future periods through an adjustment to recoverable costs, the gain should be reported as a deferred inflow of resources. In both cases, the deferred inflow is reduced over the period of related rate recovery.

The accounting and reporting for derivative instruments is discussed in Chapter 3. GASB No. 53 requires that hedging derivatives be classified as deferred inflows or deferred outflows of resources.

FINANCIAL REPORTING ENTITY

Governmental financial reporting is further complicated by the relationships between different governments. If the utility is a fund of a municipality, the utility's financial information is included in the municipality's financial statements whether or not the utility issues separate financial statements. In other cases, the utility is a standalone government, in which case the utility must evaluate whether it must report to another government – say a county – or if there are other governments that should be included in the utility's financial reporting – say a financing district.

GASB No. 14 initially established criteria for evaluating when one governmental entity should be included in the financial statements of another entity as a component unit. GASB No. 61 clarifies certain issues relating to the financial reporting entity including the reporting of component units. In addition, GASB No. 90 provides clarity around the limited situation of a government that has a majority equity interest in a separate organization.

Component units are defined in GASB No. 14 as legally separate entities for which elected officials of the primary government are financially accountable or organizations for which the nature and significance of their relationship with the primary government would cause the financial statements to be misleading if they were not included.

In evaluating if the utility is or has a component unit, the following questions should be asked:

ARE THE TWO ENTITIES LEGALLY SEPARATE?

DOES THE POTENTIAL PRIMARY GOVERNMENT (PPG) APPOINT A VOTING MAJORITY OF THE POTENTIAL COMPONENT UNIT'S (PCU) GOVERNING BODY?

Does the relationship result in a financial benefit or burden for the PPG?

Is the PPG able to impose its will on the PCU?

IS THE PCU FISCALLY DEPENDING ON THE PPG AND IS THERE A FINANCIAL BENEFIT OR BURDEN RELATIONSHIP?

WOULD IT BE MISLEADING TO EXCLUDE THE PCU FROM THE PPG FINANCIAL STATEMENTS?

This determination should be based on the nature and significance of the relationship between the two entities.

The answers to these questions will determine whether the potential component unit is a component unit. If a component unit exists and (a) the governing bodies of the two entities are substantially the same and there is a benefit/burden relationship or management is substantially the same, or (b) the component unit provides services almost entirely or entirely to the primary government, or (c) resources of the primary government are expected to be required to repay almost entirely all of the outstanding debt of the component unit, then the financial statements should be blended. If none of these are true, then the component unit should be discretely presented or shown in a separate column within the financial statements.

GASB No. 84 provides clarity and guidance for reporting fiduciary activities. Fiduciary activities are those that meet the specified criteria related to control of the assets, source of the resources, beneficiaries of the assets, and administration of the assets. In many cases, single employer pension and other post-employment benefit plans will meet the criteria for fiduciary component units or fiduciary funds and thus must be reported on separate statements within the financial report of the primary government or the utility. This standard exempts custodial activities in an enterprise fund that are expected to be held for three months or fewer. If this exemption applies, the utility would report the assets, a corresponding liability and should report the related cash flows gross, not net.

While it is not overly common, there are situations in which governmental operations may transfer between entities or two governments may combine. In addition to the operational challenges and managing the logistics of such an event, management needs to consider the proper accounting and reporting for the transition. GASB No. 69 provides guidance for accounting and reporting of government combinations (including mergers, acquisitions, and transfers) and the disposal of operations. Key distinctions made within this standard and guidance include:

- A merger is the combination of two legally separate entities with no significant consideration involved. The assets and liabilities are accounted for at carrying value in this transaction.
- When one governmental entity acquires another or the operations of another for significant consideration, the acquisition is generally accounted for at acquisition value.
- GASB defines an operation, for the transfer or disposal of operations, as "an integrated set of activities conducted and managed for the purpose of providing identifiable services with associated assets or liabilities."

FOOTNOTES TO THE FINANCIAL STATEMENTS

Although the basic financial statements previously discussed provide a substantial amount of information about utility's financial position, there may be other information that cannot be provided on the face of the statements. The financial statement footnotes are designed to supplement the basic financial statements and provide additional information. Items required to be discussed in the footnotes include, but are not limited to:

- A description of the entity, its operations, the basis of accounting used, and certain accounting policies
- Detailed information on capital assets and long-term obligations
- Information on leases and other significant contracts
- Descriptions of the impact of the application of new accounting standards, changes in accounting principles, or corrections of errors
- Additional details related to pensions and other post-employment benefits
- Detailed information on the entity's cash and investments and related specified risks

While many of these disclosures will be discussed in other sections of this manual, we want to discuss cash and investment disclosures here, as they are among the more complex disclosures required by GAAP.

Cash and Investment Disclosures

Proper cash management requires the temporary investment of excess cash. Many utilities have excess cash because the period of highest cash inflows does not coincide with the period of highest cash needs. Peak cash inflows generally follow the highest level of sales activity. For efficient cash management, excess cash must be invested from the time of peak inflows until the next period of cash outflows. The investment vehicles a utility uses will depend on investing restrictions set forth by a utility's governing board and state laws. In addition, a utility's lender may place restrictions on the type of investment vehicle that may be used.

Generally accepted accounting principles require investments to be carried on the books at their fair values. Fair value is defined as "the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date." GASB No. 72 details the fair value measurement for investments and requires that the following be disclosed:

- Valuation technique, which can be a market approach, cost approach or income approach
- Level of inputs within the fair value hierarchy
  - Level 1 - quoted prices in active markets for identical assets or liabilities
  - Level 2 - observable inputs, including quoted prices for similar assets or liabilities in active markets, quoted prices for identical assets or liabilities in markets that are not active, interest rates, yield curves, credit spreads, or market corroborated inputs
  - Level 3 - unobservable inputs such as management assumptions

However, there are a few exceptions to this rule. These include:

Exceptions to the rule

- Money market investments
- Investments held by and in 2a7-like external investment pools, or qualifying investment pools, as defined by GASB No. 79
- Non-participating interest-earning investment contracts
- Investments in life insurance contracts
- Common stock meeting criteria for applying the equity method
- Unallocated insurance contracts
- Synthetic guaranteed investment contracts

Cash and investments are inherently exposed to various risks, including risk of loss. Due to the focus on transparency in government activity and in response to some losses in the past, GASB has established a series of key risks for which governments are required to disclose any exposure as of the statement of net position date and how their investment policy addresses the risk. Although GASB cannot require governments to establish investment policies, the requirement to disclose how the policy addresses key risks, or that the government does not have a policy, may apply indirect pressure on governments to evaluate their current policies.

These rules are outlined in GASB No. 40. Each of the risks addressed by the standard is outlined below with a definition and a discussion of the disclosure requirements. Disclosures related to each risk should be organized by investment type. The guidance distinguishes between deposits at financial institutions and all other investments. The discussion of the investment policy can be provided for each individual risk or as an overall policy discussion.

Custodial Credit Risk is the risk that a utility's deposits or investments will be lost in the event of a failure of the related financial institution or counterparty. Any deposits that are not insured or collateralized need to be disclosed. In addition, if deposits are collateralized but the collateral is held by the pledging institution or its agent, not in the utility's name, those should be disclosed as such. Investments that are not insured nor registered in the utility's name should be disclosed.

Credit Risk is the risk that the issuer or counterparty to an investment will not be able to fulfill its obligation, resulting in a loss by the utility. For any investments other than U.S. Treasuries and U.S. agency securities that are explicitly guaranteed, the utility should disclose the rating by at least one of the major rating companies or note that the investment is not rated.

Concentration of Credit Risk is the risk of loss resulting from an insufficiently diversified investment portfolio. Although GASB has not established a limitation on the portion of the portfolio that can be invested with one issuer, it has established a disclosure threshold. Investments with any one issuer that are equal to or greater than 5 percent of the utility's portfolio must be disclosed. This disclosure does not apply to investments in U.S. Treasuries, U.S. agencies that are explicitly guaranteed, mutual funds, or investment pools.

Interest Rate Risk is the risk that changes in interest rates over time will result in a decrease in the value of an investment. Depending upon the composition of a utility's investment portfolio, one of five acceptable methods for disclosing the exposure to this risk can be chosen. The first three methods are the most commonly used.

- **Segmented Time Distribution:** Presented in a table, each type of investment is listed in the first column and the total value that matures in designated time periods (i.e., within 1 year, 2-3 years, over 3 years) is shown in subsequent columns.
- **Specific Identification:** Individual investments are listed with the fair value, maturity date and call options shown for each.
- **Weighted Average Maturity:** The weighted average maturity of each type of investment as well as the entire portfolio is presented in either years or months.
- **Duration:** This method uses present value of cash flow calculations to present the exposure to fair value changes arising from changing interest rates for debt instruments.
- **Simulation Models:** Simulation models estimate changes in an investment's fair value, given hypothetical changes in interest rates. Various models or techniques may be used, such as "shock tests" or value-at-risk.

Foreign Currency Risk is the risk of loss from subsequent changes in exchange rates. If a utility has any investments in foreign currencies, information on the value, currency, and type of investment should be disclosed.

Disclosure requirements for investments in derivative instruments are discussed in Chapter 3.

CHAPTER THREE
DERIVATIVES

INTRODUCTION

Increasingly, utilities invest in derivatives to help manage risks. Derivative instruments can be used as investments, hedges of identified financial or cash flow risk, or to lower the cost of borrowing. Often the intention of entering into derivative instruments is to fix cash flows or to alleviate price volatility. However, derivative instruments can expose utilities to significant risks and liabilities. GASB No. 53 provides guidance on accounting for derivatives. Some common derivatives used by utilities are:

Common derivatives used

- Forward contracts
- Future contracts
- Commodity swaps
- Interest rate swaps
- Options (caps, floors and collars)
- Swaptions

DEFINITION OF A DERIVATIVE

A derivative is an arrangement to receive or make payments based on prices related to a specified transaction without entering into that transaction. A derivative instrument is a financial instrument or other contract that has all of these characteristics:

- Contains ***settlement*** factors that tie its value to what happens in separate transactions, agreements, or rates;
- The financial arrangements are ***leveraged;*** and
- The financial arrangements can be settled early with a cash payment or the transfer of an equivalent asset ***(net settlement)***.

Settlement Factors

A derivative instrument will usually involve two settlement factors:

- The reference rate and
- Notional amount, or payment provisions.

A ***reference rate*** may be a price or rate of an asset or liability but is not the asset or liability itself and may be any variable ***(reference rate)*** that has changes that are observable or otherwise objectively verifiable.

Reference rate examples

- A security price or security price index
- A commodity price or commodity price index
- An interest rate or interest rate index
- A credit rating or credit index
- An exchange rate or exchange rate index
- An insurance index or catastrophe loss index
- A climatic or geological condition (such as temperature, earthquake severity, or rainfall), another physical variable, or a related index

Some common reference rates include:

- London Interbank Offered Rate (LIBOR),
- Securities Industry and Financial Markets Association (SIFMA) swap index,
- AAA general obligations index published by Municipal Market Data, or
- A commodity pricing point, such as Henry Hub on NYMEX.

The reference rate can be applied in one of two ways:

1. The reference rate can be applied to a ***notional amount,*** usually a quantity or a dollar amount. The notional amount is commonly expressed as the number of currency units, shares, bushels, pounds, MMBtu, MWh, or other units specified in the derivative instrument.
2. The reference rate can be used to trigger a payment. A ***payment provision*** may specify a payment to be made if the reference rate behaves in a specified manner, such as the three-month average of fuel prices at a certain pricing point that exceeds a certain price.

Leverage

Leverage means a small or no initial net investment but achieves changes in fair value that would have required a far larger initial investment.

Net Settlement

Net settlement allows for the financial instrument to be settled through means other than physical delivery.

DERIVATIVE EXAMPLE

A utility wants to lock in to a fixed price of $7 per MMBtu to easily forecast future rate requirements. To do this, the utility enters into a commodity forward natural gas contract to pay a fixed price of $7 per MMBtu ***(reference rate)*** on a quantity of 100,000 MMBtus ***(notional amount)*** and agrees to receive a variable payment based on the actual price of natural gas at Henry Hub. Upon entering into the contract, there was no required initial investment ***(leverage)*** and the commodity is exchange traded and therefore can be easily ***net settled***.

Exceptions

For practical reasons, there are certain exceptions noted, even if the financial instrument meets all criteria for a derivative instrument. The exceptions are:

- **Normal purchases, normal sales contracts –** Contracts that are used in the normal course of business that result in a physical delivery of the commodity. (For example, a purchase of natural gas to use in electric generation plant.) This also includes financial transmission rights (FTRs), if they will be used as factors in the cost of transmission.
- **Insurance contracts –** Insurance contracts covered by the standards that govern risk financing and related insurance issues. These are covered in GASB No. 10.
- **Not exchange-traded contracts –** Contracts that are not exchange-traded and have a reference rate based on a climatic, geological or other physical variable, or on the price or value of a nonfinancial asset that is not readily convertible to cash. (For example, weather hedges.)
- **Loan commitments**

Recognition and Measurement of Derivative Instruments

Derivative instruments should be reported at fair value on the Statement of Net Position. Unless a right to offset exists, derivative assets should be reported separately from derivative liabilities, even if the instruments are involved in one hedging relationship. Changes in fair values of investment derivative instruments, including derivative instruments that are determined to be ineffective, should be reported within the investment revenue classification on the flow of resources statement (i.e., Income Statement or Statement of Revenues, Expenses, and Changes in Net Position). Changes in fair values of hedging derivative instruments should be recognized through the application of hedge accounting.

Fair Value Measurement

Fair value should be measured by the market price, if there is an active market for the derivative instrument. If a market price is not available, a forecast of expected cash flows may be used, provided the expected cash flows are discounted. Formula-based methods and mathematical methods are acceptable; for example, matrix pricing, the zero-coupon method, and the par-value method.

Classification of Derivative Instruments

There are two types of derivative instruments:

1. Investment derivatives are not associated with a hedgeable item or determined to be ineffective hedges of a hedgeable item. Investment derivatives have different accounting and reporting than hedging derivatives. The fair value mark-to-market is recognized in investment income the same as any other investment. Follow GASB No. 40 for reporting.

2. Hedging derivatives have a relationship with a hedgeable item and when associated with that item reduce identified financial risks by offsetting (or by moving in the opposite direction of) changes in cash flows or fair values of the hedgeable item. The pairing of an asset, liability or future cash flow with a financial arrangement intended to compensate for volatility is a hedge. The derivative used to reduce potential volatility is the hedging instrument, while the related asset, liability, or future cash flow is known as the hedgeable item.

A derivative instrument of unknown effectiveness in reducing the identified financial risk is referred to here as a ***potential hedging derivative instrument***.

HEDGE ACCOUNTING

Under hedge accounting, the changes in fair values of hedging derivative instruments are reported as either deferred inflows or deferred outflows in the Statement of Net Position (i.e., balance sheet). This avoids any immediate impact on the statement of resource flows until the hedgeble item impact is recognized.

Hedge accounting should be applied beginning in the period that a hedging derivative instrument is established and until a termination event occurs. (See below for further discussion of termination events).

Qualification of Hedge Accounting

For a potential hedging derivative instrument to qualify for deferred recognition of changes in the fair value of the instrument ***(hedge accounting)***, there must be clear association between the hedged item and the derivative instrument, and the hedge must be effective. (See below for further discussion of effectiveness testing.)

To have a clear association, the hedgeable item must have the following:

- The notional amount of the derivative instrument is consistent with the principal amount or quantity of the hedgeable item.
- The derivative instrument and hedgeable item must be in the same fund.
- The term or time period of the derivative instrument is consistent with the term or time period of the hedgeable item.

If a derivative instrument is deemed to be a potential hedging derivative, by significantly reducing risk, hedge accounting (measure of effectiveness) must be applied.

Measuring Effectiveness

Once a potential hedgeable item has been identified and is deemed to have a clear association with the hedgeable item, effectiveness must be determined by comparing the terms of each item. There are two basic approaches to assessing effectiveness of a hedge:

- **Qualitative method –** Compare the terms of the hedging item with the terms of the hedged item to see if the two mirror one another for duration of contract, pricing reference rate (i.e., LIBOR, Henry Hub), amounts, etc. (consistent critical terms); or
- **Quantitative method.**

Effectiveness of the potential hedging derivative needs to be evaluated at the end of each financial reporting period. If a utility issues only annual GAAP financial statements, the measurement date is the year associated with the issuance of the annual GAAP financial statements.

If a potential hedging derivative instrument is first evaluated using the ***consistent critical terms method*** and does not meet the criteria for effectiveness, at least one ***quantitative method*** should also be applied before concluding that the potential hedging derivative instrument is ineffective.

All potential hedging derivative instruments that were determined to be effective in the prior reporting period should be re-evaluated at the end of the current reporting period using the method applied in the prior reporting period. If the hedging derivative instrument no longer meets the criteria for effectiveness using the original method, a utility may, but is not required to, apply another method(s) before concluding that the hedging derivative instrument is no longer effective.

Note that if a potential hedging derivative is purchased after the prior measurement date and closed prior to the end of the next measurement date, this derivative must also be tested for effectiveness, even if it does not exist at the reporting period date.

Methods for Evaluation of Effectiveness

GASB provides five methods for evaluating potential hedging derivative instruments for effectiveness:

Qualitative Method:

1. **Consistent critical terms –** Applied when you can measure and determine that critical terms of the hedgeable item and the potential hedging derivative instrument are the same, or similar in certain circumstances the changes in

cash flows or fair values of the potential hedging derivative instrument will substantially offset the changes in cash flows or fair values of the hedgeable item. For example, a forward contract is effective under the consistent critical terms method if all of the following criteria are met:

THE FORWARD CONTRACT IS FOR THE PURCHASE OR SALE OF THE SAME QUANTITY (NOTIONAL AMOUNT) OF THE SAME HEDGEABLE ITEM AT THE SAME TIME AND LOCATION AS THE HEDGEABLE ITEM.

UPON ASSOCIATION WITH THE HEDGEABLE ITEM, THE FAIR VALUE OF THE FORWARD CONTRACT IS ZERO.

THE REFERENCE RATE OF THE FORWARD CONTRACT IS CONSISTENT WITH THE REFERENCE RATE OF THE HEDGEABLE ITEM.

Quantitative methods:

2. **Synthetic instrument –** Combines the hedgeable item and the potential hedging derivative instrument to simulate a third synthetic instrument. Under this method, effectiveness is achieved if the synthetic rate is substantially fixed and is within 90 to 111 percent of the potential hedging derivative instrument. For example, if a synthetic price of a futures contract for natural gas is determined to be $7.50 per MMBtu and the forward price of the expected purchase is $8.00 MMBtu this results in 94 percent, which is in the target range for effectiveness. All other terms such as quantity, delivery point and time period are identical.
3. **Dollar offset –** Compares changes in expected cash flows or fair values of the potential hedging derivative instrument with the changes in expected cash flows or fair values of the hedgeable item. An item is considered effective when using this method when the dollar value of one change, expressed as a percentage of the other, falls within the range of 80 to 125 percent. For example, if the cash flow for the purchase of natural gas for $130 (hedged item) is divided by the cash flow of the forward contract (derivative) of $150, the calculated ratio is .8667 or 1.15 (if reversed). Both ratios fall within the .80 and 1.25, and therefore the instrument is deemed effective.
4. **Regression analysis –** Considers the statistical relationship between the cash flows or fair values of the potential hedging derivative instrument and the hedgeable item. The following parameters must be met for a hedge to be considered effective:
   - The R-squared must be at least 0.80;
   - The F-statistic should demonstrate significance using a 95 percent confidence interval; and
   - The regression coefficient for the slope should fall between -1.25 and -0.80.
5. **Other quantitative methods** can be used, but must meet the following criteria:
   - Changes in the hedged item must substantially offset changes in the hedging item;
   - Application of the method must be replicable; and
   - The method must consider all substantive characteristics that could affect changes of both the hedged and hedging item.

Termination of Hedge Accounting

Hedge accounting, or recording the changes in fair value of the hedge as a deferred inflow or outflow of resources, should be discontinued on the occurrence of **one** of the following termination events:

- The hedging derivative instrument is no longer effective ***(ineffective)***;
- The likelihood that a hedged transaction will not occur;
- The hedged item is sold or retired;
- The hedging derivative instrument is terminated early;
- The hedged item is debt that is defeased;
- The hedged expected transaction occurs, such as the purchase of an energy commodity or the sale of bonds.

If a termination event occurs, the balance in any deferred outflows of resources or deferred inflows of resources must be eliminated and would normally be reported in the Income Statement (or Statement of Net Position) as investment revenue.

There are situations when the elimination of the deferred inflows or outflows of resources related to a hedge would not be treated as an adjustment to investment income:

- If the termination event is a refunding, the deferral amount should be included in the net carrying amount of the old debt for purposes of calculating the difference between that amount and the reacquisition price of the old debt;

- If the termination event is the occurrence of the hedged expected transaction resulting in a financial instrument and there is no re-exposure to the hedged risk, the balance in the deferral account should be reported on the flow of resources statement (i.e., Income Statement or Statement of Net Position) consistent with the hedged item.
- If the expected transaction results in a purchase of a commodity, the related deferred inflows or outflows would be treated as an adjustment to the purchase of the commodity. For example, if the expected transaction is a hedge of market risk associated with the purchase of electricity and the purchase occurs, the related deferral would be recorded in the purchased power account.

In some instances, an interest-rate-swap agreement may end because a counterparty has committed or experienced an act of default or experienced a termination event as described in a swap agreement. When this happens, the agreement may be amended to incorporate a new counterparty. It is possible to continue using hedge accounting on the new swap agreement if all the following apply:

THE COLLECTABILITY OF SWAP PAYMENTS IS CONSIDERED PROBABLE;

THE COUNTERPARTY IS REPLACED WITH AN ASSIGNMENT OR IN-SUBSTANCE ASSIGNMENT; AND

THE NEW ASSIGNMENT OR IN-SUBSTANCE ASSIGNMENT IS A RESPONSE TO THE COUNTERPARTY COMMITTING OR EXPERIENCING AN ACT OF DEFAULT OR A TERMINATION EVENT AS DESCRIBED IN THE SWAP AGREEMENT.

Application of Regulatory Accounting

If a derivative instrument does not meet the criteria to allow hedge accounting, a regulated utility may elect to follow regulatory accounting and defer any amount that would normally be recognized in investment income at the end of the reporting period until the amount is recovered in rates. The utility must ensure that all provisions under regulatory accounting are met to correctly apply this accounting. Regulatory accounting is covered in more detail in Chapter 5.

Required Note Disclosures

Summary information should be provided for all derivative instrument activity during the reporting period. In many respects, the required disclosures mirror the GASB No. 40 requirement, especially for investment derivatives, with a little more detail to be provided for all hedging derivatives. In addition, the fair value disclosures required by GASB 72 apply to derivatives.

Summary Information for All Derivatives

Derivatives should be aggregated by type (future contracts, options, swaps) and detailed between investment and hedging derivatives. For each type of derivative, the following should be disclosed:

- Notional amount
- Changes in fair value during the reporting period
- Where the fair values are reported
- Fair value at the end of the reporting period
- How fair value was determined
- Fair values of derivatives that were reclassified from hedging to investment derivatives

Hedging Derivative Instruments

For hedging derivatives, the following should be disclosed:

- ***Objectives*** for entering into those instruments.
- Significant ***terms***, including:
  - Notional amount
  - Reference rates, such as indexes or interest rates
  - Embedded options, such as caps, floors, or collars
  - The date the hedging derivative instrument was entered into and when it is scheduled to terminate or mature
  - The amount of cash paid or received, if any, when a forward contract or swap (including swaptions) was entered into
- ***Risks*** applicable to the derivative that could give rise to financial loss. Possible risks could include:
  - Credit risk
  - Concentration of credit risk
  - Interest rate risk
  - Basis risk
  - Termination risk
  - Rollover risk
  - Market-access risk
  - Foreign currency risk

- ***Hedged debt.*** If the hedged item is a debt obligation, governments should disclose the hedging derivative instrument's net cash flows based on the requirements established by Statement No. 38, Certain Financial Statement Note Disclosures, paragraphs 10 and 11.
- ***Other quantitative method of evaluating effectiveness.*** If effectiveness is evaluated by application of a quantitative method, disclosure of the following information is required:
  – The identity and characteristics of the method used
  – The range of critical terms the method tolerates
  – The actual critical terms of the hedge

See the GASB website (www.gasb.org) for GASB Statement No. 53 and the implementation guide, which provides good note disclosures and effectiveness testing examples.

Investment Derivative Instruments

For investment derivative instruments, disclosures should include their exposure to risks that could give rise to financial loss. These disclosures should be presented in the context of an investment risk as described in GASB No. 40, such as ***credit, interest rate and foreign currency risk***. GASB No. 40 investment disclosures are discussed further in Chapter 2.

Contingent Features

Any contingent features included in derivative instruments should be disclosed. An example would be a government's obligation to post collateral if the credit quality of the government's hedgeable item declines. For derivative instruments with contingent features reported as of the end of the reporting period, disclosure should include:

- The existence and nature of contingent features and the circumstances in which the features could be triggered;
- The aggregate fair value of derivative instruments that contain those features;
- The aggregate fair value of assets that would be required to be posted as collateral or transferred in accordance with the provisions related to the triggering of the contingent liabilities;
- The amount that has been posted as collateral.

CHAPTER FOUR
CAPITAL ASSETS

INTRODUCTION

By far, capital assets are a utility's largest category of assets. Proper accounting for these assets is critical for accurately reflecting financial results. This chapter discusses general utility accounting practices for capital assets. Capital assets are used in delivering services to customers and have a useful life greater than a year. Topics in this chapter include work order asset management systems, depreciation, accounting for contributed assets, capitalized interest, asset impairments, and intangible assets.

WORK ORDER ASSET MANAGEMENT SYSTEMS

The single largest asset on a utility's statement of net position is often utility plant or capital assets. Capital assets have many different forms ranging from small, inexpensive items to large, high-dollar-value assets such as generating facilities. All are necessary for the utility to deliver electricty to the customer.

Work order asset management systems allow utilities to accumulate all costs associated with these long-lived utility construction and maintenance projects. The cost accumulation process is used as a tracking mechanism to segregate various types of costs between separate, identifiable projects. Projects expected to benefit more than one period or increase the useful life of an asset are generally capitalized and closed to their respective FERC or utility asset infrastructure account and depreciated over the expected useful life of the asset. Work orders closed as maintenance projects are expensed to the statement of revenues, expenses, and changes in net position in the period for which the costs relate. The cost accumulation process provides detailed cost and quantity information when allocating property units, calculating depreciation expense, and retiring assets when taken out of service.

Tracking accumulated costs and the associated assets through work orders is critical for utilities as it provides accurate and defensible information used in cost-of-service studies and the design of equitable utility rates. Other benefits of a work order system include:

- Facilitates and improves capital improvement planning and budgeting
- Provides consistent data for benchmarking utility operations within a peer group
- Provides support for issuing long-term debt to finance projects
- Provides defensible support for cost allocations among various departments and entities as well as support for cost estimates and project reimbursements (e.g., grants)
- Provides information for more accurate recording of depreciation
- Allows less work in record keeping, cost accumulation and reporting

The work order system process is divided into five main sub processes, each of which must be considered by utility management and the oversight body. The subcategories include the political process, engineering, construction, project closing, and retirement.

Many factors must be considered when planning the work order process. Factors outside of the utility's control, such as political obstacles, laws and regulations, and public perception, must be reviewed. Factors within the utility's control, such as budgetary constraints and other economic issues, also must be addressed. Upon approval from all oversight bodies, including the utility's governing body, the engineering planning process can begin.

The engineering phase is one of the most critical processes for the construction of utility plant assets because it develops the necessary inputs needed to complete the project. Resources, labor, material, and a completion time frame are all necessary components of the engineering process. Utilities can leverage their experience with similar projects and industry standards and benchmarks to obtain the best estimate of what is needed to complete the project. Whether the utility completes the engineering process in-house or outsources this phase, careful planning and continuous monitoring are critical.

Construction for a project begins after the necessary approvals have been obtained and the engineering planning process is completed. During this phase, costs are accumulated to work orders and closed each fiscal period to the construction work in progress account. The work order remains open until all necessary costs related to the project have been incurred and the assets are ready to be placed into service. The method under which costs are assigned to work orders depends on the technological capabilities of a utility's hardware and software. Advanced work order systems automate the entire process by allowing employees to allocate their time to specific job codes attached to a work order. Payments to outside contractors and materials are allocated to specific job codes through the system too, while predetermined overhead rates are applied periodically (e.g., monthly) based upon accumulated charges recorded to the work order. More simplistic systems may be manual and employ the use of spreadsheets and databases to accumulate information.

Before a project or work order can be closed, all necessary property tracking and accounting functions must be completed. Retirements for the replacement of existing assets are recorded to the utility's accounting system and CPR ledgers are updated for both the installation of the new assets and retirement of the replacement assets, if necessary. Upon completion of these activities, the work order is closed by moving the costs from the CWIP account to their final FERC plant asset account.

The following sections in this chapter detail the various components of a work order system as well as the inputs and end product.

COMPONENTS OF A WORK ORDER ASSET MANAGEMENT SYSTEM

Work order systems contain multiple components, which allow utilities to maintain accurate, reliable records and manage the capital-intensive side of the utility business. These components track cost and property unit information from initial installation to eventual retirement or replacement of the asset. Maintaining detailed information leads to accurate financial reporting and rate structures. Listed below are common components of a work order system along with their purpose.

Control Accounts

Control accounts are used to accumulate cost information for a specific project or group of projects during the construction process for financial reporting purposes. The accumulated costs are placed in a Construction Work in Progress (CWIP) account, which is a temporary holding place for the costs before assets are placed into service and transferred to their respective FERC asset infrastructure account. Projects are closed out or transferred out of CWIP when the asset is placed into service or the work has been substantially complete.

Another type of control account is a ***blanket work order***. This is used when similar types of homogeneous costs or construction processes (e.g., pole replacements and service additions) are accumulated to an individual work order. The underlying asset is the same, however, the project or location may be different. Blanket work orders are often used to track mass unit assets (described in the assembly unit section below). At the end of the utility's reporting period, blanket work orders are moved from the CWIP account to the FERC plant asset or maintenance expense accounts.

Overhead Rates

Overhead rates allow utilities to allocate and recover various costs associated with construction and maintenance projects that are not directly tied to a specific project but are attached to a cost driver charged to the project. The cost charged to the project is identifiable, but may carry other ancillary charges. Additional charges, such as employee benefits, equipment charges, materials management, administrative and general, and capitalized interest costs, are attached to costs that are charged directly to work orders. These additional costs are charged in the form of an overhead rate and are applied whenever a cost driver is charged to a work order.

