BEFORE THE CORPORATION COMMISSION OF OKLAHOMA

IN THE MATTER OF THE APPLICATION OF OKLAHOMA GAS AND ELECTRIC COMPANY FOR AN ORDER OF THE COMMISSION AUTHORIZING APPLICANT TO MODIFY ITS RATES, CHARGES, AND TARIFFS FOR RETAIL ELECTRIC SERVICE IN OKLAHOMA	)))))))	CAUSE NO. PUD 201500273

DIRECT TESTIMONY AND EXHIBITS

OF

DAVID C. PARCELL

FILED
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COURT CLERK'S OFFICE - OKC
CORPORATION COMMISSION
OF OKLAHOMA

ON BEHALF OF

OKLAHOMA INDUSTRIAL ENERGY CONSUMERS AND OKLAHOMA ENERGY RESULTS, LLC,

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I. INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My name is David C. Parcell. I am President and Senior Economist of Technical Associates, Inc. My business address is Suite 130, 1503 Santa Rosa Rd., Richmond, Virginia 23229.

Q. Please summarize your educational background and professional experience.

A. I hold B.A. (1969) and M.A. (1970) degrees in economics from Virginia Polytechnic Institute and State University (Virginia Tech) and a M.B.A. (1985) from Virginia Commonwealth University. I have been a consulting economist with Technical Associates since 1970. I have provided cost of capital testimony in public utility ratemaking proceedings dating back to 1972. In this regard, I have previously filed testimony and/or testified in over 525 utility proceedings before about 50 regulatory agencies in the United States and Canada. I have previously filed testimony in several proceedings before this Commission. Attachment 1 provides a more complete description of my education and relevant work experience.

Q. What is the purpose of your testimony in this proceeding?

A. I have been retained by Oklahoma Industrial Energy Consumers ("OIEC) and Oklahoma Energy Results, LLC ("OER") to evaluate the cost of capital ("COC") aspects of the current filing of Oklahoma Gas & Electric Company ("OG&E"). I have performed independent studies and I am making recommendations of the current COC for OG&E. In addition, since OG&E is a subsidiary of OGE Energy Corp ("OGE" or "Parent"), I have also evaluated OGE in my analyses.

Q. Have you prepared an exhibit in support of your testimony?

A. Yes, I have prepared one exhibit, comprised of 20 schedules. This exhibit was prepared either by me or under my direction. The information contained in this exhibit is correct to the best of my knowledge and belief.

II. RECOMMENDATIONS AND SUMMARY

Q. What is your recommendation in this proceeding?

A. My overall cost of capital recommendation for OG&E is shown on Schedule 1 and is summarized as follows:

Item	Percent	Cost			Weighted Cost	
Long-Term Debt	46.69%	5.62%			2.62%	
Common Equity	53.31%	8.85%	9.00%	9.50%	4.72%	4.80%	5.06%
Total	100.0%				7.34%		7.69%
						7.42%	

I recommend a COC of 7.42 percent for OG&E, which incorporates a 9.0 percent cost of equity ("ROE").

OG&E's application requests a COC of 8.088 percent and a ROE of 10.25 percent.

Q. Please summarize your analyses and conclusions.

A. This proceeding is concerned with OG&E's regulated electric utility operations in Oklahoma. My analyses concern the Company's COC. The first step in performing these analyses is to develop the appropriate capital structure. OG&E proposes use of its actual capital structure as of the June 30, 2015 test period. I also use this capital structure although I note that the Company's equity ratio exceeds that of many other electric utilities. Therefore, I recommend that OG&E reduce its equity ratio in future cases to a lower, more balanced level that is more appropriate relative to other electric utilities, and which takes into account the current low interest rate environment (which the Company should take advantage of by securing lower cost debt).

The second step in a cost of capital calculation is to determine the embedded cost rate of debt. As noted, OG&E proposes to use the 5.62 percent test period cost of debt. I also use OG&E's proposed cost rate for long-term debt.

The third step in the COC calculation is to estimate the ROE. I employ three recognized methodologies to estimate OG&E's ROE, each of which I apply to two proxy groups of utilities. These three methodologies and my findings are:

Methodology	Range
Discounted Cash Flow ("DCF")	8.3%-9.4% (8.85% mid-point)
Capital Asset Pricing Model ("CAPM")	6.7-7.0% (6.85% mid-point)
Comparable Earnings ("CE")	9.0%-10.0% (9.50% mid-point)

Based upon these findings, I conclude that OG&E's ROE is within a range of 8.85 percent to 9.5 percent, which is based upon the mid-point of the range of the results for the DCF and CE models.[1] I specifically recommend a 9.00 percent ROE.

Combining these three steps into the weighted COC results in an overall rate of return of 7.34 percent to 7.69 percent (which incorporates an 8.85 percent to 9.50 percent ROE). My specific recommendation is a 7.42 percent COC and 9.00 percent ROE.

III. ECONOMIC/LEGAL PRINCIPLES AND METHODOLOGIES

Q. What are the primary economic and legal principles that establish the standards for determining a fair rate of return for a regulated utility?

A. Public utility rates are normally established in a manner designed to allow the recovery of their costs, including capital costs. This is frequently referred to as "cost of service" ratemaking. Rates for regulated public utilities traditionally have been primarily established using the "rate base – rate of return" concept. Under this method, utilities are allowed to recover a level of operating expenses, taxes, and depreciation deemed reasonable for rate-setting purposes, and are granted an opportunity to earn a fair rate of return on the assets utilized (i.e. rate base) in providing service to their customers.