Each utility may differ in its rationale for designing overhead rates, but the inputs should have a direct relationship with the cost driver it follows. For example, labor is a necessary cost in construction projects, whether it be for engineering, physical construction, or administrative and general expenses. Ancillary charges such as pensions and benefits, taxes, insurance, and worker's compensation all result from labor charges. There is a rational relationship between labor charges and these ancillary costs. The simplest method for calculating a labor-related overhead rate is to divide total annual payroll dollars into the total annual ancillary costs to obtain a percentage that represents the overhead rate. The overhead rate is then multiplied by the total labor dollars allocated to the work order. The example in Figure 2 illustrates the allocation process related to labor overhead rates.

The example in Figure 2 can be applied to other expenses, including equipment and materials management charges. Calculating overhead rates can be more complex for larger organizations because multiple ancillary charges may be applicable to employees and other direct costs. Whichever process the utility employs, the calculation should remain consistent and reasonable and should be reviewed on a periodic basis to ensure all costs are applied appropriately.

Construction and Assembly Units

Utilities can create a system that assigns assets to various categories as they are allocated to work orders. For example, construction units are generally categorized as mass units, non-mass units, and specialized units. Assembly units refer to assets created by the utility using a standard construction or cost process.

Figure 2 – Allocation Process Related to Labor Overhead Rates

Pension and Benefit Costs - Annual	$300,000	
Total Payroll - Annual	$500,000	
Payroll Overhead Rate	60.00%	
Standard Labor Rate per Hour - Employee	$30	/ hour
Example - 100 hours are charged to a contruction maintenance work order.		
Standard Labor	$100	
Hours charged to work order	$30	/ hour
Labor rate per hour	3,000	
Total labor dollars		
Labor Overhead	$3,000	
Total labor dollars	60.00%	
Payroll overhead rate	$1,800	
Labor overhead dollars		
Total labor and benefits charged to the work order	$4,800	

MASS UNITS

Capital assets that are homogeneous and interchangeable in operation (typically transmission and distribution plant). Often it is not feasible to report one specific asset but instead track an entire group of the same or similar assets (e.g., poles, towers, fixtures, conductors, conduits, and streetlighting)

NON MASS UNITS

Capital assets that are specifically identifiable and may be the same in functionality, but require separate tracking due to the characteristics of the asset. (e.g., generating facilities, substations, structures, land, office equipment, computers)

SPECIAL UNITS

Capital assets that require special treatment due to regulatory requirements or industry practice, such as meters and transformers. Normally, assets are not capitalized until they are placed into service or substantially complete. Under FERC guidance, the accounting treatment for meters and transformers differs; these items are capitalized before they are placed into service and remain in the utility's financial records until they are junked, sold or discarded.

Categorizing costs in these three areas allows the utility to segregate various cost types into their continuing property records and allow for accurate financial reporting and ratemaking. Management needs to consider both GAAP and FERC capital asset definitions in determining what should be included in continuing property records.

Another cost categorization employed by utilities is an ***assembly unit***. These are used to standardize a process or cost structure. An assembly unit is based on the actual costs incurred to create an asset (e.g., pole and cross-arm assembly) including labor, inventory, equipment costs and overhead. Standard inventory quantities, labor hours, equipment usage hours, and predetermined overhead rates are included in the cost when creating an assembly unit.

Unitization Process

Throughout the life of a work order, costs are accumulated from various sources and processes in the utility's accounting systems. Upon completion of the project, the accumulated costs must be allocated to the appropriate FERC plant accounts from the work order. The unitization process completes this task and closes out the work order from the CWIP account. Depending on the size and complexity of the information in the work order for the project, this process can require coordination between multiple sources in the utility, from engineers to accountants and project managers.

The unitization process begins by classifying similar costs and cost components into various "buckets" or asset types. The asset types are generally grouped with assets from the same FERC plant account while costs that do not have a specific identifiable type are considered overhead and are allocated to all identifiable assets or FERC plant accounts based on the percentage of the total project. For example, work orders for the construction of a substation will contain multiple identifiable assets (e.g., circuit breakers, transformers, insulators, etc.) along with costs necessary to build the asset that are not specifically identifiable to a particular asset within the substation (e.g., labor, overhead, equipment, capitalized interest, etc.). To unitize the work order, the identifiable assets will be accumulated and summarized by total cost while the non-specific costs will be allocated to each identifiable asset based on a percentage of the total costs. See Figure 3.

After a work order has been unitized and closed to the FERC plant account, the information from the closed work order is transferred to the continuing property record for tracking and depreciation purposes.

Continuing Property Records

Continuing property records (CPRs) contain historical cost, quantity, and other information of a utility's plant infrastructure. CPRs serve multiple purposes and are an integral part of the utility's record-keeping system. They

Figure 3 – Unitization Example

Cost Type	Work Order $ Total	% Allocation of Overheads	$ Allocation of Overheads	Total $'s to Utilize
Identifiable Assets				
Circuit Breakers	$400,000	40.00%	258,000	658,000
Transformers	300,000	30.00%	193,500	453,500
Insulators	100,000	10.00%	64,500	164,500
Other Assets	200,000	20.00%	129,000	329,000
Total Identifiable Assets	1,000,000	1000.00%	645,000	$1,645,000
Overhead Costs				
Labor	100,000			
Labor Overheads	75,000			
Engineering	200,000			
Misc. Inventory	150,000			
Equipment Costs	50,000			
Capitalized Interest	70,000			
Total Overhead Costs	645,000			
Total Project Costs	$1,645,000			

are used when calculating monthly and annual depreciation expense, accumulated depreciation, and the ability to obtain detailed retirement information. CPRs provide a complete record by plant account of the quantity and type of property unit included in the plant account.

In addition to cost and unit information, CPRs help identify specific assets by other non-qualitative factors such as asset number, vintage, location, and description. This information can be useful during the budgeting and planning processes because it provides an overview of the relative age of assets and approximately when they will need to be replaced. Property unit detail should generally consist of the following items:

For each unit (or class of units) on non-mass property, include:

- The name and description of the unit
- The location of the unit
- The date the unit was placed into service
- The cost of the unit
- The plant control account to which the cost of the unit was charged

For each category of mass property:

- A general description of the property and quantity
- The quantity placed in service by vintage year
- The average cost
- The plant control account to which the costs are charged

Retirement Accounting Procedures

Plant assets are routinely replaced or taken out of service to maintain and upgrade infrastructure. Retiring assets as they are removed from service allows the utility to maintain accurate and up-to-date historical cost and quantity information.

The retirement process begins by identifying the location and property units being removed or replaced. If the utility maintains detailed CPRs, historical cost and accumulated depreciation information are extracted from the CPRs.

Table 3: Summary of the Financial Statement Line Items that Can Be Affected by a Work Order System	
STATEMENT OF NET POSITION	**STATEMENT OF REVENUES, EXPENSES AND CHANGES IN NET POSITION**
Utility Plant – Including CWIP and Accumulated Depreciation	Operating Expenses – Maintenance Projects Depreciation Expense
Construction Cash – From debt proceeds	Capitalized Interest
Materials and Supplies Inventory	Grants & Capital Contributions
Accounts Payable	Gains/Loss on the sale of assets

Utilities that do not maintain detailed CPRs typically use industry benchmarks and estimates, such as replacement quantities on contractor invoices and engineering reports, when retiring plant assets.

Upon identification of the historical cost and proper unit information, the accounting system is updated to eliminate the historical cost and accumulated depreciation. When an asset has been fully depreciated, the entire historical cost of the asset is deducted from the accumulated depreciation balance. For mass units where accumulated depreciation is tracked at the class level, the entire historical cost is removed from accumulated depreciation as if the unit is fully depreciated. Any salvage value is credited to accumulated depreciation because it approximates the actual book value. Assets not fully depreciated may be valued to reflect a gain or loss depending on any salvage value or costs to remove the asset from service. After the asset has been removed from the accounting system, CPR records are updated to reflect retirement activity.

Presentation

A work order system's main purpose is to record costs associated with construction and maintenance projects and attach those costs to the final product, which is a utility asset. Depending upon the size and complexity of the utility, work order systems can contain open work orders and projects that span multiple accounting periods. Tracking the accumulated activity and closing work orders are essential to the utility's financial reporting process because a majority of a utility's infrastructure cost is recovered through customer rates. The activity in work order systems affects multiple portions of the utility's balance sheet and income statement. Information derived from the work order system and presented on these statements offers valuable insight into utility operations. Listed in Table 3 above is a summary of the financial statement line items that a work order system can affect.

DEPRECIATION

Nature of Depreciation

Depreciation expense is the allocation of a portion of the total cost of depreciable plant to one accounting period based on its useful life. For example, if a group of 50-foot poles has an expected life of 30 years, each year 1/30th of the historical installed cost of those poles is charged to depreciation expense. Accumulated depreciation represents the aggregate of the charges to depreciation expense, net of retirements, cost of removal, and salvage proceeds.

The three major reasons for recognizing depreciation expense as a cost of doing business are as follows:

1 **MEASUREMENT OF THE RESULTS OF OPERATIONS**

This is the most important reason for recognizing depreciation as a cost of doing business and measuring income. Capital investment in the property, plant and equipment necessary for providing utility service is a prepaid expense. The depreciation accrual allocates this expense to each accounting period for inclusion on the statement of net position over the service life of the passet.

2 **INCLUSION IN UTILITY RATES**

Utility rates are designed to provide adequate revenue to cover the cost of doing business and provide a fair return for the risk to the utility in providing service to its customers. Depreciation expense recognizes that current ratepayers must provide funds through their rates to replace current plant when it is taken out of service.

3 CONSERVATION OF INVESTED CAPITAL

Recognition of depreciation helps the utility meet ongoing capital investment needs. When depreciation is recognized as an expense, utility earnings are reduced, thus reducing income available for distribution to the utility's owners.

Methods

The depreciation method describes the pattern of depreciation accruals in relation to accounting periods, or in some instances, in relation to use. It may be thought of as the basic capital recovery formula.

Most often, utilities use the straight-line depreciation method, which spreads depreciation expense in direct proportion to the estimated service life of the plant in service.

Depreciation = (Cost – Salvage Value + Cost of Removal) / Estimated Useful Life

Depreciation may be based on the estimated useful life of a class of assets, a network of assets, a subsystem of a network, or individual assets. The most important and sensitive part of this equation is the estimated useful life. For estimated useful lives, utilities can use general guidelines obtained from professional or industry organizations, information for comparable assets of other public utilities, or internal information obtained through a depreciation study, which uses the utility's experience with plant as the basis for depreciation rates. In determining estimated useful life, a utility also should consider an asset's condition and how long it is expected to meet service demands.

Public power utilities may use any established depreciation method, although the straight-line method is the most common.

Depreciation Accounting

Depreciation is debited to depreciation expense and credited to accumulated depreciation. When an asset is retired, the cost of removal charges and salvage proceeds are closed to accumulated depreciation and the original cost of the plant item is reversed from accumulated depreciation. This allows unrecognized gains and losses on the disposition of utility property to be recovered through future depreciation expense.

CONTRIBUTED ASSETS

A contribution is any nonexchange transaction in which the utility receives goods or services and gives nothing in return. Utilities frequently receive contributions such as land, buildings, equipment, materials and supplies, or services.

Under GASB No. 33, *Accounting and Financial Reporting for Nonexchange Transactions,* the value of the capital contribution should be recorded as revenue on the Statement of Net Position as a separate item after non-operating revenues and expenses. In utility stand-alone financial statements, utilities would show municipal contributions of utility plant as capital contributions. In government-wide statements, these contributions would be shown as transfers.

This treatment differs from FERC accounting practices, where contributions are booked net of the plant balances. Utilities can still follow this treatment if they elect to adopt regulatory accounting as discussed in SFAS No. 71/ASC 980/ GASB No. 62. Regulatory accounting is covered in more detail in Chapter 5. The utility's ability to use this treatment will depend on its specific rate recovery model.

Interest Incurred During Construction

Utilities invest significant resources in the construction of infrastructure. To finance major projects, utilities generally issue long-term debt. Some accounting guidance, including FERC and FASB, allows the utility to calculate the cost of borrowing associated with the construction period and record this as part of the project cost. This is called capitalized interest. However, GASB No. 89 directs the cost of interest incurred during the construction to be expensed as incurred rather than capitalized as part of the project cost.

Given the capital-intensive nature of the industry, utilities may elect to capitalize interest incurred during construction. This associates expenses with related revenues. A public utility can match asset costs with revenues generated by that asset. Regulated rates generally allow revenues to be recorded only after an asset is placed in service. Interest incurred during construction could be deferred (capitalized) and allocated over the asset's useful life.

Assets that would qualify for capitalized interest include:

- Assets constructed for internal use
  - Constructed by utility staff
  - Constructed by contractors, if required progress payments are made during construction
- Land, if it requires additional time and effort to be placed into service

Non-qualifying assets include:

- Equipment purchases (which do not require additional investments to be in service)
- Land that can be placed into service immediately

GASB No. 62, paragraphs 5 through 22, discusses the rules related to capitalized interest, if properly elected under regulatory accounting, as discussed in Chapter 5 of this guidebook.

ASSET IMPAIRMENT

GASB No. 42 defines asset impairment as a "significant, unexpected decline in the service utility of a capital asset" (GASB 42, paragraph 5) that is not expected to occur during the normal course of business.

Determining Whether an Asset Is Impaired

Determining whether an asset is impaired is a two-step process.

1. Identify potential impairments
2. Test for impairment

Examples of unexpected events that could lead to a potential impairment include:

- Physical damage
- Change in law
- Environmental factors
- Technology changes
- Obsolescence
- Construction stoppage
- Change in the manner of use

An asset's decline in service must be both "significant" and "unexpected" to be treated as impaired. "Significant" would refer to the cost-benefit of continued use. For instance, if the cost to maintain and operate the asset or restore it increased to an extent greater than the service utility of the asset. "Unexpected" refers to an event that would not have been foreseen by management. Such an event, if expected, would have prompted an adjustment to the assets' depreciable lives and so is not considered an impairment.

A significant reduction in the demand for services is not necessarily an indicator of impairment. However, it could be indicative of an underlying impairment (e.g., obsolescence). The utility must determine whether the impairment is temporary or permanent. Temporary impairments should not be recorded because once an impairment loss is recorded, it cannot be reversed, even if circumstances have changed.

Measurement of Impairment

Measurement of the impairment will depend on whether the asset will continue to be used by the utility. If the asset will no longer be used by the utility, it should be reclassified from ***plant in service*** to an ***asset held for sale***.

Continued Use of Impaired Asset

Table 4 (page 35) summarizes various methods of measuring impairment if the asset will continue to be used by the utility.

The examples below illustrate the calculation of the impairment of a capital asset.

Restoration Cost Approach

A building is damaged by a storm, and the utility decides to tear it down rather than repair it. The building had an original cost of $500,000 and the current carrying value is $350,000. The estimated cost to restore the damaged portion of the building is $100,000.

$100,000 restoration cost / $500,000 historical cost
$350,000 carrying value = $70,000 impairment

Service Units Approach

A fuel storage tank that was expected to be used for 20 years does not meet new regulatory standards. Therefore, the tank, which has been used for seven years, will remain in service for another five years (for a total life of 12 years). The tank has a current carrying value of $50,000.

8 years of usage lost / 20 years initial estimated usage
$50,000 carrying value = $20,000 impairment

Deflated Depreciated Replacement Cost

A building constructed five years ago to house a peaking generator will now be used for storage. The current carrying value of the building is $300,000, but constructing a storage building of equal size would cost $200,000 and the estimated depreciation on such a storage facility for the five years would be $25,000, resulting in an estimated carrying cost of an equivalent storage facility of $175,000.

$300,000 current carrying value - $175,000 estimated carrying value for storage facility (current use) = $125,000 impairment

Table 4: Approaches to Calculating the Impairment of a Capital Asset[6]

METHOD	HOW IMPAIRMENT IS CALCULATED	USE
Restoration Cost Approach	Cost to restore / cost of asset X carrying value = IMPAIRMENT	Impairments resulting from physical damage
Service Units Approach	**Option 1: Focus on units of service lost *in total*:** Units lost / prior total units X carrying value = IMPAIRMENT	Changes in laws, regulations, or other environmental factors that negatively affect service utility
	Option 2: Focus on units of service lost *each* year: Annual units lost / prior annual units X carrying value = IMPAIRMENT	Technological developments that negatively affect service utility, or evidence of obsolescense
	Option 3: Focus on units of service *remaining*: Carrying value - [unit price X remaining units] = IMPAIRMENT	A change in the manner or duration of use of the asset that negatively affects service utility

Accounting Treatment of Impairment Loss

The loss on impairment should be reported as a program or operating expense, special item, or extraordinary item, depending on the circumstance leading to the impairment. To meet the extraordinary item category, the impairment must be both unusual and infrequent. A special item must be either unusual or infrequent but under the control of management.

If the impairment loss is covered by insurance, the loss on impairment should be recorded net of any insurance proceeds received.

There are two ways the utility could record the change in the carrying value of an impaired asset:

1. The entire impaired amount is recorded as an increase to the associated accumulated depreciation account. This treatment signifies that the impairment decreased the useful life of the asset.
2. The impaired amount proportionately decreases both the value of the asset and the associated accumulated depreciation. This signifies that the impairment is equivalent to a retirement of a portion of the asset[7].

INTANGIBLE ASSETS

An intangible asset possesses all these characteristics:

- Lack of physical substance
- Nonfinancial nature
- Initial useful life extending beyond a single reporting period (GASB No. 51, paragraph 3)

Common examples of intangible assets held by utilities include easements or rights of way for transmission lines, water rights, and computer software. Intangible assets follow all the financial and accounting guidance applicable to tangible capital assets. Instead of being depreciated, intangible assets are amortized over their useful life. An intangible asset could have an indefinite useful life, and not be amortized, if there are no legal, regulatory or other factors that would limit its useful life. If changes occur that may lead to a potential impairment, the intangible asset would have to go through the impairment test.

GASB No. 51, *Accounting and Financial Reporting for Intangible Assets,* has additional guidance related to internally generated intangible assets, such as computer software. All the following

[6] Stephen J. Gauthier, GAAFR: Governmental Accounting, Auditing, and Financial Reporting, page 484.
[7] GASB Comprehensive Implementation Guide, Z.42.12.

criteria must be met in order to begin capitalizing internally generated assets:

- The ***specific objective*** of the project has been determined;
- The ***nature of the service capacity*** to be provided has been determined;
- The ***feasibility*** of successfully completing the project has been demonstrated; and
- The government has demonstrated that it: 1) intends, 2) is able to, and 3) is making an *effort* to develop and complete the project.[8]

In addition, GASB No. 51 provides specific guidance related to the capitalization of internally generated computer software. It categorizes the different project phases related to developing computer software into the preliminary project phase, the application development stage; and the post-implementation/operation stage. The table below summarizes the capitalization requirements for the three stages.

Table 5: Internally Generated Computer Software: Capitalizable Costs[9]

STAGE	RELATED ACTIVITIES	CAPITALIZE?
Preliminary project stage	Conceptual formulation and evaluation of alternatives; Determination of the existence of needed technology; and Final selection of alternatives for development	No
Application development stage	Design of the chosen path, including software configuration and software interfaces; Coding; Installation to hardware; Minimum data conversion necessary to make the software operational; and Testing, including the parallel processing phase	Yes (but only if incurred after completion of the preliminary project stage)
Post-implementation/ Operation stage	Application training; Data conversion beyond what is strictly necessary to make the software operational; and Software maintenance	No

[8] Stephen J. Gauthier, GAAFR: Governmental Accounting, Auditing, and Financial Reporting, page 445.
[9] Stephen J. Gauthier, GAAFR: Governmental Accounting, Auditing, and Financial Reporting, page 446.

CHAPTER FIVE
REGULATORY ACCOUNTING

INTRODUCTION

Governmental Accounting Standards Board rules are often inadequate to meet utilities' need to recover costs through electric rates. In addition, utility governing bodies may order rate recovery of certain items for which the accounting treatment is not consistent with rate recovery needs. Other accounting practices may be dictated by regulatory requirements not related to ratemaking, or by regulation related to aspects of ratemaking other than the timing of income and expenses. Because public power utilities are required to follow all standards of the Governmental Accounting Standards Board, accounting practices that depart from the utility's normal operational cycle but are not related solely to timing differences or ratemaking considerations must be analyzed to determine whether they conform to GAAP.

GASB No. 62 *Codification of Accounting and Financial Reporting Guidance Contained in Pre-November 30, 1989 FASB and AICPA Pronouncements - Regulated Operations* provides guidance for utilities to match revenues or expenses to rate recovery. Any utility subject to federal, state, or local oversight of rates can follow GASB 62. The statement recognizes that in some cases revenues intended to cover specific costs are provided either before or after costs are incurred, and it provides a mechanism for deferring either expenses or revenues as assets or liabilities to allow for recognition in the same period. Under GASB 62, if a regulatory body provides assurance, incurred costs will be recovered in the future; the entity can record the costs as an asset. If there are revenues incurred in the current period relating to future costs, the entity can recognize the receipt of the revenues as a liability or a deferred inflow of resources. These requirements are specifically driven by the regulated rate recovery structure for such costs.

Can Your Utility Apply Regulatory Accounting Using GASB 62?

Regulatory accounting applies to business activities that are regulated. The standards define regulated operations as those that meet all three of the following criteria:

1. Rates are established by or are subject to approval by ***an independent, third party regulator, or by the governing board*** empowered by statute or contract to establish rates that bind customers.
2. The regulated rates are designed to recover the costs of providing the regulated services or products. The costs or revenues should be included in the utility's current revenue requirement that is used to develop rates.

3. Based on information about the demand for service as well as competition, it is reasonable to believe that the cost-based rates can be charged and collected from customers. In determining this, historical, current and anticipated future demand and competition should be considered.

If it is probable that future revenues will be recognized through charging rates to recover deferred costs or revenues and there is a clear link between the future rate recovery and the previously incurred costs or recognized revenues (rather than similar future items), the utility may use GASB 62 for these items.

IMPORTANCE OF GOVERNING BODY APPROVAL FOR GASB 62 ITEMS

Because the GASB 62 criteria for use by a utility requires that the governing board regulate rates and that these rates are designed to recover the identified costs or revenues, it is a best practice to require the governing body to approve any application of GASB No. 62. This approval would include the following:

- Specific item that will receive GASB 62 treatment
- Purpose of the GASB 62 treatment
- Recovery period through utility rates of the GASB 62 item

The notes to the financial statements should include a statement on the utility's general policy in applying GASB 62. If several GASB 62 items are listed, industry best practices call for a separate disclosure note detailing GASB 62 items.

The governing board may opt to issue a blanket resolution to approve common transactions that receive GASB 62 treatment. This will make the process for recording these common items more efficient and timely. The utility should review GASB 62 items annually to ensure cost recovery in the expected manner and timeframe.

Common Uses

GASB No. 62 does not list items that can be accounted for under the standard. Common industry applications include regulatory assets, regulatory liabilities, and deferred inflows of resources.

Common Application of GASB 62 Asset and Liabilities

REGULATORY ASSETS

Extraordinary, non-routine maintenance

Loss on early retirement of assets

Future recoverable costs

Future pension liabilities

Future other post-employment benefit liabilities

Deferred power costs

Unrealized derivative and investment mark-to-market losses

Decommissioning costs

Unreimbursed storm damage

Debt issuance costs

Capitalized interest (with the implementation of GASB Statement No. 89 – Accounting for Interest Cost Incurred before the End of Construction Period (effective for reporting periods beginning after December 15, 2019)

REGULATORY LIABILITIES

Unrealized derivative gains

Refunds

Grant revenues

DEFERRED INFLOWS OF RESOURCES

Rate stabilization

Revenues from contributed assets

Depreciation attributable to contributed assets

The following provides illustrative examples of regulatory accounting:

Example One – Deferral of Major Maintenance Expenses: The utility completes a $1 million major maintenance project in year one. The regulatory body has approved a rate structure that includes recovery of this project as a normalized expense over a five-year period. The board has approved the GASB No. 62 treatment of the project and a rate study, including the normalized cost of $200,000, has been completed and approved.

Analysis: The utility will collect the major maintenance costs from its ratepayers at $200,000 per year over five years. The utility should include an additional $200,000 a year in its revenue requirement as a separate line item to show the recovery of this cost.

To utilize GASB 62 to recover the major maintenance expense, the following journal entries would be made:

1. To create the regulatory asset:

Regulatory Asset – Major Maintenance Expense	$1,000,000
Cash	$1,000,000

If the costs will be recovered over a five-year period, the entity would use straight-line amortization and record the following journal entry each year until the regulatory asset is fully amortized:

2. Amortization:

Maintenance Expense	$200,000
Regulatory Asset – Major Maintenance Expense	$200,000

The "Regulatory Asset – Major Maintenance Expense" and the Maintenance Expense for amortization of the GASB 62 item should be shown separate from the maintenance expenses on the face of the statement of revenues, expenses, and changes in net position or be disclosed in the footnotes to the financial statements.

Example Two – Debt Issuance Expenses

The utility constructs a new generation facility at a cost of $50 million. The bond discount on the bond issue is $1.5 million, and bond issuance expenses are $1 million. The utility financed these costs as part of the bond issue. The bonds will be repaid over 20 years. The utility uses the cash basis for setting rates and collects bond principal in rates.

Analysis: The bond principal of $50 million includes $1.5 million of bond discount and $1 million of issuance costs. The utility includes the annual bond principal and interest in its rates and recovers the discount and issuance costs over the 20-year repayment period of the bonds. Accounting standards under GASB Statement No. 34 *Basic Financial Statements—and Management's Discussion and Analysis—for State and Local Governments* require the recording of the bond discount on the Statement of Net Position and amortization of that discount over the bond repayment period. GASB Statement No. 65 - Items Previously Reported as Assets and Liabilities requires that the full amount of bond issuance costs be expensed in the year the bonds are issued.

Since the utility recovers the costs of bond issuance over the repayment period of the bonds (through the recovery of each year's bond principal payment in utility rates), the issuance costs should be recorded on the Statement of Net Position and amortized over the bond repayment period, or there is a mismatch between revenues collected and the annual piece of bond issuance expenses in each year's payment. The utility should also include an additional $200,000 a year in its revenue requirement as a separate line item to show the recovery of the issuance costs.

To utilize GASB 62 to recover the bond issuance costs the following journal entries are required:

1. To record the bond issue:

Regulatory Asset – Bond Issuance Costs	$ 1,000,000
Unamortized Debt Discount	$ 1,500,000
Cash	$47,500,000
Revenue Bonds	$50,000,000

2. To record annual amortization of debt discount and bond issuance:

Amortization expense	$125,000
Bond Discount	$ 75,000
Regulatory Asset – Bond Issuance Costs	$ 50,000

Common industry practice is to amortize these costs using the effective interest or straight-line methods.

Example Three – Rate Stabilization

The utility experiences significant swings in its purchased power costs due to market rates, maintenance on base load plants requiring increased purchases or fuel cost changes. As a result, the utility's oversight body has established a rate stabilization reserve to mitigate large swings from the monthly or annual operations as well as to minimize the impacts on customers.

Assume the following scenario:

THE UTILITY HAS DETERMINED THAT IT CAN ALLOCATE $2 MILLION OF REVENUES TOWARD RATE STABILIZATION IN THE CURRENT YEAR.

IN THE FOLLOWING YEAR, THE UTILITY INCURS AN ADDITIONAL $750,000 OF POWER COSTS THAT IT DETERMINES IT WILL NOT INCLUDE IN RATES.

THE UTILITY'S OVERSIGHT BODY AUTHORIZES THE USE OF $750,000 OF THE PREVIOUS RATE STABILIZATION REVENUES CAN BE USED TO OFFSET THOSE POWER COSTS.

Analysis: Utility rates are designed and approved by its oversight body (board, city council) so that during periods of lower power costs, additional costs are built into the rates and reserves are accumulated for future use. During periods of higher-than-normal power costs, these reserves can be used. Such usage would require action or approval from the oversight body.

Rate stabilization reserves help maintain bond coverage, which otherwise would be threatened when power costs spike and revenues do not increase. The following entries would be made:

1. Establish the rate stabilization reserves:

Revenues	$2,000,000	
Regulatory Deferred Inflow – Rate Stabilization		$2,000,000

2. To use rate stabilization reserves to offset increased power costs:

Regulatory Deferred Inflow – Rate Stabilization	$750,000	
Revenues		$750,000

This treatment should be approved by the utility's governing body to meet the requirements of regulatory accounting under GASB 62.

How Should Rate Stabilization be Funded?

GASB 62 allows establishing and using the regulatory deferred inflow for rate stabilization, but it does not require that the amount recorded as rate stabilization be funded with cash. As the use of rate stabilization in future years requires the use of cash in many cases, best practices are to fund the amount of rate stabilization with a corresponding amount of cash in a designated cash account.

Reporting Implications

Calculation of debt coverage ratios is affected by GASB No. 62. The utility should consult bond counsel or other financial advisers to ensure that future bond resolutions specify that normalized costs accounted for under this statement are treated as such for debt coverage purposes. Existing bond resolutions may not specify how to handle normalized costs or regulated accounting. Best practice is to have bond counsel write a memo to clarify that these items, either deferrals or recognition of previously deferred items, are to be included in the debt coverage calculation as they are reported in the audited statements.

Implementation Checklist

The following checklist can be used in implementing regulatory accounting under GASB 62.

- Ensure the proposed deferral meets these three criteria:
  - The utility's rates are regulated by an independent body with authority to set customer rates
  - Rates are designed to recover the proposed costs over a time period other than that required for recognition by traditional non-regulated accounting
  - It is reasonable to assume that rates with consistent recovery methodology will remain in effect over the recovery period
- Document the proposed cost, logic for deferral, proposed recovery period and support for probable rate recovery over such period
- Obtain formal governing body approval of the deferral and recovery plan for this item (suggested in minutes or resolution).
- Document proposed accounting treatment, including journal entries for deferrals and future recognition
- Prepare proposed financial statement presentation and disclosures and review with auditor.
- Discuss with bond counsel or other financial advisers any special language to be incorporated into bond resolutions to ensure that normalized cost treatment is recognized in debt coverage calculations.
- Periodically (annually) review deferred costs to ensure future recovery and recovery period remain reasonable and probable.

CHAPTER SIX
PENSIONS & OTHER POST-EMPLOYMENT BENEFITS

INTRODUCTION

Pensions are a form of retirement compensation that utilities often use to help attract and retain employees. There are two types of pension plans – defined benefit plans and defined contribution plans. Defined benefit plans provide a guaranteed benefit the employee will receive upon retirement, no matter how the underlying investments supporting the pension payments perform. With defined contribution plans, the employer makes predetermined contributions for the employee and the amount of benefits will depend on the performance of the underlying investment portfolio.