The rate base is derived from the asset side of the utility's balance sheet as a dollar amount and the rate of return is developed from the liabilities/owners' equity side of the balance sheet as a percentage. Thus, the revenue impact of the cost of capital is derived by multiplying the rate base by the rate of return, including income taxes.

[1] As I indicate in a later section, my ROE recommendation does not directly incorporate the CAPM results, which I believe to be somewhat low at this time, relative to the DCF and CE results.

The rate of return is developed from the cost of capital, which is estimated by weighting the capital structure components (i.e. debt, preferred stock, and common equity) by their percentages in the capital structure and multiplying these values by their cost rates. This is also known as the weighted cost of capital.

Technically, "fair rate of return" is a legal and accounting concept that refers to an ex post (after the fact) earned return on an asset base, while the cost of capital is an economic and financial concept which refers to an ex ante (before the fact) expected, or required, return on a capital base. In regulatory proceedings, however, the two terms are often used interchangeably, and I have equated the two concepts in my testimony.

From an economic standpoint, a fair rate of return is normally interpreted to mean that an efficient and economically managed utility will be able to maintain its financial integrity, attract capital, and establish comparable returns for similar risk investments. These concepts are derived from economic and financial theory and are generally implemented using financial models and economic concepts.

Although I am not a lawyer and I do not offer a legal opinion, my testimony is based on my understanding that two United States Supreme Court decisions provide the controlling standards for a fair rate of return. The first decision is Bluefield Water Works and Improvement Co. v. Public Serv. Comm'n of West Virginia, 262 U.S. 679 (1923). In this decision, the Court stated:

> The annual rate that will constitute just compensation depends upon many circumstances and must be determined by the exercise of fair and enlightened judgment, having regard to all relevant facts. A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties; but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility, and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties. A rate of return may be reasonable at one time, and become too high or too low by changes affecting opportunities for investment, the money market, and business conditions generally.

It is generally understood that the Bluefield decision established the following standards for a fair rate of return: comparable earnings, financial integrity, and capital attraction. It also noted that required returns change over time, and there is an underlying assumption that the utility be operated efficiently.

The second decision is Federal Power Comm'n v. Hope Natural Gas Co., 320 U.S. 591 (1942). In that decision, the Court stated:

> The rate-making process under the [Natural Gas] Act, i.e., the fixing of 'just and reasonable' rates, involves a balancing of the investor and consumer interests . . . From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock. By this standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.

The three economic and financial parameters in the Bluefield and Hope decisions – comparable earnings, financial integrity, and capital attraction – reflect the economic criteria encompassed in the "opportunity cost" principle of economics. The opportunity cost principle provides that a utility and its investors should be afforded an opportunity (not a guarantee) to earn a return commensurate with returns they could expect to achieve on investments of similar risk. The opportunity cost principle is consistent with the fundamental premise on which regulation rests, namely, that it is intended to act as a surrogate for competition.

Q. How can the Bluefield and Hope parameters be employed to estimate the cost of capital for a utility?

A. Neither the courts nor economic/financial theory has developed exact and mechanical procedures for precisely determining the cost of capital. This is the case because the cost of capital is an opportunity cost and is prospective-looking, which dictates that it must be estimated. However, there are several useful models that can be employed to assist in estimating the ROE, which is the capital structure item that is the most difficult to determine. These include the DCF, CAPM, CE and risk premium ("RP") methods. I

have not directly employed a RP model in my analyses although, as discussed later, my CAPM analysis is a form of the RP methodology. Each of these methodologies will be described in more detail later in my testimony.

IV. GENERAL ECONOMIC CONDITIONS

Q. Are economic and financial conditions important in determining the costs of capital for a public utility?

A. Yes. The costs of capital, for both fixed-cost (debt and preferred stock) components and common equity, are determined in part by current and prospective economic and financial conditions. At any given time, each of the following factors has an influence on the costs of capital:

- The level of economic activity (i.e., growth rate of the economy);
- The stage of the business cycle (i.e., recession, expansion, or transition);
- The level of inflation;
- The level and trend of interest rates; and,
- Current and expected economic conditions.

My understanding is that this position is consistent with the Bluefield decision that noted "[a] rate of return may be reasonable at one time and become too high or too low by changes affecting opportunities for investment, the money market, and business conditions generally." Bluefield, 262 U.S. at 693.

Q. What indicators of economic and financial activity did you evaluate in your analyses?

A. I examined several sets of economic statistics from 1975 to the present. I chose this time period because it permits the evaluation of economic conditions over four full business cycles plus the current cycle, allowing for an assessment of changes in long-term trends. Consideration of economic/financial conditions over a relatively long period of time allows me to assess how such conditions have had impacts on the level and trends of the

costs of capital. This period also approximates the beginning and continuation of active rate case activities by public utilities, which generally began in the mid-1970s.

A business cycle is commonly defined as a complete period of expansion (recovery and growth) and contraction (recession). A full business cycle is a useful and convenient period over which to measure levels and trends in long-term capital costs because it incorporates the cyclical (i.e., stage of business cycle) influences and, thus, permits a comparison of structural (or long-term) trends.