Other post-employment benefits (OPEB) include post-employment health care (i.e., medical, prescription drug, dental, vision, hearing, and other long-term care) and other benefits (i.e., life insurance). In either case, individuals are earning these benefits during the years that they are active employees, but they will not be paid out until some future time when the employee is no longer working. Accrual accounting concepts require that these benefits be recognized as an expense in the period earned and a liability until paid. Given the amount of time that can pass between earning and receiving benefits, there are some inherent complexities that go along with the measurement and accounting for pensions and other post-employment benefits. This chapter will discuss the key concepts and accounting for employers offering benefits required by GASB No. 68 (pensions) and 75 (OPEBs). The requirements here are those for accounting and financial reporting in financial statements prepared in accordance with generally accepted accounting principles established by GASB. The GASB has no authority related to funding policies for pension plans or other post-employment benefits. Thus, it is common for plans to have a separate methodology to determine the annual funding requirements.

PENSIONS

Types of Pension Plans

A defined benefit pension plan specifies the amount of benefits to be provided to employees upon retirement. The defined contribution plan determines only the amount to be contributed by the utility to a plan member's account each year of active employment.

Plans can also be classified by how many employers participate in the plan. The single-employer plan involves only the utility. A multiple-employer plan includes more than one government. In a cost-sharing, multiple-employer plan, governments pool or share the costs of financing the benefits and administering the plan and assets accumulated to pay benefits. Generally, only one actuarial valuation is conducted for all participating governments. In an agent, multiple-employer plan, there is no pooling of the benefit costs, and each employer has its own account. Separate actuarial valuations are conducted for each participating governmental employer.

Trusted vs. Untrusted Plans

From an accounting and reporting perspective, it is important to distinguish between trusted and untrusted plans. A trusted plan is administered through a trust that meets the following criteria established by GASB:

- Contributions by employers or other contributing entities as well as the earnings on those contributions are irrevocable.
- Plan assets are dedicated to providing benefits in accordance with the benefit terms to the plan members.
- Plan assets are legally protected from the creditors of the employer, other contributing entities, the administrator and plan members.

If the assets accumulated for paying the benefits are not maintained in a trust that meets the above criteria, or if no assets have been accumulated for the payment of future benefits, the plan is considered an untrusted plan.

Defined Benefit Pension Plans – Sole and Agent Employers

Actuarial Calculation of Pension Obligation

A defined benefit pension plan provides retirees a specified benefit that is earned during the years of active employment. To recognize a liability for this benefit, the utility must have an actuarial calculation of the estimated future benefits, which then are allocated between the service periods already completed and the expected remaining years of service.

A – START DATE
B – MEASUREMENT DATE
C – RETIREMENT DATE
D – DEATH

Benefits earned - liability
Benefits to be earned
Total future benefit estimated

This process requires assumptions such as when people will retire, how long they will collect benefits after retirement, what will their salary be at retirement, etc. While management does not need to calculate the actuarially determined total pension liability, it is important that management agree with the reasonableness of these key assumptions.

GASB requires that the actuarial valuation be completed at least every two years, use the entry age actuarial cost method, have an actuarial valuation date no more than 30 months and one day prior to year-end, have a measurement date no earlier than the prior fiscal year-end, and use a blended discount rate that represents the long-term rate of return for the future periods, where the projected assets of the plan are expected to be available to pay benefits. For periods thereafter, the calculation uses the index rate for 20-year, tax-exempt general obligation bonds with a rating of AA/Aa or higher.

Net Pension Liability (Asset), Deferred Outflows/ Inflows of Resources and Pension Expense

The actuarial study will calculate the total pension liability. The utility is required to recognize and report the net pension liability (asset), which is the difference between the total pension liability and the fiduciary net position of the plan. The fiduciary net position of the plan is obtained from the plan's financial statements and should incorporate the same measurement date as the total pension liability. GASB recognized that several factors can impact the net pension liability from year to year, including changes in benefits or assumptions and the performance of the market impacting the valuation of the plan investments. To avoid significant swings in the pension expense recognized in the financial statements of the employer or the utility, GASB determined that these changes should be recorded as deferred outflows of resources or deferred inflows of resources and recognized as a component of pension expense systematically over time.

Table 6: Deferred Outflows of Resources Reporting

DEFERRED OUTFLOW OF RESOURCES	RECOGNITION PERIOD	REPORT GROSS OR NET
Differences between expected and actual experience	Average remaining service life of participants	Gross
Changes in assumptions	Average remaining service life of participants	Gross
Differences between expected and actual investment returns	5 years	Net
Contributions subsequent to measurement date	Subsequent period	N/A

Changes in the net pension liability, excluding those that are deferred, along with the amortization of the cumulative deferred outflows and inflows of resources, are recognized as pension expense in the current period financial statements. This is different from the cash payments to the pension plan, which may be based on statutory requirements or some other actuarially determined funding mechanism.

Cost-Sharing Employer Plans

In a cost-sharing multi-employer plan, several different governments participate in the same retirement plan. One common example is a statewide retirement system for governmental employers. In this type of plan, the benefits offered are the same for participants regardless of their employer, and the assets accumulated within the plan are available to pay the benefits of any participant. A single actuarial valuation is completed to calculate the total pension liability for the plan. Governments that participate in this type of plan must report their proportionate share of the plan's net pension liability and related deferred outflows or inflows of resources. The concepts are not different. However, rather than being calculated for each employer, the total amounts are allocated to the participating governments, most often based on the annual contributions made by each. This results in one additional change to be reported as a deferred outflow/inflow of resources: the change in proportionate share from year to year. This is amortized over the average remaining service life and can be reported net.

Note Disclosures – All Types

To assist users in understanding the nature of a utility's pension plans and the efforts to finance them, the standards require the preparation of note disclosures to accompany the expense and balance information reported in the financial statements. These disclosures are listed below.

PENSION PLAN DESCRIPTION

- Name, administrator, type (single-employer, agent multiple-employer, or cost-sharing multiple-employer) of defined benefit plan
- What benefits are offered
- Who has authority to establish or amend the benefits
- Number of participants, including inactive employees receiving benefits, inactive employees not yet receiving benefits, and active employees – Single and agent employer plans only
- Who has authority to establish or amend contributions, the basis for determining contributions, contributions made during the period (as dollars or a percentage of payroll) and the contributions recognized by the plan
- Information on how to obtain a copy of the plan's financial statement (if one is issued)

ACTUARIAL ASSUMPTIONS

- Measurement date and actuarial valuation date
- Inflation rate, salary changes, ad hoc benefit changes including COLAs
- Mortality assumptions, including sources or experience studies
- Discount rate, including the long-term rate of return, if a blended rate is used and, if so, the municipal bond rate used, assumptions used in the cash flow projection
- The assumed asset allocation for the plan and the long-term expected real rate of return for each major class of assets
- Net pension liability (asset) assuming a discount rate of +/- 1 percent

CHANGES IN NET PENSION LIABILITY (ASSET) – SINGLE AND AGENT EMPLOYER PLANS

- Beginning balances for the total pension liability, plan net position, and net pension liability (asset)
- Separately disclose the effects of service cost, interest on the total liability, changes in benefit terms, differences between expected and actual experience, changes in assumptions, contributions (by source), investment income, benefit payments, administrative expenses, and other changes
- Ending balances for the total pension liability, plan net position and net pension liability (asset)

ADDITIONAL INFORMATION

- The utility's proportionate share and proportion (percentage) of the plan net pension liability (asset) – cost-sharing employer plans only
- Balances for deferred outflows of resources and deferred inflows of resources by type

Required Supplementary Information (RSI)

Utilities that participate as sole and agent employers should disclose the following information for the most recent ten years (or since implementation if less than ten years):

As of the measurement date of the net pension liability (asset):

- Beginning balances, changes and ending balances of the total pension liability, plan fiduciary net position and net pension liability (asset), as required in the footnote
- The total pension liability, plan fiduciary net position, net pension liability (asset), fiduciary net position as a percentage of the total pension liability, covered employee payroll and net pension liability (asset) as a percentage of covered employee payroll

As of the utility's fiscal year end:

- The actuarially determined contribution, or the statutorily or contractually required contributions
- The actual contributions recognized by the plan, the excess (deficiency) between the two, the covered-employee payroll, and the actual contributions as a percentage of covered employee payroll

Notes to the RSI

- Information that had a significant impact on a valuation resulting in a notable change such as changes in benefits, contributions, assumptions, etc.

If the utility participates in the cost-sharing plan, the following information for the most recent ten years (or since implementation if less than ten years) should be disclosed:

As of the measurement date of the net pension liability (asset):

- The proportion (percentage) of the collective net pension liability (asset), the proportionate dollar share of the collective net pension liability (asset), covered employee payroll, the net pension liability (asset) as a percentage of covered employee payroll, and the plan's fiduciary net position as a percentage of the total pension liability (funded ratio)

As of the utility's fiscal year end:

- The statutorily or contractually required contributions
- The actual contributions recognized by the plan, the excess (deficiency) between the two, the covered-employee payroll, and the actual contributions as a percentage of covered employee payroll

Notes to the RSI

- Information that had a significant impact on a valuation resulting in a notable change, such as changes in benefits, contributions, assumptions, etc.

Defined Contribution Plans

Defined contribution plans should recognize annual pension expense equal to their required contributions, which is determined by the plan. A pension liability or asset will arise from the difference between contributions required by the plan and contributions made by the utility. In the notes to the financial statements, the utility should include:

- Plan name, administrator and type (defined contribution plan)
- The type of benefits provided and who has the authority to establish or amend the plan
- Contribution requirements for both employees and the employer
- Pension expense recognized in the current period
- Any liability outstanding at the end of the period related to contributions owed but not paid

OTHER POST-EMPLOYMENT BENEFITS (OPEB)

Types of Plans

Similar to pensions, there are two forms of OPEB plans public power utilities could be involved in – defined benefit plans and defined contribution plans. The classifications of single-employer, cost-sharing multiple-employer and agent multiple-employer are also used in OPEBs.

While pensions are an explicit benefit with a direct payment to retirees, OPEBs can be either explicit or implicit. For example, the utility's agreement to pay all or a portion of retiree health insurance premiums is an explicit benefit. However, some governments allow retirees to remain on the health insurance plan but require the retiree to pay the full premium. If the retiree is paying the same premium charged for an active employee, it is referred to as a blended premium, as opposed to age-adjusted premiums, which are typically higher for retirees than for active employees. GASB has defined this as an implicit rate subsidy, saying that the blended premium the employer pays for the active employees is higher than the age-adjusted premium would be to subsidize or decrease the retiree premium. In this case, the benefit is implicit, and the utility must consult an actuary to calculate the subsidy. Oftentimes, this will require recognition of an OPEB liability.

Financing the Plan

Post-employment benefits are financed two different ways. A funded plan exists when an irrevocable trust is established, and the employer makes contributions based on an actuarial calculation of future benefits earned. This is also referred to as a trusted plan.

Most utilities use the pay-as-you-go approach, paying an amount each year equal to the benefits distributed or claimed in that year. The standards for OPEB accounting and reporting do not mandate funding of OPEB benefits, meaning that setting aside assets in advance to pay future benefits is not required. Rather, the focus is on transparency in reporting the benefits committed to the utility's approved financing mechanism.

When gathering information on OPEBs, it is important to consider all the potential "contributions" that an employer might make. For example, these can include payments to a trust, payments of insurance premiums for retirees, payments of actual claims for retirees participating in a self-insured plan or the implicit subsidy paid toward active employee premiums at a blended rate.

Actuarial Valuations for OPEB plans

In general, the utility should account for and report the annual cost of OPEBs and the outstanding obligations and commitments related to OPEBs in the same manner as pension accounting. These amounts come from actuarial valuations performed in accordance with parameters established by GASB. The valuations should occur at least every two years and follow much of the same actuarial methods and assumptions as pensions. Key differences for OPEB plans include evaluating the inflation rates, such as health care inflation rates, mortality assumptions, experience studies, and participation rates. With pensions, we can assume that 100 percent of eligible employees will participate, but the same is not true with OPEBs like health insurance. Some employees have access to other options for health insurance through a spouse or markets. Therefore, understanding the participation rate is very important.

There is also an option to use the alternative measurement method for plans with fewer than 100 members. This allows the use of a simplified calculation and assumptions to lessen the financial burden of hiring an actuary. If this method is chosen as an alternative to an actuarial valuation, it must be disclosed.

While GASB provides guidance on the accounting and reporting of OPEBs, it does not establish rules related to the funding or rate recovery of these costs.

Accounting for OPEB plans

The accounting for OPEBs under GASB 75 mirrors the accounting for pensions under GASB 68. Utilities that provide benefits under a single employer or agent multi-employer defined-benefit plan will report either the net OPEB liability if the plan is trusted, or the total OPEB liability for untrusted or pay-as-you-go plans. Employers that provide benefits through a cost-sharing multi-employer defined-benefit plan will report their proportionate share of the net or total OPEB liability. In all cases, deferred outflows and inflows of resources will be reported to accommodate the changes in liability that are not recognized as OPEB expense in the current year.

Utilities that participate in a defined contribution OPEB plan are required to recognize OPEB expense for their required contributions to the plan and a liability for unpaid required contribution on the accrual basis.

Note Disclosures

To help understand the nature of a utility's OPEB and the efforts to finance it, the standards require the preparation of note disclosures to accompany the expense, expenditure, and liability information reported in the financial statements. These disclosures are listed below.

OPEB PLAN DESCRIPTION

- Name, administrator, type (single-employer, agent multiple-employer, or cost-sharing multiple-employer) of defined benefit plan
- What benefits are offered
- Who has authority to establish or amend the benefits
- Number of participants, including inactive employees receiving benefits, inactive employees not yet receiving benefits and active employees – single and agent employer plans only
- Who has authority to establish or amend contributions, the basis for determining contributions, required contribution rates, contributions made during the period (as dollars or a percentage of payroll) and the contributions recognized by the plan
- Information on how to obtain a copy of the plan's financial statement (if one is issued)

ACTUARIAL ASSUMPTIONS

- Measurement date and actuarial valuation date
- Inflation rate, salary changes, healthcare cost trend rate, benefit changes
- Mortality assumptions, including sources or experience studies
- Discount rate, including the long-term rate of return, if a blended rate is used and, if so, the municipal bond rate used, assumptions used in the cash flow projection
- The assumed asset allocation for the plan and the long-term expected real rate of return for each major class of assets
- Net OPEB liability (asset) assuming a discount rate of +/- 1%
- Net OPEB liability (asset) assuming a healthcare cost trend rate of +/- 1%

CHANGES IN NET OPEB LIABILITY (ASSET) – SINGLE AND AGENT EMPLOYER PLANS

- Beginning balances for the total OPEB liability, plan net position, and net OPEB liability (asset)
- Separately disclose the effects of service cost, interest on the total liability, changes in benefit terms, differences between expected and actual experience, changes in assumptions, contributions (by source), investment income, benefit payments, administrative expenses, and other changes
- Ending balances for the total OPEB liability, plan net position and net OPEB liability (asset)

ADDITIONAL INFORMATION

- The utility's proportionate share and proportion (percentage) of the plan net OPEB liability (asset) – cost-sharing employer plans only
- Balances for deferred outflows of resources and deferred inflows of resources by type
- A schedule of the amounts to be recognized in OPEB expense from the deferred outflows/inflows of resources for each of the next five years, and in the aggregate thereafter
- Reference to required supplemental information
- Discussion of key assumptions that changed from the last valuation

Required Supplementary Information (RSI)

Utilities that participate as sole and agent employers should disclose the following information for the most recent ten years (or since implementation, if less than ten years):

As of the measurement date of the net OPEB liability (asset):

- Beginning balances, changes and ending balances of the total OPEB liability, plan fiduciary net position and net OPEB liability (asset) as required in the footnote
- The total OPEB liability, plan fiduciary net position, net OPEB liability (asset), fiduciary net position as a percentage of the total OPEB liability, covered employee payroll and net OPEB liability (asset) as a percentage of covered employee payroll

As of the utility's fiscal year end:

- The actuarially determined contribution, or the statutorily or contractually required contributions
- The actual contributions recognized by the plan, the excess (deficiency) between the two, the covered-employee payroll, and the actual contributions as a percentage of covered employee payroll

Notes to the RSI

- Information that had a significant impact on a valuation resulting in a notable change, such as changes in benefits, contributions, assumptions, etc.

If the utility participates in the cost-sharing plan, the following information for the most recent ten years (or since implementation if less than ten years) should be disclosed:

As of the measurement date of the net OPEB liability (asset):

- The proportion (percentage) of the collective net OPEB liability (asset), the proportionate dollar share of the collective net OPEB liability (asset), covered employee payroll, the net OPEB liability (asset) as a percentage of covered employee payroll, and the plan's fiduciary net position as a percentage of the total OPEB liability (funded ratio)

As of the utility's fiscal year end:

- The statutorily or contractually required contributions
- The actual contributions recognized by the plan, the excess (deficiency) between the two, the covered-employee payroll, and the actual contributions as a percentage of covered employee payroll

Notes to the RSI

- Information that had a significant impact on a valuation, resulting in a notable change such as changes in benefits, contributions, assumptions, etc.

Defined Contribution Plans

Defined contribution plans should recognize annual pension expense equal to their required contributions, which is determined by the plan. A pension liability or asset will arise from the difference between contributions required by the plan and contributions made by the utility.

In the notes to the financial statements, the utility should include:

- Plan name, administrator, and type (defined contribution plan)
- The type of benefits provided and who has authority to establish or amend the plan
- Contribution requirements for both employees and the employer
- Pension expense recognized in the current period
- Any liability outstanding at the end of the period related to contributions owed but not paid

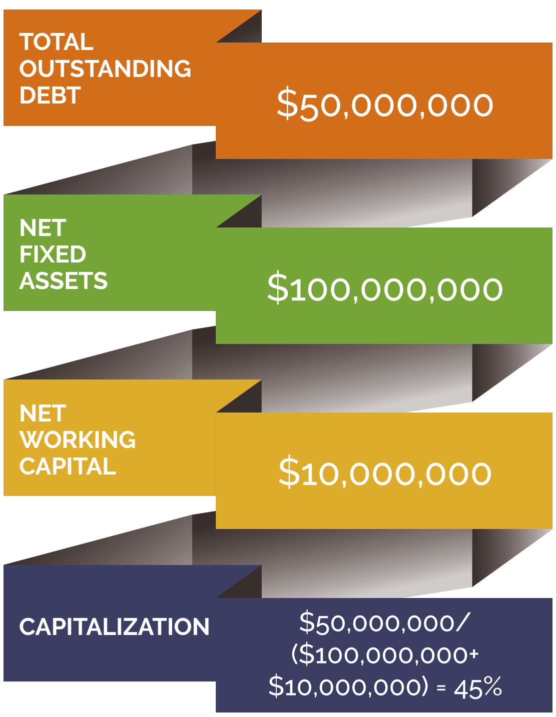
CHAPTER SEVEN
CAPITAL STRUCTURE & LONG-TERM FINANCING

INTRODUCTION – WHAT IS CAPITALIZATION?

In finance, capitalization is the sum of a corporation's stock, long-term debt, and retained earnings. Since public power utilities do not issue capital stock, the ratio is calculated differently. In general, the utility's capital structure should be managed at the level of analysis and grading used by the rating companies in developing a bond rating for the utility. So, we look to the methodology used by the rating companies for guidance. The standard formula used for calculating capitalization is:

Total Debt / (Net Fixed Assets + Net Working Capital)[10]

As an example, we calculate the capitalization of a utility with the following financial characteristics:



[10] Moody's Investor Service – Public Power Ratings Methodology (2016)

What does this level of capitalization mean? We discuss capitalization levels in this section.

How Does Capitalization Impact Utility Finances?

The direct impact of capitalization on a utility is in two main areas:

1. Impact on cash flows
2. Impact on bond rating, which impacts future borrowings and debt interest rates

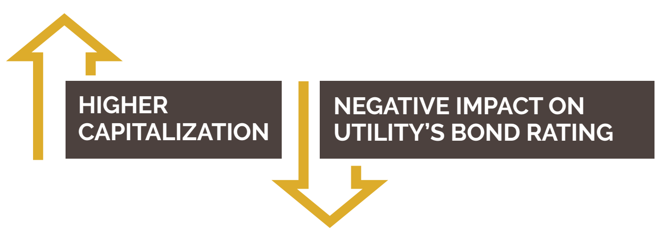
Impact on Cash Flow

As the utility adds more debt, its capitalization and bond principal and interest payments will increase, necessitating an increase in cash flows. To meet the funding requirements, the utility must either increase rates or decrease planned expenditures for operation and maintenance and capital improvements. The opposite is true for decreasing capitalization.

Impact on Bond Rating

As the utility's capitalization increases, from a bondholder's perspective, the financial risk has increased as the utility must maintain higher rate levels or a lower operation and maintenance/capital expenditure cost structure to meet scheduled bond principal and interest payments.

From a ratings company perspective, a higher capitalization also means a higher degree of risk for these same reasons. The ratings company includes the utility's capitalization in its determination of bond rating for the utility. The higher the utility's capitalization, the more negative impact this will have on the utility's bond rating.



The bond rating companies[11] evaluate several factors in developing a bond rating for an organization. Their process includes weighting various financial and non-financial factors in modeling scenarios of future cash flows available for debt service and assigning a risk factor to these outcomes.

For example, Moody's publishes methodology guidebooks on its website for potential bond issuers to review to evaluate their financial condition and how that condition will be viewed in the ratings process.[12] Moody's states in its guidebook that financial strength is one of its key measures and in that area capitalization accounts for 10 percent of the weight in determining a utility's bond rating. Moody's guidebook states the following levels of capitalization translate into the related level of bond rating:

Table 7: Capitalization Impact On Bond Rating

CAPITALIZATION	WEIGHT ON BOND RATING[13]
>25%	Aaa
>25% - 50%	Aa
>50% - 75%	A
>75% - 100%	Baa
>100%	Ba

As capitalization increases, it results in a downward pressure on the related evaluation of bond rating. This will raise the utility's interest rates for future borrowings because the rating company will view this portion of the utility's financial structure as holding greater risk for repayment to bondholders.

Reducing Capitalization

Three methods of correcting overcapitalization are available to utilities:

1. Exercising call provisions of revenue bonds, i.e., paying bonds before they come due, will reduce long-term debt and capitalization
2. Buying back a utility's bonds on the open bond market to reduce long-term debt and capitalization
3. Increasing rates to increase cash flows and provide for debt service

Each of these methods requires the use of or an increase in liquid assets. Any method also requires long-term planning on strategy, planned rate increases and capital budgeting for projects. Good utility governance requires a long-term view of a utility's operation and strategy over a 5- to 20-year period and developing the tools for this type of planning and analysis.

Long-Term Debt

The utility industry is heavily dependent on debt financing. The industry business model is to issue long-term debt instruments that are repayable for a 20- to 30-year period, matching the life of those debt-financed assets.[14] Customers are then charged debt service through their rates over the same period as they are using these debt-financed assets. This matching of asset life to customer usage is the cornerstone of utility customer rates.

These long-term debt instruments are called bonds and there are two main types of bonds issued by public sector entities:

1. General obligation bonds, secured by the taxing power of the utility or municipal government
2. Revenue bonds, secured by the revenues of the bond issuer

General obligation bonds are issued by state and local governments to fund operations, while the revenue bond is the major debt vehicle of public power utilities.[15] Revenue bond holders are repaid through a pledge from the bond issuer that it will establish rates that will recover the costs of debt service owed to bondholders. The claims of all bondholders, for repayment of interest and principal, come ahead of any claims of the owners.

Bond Covenants

Bond covenants are the contract between the issuer and the bondholders. The bond covenant is designed to protect the interests of bondholders by requiring the bond issuer to meet certain funding requirements and restricting the issuer from certain activities that could jeopardize the bondholders' position. The covenants are designed to ensure that bondholders are paid first from utility rates, before any funds generated by utility rates can be used for utility operations. Some general requirements of bond covenants include:

- **Required debt service accounts –** A covenant generally requires that accounts for repayment of debt and a debt service reserve be established. A debt service reserve is equal to the highest year's debt principal and interest

[11] The three major bond ratings companies are Fitch Ratings, Moody's and Standard & Poor's.
[12] Moody's public power ratings methodology - https://www.moodys.com/research/Moody-updates-its-methodology-for-rating-US-public-power-electric--PR_375471
[13] 10 percent of total weighting
[14] In an electric distribution utility, these assets would consist of substations, poles, conductors, transformers, customer home connections (services), meters, equipment and office support equipment. If the utility generates its power supply, generation plants would be included, but the debt issued would be over a longer period (30 – 50 years).
[15] Public sector utilities, i.e., utilities that are an enterprise fund of a city government or stand-alone power district formed under state or federal statutes

payments. The reserve is required to be held until the bond issue is fully paid – used only as a resource in the event the utility has not generated sufficient funding through rates to meet bond principal and interest payments in any given year, or to pay the final year's bond payment.

- **Order of assignment of cash flow to various accounts** – A typical bond covenant dictates that funds from rates can be used to fund operations, then capital improvements, then rate stabilization. All of these are allowable only after bond principal and interest has been paid.
- **Rates** – A utility will be required to charge rates that will meet its operating and debt service requirements and a multiple of debt service payments, i.e., debt coverage.
- **Issuance of new debt.** In general, additional debt issued after the current bond issue may have a less senior lien on the utility's revenues for repayment of principal and interest.
- **Capital investment.** A utility may be restricted in its ability to dispose of the debt-funded assets until the bonds are fully paid.

If violations of debt covenants exist, they are to be reported in the utility's annual audit report, along with management's plan to address the covenant violation.

Bond Ratings

Bond ratings, assigned by independent rating companies, represent an assessment of the borrower's overall financial ability to repay bond principal and interest. The main three independent rating agencies are Moody's Investors Service (Moody's), Standard & Poor's Corp. (S&P), and Fitch Ratings.

The rating companies evaluate a number of financial and operational factors to assess an organization's financial health. Based on this assessment, a rating or grade is assigned to the utility's upcoming bond issues. These ratings give investors a grading system for comparing the investment quality of bonds.

The ratings are a main driver in the interest rate a borrower must pay on bond issues – the lower the rating (or grade) the higher the interest rate that will be paid on a bond issue due to perceived higher risk of default. Higher ratings are also desirable because they give a utility better access to capital markets, signifying less risk to potential investors.

For such a service to be of value to investors, the ratings must be developed carefully under uniform evaluation standards. The ratings assigned to debt securities are not static but may be changed by the rating companies as an individual utility's circumstances change. The rating companies publish the overall criteria they use to evaluate a borrower,[16] which provides invaluable information for a utility to use in performing a self-assessment of its current ratable state and areas to focus on improving for future improvements to its bond rating.

Ratings Factors and Rating Companies Rating Scale

Moody's details the area of analysis in developing a bond rating for a public power distribution utility.[17] Some of these factors include:

- **Regulation** – exposure to unregulated business, the ability to recover costs through utility rates
- **Risk assessment** – Overall industry and specific local utility economic and operational risk
- **Financial strength** – cash reserves, debt coverage and capitalization (current debt to assets)
- **Power portfolio mix** – generation, jointly owned generating units, purchased power agreements (PPAs), fuel mix, sufficient or excess capacity, etc.
- **Customer base** – customer portfolio, dependence on significant customers or industries, current and projected competition, anticipated growth in market
- **Debt structure** – capitalization, types of debt outstanding, compliance with existing covenants
- **Utility management practices** – risk management, reserve policies, debt covenant compliance, proactive or reactive to market changes

Table 8 provides an overview of the ratings that the three major rating companies use. It explains the rating scales used by each of the major rating companies.[18]

[16] Moody's Investors Service – Public Power Ratings Methodology (2016) provides an example of a discussion on the ratings criteria used to evaluate public power distribution utilities
[17] Moody's Investors Service – Public Power Ratings Methodology (2016)
[18] Fitch Ratings Register, Moody's Bond Record and Standard & Poor's Bond Guide, Investopedia

Table 8: Bond Ratings

FITCH	MOODY'S	S&P	RATING
AAA	Aaa	AAA	High-grade investment bonds. The highest rating assigned, denoting extremely strong capacity to pay principal and interest.
AA	Aa	AA	High-grade investment bonds. High quality by all standards, rate lower primarily because the margins of protection are not quite as strong.
A	A	A	Medium-grade investment bonds. Many favorable investment attributes, but elements may be present that suggest susceptibility to adverse economic changes.
BBB	Baa	BBB	Medium-grade investment bonds. Adequate capacity to pay principal and interest but possibly lacking certain protective elements against adverse economic conditions.
BB	Ba	BB	Speculative issues. Only moderate protection of principal and interest in varied economic times.
B	B	B	Speculative issues. Generally lacking desirable characteristics of investment bonds. Assurance of principal and interest may be small.
CCC	Caa	CCC	Default. Poor-quality issue that may be in default or danger of default.
CC	Ca	CC	Default. Highly speculative issues, often in default or possessing other marked shortcomings.
	C		Default. These issues may be regarded as extremely poor in investment quality.
C		C	Default. Rating given to income bonds on which no interest is paid.
D		D	Default. Issues actually in default, with principal or interest in arrears.

Maintaining and Improving Bond Ratings

Rating companies also provide information on how a utility can improve its bond rating, for example, a utility should:[19]

- Establish or enhance rate stabilization reserves
- Establish regular economic and revenue reviews to identify potential budget problems early
- Prioritize spending plans and establish contingency plans for operating budgets as a fallback strategy
- Have a formalized capital improvement plan to assess future infrastructure requirements
- Establish a debt affordability model
- Develop a pay-as-you-go financing strategy
- Develop a long-range financial forecast to predict future spending and financing needs
- Develop plans for funding long-term obligations, such as post-employment benefits
- Establish and maintain effective management systems
- Have a well-defined rate strategy

In summary, a strong rating is a result of meeting current bond covenant requirements, having strong reserves, managing debt, passing rate increases when needed, and preparing long-term financial forecasts and budgets to meet the utility's overall long-term strategies.

BOND PREMIUMS, DISCOUNTS AND EXPENSES

Bond premiums and discounts result from differences between the stated face value of a bond issue and the amounts received by the bond issuer when the bonds are initially sold in the credit market. A bond generally has a face value of $5,000. If the market prices this bond at $5,200, a premium of $200 has been realized by the bond issuer. Likewise, if the market prices this bond at $4,800, the issuer has realized a $200 discount.

Generally accepted accounting principles require that these premiums or discounts be recorded and amortized over the life of the bond issues. The main allowable method is the effective interest method, although common practice is to

[19] Standard & Poor's bond rating methodology

use the straight-line method or weighted-bonds methods, which are allowed if not materially different from the effective interest method. The FERC Uniform System of Accounts has assigned various accounts to be used in the accounting for premiums, discounts and amortization, as shown in the following table:

Table 9: FERC Accounts Used for Bond Premiums and Discounts

ACCOUNT	DESCRIPTION
225	Unamortized Premium on Long-Term Debt
226	Unamortized Discount on Long-Term Debt – Debit
428	Amortization of Debt Discount and Expenses
429	Amortization of Premium on Debt – Credit

Bond Issuance Expenses

When issuing bonds, utilities will incur issuance costs for legal, consulting, and other services to complete the official bond statement and sell the bonds. Under GASB Statement No. 65 – *Items Previously Reported as Assets and Liabilities,* all bond issuance costs should be expensed in the year the bonds are issued.

If the utility recovers the costs of bond issuance over the repayment period of the bonds (through the recovery of each year's bond principal payment in utility rates), the issuance costs should be recorded on the Statement of Net Position as an asset and amortized over the bond repayment period. This is discussed further in Chapter 5 under Regulatory Accounting.

FULFILLING DEBT OBLIGATIONS

There are three ways a utility can fulfill its debt repayment obligations to bondholders:

1. Redeem bonds using the scheduled principal and interest payments, per the bond issue repayment schedule, to the bond issue's final maturity
2. Redeem the bond issue before its final maturity by using existing utility financial assets
3. Advance refund the bond issue

The first method is straightforward, i.e., *systematically pay bondholders when the payments become due.* The other methods are discussed below.

Redeem Bonds Before Their Final Maturity with Existing Financial Assets

Generally, revenue bonds include a "call" provision that says the issuer can redeem certain principal years of the bond issue before they are payable if the issuer pays a premium over the bond's face value. For example, if a $5,000 bond has a call provision of "par plus 2 percent," the issuer could redeem the bonds before their due date for $5,100 ($5,000 x (1+ 2 percent). The call provision applies to bonds that are within several years of their redemption date.

Bond issuers also have an opportunity to redeem bonds by buying their own debt securities in the secondary credit markets. In the secondary credit market, debt securities are traded between willing sellers and buyers, like the stock market. A utility would undertake this trading activity if it would be economically advantageous. Circumstances might include:

- Excess cash reserves the utility can use to purchase its debt securities
- The market value of the debt security is less than the face value, i.e., the debt securities are trading at a discount to the par (face) value of the bond
- Positive cash flow savings would result from the transaction by purchasing its debt securities vs. investing cash reserves elsewhere

A bond will trade at a discount to its par value when its stated coupon rate is lower than the underlying general interest rate in the economy as the market moves the bond purchase price lower to raise the bond yield[20] toward the general interest rate. Thus, a rising interest rate environment tends to lower the market value of bonds.

Conversely, bonds will trade at a premium to par when the stated coupon rate is higher than the underlying general interest rate in the economy. A declining interest rate environment tends to move the market value of bonds higher.

Once a utility decides it is economically advantageous to buy its debt securities in the secondary market, the accounting for this transaction is shown in Illustration 7-1.

[20] The bond yield is the effective interest rate earned on a bond, calculated as (interest paid on the bond/bond purchase price). Example - a $5,000 par value bond has a stated interest rate of 5 percent. The annual interest paid on this bond is $250 ($5,000 x 5 percent). If the bond is trading in the secondary market at a discounted purchase price of $4,800, the effective bond yield is 5.21 percent ($250/$4,800).

Illustration 7-1: Redeem Bonds Before Their Final Maturity by Purchasing Issuer's Bonds in the Secondary Credit Market

SCENARIO:

Utility A determines that it is economically advantageous to purchase some of its outstanding bonds in the secondary credit market because those bonds are trading at a discount to par. The utility can use $1 million of excess cash reserves for bond purchases. It has identified 200 bonds for purchase that have a par value of $5,000. The bonds have a coupon interest rate of 5 percent. The current market value of these bonds is $4,800 each and the bonds are due for payment to bondholders in 10 years.

Table 10: Example of Illustration 7-1

DESCRIPTION	CALCULATION	AMOUNT
Face value of bonds	200 x $5,000	$1,000,000
Market value of bonds	200 x $4,800	$960,000
Annual interest payments on redeemed bonds	200 x $5,000 x 5%	$50,000
Estimated interest earnings on $1,000,000 used for bond repurchase (1.5%)	$1,000,000 x 1.5%	$15,000
Estimated annual cash flow savings	$50,000 minus $15,000	$35,000

The journal entries for this transaction are as follows:

Table 11: Journal Entries

ACCOUNT	DESCRIPTION	DEBIT	CREDIT
221	Bonds Payable	$1,000,000	
131	Cash		$960,000
257	Unamortized Gain on Reacquired Debt		$40,000
	To record the purchase of debt securities and gain on the transaction.		
257	Unamortized Gain on Reacquired Debt	$4,000	
429.1	Amortization of Gain on Reacquired Debt		$4,000
	To record the annual amortization of the gain on reacquired debt over the 10-year period until the bonds were originally payable.		

This illustration does not include any discount or premium on the original bonds issued. Those amounts should be charged to the gain or loss on reacquired debt as part of the recording of the transaction.

Losses on reacquired debt should be charged to Account 189, *Unamortized Loss on Reacquired Debt* and the amortization of any losses should be charged to Account 428.1, *Amortization of Loss on Reacquired Debt* over the life of the reacquired debt.

For GAAP reporting, the gain on reacquired debt is reported as a *deferred inflow of resources* and a loss on reacquired debt is recorded as a *deferred outflow of resources*.

ADVANCE REFUNDING OF OUTSTANDING DEBT

Debt agreements may contain a call provision and a defeasance provision. A call provision grants the issuer the right to call in part or all the debt before its scheduled maturity date, usually in exchange for a premium price. A defeasance provision allows the issuer to satisfy the debt legally and obtain a release of lien without necessarily retiring the debt. Thus, in a defeasance transaction, the old debt is satisfied legally.

Also, under certain conditions, a non-defeasance transaction may be accounted for as an in-substance defeasance. In an in-substance defeasance transaction, assets are deposited in a trust account for the sole purpose of paying the interest and principal as they become due, but the debt is not satisfied legally.

In an advance refunding, new debt is issued to replace the old debt issue that cannot be called. The proceeds from the sale of the new debt issue are used to purchase state and local government securities, which are placed with a third-party escrow agent. The earnings from the investments in escrow are used to pay the interest and/or principal payments on the existing debt, up to the date that the existing debt can be called. On the call date of the existing debt, the escrowed funds are used to pay the call premium, if any, and all remaining principal and interest.

In general, the bond is considered extinguished for accounting purposes when the debtor places cash or certain other assets in an irrevocable trust for the sole purpose of servicing interest and principal payments of debt with specified maturities and fixed schedule payments, and there is only a remote possibility that the debtor will be required to make any future payments on the debt.

This accounting treatment is defined in the description of FERC account 222, *Reacquired Bonds*. This account shall include the face value of bonds issued or assumed by the utility and reacquired and not canceled. The account for reacquired debt shall not include securities held by trustees in sinking or other funds.

The 2017 *Tax Cuts and Jobs Act (TCJA)* has a provision that makes the interest income from tax-exempt advance refundings taxable for bondholders, with certain exceptions. This should make the economics less advantageous for these types of financings for public sector entities by raising the bond's interest rate to the level of a taxable bond issue.

FINANCIAL STATEMENT DISCLOSURES

Financial statements issued for external purposes in compliance with GAAP have required notes disclosures for all outstanding long-term debt obligations, including:

- Dates issued, original amount issued, purpose for the issue, interest rates and amount outstanding at year-end
- Principal and interest payments due to maturity shown in detail for the next five years, then aggregated for each five-year period until the final year's payment
- Current year activity, including obligations issued and payments of principal

Debt refunding requires additional information in financial statement notes, including[21]:

- A description of the transaction, including the amount of bonds refunded and the amount of bonds issued
- Internal funds used in the transaction or costs paid from the issuance
- The average interest rates of the old and new bonds
- The cash flow requirements on both the old and new bonds
- The economic gain or loss

The economic gain or loss is defined as:

Economic Gain (Economic Loss)

- Present value of the principal and interest requirements on the old bonds
- Present value of the principal and interest requirements on the new bonds

If the transaction results in an economic loss, the reason for completing a refunding should be disclosed.

After the subsequent year of the advanced refunding, the required disclosures exclude the items above and include just the amount of defeased debt, or unpaid debt to be paid by the escrow account trustee.

[21] In the year of the advance refunding and subsequent year, if two years of financial statements are shown in the audit report

GASB STATEMENT NO. 86 – CERTAIN DEBT EXTINGUISHMENT ISSUES

GASB Statement No. 86 – *Certain Debt Extinguishment Issues* addresses a specific type of debt defeasance in which a public-sector entity uses existing resources to advance-refund debt. Statement No. 86 is effective for reporting periods beginning after June 15, 2017.

The statement establishes accounting and financial reporting for in-substance defeasance transactions, i.e., when cash and other monetary assets acquired only with existing resources[22] are placed in an irrevocable trust for extinguishing debt.

The amounts placed into the irrevocable trust must be essentially risk-free and would include:

- Direct obligations of the U.S. government
- Obligations guaranteed by the U.S. government
- Securities backed by U.S. government obligations as collateral

When the amounts are placed with the escrow agent, the debt should no longer be reported as a liability in the financial statements. Any difference between the reacquisition price and the net carrying amount of the debt, together with any deferred outflows of resources or deferred inflows of resources from prior refundings, should be recognized as a separate gain or loss in the period of the in-substance defeasance.

The notes to the financial statements for an in-substance defeasance should include:

- A general description of the transaction
- The amount of the debt
- The amount of cash and other monetary assets placed with the escrow agent
- The reason for the defeasance
- The cash flows required to service the defeased debt

In years subsequent to the in-substance defeasance, the public-sector entity should disclose the amount of in-substance debt defeased that remains outstanding.

ARBITRAGE AND TAX-EXEMPT DEBT

Tax-exempt debt is the main financing vehicle for public utilities capital projects. The term *"arbitrage"* has two meanings related to tax-exempt bonds. First, it refers to the practice of investing borrowed funds and earning more in interest than the average yield rate on the bonds issued. Second, it refers to Internal Revenue Service (IRS) restrictions that require public sector entities to spend tax-exempt bond proceeds within a stated period (generally two to three years, depending on the amount of bonds issued).

The covenant associated with a bond issue defines the average allowable yield rate that can be earned on funds invested from a bond issue. For example, a utility would issue bonds, receive the bond proceeds, deposit those funds in an interest-bearing account, then spend those proceeds over a three-year period during construction of a capital project. The unspent funds would earn interest until they are used to pay project costs. The issuer may earn more on the invested funds than the average bond yield, however, the "excess earnings" are taxable under federal Internal Revenue Service regulations.

The bond issuer must calculate any tax liability within five years of the bond issue date and accrue the tax as a liability.

OTHER UTILITY FINANCING INSTRUMENTS

Revenue bonds represent the most traditional form of financing for public power utilities and raise a large part of the capital needed to finance investment in plant and equipment. Other methods for financing infrastructure are discussed below.

SHORT-TERM DEBT

Instead of issuing 20- to 30-year revenue bonds, some utilities use shorter-term bond maturities to lower their rate of interest. Short-term financing might include revolving lines of credit, commercial paper and bank loans.

PUBLIC/PRIVATE PARTNERSHIPS

Public/private partnerships are financed with a combination of public sector and private sector funding or ownership contracts with public and private partners. These arrangements allow one party, generally the public-sector entity, to mitigate the risk of ownership while the other partner, the private-sector entity, makes a return on investment commensurate with the risk it incurs.

Illustration 7-2 on page 56 is an example of a typical public/private partnership.

[22] These are internal utility monetary resources other than the proceeds of refunding debt

Illustration 7-2: Public – Private Partnership

SCENARIO:
A utility wishes to add renewable energy resources to its power supply mix. It constructs 10-MW wind turbines. The project cost is $15 million. The utility is approached by a private-sector investor who wants to purchase the turbines. The private investor will purchase the units using cash, tax credits, and private financing. The private investor will sell the output of the units to the utility through a power purchase agreement (PPA).

The evaluation of the potential transaction is as follows:

Table 12: Example of Illustration 7-2

ENTITY	EVALUATION FACTOR
Utility	Receives guaranteed output of the turbines through a PPA
	Wind-generated energy meets renewable energy goals
	Eliminates need to maintain the units
	Mitigates risk of obsolescence and replacement of the units
Private sector investor	Able to use tax credits to minimize its need for equity financing
	PPA guarantees sale of turbine generation
	Return meets investment goals

Public/private partnerships are beneficial to both parties. They are used for a variety of generation, transmission, distribution, and renewable energy projects.

LEASES

Leasing is another form of long-term financing used by utilities for both infrastructure and operational equipment, from distributed generation, power plants, and trenching equipment to office copiers. With the issuance of GASB Statement No. 87 Accounting for Leases, the definition of a lease is "the right to use an asset for a period of greater than one year." Lease accounting is discussed in detail in Chapter 8.

CHAPTER EIGHT
LEASES

ACCOUNTING FOR LEASES

The accounting for leases changes significantly with the implementation of GASB No. 87 – *Leases,* which is effective for reporting periods beginning December 15, 2019. Prior guidance classified leases in two ways:

1. Operating leases were expensed as lease payments were made
2. If a lease met certain specific criteria, it was considered a capital lease and a lease asset and lease liability were recorded for the present value of future lease payments

The new standard establishes a single model for lease accounting based on the foundation that leases are financings of the right to use an asset. Generally, most leases will be recorded similarly to the old "capital lease." The standard also provides a new definition of a lease.

Defining a Lease

The new definition of a lease is a *contract* that conveys *control of the right* to use a nonfinancial asset (the underlying asset) for a period of time in an exchange or exchange-like transaction. The right to use an underlying asset includes both the right to obtain the present service capacity from use of the underlying asset, as specified in the contract, and the right to determine the nature and manner of use of the underlying asset, as specified in the contract.

There are a few key take-aways from this definition. First, a lease is defined as a contract. Just because a contract is labeled as a lease, does not necessarily mean it meets the definition above and should be accounted for under the new guidance. Similarly, a contract may not identify as a lease, but may still meet the definition of conveying control of the right to use an asset. Under this new guidance, contracts should be evaluated for accounting as a lease based on the substance of the arrangement, rather than the label of a contract. For instance, a lease contract for computer equipment transfers ownership of the equipment to the lessee after the term of the lease. This would not be considered a lease, but a financed purchase of the asset. Therefore, you would record an asset and a note payable (with implied interest) for the payments. The note payable will follow the disclosure requirements of long-term debt as opposed to leases. Because of this change in definition, the proper identification of contracts as leases will be critical to ensure proper accounting treatment.

The second key take-away in the definition of a lease is "control of the right to use" an asset. Control of the right to use an asset includes the manner and nature of use. There was a lot of discussion when the exposure draft originally was issued on whether purchased power contracts would be included in the scope of a lease. GASB determined that supply contracts, such as purchased power contracts, convey access to the output of an asset rather than control of the right to use the asset. In that way, it would not be subject to the lease accounting standard. However, if a utility obtains 100 percent of the generating asset capacity and can control when it runs, how often it runs, etc., it would be evaluated as a potential lease under the new standard.

Exceptions to lease accounting included in the standard consist of:

- Lease contracts for intangible assets (including the right to explore for or to exploit natural resources such as oil, gas, and minerals, and similar nonregenerative resources or licensing contracts for computer software) other than sublease contracts for intangible right-to-use lease assets.
- Leases of biological assets, including timber
- Leases of inventory
- Contracts that meet the definition of a service concession arrangement under GASB No. 60
- Leases in which the underlying asset is financed with outstanding conduit debt, unless both the underlying asset and the conduit debt are reported by the lessor
- Supply contracts, such as power purchase agreements

Another exception included in the standard relates to short-term leases, which we will discuss in more detail when we discuss the lease term.

Accounting for a Lease

Once a contract is determined to meet the definition of a lease, the general accounting is:

For a Lessee:

Debit Intangible Right-to-Use Asset	$XXX	
Credit Lease Liability		$XXX

For a Lessor:

Debit Lease Receivable	$XXX	
Credit Deferred Inflow of Resources		$XXX

The initial entry would include the present value of expected future lease payments. Subsequently, the lease liability/lease receivable would be decreased for any lease payments, any implied interest from the present value calculation would be recognized as interest expense/income, and the intangible right-to-use asset/deferred inflow of resources would be amortized over a period of time.

The ***lease term*** is an important factor in the calculation of the lease liability or lease receivable. The lease term is defined as the period in which a lessee has a noncancelable right to use an underlying asset. This includes periods covered by a lessee's or lessor's option to extend the lease, if it is reasonably certain they would do so, and periods covered by a lessee's or lessor's option to terminate the lease, if it is reasonably certain they would not exercise the option. Periods for which both the lessee and lessor have an option to terminate the lease without permission from the other party are considered cancelable periods and are excluded from the lease term. This can sometimes happen when a lease term has expired, and the parties are renegotiating a new contract. During this period, when both parties can terminate the lease without notification or penalty, any lease payments are simply expensed.

Leases with a maximum term of 12 months or fewer are considered short-term. These leases are excluded from lease accounting treatment and are recorded as an expense by the lessee and a revenue by the lessor.

Another aspect of lease contracts to consider before we delve into the details are contracts with multiple components. For instance, you enter into an agreement to lease a vehicle. The lease is $500 a month and includes service and maintenance to the vehicle. This contract has two components:

1. Control of the right to use the vehicle
2. Service and maintenance to the vehicle

The first component, control of the right to use the vehicle, is considered a lease. However, the second would be considered an expense. The $500 payment would need to be split into these two components. Suppose the average cost of a similar service plan would be $50 a month. The portion of the payment related to the lease would be $450 a month, which would be included in the calculation of the lease liability.

Allocation to multiple lease components should be considered if there are service components of a contract, differing lease terms, or differing asset classes. The allocation process should entail identifying individual components and determining whether they are reasonable, maximizing observable information, and using professional judgment to estimate pricing when observable information is not available. If it is not practicable to determine a best estimate of price, the utility may account for the components of the lease as a single unit.

Accounting for the Lessee

At the inception of the lease, the lessee records an intangible right-to-use lease asset and a lease liability. The ***lease liability*** should equal the present value of payments expected to be made during the lease term, including:

- Fixed payments
- Variable payments that depend on an index or rate
- Amounts that are reasonably certain of being required to be paid by the lessee under residual value guarantees
- Exercise price of a purchase option, if it is reasonably certain the lessee will exercise the option
- Payments for penalties for terminating the lease, if the lease allows the lessee to terminate the lease
- Any incentives receivable from the lessor
- Any other required payments

The liability does not include variable payments based on future performance or use of the underlying asset. These amounts should be expensed in the period incurred. The discount rate used in the present value calculation should be the utility's incremental borrowing rate, if a rate is not specified in the contract.

The ***lease asset*** for the lessee utility equals the total of the initial lease liability, plus any payments made to the lessor at or before commencement of the lease term, less any incentives received from the lessor. In addition, add any ancillary costs necessary to place the leased asset into service. The lease asset should be amortized in a systematic and rational manner over the shorter of the lease term or the useful life of the asset. If the lease contains a purchase option (that is reasonably certain of being exercised), the lease asset should be amortized over the useful life of the asset. If the underlying asset is nondepreciable (for example, land), the lease asset should not be amortized. The lease asset may need to be reviewed for impairment if any indicators are present. Amortization of the lease asset may be combined with depreciation expense for financial reporting purposes.

The utility should remeasure the liability if any of the following occur:

- A change in lease terms
- The likelihood of changes to a residual value guarantee or exercise of a purchase
- A change in the estimated amount for payments already included in the measurement
- The interest rate the lessor charges the lessee, if it was used as the initial discount rate. The utility would not need to remeasure the liability if it uses the incremental borrowing rate to measure the liability and the rate changes.

Any change in the liability would be recorded against the lease liability and the intangible right-to-use lease asset. The amortization of the lease asset would be adjusted going forward for any change in the valuation or lease term.

Footnote disclosures for the lessee include components of the capital asset footnote and the long-term debt footnote. Disclosures should include the following:

- Description of the leasing arrangement, including the basis, terms and conditions on which variable payments not included in the measurement of the lease are determined
- The total amount of lease assets and related accumulated amortization
- The total amount of lease assets by major class of underlying assets, disclosed separately from capital assets
- The expense recognized in the period for variable payments or other payments, such as residual value guarantees, for termination penalties not included in the measurement of the lease liability.
- Principal and interest requirements to maturity, presented separately, for the lease liability for each of the five subsequent fiscal years and in five-year increments thereafter

- Any commitments under leases before commencement of the lease term
- Any components of loss associated with impairment

Accounting for the Lessor

At the inception of the lease, the lessor records a lease receivable and a deferred inflow of resources. The lease receivable equals the present value of the following items (reduced for any provisions for uncollectible amounts):

- Fixed payments
- Variable payments that depend on an index or rate
- Variable payments that are fixed in substance
- Residual value guarantee payments that are fixed in substance
- Any lease incentives

The ***deferred inflow of resources*** will equal the lease receivable plus any payments received prior to the commencement of the lease term, less any lease incentives.

The lessor would continue to apply other guidance related to the underlying asset, such as depreciation or impairment. However, if the lease contract requires the lessee to return the asset in its original or enhanced condition, a lessor should not depreciate the asset during the lease term.

The footnote disclosures for the lessor include:

- Description of the leasing arrangement, including the basis, terms and conditions on which variable payments not included in the measurement of the lease are determined
- Total revenue recognized in the reporting period from leases, if not apparent from the face of the financial statements
- Revenue recognized in the reporting period for variable and other payments not previously included in the measurement of lease receivables, including any related to residual value guarantees and termination penalties
- The existence, terms, and conditions of options by the lessee to terminate the lease or abate payments if the lessor government has issued debt for which the principal and interest payments are secured by the lease payments.

Example 1 – A Standard Lease

A utility enters into a contract to rent a portion of an office building with the following terms:

- Annual payment of $10,000
- Noncancelable term of five years, with an optional three-year extension
- The utility is reasonably certain it will exercise the optional three-year extension
- The utility will also be paying the counterparty for any utilities during the lease term
- The utility made an upfront payment of $2,000 in order to enter into the lease
- The utility's incremental borrowing rate is 3 percent and there is no rate stated in the contract

Based on the information above, the lease term would be eight years (five years noncancelable plus the optional three-year extension that is expected to be exercised). The lease liability would be calculated based on the present value of $10,000 annual payments made over eight years at a discount rate of 3 percent. The present value is shown below.

	LEASE PAYMENT	PRINCIPAL	INTEREST	LEASE LIABILITY BALANCE
LEASE COMMENCEMENT				$ 70,197
year 1	$ 10,000	$ 7,894	$ 2,106	62,303
year 2	10,000	8,131	1,869	54,172
year 3	10,000	8,375	1,625	45,797
year 4	10,000	8,626	1,374	37,171
year 5	10,000	8,885	1,115	28,286
year 6	10,000	9,151	849	19,135
year 7	10,000	9,426	574	9,709
year 8	10,000	9,709	291	–

The lease asset recorded will be $72,197 (the lease liability of $70,197 plus the $2,000 up-front payment).

The journal entries to record this lease are as follows:

		Dr.	Cr.
1)	Lease asset	$ 70,197	
	Lease liability		$ 70,197
	Record commencement of the lease.		
2)	Lease asset	2,000	
	Cash / Accounts payable		2,000
	Record initial payment made to enter into the lease.		
3)	Interest expense	2,106	
	Lease liability		2,106
	Recognize interest on the lease liability (year 1).		
4)	Amortization expense	9,025	
	Accumulated amortization on lease asset		9,025
	Record amortization of the lease asset ($72,197 / B).		
5)	Lease liability	10,000	
	Cash / Accounts payable		10,000
	Record the annual lease payment.		

Lease liability

	Dr.	Cr.
1)		70,197
3)		2,106
5)	10,000	
		62,303

Lease asset

	Dr.	Cr.
1)	70,197	
2)	2,000	
	72,197	

Accumulated amortization of lease asset

	Dr.	Cr.
4)		9,025
		9,025

Interest expense

	Dr.	Cr.
3)	2,106	
	2,106	

Amortization of of lease asset

	Dr.	Cr.
4)	9,025	
	9,025	

Cash/AP

	Dr.	Cr.
2)		2,000
		10,000
		12,000

Example 2 – A Lease with Multiple Components

A utility enters into a contract to rent computer equipment with the following terms:

- Annual payment of $10,000
- Noncancelable term of three years, with an optional two-year extension
- The utility is reasonably certain it will not exercise the optional two-year extension
- The contract covers rental of the equipment and annual maintenance/troubleshooting
- The estimated annual value of the maintenance is $1,000
- The utility's incremental borrowing rate is 3 percent and there is no rate stated in the contract.

In this example, the lease term would be three years since the utility is reasonably certain it will not exercise the two-year option to extend the lease.

The lease liability would be calculated based on the present value of $9,000 annual payments made over three years at a discount rate of 3 percent. Only the portion of the lease that relates to the lease of the equipment is included in the calculation, and not the estimated value of the service contract, which would be expensed when incurred. The present value is shown below split between principal and interest payments.

	LEASE PAYMENT	PRINCIPAL	INTEREST	LEASE LIABILITY BALANCE
LEASE COMMENCEMENT				$ 25,458
year 1	9,000	8,236	764	17,222
year 2	9,000	8,483	517	8,739
year 3	9,000	8,739	261	–

The lease asset recorded will be $25,458, or the lease liability.

The journal entries to record the lease are as follows:

		Dr.	Cr.
1)	Lease asset	$ 25,458	
	Lease liability		$ 25,458
	Record commencement of the lease.		
2)	Interest expense	764	
	Liase liability		764
	Recognize interest on the lease liability (year 1).		
3)	Amortization expense	8,486	
	Accumulated amortization on lease asset		8,486
	Record amortization of the lease asset ($25,458 / 3).		
4)	Lease liability	9,000	
	Cash / Accounts payablet		9,000
	Record the annual lease payment.		
5)	Operating expense	1,000	
	Cash / Accounts payable		1,000
	Record the annual maintenance on computer equipment.		

Lease liability

1)		25,458
2)		764
4)	9,000	
		17,222

Lease asset

1)	25,458	
	25,458	

Accumulated amortization of lease asset

3)		8,486
		8,486

Interest expense

2)	764	
	764	

Amortization of of lease asset

3)	8,486	
	8,486	

Cash/AP

2)		2,000
4)		9,000
5)		1,000
		12,000

Operating expense

5)	1,000	
	1,000	

CHAPTER NINE
OTHER SPECIAL TOPICS

INTRODUCTION

This chapter discusses other special topics that are common in the utility industry.

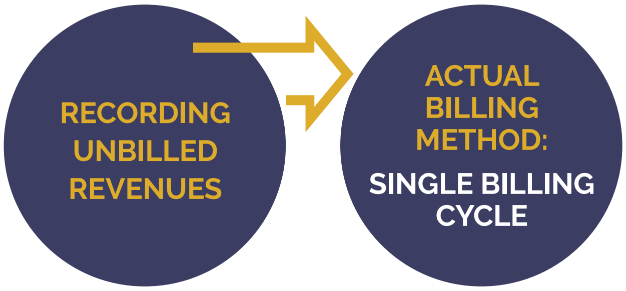
Unbilled Revenues

Unbilled revenues refer to electricity used by a customer but not yet billed due to the timing of the utility's billing cycle. The matching principle of accounting drives the recording of unbilled revenues, as the use of electricity by the customer would be reflected in the utility's cost of generation or purchased power for that electricity, while the revenues are not included since they have not been billed. As with any amount in the financial statements, record unbilled revenues only if they are material.

Smart meters integrated with billing systems in Enterprise Resource Planning (ERP) and other software platforms have modules that perform this calculation and record the appropriate amount of unbilled revenues. For utilities without that option, two methods are generally used to calculate unbilled revenues. The first uses the subsequent month's actual billings, while the other uses estimated units for calculation.

The following illustrations detail each method.

Illustration 9-1



Actual Billing Method

The actual billing method uses the actual amounts billed from actual meter readings in the next actual billing and prorates the days of usage over the billing period. The pros and cons of this method are:

CON:
Need to wait to make calculation until information is completed and this may delay the month-end close

PRO:
Amount will be more accurate as it is based on actual consumption

Actual Billing Method – **Single Billing Cycle**

Previous Month Ended	6/30/20x1
Next billing cycle reading date	7/16/20x1
Actual revenues in cycle billing	**$2,500,000**
Days attributable to prior month	15
Days in billing cycle	30
Unbilled revenues (6/15/20x1 - 6/30/20x1) ($2,500,000 x 15/30)	**$1,250,000**

Journal Entry

Assume the prior month's recorded unbilled revenue amount was $2 million. The entry in the current period is:

Table 13: Actual Billing Method – Single Billing Cycle

FERC ACCOUNT	DESCRIPTION	DEBIT	CREDIT
400	Revenues (detailed by customer class)	$2,000,000	
173	Accrued Utility Revenues		$2,000,000
173	Accrued Utility Revenues	$1,250,000	
400	Revenues (detailed by customer class)		$1,250,000

Illustration 9-2

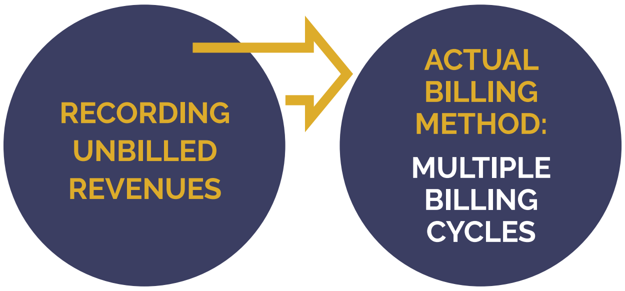


Figure 4 – Actual Billing Method: Multiple Cycles

Actual Billing Method – **Multiple Cycles**

Cycle 1

# of Billed Days In December	Total # of Billed Days in Cycle	
30	32	Book 1
30	32	Book 2
29	33	Book 19
29	33	Book 22
28	33	Book 3
28	33	Book 4
27	34	Book 14
26	34	Book 21
23	32	Book 23
250	296	
84%		

Cycle 2

# of Billed Days In December	Total # of Billed Days in Cycle	
21	34	Book 11
21	34	Book 17
20	34	Book 5
19	34	Book 15
15	34	Book 16
16	32	Book 13
112	202	
55%		

Cycle 3

# of Billed Days In December	Total # of Billed Days in Cycle	
13	34	Book 6
13	34	Book 7
12	34	Book 8
9	32	Book 9
8	34	Book 10
8	34	Book 12
5	32	Book 18
68	234	
29%		

	Actual Revenues	Weighted Average	Unbilled Revenues
Cycle 1	$1,250,000	84%	$ 1,050,000
Cycle 2	$2,500,000	55%	$ 1,375,000
Cycle 3	$ 800,000	29%	$ 232,000
		Total Unbilled Revenues	$ 2,657,000

Journal Entry

Assume the prior month's recorded unbilled revenue amount was $2 million. The entry in the current period is:

Table 14: Actual Billing Method – Multiple Billing Cycles

FERC ACCOUNT	DESCRIPTION	DEBIT	CREDIT
400	Revenues (detailed by customer class)	$2,000,000	
173	Accrued Utility Revenues		$2,000,000
173	Accrued Utility Revenues	$2,657,000	
400	Revenues (detailed by customer class)		$2,657,000

Illustration 9-3 Recording Unbilled Revenues – Estimated Units Method

Estimated Units Method

The estimated units method uses an estimate of weather-adjusted previous usage based on an average cost per unit over the period to be estimated. The pros and cons of this method are:

CON:
Method is more timely and, since this is an estimate, less accuracy is required as it will eventually be adjusted to the actual amounts

PRO:
Amount will be less accurate because it is based on historical usage, which may differ from actual usage over the unbilled revenue period

Table 15: Estimated Units Method

MONTH	REVENUES	CONSUMPTION	REVENUE PER UNIT
September	$750,000	8,402,564	$.089
October	$1,000,000	11,725,482	$.085
November	Calculated $875,570 (10,064,023 x $.087)	(2 month average) 10,064,023	(2 month average) $.087
Days to Accrue	15		
Unbilled Revenues	$437,785 (10,064,023 x $0.087 x 15)		

Another option is to estimate the consumption for the period based on known production or purchases and a historical loss factor.