Q. Please describe the timeframes of the four prior business cycles and the current cycle.

A. The four prior complete cycles and current cycle cover the following periods:

Business Cycle	Expansion Cycle	Contraction Period
1975-1982	Mar. 1975-July 1981	Aug. 1981-Oct. 1982
1982-1991	Nov. 1982-July 1990	Aug. 1990-Mar. 1991
1991-2001	Mar. 1991-Mar. 2001	Apr. 2001-Nov. 2001
2001-2009	Nov. 2001-Nov. 2007	Dec. 2007-June 2009
Current	July 2009-	

Source: National Bureau of Economic Research, "Business Cycle Expansions and Contractions."[2]

Q. Do you have any general observations concerning the recent trends in economic conditions and their impact on capital costs over this broad period?

A. Yes, I do. From the early 1980s until the end of 2007, the United States economy had enjoyed general prosperity and stability. This period had been characterized by longer economic expansions, relatively tame contractions, low and declining inflation, and declining interest rates and other capital costs.

However, in 2008 and 2009, the economy declined significantly, initially as a result of the 2007 collapse of the "sub-prime" mortgage market and the related liquidity crisis in the financial sector of the economy. Subsequently, this financial crisis intensified with a more broad-based decline, initially based on a substantial increase in petroleum prices and a dramatic decline in the U.S. financial sector, culminating with the

[2] http://www.nber.org/cycles/cyclesmain.html.

collapse and/or bailouts of a significant number of well-known institutions such as Bear Stearns, Lehman Brothers, Merrill Lynch, Freddie Mac, Fannie Mae, AIG and Wachovia. The recession also witnessed the demise of national companies such as Circuit City and the bankruptcies of automotive manufacturers such as Chrysler and General Motors.

This decline has been described as the worst financial crisis since the Great Depression and has been referred to as the "Great Recession." Beginning in 2008, the U.S. and other governments implemented unprecedented actions to attempt to correct or minimize the scope and effects of this recession.

The recession reached its low point in mid-2009, when the economy began to expand again, although at a slow and uneven rate. However, the length and severity of the recession, as well as a relatively slow and uneven recovery, indicate that the impacts of the recession have been and will be felt for an extended period of time.

Q. Please describe recent and current economic and financial conditions and their impact on the cost of capital.

A. One impact of the Great Recession has been a reduction in actual and expected investment returns and a corresponding reduction in the costs of capital. This decline is evidenced by a decline in both short-term and long-term interest rates and the expectations of investors and is reflected in ROE model results (such as DCF, CAPM and CE). Regulatory agencies throughout the U.S. have recognized the decline in capital costs by authorizing lower ROEs for regulated utilities.

Schedule 2 shows several sets of relevant economic and financial statistics for the cited time periods. Pages 1 and 2 contain general macroeconomic statistics; page 3 and 4 show interest rates; and pages 5 and 6 contain equity market statistics.

Pages 1 and 2 show that in 2007 the economy subsequently entered a significant decline, as indicated by the growth in real (i.e., adjusted for inflation) Gross Domestic Product ("GDP"), industrial production, and an increase in the unemployment rate. This recession lasted until mid-2009, making it a longer-than-normal recession, as well as a much deeper recession. Since then, economic growth has been somewhat erratic and the economy has grown slower than the prior expansions.

Pages 1 and 2 also show the rate of inflation. As reflected in the Consumer Price Index ("CPI"), for example, inflation rose significantly during the 1975-1982 business cycle and reached double-digit levels in 1979-1980. The rate of inflation has declined substantially since 1981. Since 2008, the CPI has been 3 percent or lower, with 2013 being only 1.5 percent and both 2014 and 2015 being below 1 percent. It is thus apparent that the rate of inflation has generally been declining over the past several business cycles. Recent and current levels of inflation are at the lowest levels of the past 35 years, which is reflective of lower capital costs.[3]

Q. What have been the trends in interest rates over the four prior business cycles and at the current time?

A. Pages 3 and 4 of Schedule 2 show several series of interest rates. Both short-term and long-term rates rose sharply to record levels in 1975-1981 when the inflation rate was high. Interest rates declined substantially in conjunction with inflation since the early 1980's.

From 2008 to late 2015, the Federal Reserve System ("Federal Reserve") maintained the Federal Funds rate (i.e., short-term interest rate) at 0.25 percent, an all-time low. The Federal Reserve recently raised it slightly to 0.50 percent. The Federal Reserve also purchased U.S. Treasury securities to stimulate the economy.[4] As seen on page 4, in 2012, both U.S. and corporate bond yields declined to their lowest levels in the past four business cycles and in more than 35 years. Even with the "tapering" and eventual ending of the Federal Reserve's Quantitative Easing program, interest rates have remained low. Currently, both government and corporate lending rates remain at historically low levels, again reflective of lower capital costs. In fact, single-A utility bonds (i.e., OG&E's Rating) are currently yielding just over four percent.

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[3] The rate of inflation is one component of interest rate expectations of investors, who generally expect to receive a return in excess of the rate of inflation. Thus, a lower rate of inflation has a downward impact on interest rates and other capital costs.

[4] This is referred to as Quantitative Easing which was comprised of three "rounds". In "round" 3, known as QE3, the Federal Reserve initially purchased some $85 billion of U.S. Treasury Securities per month in order to stimulate the economy. The Federal Reserve eventually "tapered" its purchase of U.S. Treasury securities through October 2014, at which time Quantitative Easing ended.

Q. What does this schedule show for trends of common share prices?

A. Pages 5 and 6 show several series of common stock prices and ratios. These indicate that stock prices were essentially stagnant during the high inflation/high interest rate environment of the late 1970s and early 1980s. The 1983-1991 business cycle and the more recent cycles witnessed a significant upward trend in stock prices. The beginning of the recent financial crisis saw stock prices decline precipitously, as stock prices in 2008 and early 2009 were down significantly from peak 2007 levels, reflecting the financial/economic crisis. Beginning in the second quarter of 2009, prices recovered substantially and ultimately reached and exceeded the levels achieved prior to the "crash". On the other hand, recent equity markets have been somewhat volatile.

Q. What conclusions do you draw from your discussion of economic and financial conditions?

A. Recent economic and financial circumstances have differed from any that have prevailed since at least the 1930s. The late 2008-early 2009 deterioration in stock prices, the decline in U.S. Treasury bond yields, and an increase in corporate bond yields were evidenced in the then-evident "flight to safety." Concurrently, there was a decline in capital costs and returns, which significantly reduced the value of most retirement accounts, investment portfolios and other assets. One significant aspect of this has been a decline in investor expectations of returns,[5] even with the return of stock prices to levels achieved prior to the "crash". This is evident in several ways: 1) lower interest rates on bank deposits; 2) lower interest rates on U.S. Treasury and corporate bonds; 3), lower increases in social security cost of living benefits;[6] and 4), lower authorized ROEs by regulatory commissions. Finally, as noted above, utility bond interest rates are currently at levels below those prevailing prior to the financial crisis of late 2008 to early 2009 and are near the lowest levels in the past 35 years. It is also noteworthy that long-term

[5] *See*, for example, Kiplinger's Personal Finance, "Investors Brace for Smaller Gains, Focus on Long-Term," August 30, 2015.

[6] The 2015 increase in Social Security benefits was 1.70 percent – near an all-time. There is no increase in 2016 Social Security benefits.

interest rates have declined slightly in recent months, in spite of the Federal Reserve's raising of short-term rates in December of 2015.

Q. How do these economic/financial conditions impact the determination of a return on equity for regulated utilities?

A. The costs of capital for regulated utilities have declined in recent years. For example, the current interest costs that utilities pay on new debt remain near the low point of the last several decades. In addition, the results of the traditional ROE models (i.e., DCF, CAPM and CE) are lower than was the case prior to the Great Recession. In light of this, it is not surprising that the average ROE authorized by state regulatory agencies has declined and continue to decline through 2015, as follows:

Year	Electric[7]	Natural Gas
2012	10.01%	9.94%
2013	9.94%	9.68%
2014	9.76%	9.78%
2015	9.58%	9.60%

V. OG&E'S OPERATIONS AND BUSINESS RISKS

Q. Please summarize OG&E and its operations.

A. OG&E is a public utility that generates, transmits, and distributes electric energy to 822,000 customers in Oklahoma and a small portion of Arkansas. The Company is the largest electric utility in Oklahoma. OG&E is a subsidiary of OGE Energy.

Q. Please describe OGE Energy.

A. OGE Energy (OGE) is a holding company. Its principal subsidiary is OG&E. Until 2013, OGE had another subsidiary - Enogex Holdings (a midstream natural gas pipeline business). On May 1, 2013, OGE "deconsolidated" Enogex and formed a Master Limited Partnership ("MLP") – Enable Midstream Partners LLC ("Enable"). Through OGE

[7] Average ROE values for electric utilities exclude Virginia surcharge/rider generation cases that incorporate plan-specific ROE premiums. *See* Regulatory Research Associates, Regulatory Focus, January 14, 2016, page 1.

Enogex Holdings, LLC (another subsidiary of OGE), Enable was created to operate the natural gas midstream businesses of OGE and CenterPoint Energy Resources Corp. OGE owns a 26.3 percent limited partner interest and a 50 percent general partner interest in Enable.

Q. What are the current security ratings of OGE Energy and OG&E?

A. The ratings of these entities are shown below:

	OG&E	OGE Energy
S&P	A- (Stable)	BBB+ (Stable)
Moody's	A1 (Stable)	A3 (Stable)
Fitch	A+ (Stable)	A- (Stable)

Source: Response to OIEC 7-8.

The ratings of OGE Energy are generally one rating category below those of OG&E. This indicates that OG&E is regarded as less risky than OGE Energy.

Q. What has been the trend in OG&E's bond ratings in recent years?

A. This is shown on Schedule 3. OG&E's debt has been rated in the A1 category (per Moody's) and A- category (per Standard & Poor's) since 2014, when they were increased by both rating agencies.

Q. How do the bond ratings of OG&E compare to other electric and combination gas/electric utilities?

A. As I indicated in the previous answer, OG&E has Single A bond ratings on its long-term debt. Below is a table depicting the bond rating data of the 48 electric utilities and combination gas/electric utilities covered by AUS Utility Reports:

Moody's Rating	Number of Companies	S&P Rating	Number of Companies
Aa2	1	AA	-
Aa3	-	AA-	1
A1*	1	A+	--
A2	7	A	7
A3	18	A-*	18
Baa1	11	BBB+	11
Baa2	7	BBB	9
Baa3	--	BBB-	3
Ba or less	--	BB	--
NR	3	NR	3

* OG&E's ratings.

As this indicates, OG&E ratings are higher than most utilities. This is an indication of lower risk of OG&E relative to most electric utilities.