Journal Entry

Assume the prior month's recorded unbilled revenue amount was $500,000. The entry in the current period is:

Table 16: Estimated Units Method – Journal Entry

FERC ACCOUNT	DESCRIPTION	DEBIT	CREDIT
400	Revenues (detailed by customer class)	$500,000	
173	Accrued Utility Revenues		$500,000
173	Accrued Utility Revenues (rounded)	$438,000	
400	Revenues (rounded by customer class)		$438,000

As with any estimate such as unbilled revenues, if the amount calculated is immaterial, recording it would be optional.

ALLOWANCE FOR DOUBTFUL ACCOUNTS

Estimated billing amounts that will not be collected should be recognized each billing period. This is an application of the matching concept, i.e., matching amounts billed to the future uncollectibility of an estimatable percentage of those amounts. Estimates of uncollectible amounts billed can be developed based on historical collections and adjusted for other known factors. The estimate is recorded as a contra-asset to customer accounts receivable, which would be a more accurate estimate of expected collections.

The history of the write-off of customer accounts receivable balances is used to develop an ongoing estimate of future uncollectible amounts. This calculation can be shown as follows:

Table 17: Estimate of Future Uncollectible Amounts

YEAR	ACTUAL AMOUNT WRITTEN OFF AS UNCOLLECTIBLE	ANNUAL REVENUES	PERCENT
20x1	$100,000	$100,000,000	0.100%
20x2	$120,000	$110,000,000	0.109%
20x3	$110,000	$105,000,000	0.105%
		Average Three-Year History	0.105%
		X Current Year (20x4) Budget Revenues	$115,000,000
		Estimated Allowance – 20x4	$120,750

Because this is an estimate, it should be adjusted for changes in local economic conditions.

Journal Entries

1. Once the allowance balance has been determined, a journal entry should be recorded to establish the balance.

Table 18: Estimate of Future Uncollectible Amounts – Journal Entry 1

FERC ACCOUNT	DESCRIPTION	DEBIT	CREDIT
904	Uncollectible Accounts	$120,750	
144	Allowance for Doubtful Accounts		$120,750

2. As individual customer accounts are determined to be uncollectable during the year, this should be recognized as a reduction in the Allowance for Doubtful Accounts. An example write-off of $1,100 would be recorded as follows:

Table 19: Estimate of Future Uncollectible Amounts – Journal Entry 2

FERC ACCOUNT	DESCRIPTION	DEBIT	CREDIT
144	Allowance for Doubtful Accounts	$1,100	
904	Uncollectible Accounts		$1,100

For financial reporting purposes, while the FERC chart of accounts includes the expense portion of uncollectible accounts as an operating expense, Generally Accepted Accounting Principles (GAAP) require these expenses to be reported as a decrease in operating revenues. Because it is rare that uncollectible amounts are material to financial statements, presentation of the amounts would be at the utility's discretion. However, if uncollectible amounts are material to the financial statements, the utility should follow GAAP requirements.

ASSET RETIREMENT OBLIGATIONS

Certain long-lived assets are acquired or constructed with the knowledge that at some future date they will be retired and there will be a significant cost involved with the retirement. In these and other cases, federal, state, or local governments or a contract will mandate that the facility be returned to pre-construction status or that other remediation be performed on the plant site. These activities governed by contract terms are known as ***asset retirement obligations (ARO)***.

The accounting standard for AROs was contained in the Financial Accounting Standards Board (FASB) Statement No. 143 – *Accounting for Asset Retirement Obligations,* but in 2016 GASB issued Statement No. 83 – *Certain Asset Retirement Obligations,* which is now definitive. An asset retirement obligation (ARO) is a contractual requirement associated with the retirement of a tangible capital asset. A government that has legal obligations to perform future asset retirement activities related to its tangible capital assets should recognize a liability based on the guidance in this statement.

GASB Statement No. 83 is effective for reporting periods after June 15, 2018. It does not apply to accounting for landfill closing costs, which is prescribed in GASB No. 18, *Accounting for Municipal Solid Waste Landfill Closure and Postclosure Care Costs.* Also, accounting for pollution remediation liabilities, or hazardous waste clean-up costs, is outlined in GASB No. 49.

Overall Requirements

GASB Statement No. 83 requires the measurement and recognition of a legally enforceable liability for retirement of an asset. This estimate for additional retirement costs is usually based on laws and regulations that require certain activities be done, such as decommissioning power plants or removing sewage treatment plants.

Statement No. 83 requires the measurement of an ARO to be based on the best estimate of the current value of outlays. This estimate should include the probability weighting of all potential outcomes, when the information is available or can be obtained at a reasonable cost. If probability weighting is not feasible, a most likely amount should be used. The statement requires that a deferred outflow of resources be measured at the amount of the corresponding liability. The current value of the ARO must be adjusted at least annually for the effects of general inflation or deflation. The factors used in determining the ARO should also be evaluated annually.

Application of GASB 83 to a Wind Turbine Facility

A utility places a wind farm into service in 2xx1. As part of the license for the facility, the county government has included a requirement that the facility property be returned to pre-wind-farm greenfield status after the wind units are retired in 20 years.

The utility uses an independent firm to estimate the ARO of $2 million in 2xx1 dollars.

1. Record the asset retirement obligation

Description	Debit	Credit
Other deferred outflows – Asset retirement obligation	$2,000,000	
Asset retirement obligation (long-term liability)		$2,000,000

2. Record amortization of the asset retirement obligation in Year 1

Description	Debit	Credit
Asset retirement obligation amortization ($2 million/20 years)	$100,000	
Other deferred outflows – Asset retirement obligation		$100,000

3. The ARO must be updated annually under GASB Statement No. 83, either through an evaluation of the current ARO costs or by the rate of inflation. In the current year, the utility chooses to increase the ARO by the 2 percent inflation. The increase in the ARO is ($2,000,000 - $100,000) x 2% = $38,000.

Description	Debit	Credit
Other deferred outflows – Asset retirement obligation	$38,000	
Asset retirement obligation (long-term liability)		$38,000

4. Record amortization of the asset retirement obligation in Year 2 ($2,000,000 - $100,000 + $38,000)/19 years remaining)

Description	Debit	Credit
Asset retirement obligation ($1,938,000/19 years)	$102,000	
Other deferred outflows – (Asset retirement obligation)		$102,000

How does this impact this utility's business?

The asset retirement obligation liability will need to be paid in 20 years when work is done to restore the wind farm property to its greenfield state. To have enough funds on hand to pay for this obligation, the utility should increase its rates by the amount of the annual ARO amortization and accumulate the cash generated by those increased rates in a designated cash account.

GASB 83 Exemption – Joint asset ownership with a non-GASB-following utility where the GASB-following utility is a minority owner of the facility

GASB 83 provides an exception for utilities that have joint ownership of facilities with another organization that is not required to follow GASB standards. Such an entity would follow the standards of the Financial Accounting Standards Board (FASB). This situation arises often in public power ownership of generating units or transmission facilities with investor-owned utilities. The ARO standards of GASB 83 and the FASB version of determining AROs (ASC 410 – *Asset Retirement and Environmental Obligations*) are not the same when measuring the value of AROs. Measuring liability at the current value of outlays is an important difference from the FASB Statement No. 143 ARO standard.

Potential ownership situations could arise under these scenarios:

1 The entity that follows GASB standards has a minority share (less than 50 percent) of ownership in the facility and each joint owner is liable for its share of the ARO

2 There are multiple owners, none of which have an ownership share of more than 50 percent and each joint owner is liable for its share of the ARO

In these situations, the minority owners should value their share of an ARO using the measurement produced by the non-GASB-following majority owner, or the non-GASB minority owner with operational responsibility for the asset and which follows the FASB standard of ASC 410. Importantly, the ARO measurement date should not be more than one year prior to the audit report year-end of the GASB-following entity.

Financial Statement Disclosures

Given that AROs are often a significant item within the financial statements and require sensitive estimates, GASB 83 requires that certain additional information be included in the footnotes to aid the reader in evaluating these transactions. This information includes:

- A general description of the ARO and associated tangible capital assets, as well as the source of the obligations (whether a result of federal, state, or local laws or regulations, contracts, or court judgments)
- The methods and assumptions used to measure the liabilities
- The estimated remaining useful life of the associated tangible capital assets
- How any legally required funding and assurance provisions associated with AROs are met; for example, surety bonds, insurance policies, letters of credit, guarantees by other entities, or trusts used for funding and assurance
- The amount of assets restricted for payment of liabilities, if not separately displayed in the financial statements.

If an ARO or portions of an ARO have been incurred but not yet recognized because it is not reasonably estimable, the utility should disclose this and the reasons why the ARO cannot be estimated.

This information as an audit trail is invaluable because AROs may occur 20 to 30 years or more in the future. It is likely that the finance group recording this future estimate would not be the finance group when the ARO work occurs.

Pollution Remediation Obligations

GASB Statement No. 49 *Accounting and Financial Reporting for Pollution Remediation Obligations,* requires estimating and recording liabilities for actual or potential activities involved with cleanup of polluted sites. An example would be the costs to clean up a property that has leaking diesel fuel tanks or removal of asbestos from a facility.

A pollution remediation obligation is distinct from an asset retirement obligation (ARO) as defined by GASB Statement No. 83 *Certain Asset Retirement Obligations*. An ARO is a government-mandated return of a site to greenfield status when the asset has been retired. It is predicated on a future event. Pollution remediation obligations are utility liabilities.

GASB 49 identifies five events that require the utility to estimate and accrue the cost of its share of future pollution remediation activties. These include:

- Imminent danger
- Violation of a permit or license related to pollution prevention
- The utility is named by regulators as a responsible party
- Having been named or likely will be named in a lawsuit related to site cleanup
- Taking action to begin or legally commit to remediation activities

Activities that are defined by GASB as pollution remediation activities include:

- Pre-cleanup activities, such as site assessment, studies, or planning
- Cleanup activities, such as removal or disposal of hazardous waste and site restoration
- Costs associated with oversight or enforcement
- Ongoing monitoring of the sites

The liability should be estimated by using a weighted cash flows approach, weighing the probability of potential costs under differing scenarios of clean-up activities. GASB 49 financial statement footnote disclosures should include:

- Type of pollution and its source, if known,
- Estimated liability and key assumptions used in creating the estimate
- Known information that may impact the estimate in the future
- Anticipated recoveries from outside parties
- If a reasonable estimate of the costs cannot be determined

Pollution remediation obligations do not include pollution prevention or control obligations for current operations and do not include fines and penalties for not performing pollution remediation activities.

TERMINATION BENEFITS

GASB Statement No. 47 *Accounting for Termination Benefits* governs costs incurred or future liabilities for incentives or benefits to employees to terminate their employment. These can result from voluntary activities, such as early retirement incentives, or involuntary separation, leading to severance packages. In either case, the post-employment benefits should be recognized as an expense and liability when they are incurred and can be estimated.

When determining proper measurement of termination benefits, healthcare- and non-healthcare-related termination benefits are valued using differing methodologies:

1. **Healthcare-related benefits** are recognized at the discounted present value of expected future benefit payments.

2. **Non-healthcare-related benefits that are to be paid** as predetermined amounts at set future dates should be calculated at the discounted present value of these future payments.

3. **Non-healthcare benefits that do not specify the amount to be paid** on a fixed date can be calculated either as the discounted present value or the undiscounted total value of the estimated future benefits.

Recognition of the benefits should be accrued as follows:

- Voluntary termination benefits should be accrued once employees accept the termination offer.
- Involuntary termination benefits should be accrued at the time the termination plan has been approved by the governing body, has been communicated to the employees, and can be estimated.
- Benefits that incorporate future service requirements, for example a lump sum payment that will be paid contingent upon the employee remaining with the utility until a future date, the benefits should be accrued proportionately over the period of future required service.

GASB 47 financial statement footnote disclosures should include:

- Description of the benefit arrangements
- Number of employees affected
- The amount and type of benefits
- Significant assumptions or information used in calculating the estimated benefits accrued and the amount
- If the benefits could not be estimated

CONTINGENCIES

Daily operations of a business may result in uncertain situations. Common events that can result in unknown future gains or losses include lawsuits, contract settlements, labor negotiations, and property damage. From a financial reporting perspective, the question is "when should such items be recognized in the financial statements?"

The answer lies in the guidance in FASB No. 5, codified within GASB No. 62 *Codification of Accounting and Financial Reporting Guidance Contained in Pre-November 30, 1989 FASB and AICPA Pronouncements*. Contingent losses, or potential future losses, should be recognized as liabilities once they are at certain levels, defined in Table 20.

In some instances, a general note in the financial statements is included on the general exposure of the utility to potential litigation as a matter of course in conducting business.

Gain contingencies are not reflected in the financial statements.

ACCOUNTING FOR EMISSION ALLOWANCES AND RENEWABLE ENERGY CREDITS

Emission allowances are allotted by the Environmental Protection Agency to power producers and purchased on the open market. These allowances are used to meet emission requirements and offset the SO_2 and NO_X produced by generating facilities. Highly efficient facilities that produce little to no emissions can sell their unused allowances to less efficient facilities to offset the pollutants they emit.

A similar instrument is a renewable energy credit or REC. A REC represents 1 MWH produced through a renewable energy source. A REC is often sold separately from the energy produced by the renewable energy source because the energy is indistinguishable once it enters the power grid. Utilities purchase RECs either to support renewable energy production or to meet governmental renewable energy mandates.

Accounting standards do not address accounting for emission allowances or RECs; however, the Federal Energy Regulatory Commission (FERC) Uniform System of Accounts provides guidance for these areas. It is appropriate to follow the FERC guidance in the absence of other accounting standards guidance.

Table 20: Contingency Levels

CONTINGENCY LEVEL	ACCOUNTING TREATMENT
Remote	No amounts should be accrued and no disclosures are required
Reasonably possible	Financial statement footnote disclosure is required, an estimate or range of estimate should be disclosed in the footnotes
Probable	A reasonable estimate of the loss should be accrued, and the footnotes should disclose the nature of contingency

FERC provides two approaches to use in accounting for emission allowances and RECS:

METHOD	APPLICATION	ACCOUNTING TREATMENT
Inventory Method	Allowances and RECs are used in operations	Allowances and RECs are valued at weighted average cost
Investment Method	Allowances and RECs are held for sale	Allowances and RECs are marked to the market price at each audit report date

The accounting under each method is as follows:

Table 21: Accounting for Inventory and Investment Methods

METHOD	UNUSED OR HELD ALLOWANCES/RECs ACCOUNT	WHEN USED OR SOLD
Inventory Method	FERC 158.1 *Allowance Inventory*	Debit FERC 509 *Allowances*
Investment Method	FERC 128 *Other Investments*	Credit FERC 421 *Miscellaneous Non-Operating Income* for Gains and Debt FERC 426.5 *Other Deductions* for Losses

Financial statements should contain a note in the Summary of Significant Accounting Policies describing the accounting treatment for emission allowances and RECs.

Regional Transmission Organization Charges

In the 1990s, FERC created regional transmission organizations across the United States to address the challenges posed by a power grid managed by independent utilities with potentially competing interests. Independent system operators (ISOs) are intended to be revenue-neutral entities and pass on all their operating costs to the market participants.

Each market service provided by an ISO is defined by a charge type. Some examples of these charge types are administrative fees, purchased power, load and resource balancing and transmission costs.

The FERC Uniform System of Accounts provides guidance on accounting for these services. The Code of Federal Regulations (CFR) 18, Part 101 defines the use of the following accounts:

555 Purchased Power

A. This account shall include the cost at point of receipt by the utility of electricity purchased for resale. It shall include, also, net settlements for exchange of electricity or power, such as economy energy, off-peak energy for on-peak energy, spinning reserve capacity, etc. In addition, the account shall include the net settlements for transactions under pooling or interconnection agreements wherein there is a balancing of debits and credits for energy, capacity, etc. Distinct purchases and sales shall not be recorded as exchanges and net amounts only recorded merely because debit and credit amounts are combined in the voucher settlement.

B. The records supporting this account shall show, by months, the demands and demand charges, kilowatt-hours and prices thereof under each purchase contract and the charges and credits under each exchange or power pooling contract.

556 System Control and Load Dispatching (Major Only)

This account shall include the cost of labor and expenses incurred in load dispatching activities for system control. Utilities having an interconnected electric system or operating under a central authority that controls the production and dispatching of electricity may apportion these costs to this account and transmission expense Accounts 561.1 through 561.4, and Account 581, Load Dispatching-Distribution.

565 Transmission of Electricity by Others (Major Only)

This account shall include amounts payable to others for the transmission of the utility's electricity over transmission facilities owned by others.

447 Sales for resale

A. This account shall include the net billing for electricity supplied to other electric utilities or to public authorities for resale purposes.

B. Records shall be maintained to show the quantity of electricity sold and the revenue received from each customer.

Additionally, a FERC docket discusses the accounting treatment for congestion charges, stating:

"Congestion costs share characteristics of both generation and transmission. The additional costs incurred to produce energy by running units out of merit is a generation cost, while the need to run the unit out of merit is caused by a constraint on the transmission system. Therefore, congestion costs could be considered a production cost, or an additional amount paid for delivered supply properly recorded in Account 555. Alternatively, since the underlying cause of the additional production costs is transmission-related, they could be considered a transmission cost and properly recorded in Account 565. For these reasons, we have as a general matter accepted classification in either account, though facts and circumstances in a given case might make one account preferable over the other." [23]

Market/Settlement Charges Accounting Treatment

It is standard industry practice to record most of these cost types in either FERC Account 555 or 556. As described above, the utility can detail these individual charges or credit types and record them as purchased power, transmission, or generation charges. While activity related to power exchanges can be recorded as net transactions, true purchases and sales should be segregated with market sales charged to FERC Account 447.

Market Power Transactions Netting Considerations

Utilities that operate in some energy markets (such as MISO, NYISO, PJM, and others) must determine the proper accounting treatment for purchased power transactions where the utility both sells into and buys power from the market. The utility must decide whether the transactions should be recorded at net or gross in financial statements.

Accounting Standard Guidance

There is not specific and clear guidance in the accounting standards for these types of transactions. The general approach has been to look at the substance of the transaction over the form of the standards and get to the heart of the intent of the transaction. For example, certain energy markets require utilities to sell their output into the market and then buy it back for the utility to supply its customers (retail or wholesale), so the substance of that type of transaction would be:

- If the utility did not have to sell its generated output into the market, it would use it for its native load
- If the power is used for native load, then the monies received from native load customers would be revenues to the utility, while it would incur generating expense for those revenues

Recording yet another transaction of the utility's sale of generation into a market and a buy-back of that same output to serve customers is an unnecessary entry that increases both utility revenues and expenses and inflates both for the occurrence of an event that did not add any economic benefit to the utility. Common industry practice is for utilities to record these types of buy/purchase transactions at their net impact, if this was the intent of the original transaction.

Emerging Issues Task Force (EITF) 99-19 reviews the reporting of revenues on either a gross or net basis and provides questions to assist in determining the appropriate

[23] FERC Docket AC02-28-000.

accounting treatment. The guidance in EITF 99-19 states that if the answers to the questions are ambiguous, then the facts and circumstances of the transactions should be evaluated to form a judgment about the proper recording of the transactions.

As there is no clear accounting guidance in this area, it is important for the transactional parties to use their best judgment as to the intent of the transaction and record it accordingly.

MANAGERIAL GUIDANCE

CHAPTER TEN
FINANCIAL STATEMENT ANALYSIS

INTRODUCTION – THE NATURE OF FINANCIAL ANALYSIS

Financial statement analysis entails applying analytical tools and techniques to financial data to identify measurements and relationships that are significant and useful for decision making. Indeed, the primary goal of financial analysis is to facilitate good business decisions. Thus, financial statement analysis first and foremost serves the essential function of converting data into useful information.

Financial analysis can be described in various ways, depending on the objectives. It can be used as a preliminary screening tool in selection of investments. It can be used to forecast future financial conditions. It may be used to diagnose managerial, operating, or other problem areas. It can serve as a tool in the evaluation of management. Above all, financial analysis reduces reliance on pure hunches, guesses, and intuition, which reduces areas of uncertainty that attend all decision-making processes. Financial analysis does not lessen the need for judgment; rather, it establishes a sound and systematic basis for making decisions.[24]

TOOLS AND TECHNIQUES OF FINANCIAL STATEMENT ANALYSIS

A variety of tools can be used for financial analysis. In this chapter, we examine four tools.

[24] Leopold A. Bernstein, Financial Statement Analysis, page 3.

Comparative Financial Statements

The comparison of financial statements is accomplished by setting up the basic financial statements side by side and reviewing the changes that have occurred in individual categories from year to year and over the years. The most important factor revealed by comparative financial statements is trend. The comparison of financial statements over several years will also reveal the direction, velocity and amplitude of trend. Further analyses can be undertaken to compare the trends in related items.

A comparison of financial statements over two or three years can be undertaken by computing the year-to-year change in absolute amounts and examining percentage changes. These comparisons are manageable and easily understood. They have the advantage of presenting changes in terms of absolute dollar amounts and in percentages. Both must be considered because the percentage change computations may yield large percentage changes indicating a financial statement needs attention while dollar change computations may show the item is financially immaterial. The computation of year-to-year changes is simple. However, a few clarifying points are noteworthy. When a negative amount appears in the base year and a positive amount in the following year, or vice versa, no percentage change can be meaningfully computed. When an item has a value in a base year and none in the following period, the decrease is 100 percent. Where there is no figure for the base year, no percentage change can be computed.

Index-Number Trend Series

When comparing financial statements covering more than three years, the year-to-year method of comparison may become too cumbersome. Longer-term trend comparisons are better handled using index numbers. The computation of a series of index numbers requires the choice of a base year that will, for all items, have an index amount of 100.

Since the base year represents a frame of reference for all comparisons, it is best to choose a year when business conditions were as typical or normal as possible. In planning an index-number trend comparison, it is not necessary to include all the items in the financial statements. Only the most significant items need be included. See Figure 5 for an example of an index-number trend. Many published indices can be used to compute an index-series analysis. Some are designed specifically for the electric utility industry. These industry-specific indices facilitate conversion of any year to a base-year amount.

Common-Size Financial Statements

In analyzing financial statements, it is helpful to determine the proportion that a single item represents of a total group or subgroup. For example, in a balance sheet, assets, liabilities, and capital are all expressed as 100 percent, and each item in these categories is expressed as a percentage of the respective totals. Similarly, in the income statement, sales are set at 100 percent and every other item in the statement is expressed as a percent of sales. Figure 6 is a simplified example of a Statement of Net Position.

Figure 5 – Example of an Index-Number Trend

	Index Values			Actual Values		
	Year 3	Year 2	Year 1	Year 3	Year 2	Year 1
Operating revenues	$ 110	$ 200	$ 100	$ 550	$1,000	$ 500
Operating costs & expenses	113	150	100	450	600	400
Operating income	$ 100	$ 400	$ 100	$ 100	$ 400	$ 100

Figure 6 – Example of a Common-Size Statement of Net Position

	Actual	Common-size
ASSETS:		
Cash	$ 2,500	25%
Receivables	1,000	10%
Plant in Service, Net of Accumulated Depreciation	6,500	65%
Total Assets	$ 10,000	100%
LIABILITIES:		
Accounts Payable	$ 750	8%
Long-term Debt	3,000	30%
NET POSITION:		
Net Investment in Capital Assets	3,500	35%
Restricted	750	8%
Unrestricted	2,000	20%
Total Liabilities and Equity	$ 10,000	100%

Since the totals always add up to 100 percent, this community of size has resulted in these statements being referred to as common-size. Similarly, following the eye as it reviews the common-size statement, this analysis is referred to as "vertical" for the same reason that trend analysis is often referred to as "horizontal" analysis.

Common-size statements are very well suited to intercompany comparison because the financial statements of a variety of companies can be recast into the uniform common-size format regardless of the size of individual accounts. Comparison of the common-size statements for companies within the electric industry can alert an analyst's attention to variations that could answer important questions.

Ratio Analysis

Ratios are among the most widely used tools of financial analysis. A ratio expresses the mathematical relationship between one quantity and another. While the computation of a ratio involves a simple arithmetical operation, its interpretation is far more complex.

Ratios can be used to standardize reporting methods, financial statements, and other relevant variables, allowing for comparisons over time and between companies. The second purpose of ratios, however, is more meaningful; ratios measure a company's crucial relationships by relating inputs (costs) with outputs (benefits) and facilitating comparisons of these relationships over time and across companies.

Categories of Common Ratios

The ratios discussed in this chapter are neither exhaustive nor uniquely correct. The definition of ratios is not standardized and may vary from analyst to analyst, textbook to textbook, and annual report to annual report. However, the following categories of ratios have gained wide acceptance and are common to the utility industry.

- **Liquidity Ratios** – measures an enterprise's short-run ability to pay its maturing obligations
- **Activity Ratios** – measures how effectively an enterprise is using its assets
- **Profitability Ratios** – measures the degree of financial success or failure of a given enterprise for a given period
- **Coverage Ratios** – measures the degree of protection for long-term creditors and investors

The categories are not distinct, but are interrelated. Thus, profitability affects solvency, and the efficiency with which assets are used impacts the analysis of profitability. When examined, these ratios provide a profile of a company and its management's operating, financial, and investing decisions. Thus, an intelligent analysis of the ratios can provide insight into a firm's economic characteristics and competitive strategies. The foundation of good financial analysis includes the mastery of the tools of financial analysis. A solid understanding of these categories of ratios is necessary to gain such mastery. Some of the more common examples of ratios in these four categories follow.[25]

Figure 7 – Ratios by Category

Ratio	Formula for Computation
I. Liquidity	
1. Current ratio	Current assets / Current liabilities
2. Quick or acid-test ratio	Cash, marketable securities, & receivables / Current liabilities
3. Defensive-interval measure	Defensive assets / Projected daily expenditures minus noncash expenditures
II. Activity	
4. Receivable turnover	Net sales / Average trade receivables (net)
5. Inventory turnover	Cost of goods sold / Average inventory
6. Asset turnover	Net sales / Average total assets
III. Profitability	
7. Profit margin on sales	Net income / Net sales
8. Rate of return on assets	Net income / Average total assets
9. Rate of return on common stock equity	Net income minus preferred dividends / Average common stockholders' equity
10. Earnings per share	Net income minus preferred dividends / Weighted shares outstanding
11. Price earnings ratio	Market price of stock / Earnings per share
12. Payout ratio	Cash dividends / Net income
IV. Coverage	
13. Debt to total assets	Debt / Total assets of equities
14. Times interest earned	Income before interest charges and taxes / Interest charges
15. Book value per share	Common stockholders' equity / Outstanding shares
16. Cash flow per share	Income plus noncash adjustments / Outstanding shares

[25] Kieso & Weygandt, Intermediate Accounting 7th Edition.

Ratio Integration

Comprehensive financial analysis requires a review of the interrelationships among ratios resulting from the following factors:[26]

1. Economic Relationships. The underlying economics of a company result in elements of the financial statements moving in tandem. For example, higher sales are generally associated with higher investment in working capital components such as accounts receivable and inventory. Ratios comprising these various elements would be correlated.

2. Overlap of Components. A cursory examination of the ratios examined indicates that the components of many ratios overlap. This overlap may result from ratios containing an identical term in the numerator or denominator or because a term in one ratio is a subset of a component of another ratio.

3. Ratios as Composites of Other Ratios. Some ratios are related to other ratios across categories. For example, the return on assets ratio is a combination of a profitability and turnover ratio.

The interrelationships among ratios have important implications for financial analysis. Disaggregation of a ratio into its component elements provides insight into the factors affecting a company's performance. Further, ratio differences can highlight the economic characteristics and strategies of:

COMPANIES IN THE SAME INDUSTRY	THE SAME COMPANY OVER TIME	COMPANIES IN DIFFERENT INDUSTRIES

The relationships between ratios imply that one might be able to ignore some component ratios and use a composite or representative ratio to capture the information in other ratios.

Factors Affecting Ratios

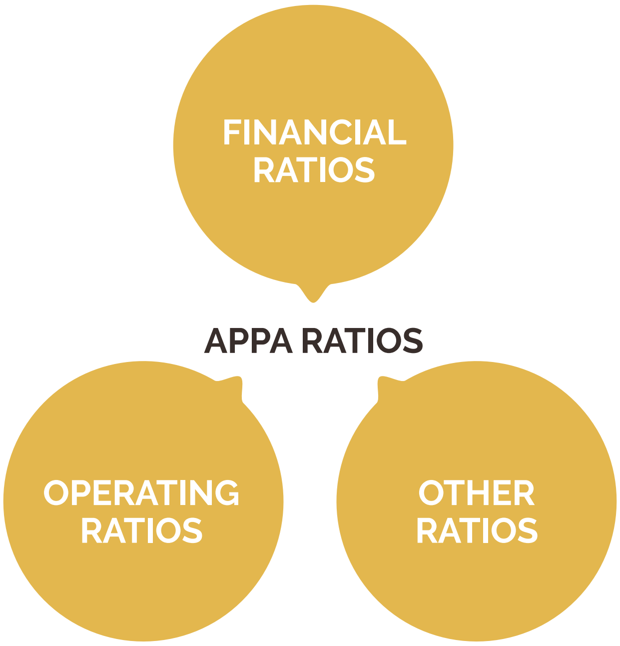
In addition to internal operating conditions that affect ratios, analysts must remember that factors such as general business conditions, industry position, and accounting principles can affect ratios. Two accounting-related factors are inherent in most ratios:

Historical Costs. One of the basic premises of GAAP is that transactions are recorded at original costs. Over time these costs become historical and may not be a relevant estimate of current or future conditions.

Estimates. Accounting data contains estimates. One significant piece of accounting information based on estimates is depreciation. Since these estimates are embedded in the accounting data that many ratios are based on, the integrity of the ratios is directly related to quality of the estimates.

APPA Ratios

The American Public Power Association publishes ratios that can be extremely valuable in the financial analysis of public power utilities. The annual publication titled Selected Financial and Operating Ratios of Public Power Systems presents data for 21 categories of financial and operating ratios (as of December 2018 publication) and is available for purchase at www.PublicPower.org. The publication provides groupings of ratios by customer size class, region, and net power generation. APPA ratios are separated into three categories:



[26] Gerald I. White, The Analysis and Use of Financial Statements, page 231.

The 21 ratios included in the publication are listed below.

FINANCIAL RATIOS

1. Revenue per kWh
2. Debt to Total Assets
3. Operating Ratio
4. Current Ratio

5a. Times Interest Earned
5b. Debt Service Coverage

6. Net Income per Revenue Dollar
7. Uncollectible Accounts per Revenue Dollar

OPERATING RATIOS

8. Retail Customer per Non-Power Generation Employee
9. Total O&M Expense per kWh Sold
10. Total O&M Expense (Excluding Power Supply Exp.) per Retail Customer
11. Total Power Supply Expense per kWH Sold
12. Purchased Power Cost per kWh
13. Retail Customers per Meter Reader
14. Distribution O&M Expense per Retail Customer
15. Distribution O&M Expense per Circuit Mile
16. Customer Accounting, Service, and Sales Expense per Retail Customer
17. Administrative and General Expense per Retail Customer

OTHER RATIOS

18. Labor Expense per Worker-Hour
19. Energy Loss Percentage
20. System Load Factor
21. Capital Expenditures to Depreciation Expense

These ratios are presented in summary, with the median value of all applicable surveyed customer classes illustrated on page 7 of the report, as illustrated in Figure 8. This provides a base level for understanding the metrics of common ratios in the industry.

Figure 8 – APPA Ratios[27]

FINANCIAL RATIOS	NO. of UTILITIES	MEDIAN
1. Revenue per kWh		
a. All Retail Customers	138	$0.097
b. Residential Customers	138	$0.109
c. Commercial Customers	138	$0.101
d. Industrial Customers	124	$0.074
2. Debt to Total Assets	132	0.321
3. Operating Ratio	135	0.850
4. Current Ratio	135	2.66
5a. Times Interest Earned	112	3.74
5b. Debt Service Coverage	112	2.78
6. Net Income per Revenue Dollar	137	$0.055
7. Uncollectible Accounts per Revenue Dollar	133	$0.0015
OPERATING RATIOS		
8. Retail Customer per Non-Power Generation Employee	138	313
9. Total O&M Expense per kWh Sold	138	$0.080
10. Total O&M Expense (Excluding Power Supply) per Retail Customer	136	$540
11. Total Power Supply Expense per kWh Sold	138	$0.061
12. Purchased Power Cost per kWh	137	$0.059
13. Retail Customers per Meter Reader*	109	6,609
14. Distribution O&M Expense per Retail Customer	128	$184
15. Distribution O&M Expense per Circuit Mile	127	$7,637
16. Customer Accounting, Service, and Sales Expense per Retail Customer	128	$62
17. Administrative and General Expense per Retail Customer	127	$194
OTHER RATIOS		
18. Labor Expense per Worker-Hour	131	$41.04
19. Energy Loss Percentage	132	3.39%
20. System Load Factor	133	57.4%
21. Capital Expenditures to Depreciation Expense	134	1.14

In addition to this summary of ratios, the APPA report provides summaries broken down into the following categories: customer size class, region, and power generation class. These categories are further broken down into extended tables highlighting ratio breakouts through value ranges with statistical analysis for each category. This allows for effective identification of ratios that may be most applicable to the report user, making the report relevant for many of the users, as they are able to identify applicable ratios based on their respective categorical ranges.

These ratios provide information specific to customers based on financial and non-financial data. When examined individually in relation to the components of the calculation, these values (median or mean) can be used for benchmarking analysis, a valuable tool for assessing the efficiency and effectiveness of utility performance. Benchmarking as a management tool is discussed in Chapter 11, "Key Performance Indicators."

[27] American Public Power Association, APPA Selected Financial and Operating Ratios of Public Power Systems, 2018 Data, p. 7.

KEYS TO SUCCESS IN FINANCIAL STATEMENT ANALYSIS

Whatever approach to financial statement analysis is taken, one or more aspects of a company's financial condition or results of operations will need to be examined. Most of these aspects can be found in one of the following six categories:[28]

1. Short-term liquidity	**2.** Funds flow	**3.** Capital structure and long-term solvency
4. Return on investment	**5.** Operating performance	**6.** Asset utilization

The financial analysis required by any set of objectives may be structured to examine any or all the areas above in any sequence and with any degree of relative emphasis called for by the circumstances. Thus, these six areas of inquiry and investigations can be building blocks of financial statement analysis. The building block approach to financial statement analysis involves:

- The determination of the major objectives that a particular financial analysis is to achieve.
- Arriving at a judgment about which of the six major areas of analysis (building blocks) must be evaluated with what degree of emphasis and in what order of priority.

METHODOLOGY OF FINANCIAL STATEMENT ANALYSIS

The marshaling, arrangement, and presentation of data for financial statement analysis can be standardized. However, each analyst must apply judgment to account for the great diversity of circumstances. Financial statement analysis must be tailored to the specific needs of a given situation. An analyst must consider his or her own knowledge, skills, and abilities to determine the best process to meet the specific objectives. The following five-step approach to financial statement analysis is presented as a generalized approach.

1. **Define the objectives** of the financial analysis.
2. **Formulate questions** that must be answered to achieve the objectives.
3. **Decide which tools and techniques** are the most appropriate, effective and efficient to answer the questions formulated to achieve the objectives.
4. **Analyze and interpret the data and measures assembled** as a basis for decision and action. This is the most critical and difficult of the steps, and the one requiring the application of a great deal of judgment, skill and effort.
5. **Prepare a written analysis and report.** A good analysis separates clearly for the reader the interpretations and conclusions of the analysis from the facts and data upon which they are based. This not only separates fact from opinion and estimate but also enables the reader to follow the rationale of the analyst's conclusions. To this end, the analysis should contain distinct sections devoted to:[29]

a. General background material on the enterprise analyzed, the industry of which it is a part, and the economic environment in which it operates.

b. Financial and other data used in the analysis as well as ratios, trends, and other analytical measures that have been developed from them.

c. Assumptions regarding the general economic environment and other conditions on which estimates and projections are based.

d. A list of positive and negative factors, quantitative and qualitative, by important areas of analysis.

e. Projections, estimates, interpretations, and conclusions based on the aforementioned data.

A good analysis should start with a brief summary and conclusions section as well as a table of contents to help the busy reader decide how much of the report to read and on which parts to concentrate.

[28] Leopold A. Bernstein, Financial Statement Analysis, page 94.
[29] Ibid, page 784.

CHAPTER ELEVEN
ALLOCATING COSTS

INTRODUCTION

Serving customers requires certain support operations that provide internal services to multiple utility departments. If a utility provides multiple services, i.e., electric, water, wastewater, gas, communications, etc., these services are also provided to each utility service line. This requires a structured and defensible approach to allocating these costs across the multiple departments and/or utility services. This chapter discusses some common approaches to the cost allocation process in developing allocations that mimic the behavior of the underlying service provided.

COST ASSIGNMENT FUNDAMENTALS

Cost allocators that are the fairest and easiest to share within an organization are those that allocate cost based on "cost causation," i.e., the cost driver behaviors behind each cost and which department or utility service is driving that cost. The rules of cost allocations are simple:

- Direct charge all costs that can be specifically identified with a department or activity to the area or activity driving the cost
- Remaining costs should be allocated across departments or services based on an agreed-upon methodology

These cost principles are designed to provide a defensible methodology for cost allocations.

THE FUNDAMENTAL COST ALLOCATION METHODOLOGY SHOULD HAVE THESE CHARACTERISTICS:

01 **COST-CAUSATIVE**: There should be a relationship between the cause for the expense and the effect the activity had on the benefiting business unit

02 **MEASURABLE**: Amounts should be recorded in the financial data, subject to internal controls and auditable

03 **OBJECTIVE**: The method should determine how costs should be allocated without bias

04 **STABLE & PREDICTABLE**: The method should not produce variations that are not in line with service level variations

05 **CONSISTENTLY APPLIED**: The calculated cost per unit should be the same for all users of that service

SHARED SERVICES

Shared services are an approach to delivering high-quality internal services efficiently and effectively. They:

- Are centralized internal departments with consolidated, dedicated resources
- Provide process or knowledge-based services to several organizations or departments within an organization
- Operate as a quasi-standalone business with its own profit center
- Focus solely on internal customers

The functional characteristics of shared services include:

- The transactions are high-volume and routine
- Specialized skills are needed to provide the services
- The services are delivered company-wide

Analyzing and allocating shared services in a systematic manner can remove some of the give and take discussion that is inevitable when departments need and want the services but are concerned about their budget impact.

Typical Benefits of Identifying and Allocating Shared Services

The benefits of shared services can be felt across the organization in four main areas – strategy, people, technology, and process:

Strategy – A utility's strategy is to provide reliable service at a reasonable cost. This does not mean all costs should not be recovered—shared services make the utility's mission possible and contribute to driving strategy.

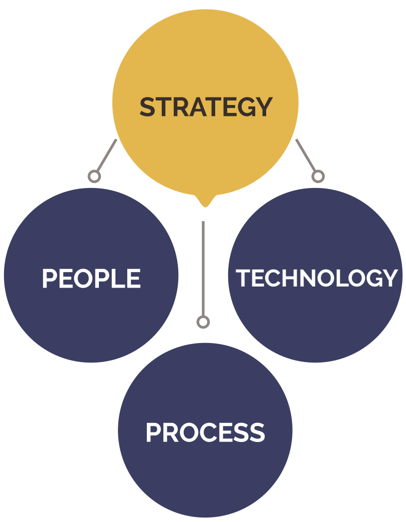
People – Dedicating resources to a shared services function allows for more focused personnel training and dedicated technical resources since the primary mission will be to serve internal customers with these services. This will allow for more effective allocation of resources across the departments of the utility.

Technology – Shared technology provides a single source of information and single point of technology solutions leading to a reduction in the need for multiple IT staffs and related maintenance.

Process – Standardized processes will lead to greater efficiencies in delivery and ease of communication across departmental lines.

Illustration 11-1: Characteristics of Shared Services

- Allows for better sharing of information
- Cross-training provides added flexibility for workload peaks
- Environment with an improved ability to build functional excellence
- Dedicated personnel
- Clear focus on primary mission
- Shared services focuses on transaction accuracy and throughput; services provided are improved through synergy and specialization
- Standardize processes
- Ease of communication
- Reduces non-value-added activities
- Shared services becomes a third-party supplier to the organization



- Eliminates multiple maintenance staffs and costs
- Eliminates need for training and skill building on different applications or architectures
- Provides a single source of information
- Provides ability for common tools among many users
- Allows for real-time access to company-wide information, therefore better management decisions
- Facilitates the move toward common data architectures
- Allows for quick migration to new technology platforms with a single investment

Areas to Review for Shared Services

Departments that are candidates for inclusion in a shared services allocation include:

Table 22: Shared Service Departments

Human Resources	Safety
Fleet Management	Information Technology
Warehousing and Inventory	Customer Service, Billings and Collections
Internal Audit	Meter Reading and Meter Shop
Central Maintenance	Finance
Procurement	Base Control and Dispatch
Facilities	Public Information

Many of these areas are common and non-critical to a specific utility department or service. Costs that are directly assignable should be charged directly to a project or department; all others could be considered for a shared services allocation.

COMMON COST ALLOCATION METHODS

Three-Factor Formula

The three-factor formula is an allocation method used when there is no direct or other reasonable cost-benefit relationship among multiple services in a single organization. Industry reviews have identified three constant drivers that determine the level of service provided to customers, regardless of the size of the utility. These drivers are:

1. Utility plant in service
2. Revenues
3. Total direct labor

The weighted average of these drivers of the utility business in a multiple service utility are calculated and used to allocate shared services expenses. Illustration 11-2 provides an example of this calculation.

Illustration 11-2: Application of the Three-Factor Formula

A utility provides electric, water, and communications services to customers. Determining the allocation factor based on the three-factor formula is calculated as follows:

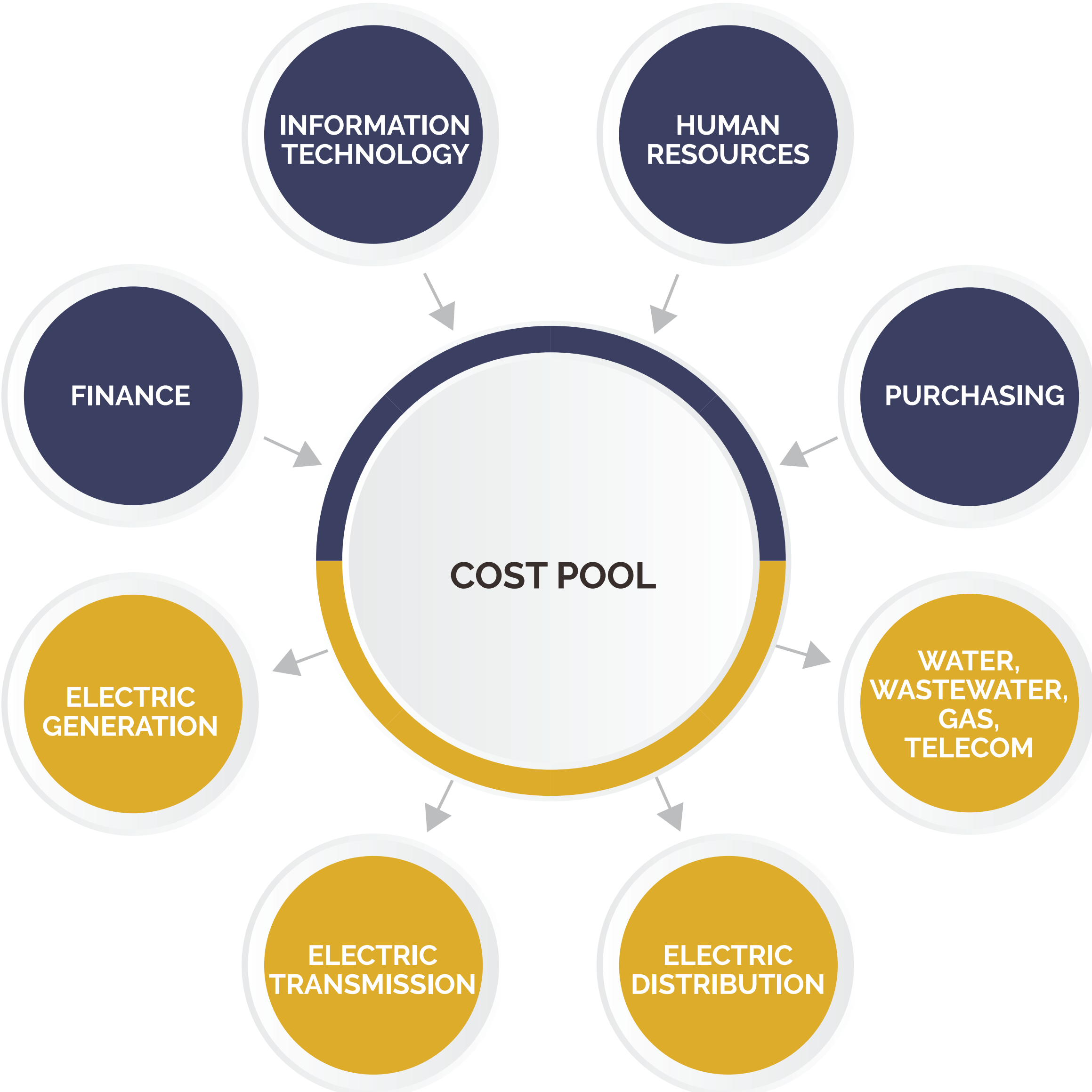
Table 23: Calculation of Three-Factor Allocation Percentage

UTILITY	PLANT	%	REVENUES	%	LABOR	%	WEIGHTED AVERAGE
Electric	$400,000	83%	$75,000	81%	$12,000	86%	83%[30]
Water	$50,000	10%	$10,000	11%	$1,000	7%	9%
Communications	$30,000	7%	$8,000	8%	$1,000	7%	8%
Total	$480,000	100%	$93,000	100%	$14,000	100%	100%
(Amounts are in 000)							

The use of the calculation is:

1. Direct charge any shared services costs to a utility if identified as caused by that utility
2. Allocate remaining shared services costs after they are pooled to Electric (83 percent), Water (9 percent) and Communications (8 percent)

[30] The weighted average is calculated as (83% + 81% + 86%)/3



Industry practice includes other alternative calculation of drivers in the three-factor formula or performs the calculation on two-factors, such as:

- Plant and revenues
- Plant and labor
- Revenues and labor
- Plant, expenses (net of power expense) and labor

OTHER ALLOCATION METHODS

Other common cost allocation methods can differ by area, but in general, the driver is the activity of the allocation. Table 24 lists allocation areas and their common cost allocation methods.

Table 24: Common Cost Allocators for Shared Services

ALLOCATION AREA	COMMON ALLOCATOR
Financial Systems	Number of transactions by cost center
Accounts Payable	Number of invoices by cost center
Fleet Services	Total of depreciable assets by cost center
Payroll	Employees by cost center
Customer Services	Customers by service type (meter count)
Information Technology	Total number of IDs assigned to employees by cost center
Administrative and general	Three-factor formula
Finance	Three-factor formula
Office Space	Number of employees by cost center or square footage by cost center
Any remaining shared services costs	Three-factor formula

The first rule of cost allocations applies – directly charge expenses when possible to their cost causation, then use one of the cost allocators in the above table for any remaining unallocated costs.

SUMMARY

A systematic and defensible allocation of shared services costs ensures that these costs are charged equitably across the utility's departments. The key is to gain acceptance by all parties to ensure an effective foundation for departmental budgeting for shared services and a basis to make investment decisions in shared services in personnel, technology, and improved business processes.

CHAPTER TWELVE
KEY PERFORMANCE INDICATORS

BENCHMARKING AND BENEFITS

Benchmarking is a process of comparing a utility to some standard. The benchmark might be an industry average, or it might be based on the utility's own performance. This process allows for management analysis of efficiencies and effectiveness in operations and allows for analysis of performance of employees and third-party service providers. Benchmarking also may be a regulatory requirement for rate cases, making performance of benchmarking in advance a time-saving tool for future projects.

As an asset to operational analysis, benchmarking can reveal potential areas where performance is lacking and point to directions for further detailed examination and business process enhancements or improvements. Further examination can serve to identify any underlying causes or mitigating factors to a performance gap. Additionally, benchmarking can help align improvement activity with related strategic goals and objectives.

COMMON INDUSTRY BENCHMARKS

Two types of benchmarks can be used: (1) internal performance and (2) peer class utilities. As illustrated in Figure 3 in Chapter 9, common ratios serve to convert financial and non-financial data into useful information for analysis of specific performance. This information is compared across multiple utilities within the industry on many levels to gain a further understanding of performance at utilities based on customer size, region, and other factors.

Taking this information one step further, ratios that are deemed reliable and relevant to a specific utility can be used as benchmarks for performance. This turns analytic information into something that can guide future decisions and establish groundwork for measuring performance and driving value creation within the organization. Ratios identified as common can be used (as appropriate) to establish benchmarks for performance in a specific area.

USES BY MANAGEMENT

As illustrated in the following example, a single ratio can be examined by component for inherent value and isolated for a range to determine a ratio useful in the establishment of a benchmark. For our example, we will use the debt-to-total assets ratio.

Table 25: Debt-to-Total Assets Equation

RATIO	FORMULA
Debt-to-Total Assets	$\dfrac{\text{Long Term Debt + Current and Accrued Liabilities}}{\text{Total Assets}}$

This equation contains two main components – the debt or "obligations" of a utility to its creditors and the assets of a utility. When the two values are compared mathematically, the result indicates, at a high level, the ability of a utility to meet outstanding obligations. A value less than one indicates the utility has sufficient capacity to meet outstanding obligations with existing assets while a value greater than one indicates additional assets would be needed to meet outstanding obligations.

As a stand-alone ratio for a single entity, one would have a difficult time determining the adequacy of the ratio in relation to the utility's needs. Assets may be sufficient to cover debt, or vice-versa, but comparability is absent from the information held. However, when compared against the same ratio for similarly sized utilities with comparable criteria (customer size class, region, generation), a user of the ratio will be able to identify meaning in the value and reasonableness when comparing the ratio to other entities in the same industry. When reviewing a volume of ratios for a set of criteria, one may be able to determine an industry norm and a desirable level for the ratio. This serves as the basis for establishing a benchmark for performance.

When doing this, ensure that reliable external sources are used to facilitate data integrity. Unreliable sources not only provide bad data for the process, but waste resources in the process of obtaining and reviewing the data. Additionally, ensure the data is current. Data that is not timely has little value.

Let us assume for this example that the company, XYZ Power, Inc., has the following relevant information:

Customer Size Class:	20,000 customers
Location:	Anytown (North Central/Plains)
Power Generation:	No Generation
Debt to Asset Ratio:	0.50

Management feels the ratio in place reflects an adequate ability to satisfy obligations with assets held but is seeking to establish an understanding of how this ratio compares to other utilities with comparable criteria. Recently, management obtained a survey of utilities and began reviewing the information (see Figure 9 below – Table 2 from Selected Financial and Operating Ratios of Public Power Systems[31]).

In reviewing the information, management noticed the debt-to-assets ratio is greater than the median ratio for customer size class (0.303), region (0.454), and generation (0.384). In addition, the ratio for XYZ Power is higher than the third quartile values and even the weighted mean values. When compared to peer entities in multiple categories, it appears that the ratio needs to be improved to be more comparable with industry peers.

Figure 9 – Debt to Total Assets

	Utilities	Mean (weighted)	1st Quartile	Median	3rd Quartile
Total	132	0.512	0.176	0.321	0.517
1. Customer Size Class					
2,000 to 5,000 Customers	6	0.193	a	0.140	a
5,000 to 10,000 Customers	22	0.360	0.143	0.204	0.345
10,000 to 20,000 Customers	31	0.303	0.165	0.196	0.357
20,000 to 50,000 Customers	34	0.349	0.168	0.308	0.477
50,000 to 100,000 Customers	19	0.479	0.361	0.512	0.575
More than 100,000 Customers	20	0.549	0.459	0.563	0.720
2. Region					
Northeast	9	0.412	0.124	0.156	0.334
Southeast	39	0.508	0.194	0.303	0.511
North Central/Plains	34	0.454	0.164	0.237	0.473
Southwest	20	0.514	0.181	0.393	0.608
West	30	0.533	0.239	0.385	0.528
3. Generation					
No generation	61	0.384	0.154	0.230	0.372
More than 0 but less than 10%	27	0.466	0.173	0.366	0.550
10 to 50%	22	0.604	0.249	0.439	0.580
50 to 100%	22	0.519	0.311	0.489	0.580

a: Quartiles are not calculated for fewer than 9 responses

[31] American Public Power Association, APPA Selected Financial and Operating Ratios of Public Power Systems, 2018 Data, p. 17.

DEVELOP A STRATEGY

Once a ratio is identified as deficient, management should create a strategy to establish a benchmark. For the sake of this example, let us say management has agreed upon a benchmark of 0.350 as one that is achievable and necessary for future industry competitiveness.

The first part of this process entails analyzing the components of the ratio. In this case, the components of the ratio are the assets and debt of the utility. To achieve the desired performance, assets must be increased sufficiently, debt must be decreased sufficiently or a combination of both must be attained to reach the benchmark value. Management should use available information to determine the components of each variable and identify which components have the most flexibility for change. Examples of solutions include:

Using excess cash to retire debt	Reduce expenses to increase profitability	Raise capital through equity issuance

Whatever the method chosen, management should thoroughly examine all reasonable options to determine a strategy and approach appropriate for the organization.

TOOLS TO MEASURE PERFORMANCE

Once a strategy has been decided, management must determine the best means to measure the progress of the strategy and establish goals for achievement. Both the measurement tools and goals should be agreed upon, and management should gain acceptance and buy-in from the process owners who will be working to achieve the desired goal. Both steps are critical to achieving the desired outcome and should be done in advance of implementation. For the example above, measurement techniques could be as simple as a chart, graph, or spreadsheet tracking the variables. In other cases, more complex tools for measurement may be necessary when variables require greater depth of measurement/calculation or impacting factors are non-numerical, such as increasing employee safety to decrease costs related to workplace injuries. Compensation for injuries at the workplace is directly measurable, but safety is not easily measured numerically. Therefore, it must be broken down into parts that are measurable and monitored appropriately.

In this case, a balanced scorecard would be an excellent tool to track measurable characteristics of safety as there are multiple components (employee injuries, severity of injuries, staffing levels, absenteeism, diversity plans, and succession planning depth, which can be tracked over a specific period of time and over multiple departments affected by safety.

This tool provides multiple data elements (vertical columns) for each area of measurement (horizontal columns), which allows for effective analysis of critical areas and facilitates awareness of areas. Results can also be posted to increase public awareness of measurement criteria, which may result in coincidental improvements outside of management directives.

Related to each area measured, an analytic page should be created and included in monthly reporting, which is shared with management. This page provides reinforcement of monthly measurements and meaningful written analysis. From this page, measurements can be analyzed, and a recovery plan can be outlined to help bring the metric back in line with objectives.

These factors must be measured in real-time with timely feedback to provide value and allow for corrective action. Whatever tool is used, remember it is only as strong and effective as the reporting process. Thoroughly plan and investigate the area(s) measured. Choose the metric that best reflects the organization's objectives and needs, understand its impact on the organization objectives, and ensure communication between involved parties is fluid and continuous. Measuring performance is an active process. With a proactive and thorough approach, the likelihood of achieving desired results is greatly increased.

MITIGATING BENCHMARKING RISK

Benchmarking can provide excellent benefits to an organization through improved bottom-line performance and understanding of key entity areas. However, this does not mean benchmarking is risk-free in design and execution. When achievement of a benchmark is tied to the performance of an individual or a department, exposure to decisions that adversely impact non-financial areas of the company increases.

Using our example of the debt-to-assets ratio, assume management chose to reduce expenses. The CEO directed each department manager to cut expenses by 25 percent and incentivized the achievement of this objective by offering a 2 percent salary bonus on achievement of this objective.

Management now has a monetary incentive to achieve the goal. Using a single benchmark of the debt-to-assets ratio, department managers may look at the easiest and most direct way to cut large expenses from their budget, such as through payroll. The field services manager, when reviewing the department expenses notices that reducing the staff from six to four personnel would achieve the objective. Management reduces staff, resulting in a 20 percent increase in response times. This is an adverse result.

To mitigate this risk, consider some of the following ideas:

- **Use multiple benchmarks** to avoid conflicts of interest and adverse performance. Ensure benchmarks used have a purpose supporting organizational objectives and, if possible, the benchmarks complement each other.
- **Avoid general solutions** – when objectives are generic, management has significant freedom to meet the objective, which may not be beneficial to the organization. Focus on S.M.A.R.T. goals and solutions (Specific, Measurable, Achievable, Realistic, and Timely) to define the path to objective success.
- **Encourage group discussions** – cross-functional discussion between department management encourages free-flowing thought and alternate perspectives. Too often, a person may be defined by his or her role and focused understanding, reducing exposure to how the department relates to the larger organization and how other managers perceive and understand their department. Seek input in non-traditional areas to maximize the idea and solution base.

CHAPTER THIRTEEN
COMPONENTS OF CUSTOMER RATES

INTRODUCTION TO UTILITY RATES

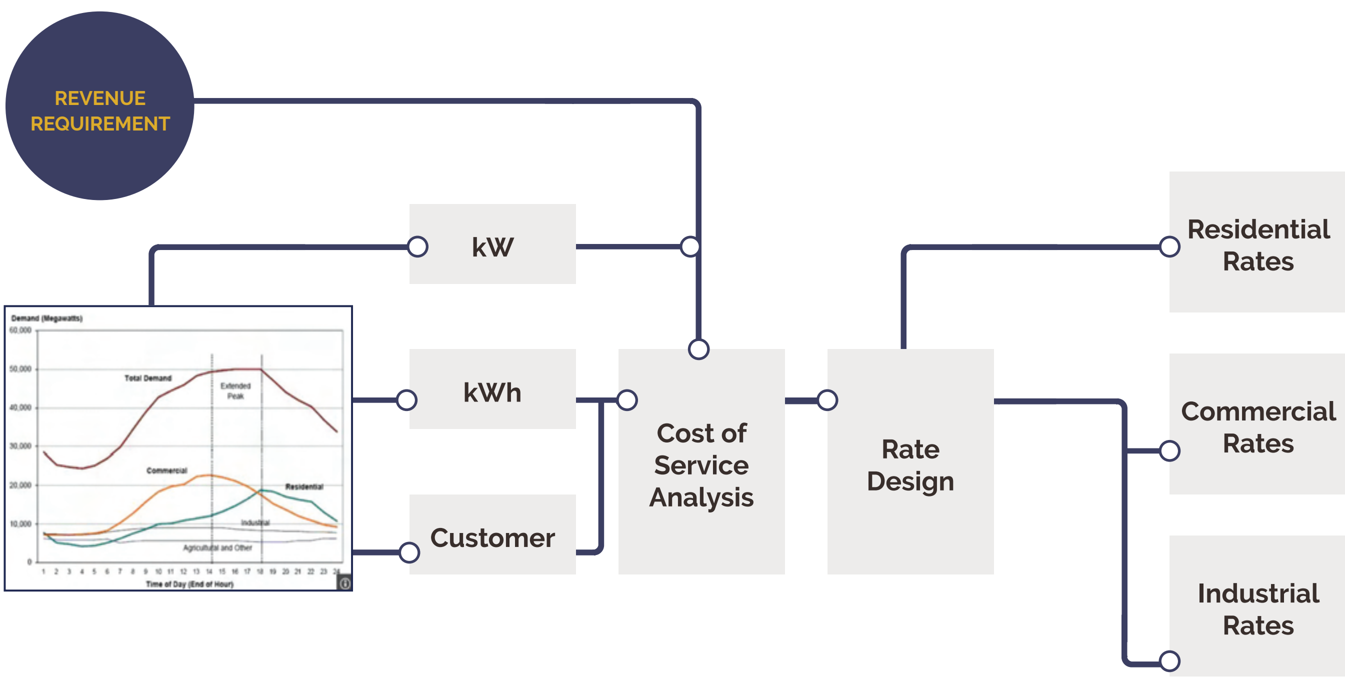
The ultimate question in any business is, ***"How will we generate revenue to pay for the services we provide to our customers?"*** It is no different in the utility industry, with customer rates at the forefront of any business decision. In the public power arena this is critically important, as public power utility oversight is by utility boards or city councils that are ultimately responsible to their community's citizens.