Q. Does OG&E have access to any regulatory mechanisms that have the effect of enhancing the recovery of its investments?

A. Yes, it does. OG&E has several regulatory "cost recovery" mechanisms that are beneficial to the Company's recovery of investments and expenses. In fact, in 2015 OG&E collected over $800 million of its total revenues through certain cost recovery mechanisms (riders), including fuel which reflected recovery of over 43 percent of the Company's total revenues through riders.[8]

Q. Do these riders reduce the risk of OG&E?

A. Yes, they do. Those riders, on both an independent and collective basis, have the effect of transferring a portion of OG&E's risk from its shareholders to its ratepayers. This is the case since the risk of fully recovering certain expenses is reduced or eliminated.

[8] Response to OIEC 10-1

Q. Are regulatory recovery mechanisms a relatively new aspect of public utility regulation?

A. No, they are not. A brief history of regulatory recovery mechanisms was provided in a March 21, 2012 report by Regulatory Research Associates, titled "Adjustment Clauses – a State-By-State Overview." A copy of the opening section of this report is attached as Schedule 4. This report stated (note that the term "Adjustment Clauses" was used in the report, which is a type of regulatory mechanism):

> The electric and natural gas utilities' use of adjustment clauses to recover variation in certain costs outside of the traditional rate case process had its origin in the 1970's Arab oil embargo, when fuel prices skyrocketed leaving the utilities with no way to recover the increased costs in a timely manner.
>
> . . .
>
> The result was the creation of the fuel adjustment clause (FAC), essentially a single-issue ratemaking process, whereby a utility is permitted to implement periodic rate adjustments (e.g., monthly, quarterly, semi-annually, annually) associated with changes in its cost of fuel.
>
> . . .
>
> Over the ensuing years, the use of adjustment clauses has expanded greatly. Such clauses are generally reserved for expenses that are outside the control of the utility or are required by law or rule.
>
> . . .
>
> **A defining characteristic of an adjustment clause is that it effectively shifts the risk associated with the recovery of the expense in question from shareholders to customers**, because if the clause operates as designed, the company is able to change its rates to recover its costs on a current basis without any negative effect on the bottom line, without the expense and delay associated with seeking recovery through the general rate case process. **[Emphasis added]**

Q. Have the rating agencies commented on the risk-reducing nature of regulatory mechanisms?

A. Yes, they have. For example, a report by Moody's Investors Service, dated June 13, 2010 and titled "Cost Recovery Provisions Key to Investor Owned Utility Ratings and Credit Quality," cited the risk-reducing nature of regulatory mechanisms. In this report (Schedule 5), Moody's noted:

> Some regulators believe that mechanisms like automatic adjustment clauses materially reduce the business and operating risk of a utility,

> providing justification for a relatively low allowed return on equity. We believe this is one of several reasons why both allowed and requested ROEs have trended downward over the last two decades.
>
> Moody's views automatic adjustment clauses, the most common of which is for fuel and purchased power, the largest component of utility operating expenses, as supportive of utility credit quality and important in reducing a utility's cash flow volatility, liquidity requirements, and credit risk.

Moody's, in fact, upgraded the bulk of the entire U.S. investor-owned utility industry in early 2014, largely due to regulators' increasing use of regulatory mechanisms and the resulting improvement of utilities' finances. Moody's noted, in a February 3, 2014 Sector Comment titled "US Utility Sector Upgrades Driven by Stable and Transparent Regulatory Frameworks" (Schedule 6):

> We recently upgraded most US investor-owned utilities and many of their holding companies due to our view that the US regulatory environment has improved over the past several years. Most of the companies placed on review for upgrade in November 2013 were upgraded in late January 2014, and most by one notch.
>
> . . .
>
> US regulated utilities appear financially secure, thanks to their suite of transparent and timely cost and investment recovery mechanisms. When compared with other regulatory environments in developed countries, the overall regulatory environment for US utilities has steadily improved over the past few years and is expected to remain supportive and constructive for at least the next 3-5 years.
>
> Supportive regulatory frameworks
>
> Over the past few years, the US regulatory environment has been very supportive of utilities. We think this is partly a function of regulators acknowledging that their utility infrastructure needs a material amount of ongoing investment for maintenance, refurbishment and renovation purposes.
>
> . . .
>
> Stable and predictable financial profile
>
> A transparent suite of timely recovery mechanisms helps utilities generate stable and predictable revenues and cash flows, which can support a material amount of leverage.

Q. Has Moody's further commented on the impact of regulatory mechanisms and reduced risk/lower authorized ROEs for utilities?

A. Yes. In a March 10, 2015 Sector In-Depth report titled "Lower Authorized Equity Returns Will Not Hurt Near-Term Credit Profiles" (Schedule 7), Moody's stated:

> The credit profiles of US regulated utilities will remain intact over the next few years despite our expectation that regulators will continue to trim the sector's profitability by lowering its authorized returns on equity (ROE). Persistently low interest rates and a comprehensive suite of cost recovery mechanisms ensure a lower business risk profile for utilities, prompting regulators to scrutinize their profitability, which is defined as the ratio of net income to book equity.

Q. Should this risk reduction be reflected in a lower ROE for OG&E?

A. As noted above, OG&E's riders reflect a significant portion of its revenues, which riders are recognized by the rating agencies and others as reflecting a transfer of the Company's risks from its shareholders to its ratepayers. Given the risk reduction to OG&E resulting from its various riders, I recommend a ROE less than the mid-point of the cost of equity range developed in my cost of equity analysis be approved in setting the Company's rates.