The ratemaking process is comprised of three components:

Revenue requirement	Cost of service analysis	Rate design

The process steps are shown in Illustration 13-1.

Illustration 13-1: Process in Developing Electric Rates



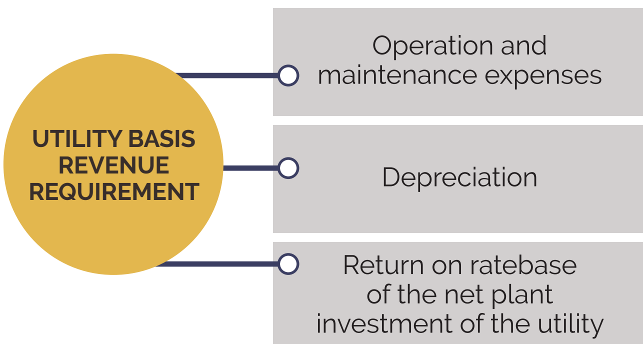
This chapter is an introduction to utility ratemaking concepts and how utility costs are recovered through customer rates. We discuss the basic components of utility rates and their impact on current utility operations and long-term utility strategic planning.

THE REVENUE REQUIREMENT

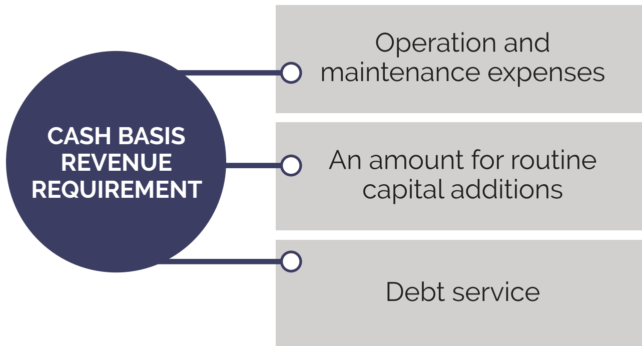
The revenue requirement is the amount of cash a utility needs to operate for a base period, which is called the test period or test year. This is generally the next year of the utility's operations, or the next budget year[32]. A test year serves to develop a representative cost of service reflecting sales, revenues, operation and maintenance expenses, depreciation expense, taxes, and a return on rate base. The revenue requirement should provide the necessary cash flows to meet the full costs of service to customers over the test period.

Utility Basis vs. Cash Basis Revenue Requirements

The ***utility basis revenue requirement*** consists of the following components for one year's utility operations:



The ***cash basis revenue requirement*** consists of the following components for one year's utility operations:



The cash basis revenue requirement is used more commonly in the public power industry. The utility basis revenue requirement is used by investor-owned utilities regulated by state utility commissions, large and regulated public power utilities, and is a traditional foundation for setting revenue requirements. However, the two methodologies should arrive at or near the same revenue requirement needed to operate the utility in the test period.

Application of Revenues Derived from Each Component of the Revenue Requirement

Utility Basis Revenue Requirement

The application of each component in the revenue requirement under the utility basis is shown in Table 26.

Table 26: Utility Basis Revenue Requirement[33]

COMPONENT	AMOUNT	USE OF FUNDS
Operating expenses	$60,000,000	Operation and maintenance expenses
+Depreciation	$5,000,000	Replacement of the historical installed cost of utility plant to which the depreciation applies
+ Return on ratebase	$5,100,000	Debt service and the inflationary increase in the historical installed cost of
= Total Revenue Requirement	$70,100,000	

[32] If this is the utility operating Year 20x1, then the Test Year would be the next year - Year 20x2
[33] Sample utility components

The return on ratebase is calculated as follows in our example:

Table 27: Calculation of Return on Ratebase

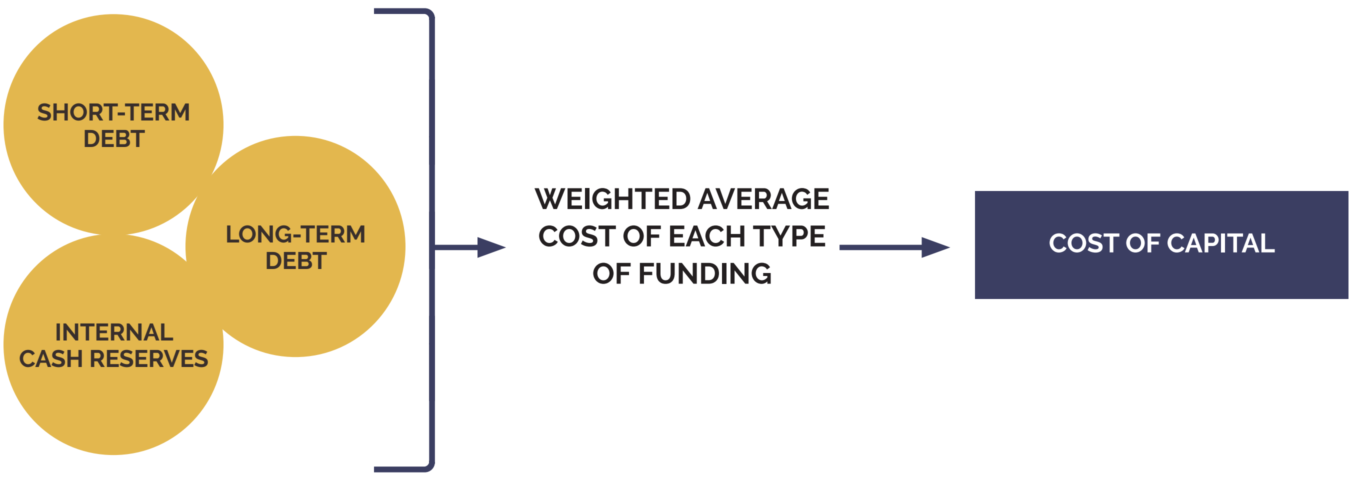
COMPONENT	CALCULATION
Plant in service	$100,000,000
Less: Accumulated depreciation	($20,000,000)
Net Plant in service	$80,000,000
Add: Working capital[34]	$5,000,000
Net investment ratebase	$85,000,000
Times: Rate of return on ratebase	X 6%
= Return on Ratebase	$5,100,000

Rate of Return on Ratebase

The rate of return is a percentage applied to the utility's total plant investment. The rate of return generally is equal to the utility's cost of capital – i.e., the cost of the funding operations with short-term debt, long-term debt, and internal funds. The return is used to pay for debt principal and interest payments, the inflationary increase in the cost to replace the historical cost of plant (amount above that covered by depreciation expense) and a return for the risk component of being in the business of providing electric service to customers. Refer to Illustration 13-2 below.

The rate of return generally is equal to the utility's cost of capital, i.e., the cost of funding operations and capital improvements with short-term debt, long-term debt and internal funds.

Illustration 13-2: Cost of Capital Components



Cash Basis Revenue Requirement

The application of each component in the revenue requirement under the cash basis is as follows:

Table 28: Cash Basis Revenue Requirement

COMPONENT	AMOUNT	USE OF FUNDS
Operating expenses	$60,000,000	Operation and maintenance expenses
+ Routine capital additions	$6,000,000	A factor used for routine capital additions – generally equates to depreciation expense
+ Debt service	$4,000,000	Current debt principal and interest payments
= Total Revenue Requirement	$70,000,000	

[34] The component of working capital is based on funds that would be set aside to carry the utility through a billing cycle, i.e., 30 to 60 days

Table 29: Cost of Service Allocations

COMPONENT	AMOUNT	KW	KWH	CUSTOMER
Revenue requirement	$70,000,000	$20,000,000	$40,000,000	$10,000,000

DETERMINING THE COST OF SERVICE

For electric utilities, the revenue requirement is allocated to major cost components, which are:

- **kW: kilowatts** – the demand placed on the utility's system by a customer, group of customers or all customers
- **kWh: kilowatt-hours** – the usage of energy over time – the amount of energy used by a customer, group of customers or all customers
- **Customer** – costs incurred to serve customers (including billing, collections, metering)

A major driver is also the FERC account to which the costs have been assigned. Table 29 shows this process.

In a simplified cost-of-service study, the revenue requirement is allocated to the cost components, based on the kW demand, kWh consumption and number of customers in each group. In a simplified cost-of-service allocation, costs would be allocated to each customer class based on their kWh consumption relative to total consumption for the utility. In practice, the calculation is more complicated. One of the main cost allocation drivers is the FERC Uniform System of Accounts, where expenses and utility plant are charged.

RATE DESIGN

While customer rates are designed to meet the utility's revenue requirement, rate design is used to meet several utility operational and strategic goals. This is more art than science. In an ideal world, customer rates would be based on the cost of service; however, each utility has decades of history in developing rates and a move from current rate structures to a cost-based approach is not always immediately feasible or desirable from a practical or political viewpoint. Overall, a utility's cost recovery philosophy should follow key standards of rate design.

Customer rates should:

- Meet the utility's revenue needs
- Provide funds to be used to meet customers' need for service reliability
- Provide stability and continuity to the utility and the customer with a minimum of unexpected changes
- Be equitable
- Provide a rate structure that does not unduly subsidize other customers
- Provide price signals and options to customers who wish to minimize their usage and billings
- Promote conservation
- Provide the utility with the foundation to meet its long-term strategic goals

For equitable rates, a utility should match rates to the cost of service for each customer class.

THE FUTURE OF COST RECOVERY

Utilities are experiencing an era of great change – in fuel supply sources and in the rise of customer-sited distributed generation such as wind, solar and biomass. These changes will challenge the traditional methods of rate design and cost recovery.

Coupled with that, methods for measuring customer consumption and time of use can lead to more efficient and accurate pricing decisions – giving customers a choice over how and when they use electricity. Those choices will also lead to a a more real-time pricing model.

However, utilities will continue to need to identify their costs and to understand what drivers are behind the cost of service. Accurate accounting for costs and capital infrastructure for customer service will remain the foundation of cost recovery and customer rates. We urge the reader to obtain a greater depth of knowledge of cost of service and rate design methods through the other American Public Power Association resources.

CHAPTER FOURTEEN
BUDGETS & LONG-RANGE FORECASTS

BUDGETS

In theory, a budget is a realistic plan for the future expressed in quantitative terms. The budget is a planning and control tool. From a governmental perspective the following is relevant.[35]

> Public agencies can operate with a haphazard budget process. However, an effective operating system that includes incentives for officials to respond to public demands is more likely to produce consistently good decisions. A good public decision will give citizens the quantity and quality of desired public services, at the desired times and locations, at the least cost to society. The budgeting process must recognize competing claims on resources and should focus directly on alternatives and options. A major portion of the process will involve presentation of accurate and relevant information to individuals making budget decisions.

A budget for a governmental unit, unlike that for a business enterprise, is a legal document resulting from a budgetary process that involves many different parties. Hence, the budget for some public power utilities constitutes the authority to spend. Accordingly, it is important to discuss some basic types of budgets.[36]

The remainder of our discussion focuses on operating budgets and capital budgets.

Sales Budget. This is usually the first budget prepared. Theoretically, this budget tells sales personnel which business lines to push. The sales budget directly impacts the purchasing levels, operating expense levels and cash flow.

Production Budget. This budget is based on sales in units. A production budget is usually stated in units instead of dollars. This budget is used to prepare raw materials, direct labor and overhead budgets.

Purchases Budget. This budget can follow after projected sales have been set. It is prepared on a monthly or weekly or daily basis to ensure the utility has adequate inventory.

Expense Budget. Department heads usually prepare departmental expense budgets. Often times, expense budgets are based on prior year's actual costs and adjusted for known changes in prices, wages, and sales volume estimates.

Capital Budget. This budget usually spans multiple years to provide sufficient time to plan for major expenditures. In most cases, this budget directly relates to some type of integrated resource plan.

Cash Budget. This budget is extremely important. An organization must have adequate cash at all times. The cash budget details projected cash receipts and disbursements. The cash budget helps the utility forecast investing opportunities and borrowing needs.

Financial Budget. Once other budgets are complete, budgeted financial statements can be prepared. These budgeted statements are often called pro forma statements because they are prepared before actual activities commence.

[35] John I. Mikesell, Fiscal Administration, page 25.
[36] Irvin N. Gleim, CPA Review: Tax-Man-Gov, page 564.

OPERATING BUDGETS

The operating budget is generally the first budget addressed. Management is likely to have a high degree of control over and strong familiarity with the elements of the operating budget. The operating budget is likely to be the subject of more intense scrutiny and cost-cutting efforts. Line items will be more closely examined, disproportionate to the actual dollar value, than would be experienced with the examination of a capital budget.

Portions of the yearly operating budget for an entire company are allocated to each corporate department for its day-to-day operating requirements. The total allocation for the facility management department is subdivided into portions allocated to personnel costs (staff salaries and benefits) and such non-personnel costs as rent, electric bills, minor repairs, and so on. Most organizations use a large portion of their revenue-generated cash flow to cover costs anticipated in the yearly operating budget. Therefore, the emphasis of an operating budget is focused primarily on planning for current expenses and the means of financing them through existing revenues, growth of these revenues or other sources.

CAPITAL BUDGETS

The capital budget addresses a plan for capital expenditures. It addresses financing and examines how capital costs impact the organization and flow into the operational budget. A capital budget typically has fewer components than an operating budget, with each component having a larger value individually. Cost drivers tend to be more external than for an operating budget because material and equipment costs are set by vendors, and financing costs are driven by interest rates and other factors over which management has limited control. As a result, the level of management scrutiny tends to be less than an operating budget.

CREATING A BUDGET

Budgeting is not simply assembling budget elements and plugging numbers in. It should encompass a process of determining resources needed, identifying process owners and personnel who are knowledgeable about the affected areas, and developing a structure for completion of the budget in a timely and accurate manner that will deliver the most benefit to the organization.

Starting off, a key person or champion of the project should be identified. Creating a budget requires a high level of coordination of information from several sources. Identifying an individual who can set deadlines, send reminders, review data for inconsistencies, etc., is an important step in ensuring timely completion of the project. This person is not intended to do all the work, but to serve as a facilitator for budget completion. Next, utility management must decide who will be involved in the process. Personnel included should be department heads (finance, engineering, operations) and other management relevant to the budgeted areas. These people will provide key input, which result in the most accurate budget figures.

Once key players have been identified, decide how the budget will be used. There are many uses for a budget with wide-ranging benefits to the organization. Some of these uses are:

- Identify components for operating/capital cost control decisions
- Facilitate spending decisions
- Provide a basis for rate adjustments
- Generate an interim reporting tool.
- Create a component of a long-range plan
- Determine timing of borrowing

During this phase, asking others for input in constructing the budget is a good way to build value in the budget process. By asking for suggestions and relying on user comments, management gains individual ownership and buy-in from the users, increasing the effectiveness of the budget. Shaping the function of the budget also helps shape the form of the budget.

There is no universal correct form for a budget, which is why this communication step is so important. The correct budget for your utility will be the one that meets your needs, with intra-department communication facilitating needs identification. Some key concepts that benefit the process would be to focus on cash flows or income as a basis. Include key benchmarks that affect the budget (rate of return, debt coverage, cash reserves, etc.). Also determine what specific information is needed to construct the budget. Information can come from multiple sources, both internal and external, and has varying degrees of importance to budget creation. Some examples of information needed might include:

INTERNAL:

Historical revenues, expenses and capital information

EXTERNAL:

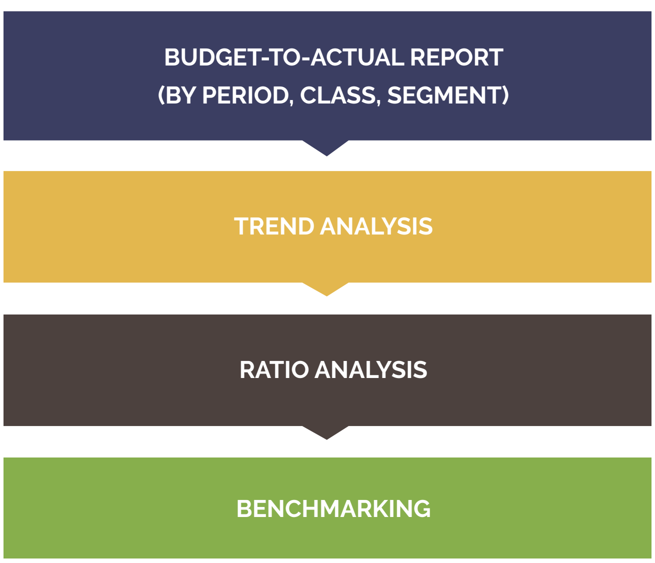
Inflation rates (anticipated or known), demographics, factors affecting wages

It is also important to pay attention to data on external forces. Consider expenses or factors that are non-routine. Will these affect the budget annually or just once? If applicable, consider input from customers. Also be aware of any regulatory changes that impact elements of the budget. Once you know the information needed for a budget, determine a means to obtain the information. Most information will be available internally from accounting systems, but discussions with vendors and customers may also provide necessary information.

The final phase of the budget creation process involves scheduling. Once you know the personnel involved, information to be used, and processes to be performed, timely completion of the budget through effective scheduling will ensure the process runs smoothly from planning through completion and implementation. Gather input and buy-in from involved parties, ensuring each person understands his or her role and how it may be dependent upon or driving another role in the process. Also set deadlines for the stages of the budget completion. Managing draft, approval, and change deadlines ensures the fluidity of the process. Understanding in all these areas prevents unnecessary conflict and delay, enhancing the effectiveness of the process, and future willingness of participants to participate in the budget process again in the future.

Post Completion

Once you have completed the budget, attention turns to implementation and monitoring. Monitoring starts with the delegation of responsibility, ensuring the correct personnel are identified to perform this task. Having personnel who benefit from budget results monitoring the budget process could adversely affect the objectivity in budget analysis. Monitoring can be conducted through multiple different means, with some methods including the following:



As with constructing the budget, there is no correct way to monitor a budget, but the method employed should provide optimal value to the utility for decision-making purposes.

LONG-RANGE FORECASTS FOR STRATEGIC PLANNING

Budgets are an excellent tool for the short-term, but they have less value over the long term. Information in a budget is susceptible to significant fluctuations over time, which decreases the reliability of projected financial information. Therefore, management should use other tools, such as a long-term forecast, for looking into the future.

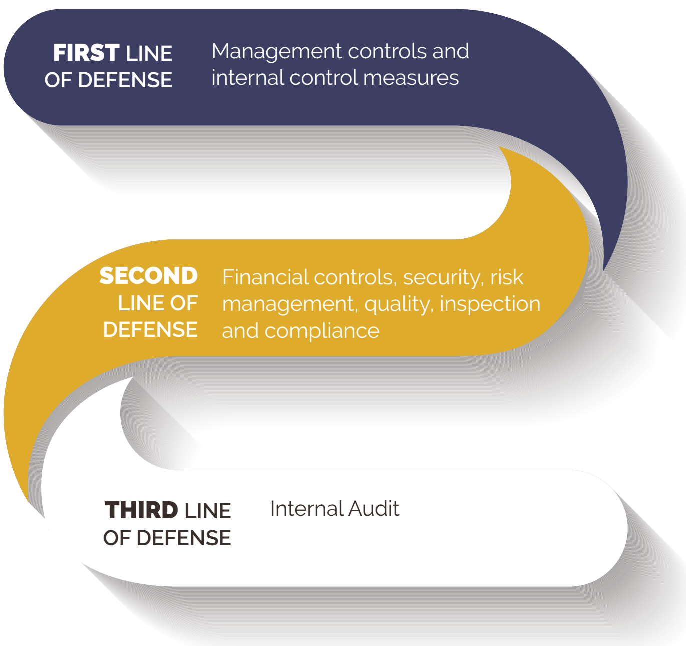
A long-range financial forecast is designed to give management an early warning on possible rate increases or future borrowing needs. With a long-range financial forecast, utilities can:

- Identify the need and timing of future borrowings and the impact on rates and debt coverage ratios.
- Identify the need and timing of future rate adjustments.
- Analyze forecasted cash position and the utility’s targeted cash requirements.

CHAPTER FIFTEEN
THE INTERNAL AUDIT FUNCTION & INTERNAL CONTROLS

THE INTERNAL AUDIT FUNCTION ADDS VALUE IN EVALUATING INTERNAL CONTROLS

Depending on your utility's size and resources, an internal audit function may or may not be present. An internal audit function is an essential component of managing organization risk. In *The Three Lines of Defense in Effective Risk Management and Control*,[37] The Institute of Internal Auditors (IIA) details the lines of defense as:



As the third line of defense, internal audit acts as:

- A firewall between regulators and external auditors
- An independent partner to assess risk and test the application of those risks against internal controls
- The reporting conduit to the governing body on the state of risk and controls in the utility

The IIA also outlines how an organization should protect itself from and work to mitigate risk by focusing in these areas:

1. Management controls and internal control measures

2. Financial control, security, risk management, quality, inspection and compliance

3. Internal audit

Say the words "internal controls" and you meet a glazed look. However, internal controls are nothing more than business processes. By definition, internal controls are:[38]

> "a process affected by those charged with governance, management, and other personnel designed to provide reasonable assurance about the achievement of the entity's objectives with regard to reliability of financial reporting, effectiveness and efficiency of operations, and compliance with applicable laws and regulations."

Thinking of internal controls in this manner contributes to the understanding that effective controls lead to an effective organization. External audits will not provide in-depth evaluation because of audit materiality and the high-level review nature of an audit. To view controls more closely, the internal audit function is necessary.

ROLE OF INTERNAL AUDITING

With a focus on control and efficiency, the internal audit function plays an important role in utilities. The Institute of Internal Auditors (IIA) states:

[37] Institute of Internal Auditors whitepaper - 2013
[38] AICPA AU-C Section 315 *Understanding the Entity and Its Environment and Assessing the Risks of Material Misstatement*

> "The role of internal audit is to provide independent assurance that an organization's risk management, governance and internal control processes are operating effectively. We have a professional duty to provide an unbiased and objective view."[39]

The internal audit function should operate as an independent department and report directly to the utility's oversight body. The internal audit function is charged with assessing areas of financial and operational risk within the utility and developing annual audit plans on that risk assessment. Internal audit also examines certain financial and operational areas on a rotating basis to test whether policies and procedures are followed or need improvement. Typical internal audit activities are shown in Table 30.

In each area of internal audit activity, the value to the utility lies in making recommendations for improvements that will lead to greater efficiencies in using utility resources and guard against fraud. The internal audit department tests controls but does not make policy.

INTERNAL CONTROLS

Internal controls are the first and second lines of defense in an organization, and industry best practices are to design internal controls based on the framework developed by the Committee of Sponsoring Organizations (COSO).

COSO has developed the most widely used framework for internal control assessments, i.e., *The 2013 COSO Framework*. Many government entities also rely on the

Table 30: Internal Audit Activities

TESTING INTERNAL CONTROLS OVER:

- Finance
- Accounts payable
- Accounts receivable
- Billing and customer service
- Inventory
- Project management
- Procurement
- Contractor management
- Work order accounting
- Meter management
- Cash and investments
- Issuance of debt
- Energy trading
- Customer information

Testing adherence to policies and procedures	Assessing and testing information technology controls
Evaluating enterprise risk management programs	Reviewing budgeting processes
Fraud investigations	NERC compliance
Commodity hedging policies and program evaluations	Grant management evaluations

[39] IIA website

framework to assess the effectiveness of internal control over external financial reporting (ICEFR) under Sarbanes-Oxley (SOX) section 404.[40]

Since SOX does not apply to public power utilities, the COSO framework is a best practice in design of internal controls, and following it establishes a strong compliance framework to support strategic goals.

The COSO framework contains five internal control components that shape the control environment and 17 principles that further define and detail the five.

Three factors within COSO's Internal Control-Integrated Framework make it easier to design and evaluate the effectiveness of internal control:

- **Inclusion of internal control principles.** Seventeen principles explain concepts associated with the five internal control components. Each of the five components of internal control and relevant principles must be present and functioning.
- **Consideration of business changes.** The framework includes guidance for assessing risk and updating related controls that consider how business may have changed, particularly through outsourcing business processes and reliance on information technology.
- **Beyond financial reporting.** Objectives are expanded beyond financial reporting, to include internal and non-financial external reporting.

OVERALL FRAMEWORK

The COSO framework provides an effective control structure designed to address three objectives:

1. Operations – effective and efficient use of resources
2. Reporting – reliability of reporting
3. Compliance with applicable laws and regulations

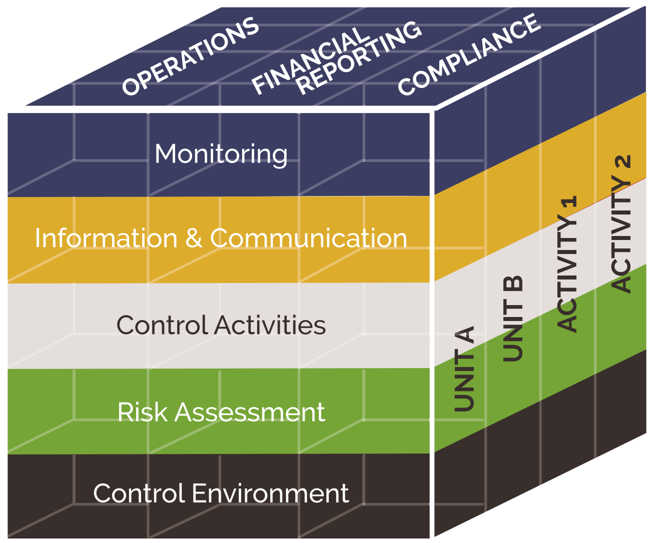
These objectives are met within the framework through five components and seventeen principles, as shown in Table 31.

When there is an evaluation of internal controls and business processes by internal or external auditors, the basis of the evaluation should be within the parameters of the framework. The framework should also be used when developing new business processes.

RESPONSIBILITIES OF RECEIVING FEDERAL GRANT FUNDS

Receipt of grant funds comes with a responsibility to monitor their use and adhere to reporting and compliance requirements. Requirements may vary, depending on the type of organization, source of funds, the contract for receipt of funds, level of fund spending, and possible repayment. This variance in requirements makes understanding the terms of the grant and applicable laws and regulations very important.

Figure 10 – COSO Objectives and Components



[40] Under Sarbanes-Oxley (SOX), Section 404 requires management and the external auditor to report on the adequacy of the company's internal control on financial reporting (ICFR). In addition, SOX increased the oversight role of boards of directors and the independence of the outside auditors who review the accuracy of corporate financial statements. While a few provisions of SOX apply to private companies, the majority of SOX applies to publicly traded corporation. SOX does not apply to public power utilities.

Table 31: COSO Framework Principles[41]				
CONTROL	**RISK ASSESSMENT**	**CONTROL ACTIVITIES**	**INFORMATION & COMMUNICATION**	**MONITORING ACTIVITIES**
Demonstrates commitment to integrity and ethical values	Specifies suitable objectives	Selects and develops control activities	Uses relevant information	Conducts ongoing and/or separate evaluations
Exercises oversight responsibility	Identifies and analyzes risk	Selects and develops general controls over technology	Communicates internally	Evaluates and communicates deficiencies
Establishes structure, authority, and responsibility	Assesses fraud risk	Deploys through policies and procedures	Communicates externally	
Enforces accountability	Identifies and analyzes significant change			

Single Audit Act

Per the Uniform Guidance (UG), entities that spend federal assistance of $750,000 or more in a fiscal year are subject to an audit performed in accordance with the UG. The audit would examine financial records and statements, federal award transaction and expenditures, general operations management, and internal control systems. The audit may be either single or program-specific. The latter occurs only for certain grant recipients that meet highly restrictive criteria, including:

- Awards are expended under a single federal program
- No financial statement audit is required.

Entities that spend less than $750,000 annually in federal awards are exempt from federal audit requirements.

The single audit is intended to provide assurance that federal grant recipients are in compliance with applicable federal and state laws and regulations. The audit will look to ensure the project meets requirements of the program, as outlined in the grant application. The audit will also review the processes, identify and separate allowable project costs, and identify unallowable costs.

The compliance requirements reviewed as part of a single audit are listed below. Not all compliance requirements are applicable for each single audit. Each grant agreement details which requirements are applicable for each program.

- Activities allowed or unallowed
- Allowable costs/cost principles
- Cash management requirements
- Eligibility (at application)
- Equipment and real property management
- Matching level of effort, earmarking
- Period of performance
- Procurement, suspension and debarment
- Program income
- Reporting
- Subrecipient monitoring
- Special tests and provisions

[41] www.coso.org

APPENDICES

APPENDIX A
GASB ACCOUNTING PRONOUNCEMENTS

GOVERNMENTAL ACCOUNTING STANDARDS BOARD

The GASB provides summaries as well as the full text of GASB statements on the Internet at www.gasb.org on the Pronouncements tab. The standards as of this writing follow.

Pronouncements

Important Notice

Certain GASB pronouncements listed below may be superseded by subsequent GASB pronouncements and are marked accordingly on the title page and download caption. Additionally, certain pronouncements have been partially superseded or amended by subsequent GASB pronouncements. Such subsequent modifications are not marked in the PDF files of the originally issued pronouncements included on this web page.

The GASB pronouncements included on this webpage are intended as a general reference to the GASB accounting standards. However, other GASB materials are not available for download, including the GASB codification, which presents, by topic, the standards as amended, and implementation guides, which provide authoritative answers to commonly asked questions and are integral to understanding financial reporting requirements for state and local governments. Publications not posted for downloading are available at the GASB store.