VI. CAPITAL STRUCTURE AND COST OF DEBT

Q. What is the importance of determining a proper capital structure in a regulatory framework?

A. A utility's capital structure is important because the concept of rate base – rate of return regulation requires the capital structure to be utilized in estimating the total cost of capital. Within this framework, it is proper to ascertain whether the utility's capital structure is appropriate relative to its level of business risk and relative to other utilities.

As discussed in Section III of my testimony, the purpose of determining the proper capital structure for a utility is to ascertain its capital costs. The rate base – rate of return concept recognizes the assets employed in providing utility services and provides for a return on these assets by identifying the liabilities and common equity (and their cost rates) used to finance the assets. In this process, the rate base is derived from the

asset side of the balance sheet and the cost of capital is derived from the liabilities/owners' equity side of the balance sheet. The inherent assumption in this procedure is that the dollar values of the capital structure and the rate base are approximately equal and the former is utilized to finance the latter.

The common equity ratio (i.e. the percentage of common equity in the capital structure) is the capital structure item which normally receives the most attention. This is the case because common equity: (1) usually commands the highest cost rate; (2) generates associated income tax liabilities; and (3) causes the most controversy since its cost cannot be precisely determined.

Q. What are the historic capital structure ratios of OG&E and OGE?

A. I have examined the historic (2011-2015) capital structure ratios of OG&E and OGE. See Schedule 8. OG&E's common equity ratios have been:

	Including S-T Debt	Excluding S-T Debt
2011	55.0%	55.0%
2012	56.9%	56.9%
2013	54.2%	55.2%
2014	53.1%	53.1%
2015	54.3%	54.3%

This indicates that OG&E's common equity ratios have been about 53-57 percent over the past five years.

Correspondingly, OGE's common equity ratios have been:

	Including S-T Debt	Excluding S-T Debt
2011	48.3%	50.7%
2012	48.4%	51.9%
2013	51.7%	55.9%
2014	53.2%	54.1%
2015	53.8%	54.7%

This indicates that OGE, on a consolidated basis, has maintained a capital structure with similar equity to OG&E since the 2013 "deconsolidation" of Enogex and subsequent creation of

Enable. I note that, even though OGE has maintained an equity ratio of over 50 percent since 2013, Value Line projects a 49 percent for the 2018-2020 period.

Q. How do these capital structures compare to those of other investor-owned electric utilities?

A. Schedule 9 shows the common equity ratios (including short-term debt in capitalization) for the groups of electric and combination electric utilities followed by AUS Utility Reports. These are:

Year	Electric	Combination Gas And Electric
2011	47%	46%
2012	47%	46%
2013	48%	47%
2014	47%	47%
2015*	48%	47%

(Source: AUS Utility Reports)
* As of September 30.

These equity ratios are much lower than those of OG&E. This is an indication of a lower level of financial risk for OG&E and OGE relative to electric utilities in general.

Q. What have been recently-authorized common equity ratios for regulated electric utilities in recent years?

A. This is shown in the table below, which summarizes the average common equity ratios authorized by state regulatory commissions for regulated electric utilities. As this indicates, the average annual authorized common equity ratios for electric utilities have been:

Year	Average C.E. Ratio [9]
2012	50.55%
2013	49.25%
2014	50.28%
2015	49.54%

This indicates that the average common equity ratio has been about 50 percent in recent years. In contrast, OG&E's proposed equity ratio is higher, at over 53 percent.

[9] Regulatory Research Associates, Regulatory Focus, January 14, 2016, attached as Schedule 10.

Q. How does OG&E's proposed 53.31 percent common equity ratio compare to other electric utilities' authorized common equity ratios in 2015?

A. There were 30 decisions cited in Regulatory Focus in 2015 where the common equity ratio was cited. Of these 30 decisions, only one had an authorized common equity ratio as high as 53.31 percent. [10]

Q. What capital structure is OG&E requesting in this proceeding?

A. OG&E is proposing the following capital structure ratios, which reflects the capital structure of the Company as of the June 30, 2015 test period.

Long-Term Debt	46.69%
Common Equity	53.31%

Q. What capital structure do you propose to use in this proceeding?

A. I have used OG&E's proposed capital structure for the purposes of this proceeding, however, I do note that OG&E continues to maintain an excessively high equity ratio during a period of very low interest rates. Further, its current equity ratios exceed those of most electric utilities.

Q. Do you have any recommendations about the future course of OG&E's common equity ratio, as it applies to the establishment of the Company's COC and rates?

A. Yes, I do. I recommend that OG&E bring its equity ratio in line with the average common equity ratios authorized by state regulatory commissions for other electric utilities by its next base rate proceeding. If the Company fails to do so, a balanced hypothetical capital structure should be imposed by this Commission in the Company's next base rate proceeding. A future equity ratio of no more than 50 percent is an appropriate ratio. I recommend a lower common equity ratio for the following reasons:

- OG&E has an excessive level of common equity;
- OG&E is engaged in a relatively large capital expenditures program, including environmental compliance;

[10] Regulatory Research Associates, Regulatory Focus, January 14, 2016.

- OG&E has the financial capability of issuing a relatively higher percentage of debt;
- Interest rates are near historic low levels; and,
- A higher level of debt financing would still allow OG&E to remain similar to its electric utility industry peers. A 50 percent equity ratio would be consistent with the 49 percent equity ratio estimated for OGE for 2018-2020, as noted above.

Q. What is the cost rate of debt in the company's application?

A. OG&E's filing requests a cost of long term debt of 5.62 percent. I also use this rate in my COC analyses. I note, however, that current yields on single A rated utility long-term debt is substantially lower than OG&E's 5.62 percent embedded cost. As a result, the issuance of any additional long-term debt would lower OG&E's cost of debt as well as COC.

Q. Can the ROE be determined with the same degree of precision as the cost of debt?

A. No. The cost rates of debt are largely determined by interest payments, issue prices, and related expenses. The ROE, on the other hand, cannot be precisely quantified, primarily because this cost is an opportunity cost. As mentioned previously, there are several models that can be employed to estimate the ROE. Three of the primary methods – DCF, CAPM, and CE – are developed in the following sections of my testimony.

VII. SELECTION OF PROXY GROUPS

Q. How have you estimated the ROE for OG&E?

A. OG&E is not a publicly-traded company. Its parent company, OGE Energy Corp. (OGE) is publicly-traded. Consequently, it is possible to directly apply ROE models to OGE. However, in COC analyses, it is customary to analyze groups of comparison, or "proxy," companies as a substitute for OG&E to determine its ROE.

I have accordingly selected two groups for comparison to OG&E. I selected one group of electric utilities similar to OG&E and OGE using the criteria listed on Schedule 11. These criteria area as follows:

(1) Market cap of $1 billion to $10 billion or greater;
(2) Electric revenues 50% or greater;
(3) Common equity ratio 40% or greater;
(4) Value Line Safety rank of 1 or 2;
(5) Standard & Poor's ("S&P") stock ranking of A or B;
(6) S&P and Moody's bond ratings of A or BBB;
(7) Currently pays dividends; and,
(8) Not involved in major merger or acquisition.

In addition, I have conducted studies of the cost of equity for the electric utilities proxy group that was selected by OG&E witness Hevert.

Q. Please explain why you are using two proxy groups in your cost of equity analyses.

A. It has long been my practice to develop my own independently-determined proxy group and to also conduct cost of equity analyses on the utility witness' proxy group. My conclusions and recommendations, in turn, are based upon the results of both proxy groups.

VIII. DCF ANALYSIS

Q. What is the theory and methodological basis of the DCF model?

A. The DCF model is one of the oldest and most commonly-used models for estimating the ROE for public utilities.[11] The DCF model is based on the "dividend discount model" of financial theory, which maintains that the value (price) of any security or commodity is the discounted present value of all future cash flows.

[11] Certain regulatory commissions (e.g., Federal Energy Regulatory Commission)_rely primarily on the DCF methodology in determining the ROE for public utilities.

The most common variant of the DCF model assumes that dividends are expected to grow at a constant rate (the "constant growth" or "Gordon DCF model"). In this framework, the ROE is derived from the following formula:

$$K = \frac{D}{P} + g$$

where: P = current price

D = current dividend rate

K = discount rate (cost of capital)

G = constant rate of expected growth

This formula essentially recognizes that the return expected or required by investors is comprised of two factors: the dividend yield (current income) and expected growth in dividends (future income).

Q. Please explain how you employ the DCF model.

A. I use the constant growth DCF model. In doing so, I combine the current dividend yield for each of the proxy utility stocks described in the previous section with several indicators of expected dividend growth.

Q. How did you derive the dividend yield component of the DCF equation?

A. Several methods can be used to calculate the dividend yield component. These methods generally differ in the manner in which the dividend rate is employed (i.e., current versus future dividends or annual versus quarterly compounding variant, which is expressed as follows:

$$Yield = \frac{D_0(1 + 0.5g)}{P_0}$$

This dividend yield component recognizes the timing of dividend payments and dividend increases.

The P_0 in my yield calculation is the average of the high and low stock price for each proxy company for the most recent three month period (December 2015 – February 2016). The D_0 is the current annualized dividend rate for each proxy company.

Q. How do you estimate the dividend growth component of the DCF equation?

A. The DCF model's dividend growth rate component is usually the most crucial and controversial element involved in using this methodology. The objective of estimating the dividend growth component is to reflect the growth expected by investors that is embodied in the price (and yield) of a company's stock. As such, it is important to recognize that individual investors have different expectations and consider alternative indicators in deriving their expectations. This is evidenced by the fact that every investment decision resulting in the purchase of a particular stock is matched by another investment decision to sell that stock.

A wide array of indicators exists for estimating investors' growth expectations. As a result, it is evident that investors do not always use one single indicator of growth. It therefore is necessary to consider alternative dividend growth indicators in deriving the growth component of the DCF model. I have considered five indicators of growth in my DCF analyses. These are:

1. Years 2011-2015 (5-year average) earnings retention, or fundamental growth;
2. Five-year average of historic growth in earnings per share (EPS), dividends per share (DPS), and book value per share (BVPS);
3. Years 2016, 2017 and 2018-2020 projections of earnings retention growth (per Value Line);
4. Years 2012-2014 to 2018-2020 projections of EPS, DPS, and BVPS (per Value Line); and,
5. Five-year projections of EPS growth (per First Call).

I believe this combination of growth indicators is a representative and appropriate set with which to begin the process of estimating investor expectations of dividend growth for the groups of proxy companies. I also believe that these growth indicators reflect the types of information that investors consider in making their investment decisions. As I indicated previously, investors have an array of information available to them, all of which would be expected to have some impact on their decision-making process.