The following pronouncements are available for download:

- Statements of Governmental Accounting Standards
- Concepts Statements
- GASB Interpretations
- GASB Technical Bulletins

Notes about Using GASB Pronouncements

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GASB Statement No. 90, ***Majority Equity Interests—an amendment of GASB Statements No. 14 and No. 61***
Effective Date: For reporting periods beginning after December 15, 2018

GASB Statement No. 89, ***Accounting for Interest Cost Incurred Before the End of a Construction Period***
Effective Date: The requirements of this Statement are effective for reporting periods beginning after December 15, 2019.
(Issued 06/18)

GASB Statement No. 88, ***Certain Disclosures Related to Debt, including Direct Borrowings and Direct Placements***
Effective Date: The requirements of this Statement are effective for reporting periods beginning after June 15, 2018.
(Issued 04/18)

GASB Statement No. 87, ***Leases***
Effective Date: The requirements of this Statement are effective for reporting periods beginning after December 15, 2019.
(Issued 06/17)

GASB Statement No. 86, ***Certain Debt Extinguishment Issues***
Effective Date: The requirements of this Statement are effective for reporting periods beginning after June 15, 2017.
(Issued 05/17)

GASB Statement No. 85, ***Omnibus 2017***
Effective Date: The provisions of this Statement are effective for periods beginning after June 15, 2017.
(Issued 03/17)

GASB Statement No. 84, ***Fiduciary Activities***
Effective Date: The requirements of this Statement are effective for reporting periods beginning after December 15, 2018.
(Issued 01/17)

GASB Statement No. 83, ***Certain Asset Retirement Obligations***
Effective Date: The requirements of this Statement are effective for reporting periods beginning after June 15, 2018.
(Issued 11/16)

GASB Statement No. 82, ***Pension Issues—An Amendment of GASB Statements No. 67, No. 68, and No. 73***
Effective Date: The requirements of this Statement are effective for reporting periods beginning after June 15, 2016, except for the requirements of paragraph 7 in a circumstance in which an employer's pension liability is measured as of a date other than the employer's most recent fiscal year-end. In that circumstance, the requirements of paragraph 7 are effective for that employer in the first reporting period in which the measurement date of the pension liability is on or after June 15, 2017.
(Issued 03/16)

GASB Statement No. 81, ***Irrevocable Split-Interest Agreements***
Effective Date: The requirements of this Statement are effective for periods beginning after December 15, 2016.
(Issued 03/16)

GASB Statement No. 80, ***Blending Requirements for Certain Component Units—An Amendment of GASB Statement No. 14***
Effective Date: The requirements of this Statement are effective for reporting periods beginning after June 15, 2016.
(Issued 01/16)

GASB Statement No. 79, ***Certain External Investment Pools and Pool Participants***
Effective Date: The requirements of this Statement are effective for reporting periods beginning after June 15, 2015, except for the provisions in paragraphs 18, 19, 23–26, and 40, which are effective for reporting periods beginning after December 15, 2015.
(Issued 12/15)

GASB Statement No. 78, ***Pensions Provided through Certain Multiple-Employer Defined Benefit Pension Plans***
Effective Date: The requirements of this Statement are effective for reporting periods beginning after December 15, 2015.
(Issued 12/15)

GASB Statement No. 77, ***Tax Abatement Disclosures***
Effective Date: The requirements of this Statement are effective for reporting periods beginning after December 15, 2015.
(Issued 08/15)

GASB Statement No. 76, *The Hierarchy of Generally Accepted Accounting Principles for State and Local Governments*
Effective Date: The provisions in Statement 76 are effective for reporting periods beginning after June 15, 2015.
(Issued 06/15)

Statement No. 75, *Accounting and Financial Reporting for Postemployment Benefits Other Than Pensions*
Effective Date: The provisions in Statement 75 are effective for fiscal years beginning after June 15, 2017.
(Issued 06/15)

Statement No. 74, *Financial Reporting for Postemployment Benefit Plans Other Than Pension Plans*
Effective Date: The provisions in Statement 74 are effective for fiscal years beginning after June 15, 2016.
(Issued 06/15)

Statement No. 73, *Accounting and Financial Reporting for Pensions and Related Assets That Are Not within the Scope of GASB Statement 68, and Amendments to Certain Provisions of GASB Statements 67 and 68*
Effective Date: The provisions in Statement 73 are effective for fiscal years beginning after June 15, 2015—except those provisions that address employers and governmental nonemployer contributing entities for pensions that are not within the scope of Statement 68, which are effective for fiscal years beginning after June 15, 2016.
(Issued 06/15)

Statement No. 72, *Fair Value Measurement and Application*
Effective Date: The requirements of this Statement are effective for financial statements for reporting periods beginning after June 15, 2015.
(Issued 02/15)

Statement No. 71, *Pension Transition for Contributions Made Subsequent to the Measurement Date—An Amendment of GASB Statement No. 68*
Effective Date: The provisions of this Statement should be applied simultaneously with the provisions of Statement 68.
(Issued 11/13)

Statement No. 70, *Accounting and Financial Reporting for Nonexchange Financial Guarantees*
Effective Date: The provisions of Statement 70 are effective for financial statements for reporting beginning after June 15, 2013.
(Issued 04/13)

Statement No. 69, *Government Combinations and Disposals of Government Operations*
Effective Date: The provisions of Statement 69 are effective for government combinations and disposals of government operations occurring in financial reporting periods beginning after December 15, 2013, and should be applied on a prospective basis.
(Issued 01/13)

Statement No. 68, *Accounting and Financial Reporting for Pensions—An Amendment of GASB Statement No. 27*
Effective Date: The provisions of Statement 68 are effective for fiscal years beginning after June 15, 2014.
(Issued 06/12)

Statement No. 67, *Financial Reporting for Pension Plans—An Amendment of GASB Statement No. 25*
Effective Date: The provisions of Statement 67 are effective for financial statements for fiscal years beginning after June 15, 2013.
(Issued 06/12)

Statement No. 66, *Technical Corrections—2012—An Amendment of GASB Statements No. 10 and No. 62*
Effective Date: The provisions of this Statement are effective for financial statements for periods beginning after December 15, 2012.
(Issued 03/12)

Statement No. 65, *Items Previously Reported as Assets and Liabilities*
Effective Date: The provisions of this Statement are effective for financial statements for periods beginning after December 15, 2012.
(Issued 03/12)

Statement No. 64, *Derivative Instruments: Application of Hedge Accounting Termination Provisions—An Amendment of GASB Statement No. 53*
Effective Date: The provisions of Statement 64 are effective for financial statements for periods beginning after June 15, 2011.
(Issued 06/11)

Statement No. 63, *Financial Reporting of Deferred Outflows of Resources, Deferred Inflows of Resources, and Net Position*
Effective Date: The provisions of Statement 63 are effective for financial statements for periods beginning after December 15, 2011.
(Issued 06/11)

Statement No. 62, *Codification of Accounting and Financial Reporting Guidance Contained in Pre-November 30, 1989 FASB and AICPA Pronouncements*
Effective Date: The requirements of this Statement are effective for financial statements for periods beginning after December 15, 2011. The provisions of this Statement generally are required to be applied retroactively for all periods presented.
(Issued 12/10)

Statement No. 61, *The Financial Reporting Entity: Omnibus—An Amendment of GASB Statements No. 14 and No. 34*
Effective Date: The provisions of this Statement are effective for financial statements for periods beginning after June 15, 2012.
(Issued 11/10)

Statement No. 60, *Accounting and Financial Reporting for Service Concession Arrangements*
Effective Date: For financial statements for periods beginning after December 15, 2011. The provisions of this Statement generally are required to be applied retroactively for all periods presented.
(Issued 11/10)

Statement No. 59, *Financial Instruments Omnibus*
Effective date: For periods beginning after June 15, 2010.
(Issued 06/10)

Statement No. 58, *Accounting and Financial Reporting for Chapter 9 Bankruptcies*
Effective date: For periods beginning after June 15, 2009. Retroactive application is required for all prior periods presented during which a government was in bankruptcy.
(Issued 12/09)

Statement No. 57, *OPEB Measurements by Agent Employers and Agent Multiple-Employer Plans*
Effective date: The provisions of Statement 57 related to the use and reporting of the alternative measurement method are effective immediately. The provisions related to the frequency and timing of measurements are effective for actuarial valuations first used to report funded status information in OPEB plan financial statements for periods beginning after June 15, 2011.
(Issued 12/09)

Statement No. 56, *Codification of Accounting and Financial Reporting Guidance Contained in the AICPA Statements on Auditing Standards*
Effective date: Effective upon issuance
(Issued 03/09)

Statement No. 55, *The Hierarchy of Generally Accepted Accounting Principles for State and Local Governments*
Effective date: Effective upon issuance
(Issued 03/09)

Statement No. 54, *Fund Balance Reporting and Governmental Fund Type Definitions*
Effective date: For periods beginning after June 15, 2010
(Issued 02/09)

Statement No. 53, *Accounting and Financial Reporting for Derivative Instruments*
Effective date: For periods beginning after June 15, 2009
(Issued 06/08)

Statement No. 52, *Land and Other Real Estate Held as Investments by Endowments*
Effective date: For periods beginning after June 15, 2008
(Issued 11/07)

Statement No. 51, *Accounting and Financial Reporting for Intangible Assets*
Effective Date: For periods beginning after June 15, 2009
(Issued 06/07)

Statement No. 50, *Pension Disclosures—An Amendment of GASB Statements No. 25 and No. 27*
Effective date: For periods beginning after June 15, 2007, except for requirements related to the use of the entry age actuarial cost method for the purpose of reporting surrogate funded status and funding progress information for plans that use the aggregate actuarial cost method, which are effective for periods for which the financial statements and required supplementary information contain information resulting from actuarial valuations as of June 15, 2007, or later.
(Issued 05/07)

Statement No. 49, *Accounting and Financial Reporting for Pollution Remediation Obligations*
Effective date: For periods beginning after December 15, 2007
(Issued 11/06)

Statement No. 48, *Sales and Pledges of Receivables and Future Revenues and Intra-Entity Transfers of Assets and Future Revenues*
Effective date: For periods beginning after December 15, 2006
(Issued 09/06)

Statement No. 47, *Accounting for Termination Benefits*
Effective date: For periods beginning after June 15, 2005
(Issued 06/05)

Statement No. 46, ***Net Assets Restricted by Enabling Legislation—An Amendment of GASB Statement No. 34***
Effective date: For periods beginning after June 15, 2005.
(Issued 12/04)

Statement No. 45 (Superseded), ***Accounting and Financial Reporting by Employers for Postemployment Benefits Other Than Pensions***
Effective date: The requirements of this Statement are effective in three phases based on a government's total annual revenues in the first fiscal year ending after June 15, 1999:

- Governments that were phase 1 governments for the purpose of implementation of Statement 34—those with annual revenues of $100 million or more—are required to implement this Statement in financial statements for periods beginning after December 15, 2006.

- Governments that were phase 2 governments for the purpose of implementation of Statement 34—those with total annual revenues of $10 million or more but less than $100 million—are required to implement this Statement in financial statements for periods beginning after December 15, 2007.

- Governments that were phase 3 governments for the purpose of implementation of Statement 34—those with total annual revenues of less than $10 million—are required to implement this Statement in financial statements for periods beginning after December 15, 2008.

All component units should implement the requirements of this Statement no later than the same year as their primary government.
(Issued 6/04)

Statement No. 44, ***Economic Condition Reporting: The Statistical Section—An Amendment of NCGA Statement 1***
Effective date: Statistical sections prepared for periods beginning after June 15, 2005
(Issued 5/04)

Statement No. 43 (Superseded), ***Financial Reporting for Postemployment Benefit Plans Other Than Pension Plans***
Effective date: The requirements of this Statement for OPEB plan reporting are effective one year prior to the effective date of the related Statement for the employer (single-employer plan) or for the largest participating employer in the plan (multiple-employer plan). The requirements of the related Statement are effective in three phases based on a government's total annual revenues in the first fiscal year ending after June 15, 1999:

- Plans in which the sole or largest employer is a phase 1 government—with annual revenues of $100 million or more—are required to implement this Statement in financial statements for periods beginning after December 15, 2005.

- Plans in which the sole or largest employer is a phase 2 government—with total annual revenues of $10 million or more but less than $100 million—are required to implement this Statement in financial statements for periods beginning after December 15, 2006.

- Plans in which the sole or largest employer is a phase 3 government—with total annual revenues of less than $10 million—are required to implement this statement in financial statements for periods beginning after December 15, 2007.

If comparative financial statements are presented, restatement of prior-period financial statements is required.
(Issued 4/04)

Statement No. 42, ***Accounting and Financial Reporting for Impairment of Capital Assets and for Insurance Recoveries***
Effective date: For periods beginning after December 15, 2004
(Issued 11/03)

Statement No. 41, ***Budgetary Comparison Schedules—Perspective Differences—An Amendment of GASB Statement No. 34***
Effective date: This Statement should be implemented simultaneously with Statement 34. For governments that have implemented Statement 34 prior to the issuance of this Statement, the requirements of this Statement are effective for financial statements for periods beginning after June 15, 2002.
(Issued 5/03)

Statement No. 40, ***Deposit and Investment Risk Disclosures—An Amendment of GASB Statement No. 3***
Effective Date: For periods beginning after June 15, 2004
(Issued 3/03)

Statement No. 39, *Determining Whether Certain Organizations Are Component Units—An Amendment of GASB Statement No. 14*
Effective Date: For periods beginning after June 15, 2003
(Issued 5/02)

Statement No. 38, *Certain Financial Statement Note Disclosures*
Effective Date: Coincides with the effective date of GASB Statement 34 for the reporting government. That is, the requirements of this Statement are effective in three phases based on a government's total annual revenues in the first fiscal year ending after June 15, 1999:

- Phase 1 governments—with total annual revenues of $100 million or more—should implement paragraphs 6 through 11 for fiscal periods beginning after June 15, 2001. These governments should implement paragraphs 12 through 15 for fiscal periods beginning after June 15, 2002.

- Phase 2 governments—with total annual revenues of $10 million or more but less than $100 million—should apply this Statement for fiscal periods beginning after June 15, 2002.

- Phase 3 governments—with total annual revenues of less than $10 million—should apply this Statement for fiscal periods beginning after June 15, 2003.

Paragraphs 6, 14, and 15 should be implemented only if Statement 34 has also been implemented.
(Issued 6/01)

Statement No. 37, *Basic Financial Statements—and Management's Discussion and Analysis—for State and Local Governments: Omnibus—An Amendment of GASB Statements No. 21 and No. 34*
Effective Date: Coincides with the effective date of GASB Statement 34 for the reporting government. That is, the requirements of this Statement are effective in three phases based on a government's total annual revenues in the first fiscal year ending after June 15, 1999:

- Phase 1 governments—with total annual revenues of $100 million or more—should apply the requirements of this statement in financial statements for periods beginning after June 15, 2001.

- Phase 2 governments—with total annual revenues of $10 million or more but less than $100 million—should apply the requirements of this statement in financial statements for periods beginning after June 15, 2002.

- Phase 3 governments—with total annual revenues of less than $10 million—should apply the requirements of this statement in financial statements for periods beginning after June 15, 2003.

This Statement should be simultaneously implemented with Statement 34.
(Issued 6/01)

Statement No. 36, *Recipient Reporting for Certain Shared Nonexchange Revenues—An Amendment of GASB Statement No. 33*
Effective date: Simultaneously with Statement 33, for periods beginning after June 15, 2000
(Issued 4/00)

Statement No. 35, *Basic Financial Statements—and Management's Discussion and Analysis—for Public Colleges and Universities—an amendment of GASB Statement No. 34*
Effective Date: In three phases based on a public institution's total annual revenues, beginning with periods after June 15, 2001 and continuing through periods after June 15, 2003. Public institutions that are component units of a primary government should implement this standard at the same time as that primary government.
(Issued 11/99)

Statement No. 34, *Basic Financial Statements—and Management's Discussion and Analysis—for State and Local Governments*
Effective dates:

- Phase 1—Financial statements for periods beginning after June 15, 2001, for governments with total annual revenues of $100 million or more in the first fiscal year ending after June 15, 1999. Different provisions apply for reporting general infrastructure assets at transition.

- Phase 2—Financial statements for periods beginning after June 15, 2002, for governments with total annual revenues of $10 million or more but less than $100 million in the first fiscal year ending after June 15, 1999. Different provisions apply for reporting general infrastructure assets at transition.

- Phase 3—Financial statements for periods beginning after June 15, 2003, for governments with total annual revenues of less than $10 million in the first fiscal year ending after June 15, 1999. Different provisions apply for reporting general infrastructure assets at transition.

(Issued 6/99)

Statement No. 33, ***Accounting and Financial Reporting for Nonexchange Transactions***
Effective date beginning after June 15, 2000.
(Issued 12/98)

Statement No. 32, ***Accounting and Financial Reporting for Internal Revenue Code Section 457 Deferred Compensation Plans—A Recission of GASB Statement No. 2 and an Amendment of GASB Statement No. 31***
Effective date beginning after: December 31, 1998, or when plan assets are held in trust under the requirements of IRC Section 457, subsection (g), if sooner.
(Issued 10/97)

Statement No. 31, ***Accounting and Financial Reporting for Certain Investments and for External Investment Pools***
Effective date beginning after June 15, 1997.
(Issued 3/97)

Statement No. 30, ***Risk Financing Omnibus—An Amendment of GASB Statement No. 10***
Effective date beginning after June 15, 1996.
(Issued 2/96)

Statement No. 29, ***The Use of Not-for-Profit Accounting and Financial Reporting Principles by Governmental Entities***
Effective date beginning after December 15, 1993 (with exceptions).
(Issued 8/95)

Statement No. 28, ***Accounting and Financial Reporting for Securities Lending Transactions***
Effective date beginning after December 15, 1997.
(Issued 5/95)

Statement No. 27 (Superseded), ***Accounting for Pensions by State and Local Governmental Employers***
Effective date beginning after June 15, 1997.
(Issued 11/94)

Statement No. 26 (Superseded), ***Financial Reporting for Postemployment Healthcare Plans Administered by Defined Benefit Pension Plans***
Effective date beginning after June 15, 1996.
(Issued 11/94)

Statement No. 25 (Superseded), ***Financial Reporting for Defined Benefit Pension Plans and Note Disclosures for Defined Contribution Plans***
Effective date beginning after June 15, 1996.
(Issued 11/94)

Statement No. 24, ***Accounting and Financial Reporting for Certain Grants and Other Financial Assistance***
Effective date beginning after June 15, 1995.
(Issued 6/94)

Statement No. 23, ***Accounting and Financial Reporting for Refundings of Debt Reported by Proprietary Activities***
Effective date beginning after June 15, 1994.
(Issued 12/93)

Statement No. 22 (Superseded), ***Accounting for Taxpayer-Assessed Tax Revenues in Governmental Funds***
Effective date beginning after June 15, 1994.
(Issued 12/93)

Statement No. 21, ***Accounting for Escheat Property***
Effective date beginning after June 15, 1994.
(Issued 10/93)

Statement No. 20 (Superseded), ***Accounting and Financial Reporting for Proprietary Funds and Other Governmental Entities That Use Proprietary Fund Accounting***
Effective date beginning after December 15, 1993.
(Issued 9/93)

Statement No. 19 (Superseded), ***Governmental College and University Omnibus Statement—An Amendment of GASB Statements No. 10 and 15***
Effective date: Various.
(Issued 9/93)

Statement No. 18, ***Accounting for Municipal Solid Waste Landfill Closure and Postclosure Care Costs***
Effective date beginning after June 15, 1993.
(Issued 8/93)

Statement No. 17, ***Measurement Focus and Basis of Accounting—Governmental Fund Operating Statements: Amendment of the Effective Dates of GASB Statement No. 11 and Related Statements—An Amendment of GASB Statements No. 10, 11, and 13***
Effective date: June 1993.
(Issued 6/93)

Statement No. 16, ***Accounting for Compensated Absences***
Effective date beginning after June 15, 1993.
(Issued 11/92)

Statement No. 15 (Superseded), ***Governmental College and University Accounting and Financial Reporting Models***
Effective date beginning after June 15, 1992.
(Issued 10/91)

Statement No. 14, ***The Financial Reporting Entity***
Effective date beginning after December 15, 1992.
(Issued 6/91)

Statement No. 13, ***Accounting for Operating Leases with Scheduled Rent Increases***
Effective date: Various.
(Issued 5/90)

Statement No. 12 (Superseded), ***Disclosure of Information on Postemployment Benefits Other Than Pension Benefits by State and Local Governmental Employers***
Effective date beginning after June 15, 1990.
(Issued 5/90)

Statement No. 11 (Superseded), ***Measurement Focus and Basis of Accounting—Governmental Fund Operating Statements***
Effective date deferred.
(Issued 5/90)

Statement No. 10, ***Accounting and Financial Reporting for Risk Financing and Related Insurance Issues***
Effective date: Various.
(Issued 11/89)

Statement No. 9, ***Reporting Cash Flows of Proprietary and Nonexpendable Trust Funds and Governmental Entities That Use Proprietary Fund Accounting***
Effective date beginning after December 15, 1989
(Issued 9/89)

Statement No. 8 (Superseded), ***Applicability of FASB Statement No. 93,"Recognition of Depreciation by Not-for-Profit Organizations," to Certain State and Local Governmental Entities***
Effective date on issuance: January 1988.
(Issued 1/88)

Statement No. 7, ***Advance Refundings Resulting in Defeasance of Debt***
Effective date beginning after December 15, 1986.
(Issued 3/87)

Statement No. 6, ***Accounting and Financial Reporting for Special Assessments***
Effective date beginning after June 15, 1987.
(Issued 1/87)

Statement No. 5 (Superseded), ***Disclosure of Pension Information by Public Employee Retirement Systems and State and Local Governmental Employers***
Effective date beginning after December 15, 1986.
(Issued 11/86)

Statement No. 4 (Superseded), ***Applicability of FASB Statement No. 87, "Employers' Accounting for Pensions," to State and Local Governmental Employers***
Effective date: September 1986.
(Issued 9/86)

Statement No. 3, ***Deposits with Financial Institutions, Investments (including Repurchase Agreements), and Reverse Repurchase Agreements***
Effective date after December 15, 1986.
(Issued 4/86)

Statement No. 2 (Superseded), ***Financial Reporting of Deferred Compensation Plans Adopted under the Provisions of Internal Revenue Code Section 457***
Effective date after December 15, 1986.
(Issued 1/86)

Statement No. 1, ***Authoritative Status of NCGA Pronouncements and AICPA Industry Audit Guide***
Effective date on issuance: July 1984.
(Issued 7/84)

GLOSSARY

Average cost – The revenue requirement of a utility divided by the utility's sales. Average cost typically includes the costs of existing power plants, transmission and distribution lines, and other facilities used by a utility to serve its customers. It also includes operating and maintenance, tax, and fuel expenses.

British thermal unit (Btu) – Quantity of heat necessary to raise one pound of water one-degree Fahrenheit at sea level pressure.

Capacity – The manufacturer-rated, full-load output potential of electric production facilities (generator, turbine, transformer, power lines).

Change in the fair value of investments – The difference between the fair value of investments at the beginning of the year and at the end of the year.

Circuit – A conductor or a system of conductors through which electric current flows.

Contracts for Differences (CfD) – A bilateral contract under which the electric generation seller is paid a fixed amount over time; the amount is based on a combination of the short-term market price and an adjustment with the purchaser for the difference.

Cost of Service – the dollar amount required to produce any given utility service.

Debt security – Any security that represents a creditor relationship with an entity. It also includes (a) preferred stock that either is required to be redeemed by the issuing entity or is redeemable at the option of the investor and (b) a collateralized mortgage obligation (CMO) or other instrument issued in equity form but is accounted for as a nonequity instrument. However, it excludes option contracts, financial futures contracts, and forward contracts. It could include U.S. Treasury securities, U.S. government agency securities, municipal securities, corporate bonds, convertible debt, commercial paper, negotiable certificates of deposit, securitized debt instruments (such as CMOs and real estate mortgage investment conduits—REMICs), and interest-only and principal-only strips.

Demand (electric) – The rate at which electric energy is delivered to or by a system, part of a system, or piece of equipment, at a given instant or averaged over any designated period.

Demand charges – A separate service charge based upon the demand for service imposed by a customer.

Derivatives – A specialized security or contract that has no intrinsic overall value but is valued based on an underlying security or index. In the energy field, may include options, futures, forwards, etc.

Disaggregation – The functional separation of the vertically integrated utility into smaller, individually owned business units (i.e., generation, dispatch/control, transmission, and distribution). The terms "deintegration" and "disintegration" are sometimes used to mean the same thing.

Distributed generation – Small-capacity electric production facilities located on a utility's distribution system to meet local (substation level) peak loads and/or displace the need to build additional facilities.

Distribution system – Portion of an electric system that is dedicated to the delivery of electric energy to an end-user.

Enterprise funds – Activities where a fee is charged to external parties for goods or services may be reported as enterprise funds. If debt is issued and secured by a pledge of the net revenues from such fees, if laws or regulations require that the fee be designed to recover capital (such as depreciation or debt service), or if the fee is designed to recover capital costs based on pricing policies, the activity must be reported as an enterprise fund. An enterprise fund is a type of proprietary fund.

EPA – the Environmental Protection Agency, a federal agency charged with protecting the environment.

External investment pool – Arrangement that commingles (pools) the money of more than one legally separate entity and invests, on the participants' behalf, in an investment portfolio; one or more of the participants is not part of the sponsor's reporting entity. An external investment pool can be sponsored by an individual government, jointly by more than one government, or by a nongovernmental entity. An investment pool sponsored by an individual state or local government is an external investment pool if participants include one or more legally separate entities that are not part of the sponsoring government.

FASB – Acronym for Financial Accounting Standards Board. The authoritative standard-setting body for accounting and financial reporting for business enterprises and not-for-profit entities.

Fair value – Price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants on the measurement date.

Federal Energy Regulatory Commission (FERC) – Agency that regulates the price, terms, and conditions of wholesale electricity and electric transmission in interstate commerce; the agency also regulates natural gas and oil.

Forwards – A commodity bought and sold for delivery at some specific time in the future. It is a customized, non-exchange traded, and a non-regulated hedging mechanism.

Futures market – Contract for delivery of a commodity at a future time at a price specified at the time of purchase. The price is based on an auction or market.

GAAP – Acronym for Generally Accepted Accounting Principles, the rules, regulations, and practices that serve as the norm for fair presentation of financial statements.

GASB – Acronym for Governmental Accounting Standards Board, the authoritative standard-setting body for accounting and financial reporting for governmental entities.

Generating unit – Any combination of physically connected generator(s), reactor(s), boiler(s), combustion turbine(s), or other prime mover(s) operated together to produce electric power.

Generation (electricity) – The process of producing electric energy by transforming other forms of energy; also, the amount of electric energy produced, expressed in watt-hours (Wh).

Generator – A machine that converts mechanical energy into electrical energy.

Grid – A system of interconnected power lines managed to deliver electric power to customers.

Hedging – A strategy used to offset financial risk associated with owning an asset.

Hedging contracts – Legal instruments that establish future prices and quantities of electricity independent of the short-term market. Derivatives may be used for this purpose. (See Contracts for Differences, Forwards, Futures Market, and Options.)

Investment – A security or other asset acquired primarily to obtain income or profit.

IOU – Investor-owned utility. A for-profit utility company owned by stockholders.

ISO – Independent System Operator – a neutral operator responsible for maintaining instantaneous balance of the electric transmission grid; the ISO dispatches power from multiple generating plants.

Kilowatt (kW) – A measure of electric energy equal to one thousand watts.

Kilowatt-hour (kWh) – A measure of electricity consumption equivalent to the use of one thousand watts of power for one hour.

Load – Total demand for service on a utility system at any given time.

Load factor – A measure of the degree to which physical facilities are used; the ratio of average output to peak output.

Money market investment – A short-term, highly liquid debt instrument, which may include commercial paper, banker's acceptances, and U.S. Treasury and agency obligations. Asset-backed securities, derivatives, and structured notes are not included in this term.

NARUC – National Association of Regulatory Utility Commissioners, an advisory council composed of utility regulators from the 50 states, the District of Columbia, Puerto Rico, and the Virgin Islands.

Net position – A measure of an entity's equity calculated as the value of all assets plus deferred outflows of resources minus the sum of all liabilities and deferred inflows of resources.

Options – A contractual agreement that gives the holder the right to buy (call option) or sell (put option) a fixed quantity of a security or commodity (for example, a commodity or commodity futures contract), at a fixed price, within a specified period. It may either be standardized, exchange-traded and government-regulated, or over-the-counter customized and unregulated.

Option contract – Agreement giving the buyer the right, but not the obligation, to buy or sell assets on or before a given date.

Overcapitalization – Capitalization exceeding the actual value of the capital in a business.

Peak load or peak demand – Electric load that corresponds to a maximum level of electric use in a specified timeframe.

Power pool – An entity established to coordinate short-term operations to maintain electric system stability and achieve least-cost dispatch.

Proprietary fund types – A fund used by governmental entities for business-like activities; examples are enterprise funds and internal service funds.

Real-time pricing – Instantaneous pricing of electricity based on the cost of the electricity available for use at the time the electricity is demanded by the customer.

Reliability – Ability of the electric production and delivery system to meet aggregate demand without momentary or longer-term interruptions.

Renewable resources – Naturally replenishable sources of electric generation; typically include solar, wind and hydro.

RTG – Regional transmission group, organization of transmission owners, users, and other entities formed to coordinate transmission planning, expansion, operation, and use on a regional and inter-regional basis.

Salvage value – The estimated dollar amount that would be received upon a sale of an asset after the property has been removed from service.

Swaps – A financial instrument used to hedge risk of currency or interest fluctuations.

Time-of-use (TOU) rates – Electricity price based on the estimated cost of producing and delivering power during a particular time block; TOU rates are usually divided into three or four time blocks per 24-hour period (on-peak, mid-peak, off-peak, and sometimes super off-peak) and by seasons of the year (summer and winter). Real-time pricing differs from TOU rates in that it is based on actual (as opposed to forecasted) prices, which may fluctuate many times a day and are weather-sensitive, rather than varying with a fixed schedule.

Transformer – Electrical device for changing the voltage (electromotive force) of alternating current.

Transmission – The movement or transfer of electric energy over an interconnected group of lines and associated equipment between points of supply and points of use. Electricity is moved at high voltage rates on transmission lines, then transformed to a lower voltage for distribution to customers.

Turbine – A machine for generating rotary mechanical power from the energy of a stream of fluid (such as water, steam, or hot gas).

Uniform System of Accounts – Prescribed financial rules and regulations established by the Federal Energy Regulatory Commission for utilities subject to its jurisdiction under the Federal Power Act.

Useful life – Period of time over which property is depreciated; the length of time property or equipment is expected to last before replacement.

Watt – A measure of energy transfer equivalent to one ampere flowing under a pressure of one volt at unity power factor.

Watthour (Wh) – Electrical energy unit of measure equal to one watt of power for one hour.

Working capital – Amount of cash required to operate a utility during the interim between the rendition of service and receipt of payment.

Yield – Dollar return realized by a security holder in proportion to actual investment.

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