Q. Please describe your DCF calculations.

A. Schedule 12 presents my DCF analysis. Page 1 shows the calculation of the "raw" (i.e. prior to adjustment for growth) dividend yield for each proxy company. Pages 2 and 3 show the growth rates for the groups of proxy companies. Page 4 shows the DCF calculations, which are presented on several bases: mean, median, low and high values. These results can be summarized as follows:

	Mean	Median	Mean Low[12]	Mean High[13]	Median Low[9]	Median High[10]
Parcell Proxy Group	8.3%	8.1%	7.6%	9.3%	7.7%	9.3%
Hevert Proxy Group	8.3%	8.1%	7.2%	9.4%	7.4%	9.3%

I note that the individual DCF calculations shown on Schedule 12 should not be interpreted to reflect the expected cost of capital for individual companies in the proxy groups; rather, the individual values shown should be interpreted as alternative information considered by investors.

Q. What do you conclude from your DCF analyses?

A. The DCF rates resulting from the analysis of the proxy groups fall into a wide range between 7.2 percent and 9.4 percent. The highest DCF rates are 9.3 percent to 9.4 percent.

I believe a range of 8.3 percent to 9.4 percent represents the current DCF-derived ROE for the proxy groups. This range includes the highest DCF rates and exceeds the low and mean/median DCF rates.

IX. CAPM ANALYSIS

Q. Please describe the theory and methodological basis of the CAPM.

A. CAPM was developed in the 1960s and 1970s as an extension of modern portfolio theory (MPT), which studies the relationships among risk, diversification, and expected returns.

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[12] Using the lowest growth rate.

[13] Using only the highest growth rate.

The CAPM describes and measures the relationship between a security's investment risk and its market rate of return.

Q. How is the CAPM derived?

A. The general form of the CAPM is:

$$K = R_f + \beta(R_m - R_f)$$

where: K = cost of equity

R_f = risk free rate

R_m = return on market

β = beta

R_m-R_f = market risk premium

The CAPM is a variant of the RP method. I believe the CAPM is generally superior to the simple RP method because the CAPM specifically recognizes the risk of a particular company or industry (i.e., beta), whereas the simple RP method assumes the same ROE for all companies exhibiting similar bond ratings or other characteristics.

Q. What do you use for the risk-free rate?

A. The first input of the CAPM is the risk-free rate (R_f). The risk-free rate reflects the level of return that can be achieved without accepting any risk.

In CAPM applications, the risk-free rate is generally recognized by use of U.S. Treasury securities. Two general types of U.S. Treasury securities are often utilized as the R_f component, short-term U.S. Treasury bills and long-term U.S. Treasury bonds.

I have performed CAPM calculations using the three-month average yield (December 2015-February 2016) for 20-year U.S. Treasury bonds. I use the yields on long-term Treasury bonds since this matches the long-term perspective of ROE analyses. Over this three month period, these bonds had an average yield of 2.43 percent.

Q. What is beta and what betas do you employ in your CAPM?

A. Beta is a measure of the relative volatility (and thus risk) of a particular stock in relation to the overall market. Betas less than 1 are considered less risky than the market, whereas betas greater than 1 are more risky. Utility stocks traditionally have had betas below 1. I utilize the most recent Value Line betas for each company in the proxy groups.

Q. How do you estimate the market risk premium component?

A. The market risk premium component (R_m-R_f) represents the investor-expected premium of common stocks over the risk-free rate, or long-term government bonds. For the purpose of estimating the market risk premium, I considered alternative measures of returns of the S&P 500 (a broad-based group of large U.S. companies) and 20-year U.S. Treasury bonds (i.e., same timeframe as employed in Morningstar sources used to develop risk premiums).

First, I compared the actual annual returns on equity of the S&P 500 with the actual annual income returns of U.S. Treasury bonds. Schedule 13 shows the ROE for the S&P 500 group for the period 1978-2014 (all available years reported by S&P). This schedule also indicates the annual income returns on 20-year U.S. Treasury bonds and the annual differentials (i.e. risk premiums) between the S&P 500 and U.S. Treasury 20-year bonds. Based upon these returns, I conclude that the risk premium from this analysis is 6.85 percent.

I next considered the total returns (i.e. dividends/interest plus capital gains/losses) for the S&P 500 group as well as for long-term government bonds, as tabulated by Morningstar (formerly Ibbotson Associates), using both arithmetic and geometric means. I considered the total returns for the entire 1926-2014 period, which are as follows:

	S&P 500	L-T Gov't Bonds	Risk Premium
Arithmetic	12.1%	6.1%	6.0%
Geometric	10.1%	5.7%	4.4%

I conclude from this analysis that the expected risk premium is about 5.75 percent (i.e. average of all three risk premiums: 6.85 percent from Schedule 13; 6.0 percent arithmetic and 4.4 percent geometric from Morningstar). I believe that a combination of

arithmetic and geometric means is appropriate since investors have access to both types of means[14] and presumably, both types are reflected in investment decisions and thus, stock prices and the ROE.

Q. What are your CAPM results?

A. Schedule 14 shows my CAPM calculations. The results are:

	Mean	Median
Parcell Proxy Group	7.0%	6.9%
Hevert Proxy Group	6.8%	6.7%

Q. What is your conclusion concerning the CAPM ROE?

A. The CAPM results collectively indicate a ROE of 6.7 percent to 7.0 percent for the groups of proxy utilities. I conclude that an appropriate CAPM ROE estimation for OG&E is 6.7 percent to 7.0 percent.

X. CE ANALYSIS

Q. Please describe the basis of the CE methodology.

A. The CE method is derived from the "corresponding risk" concept discussed in the Bluefield and Hope cases. This method is thus based upon the economic concept of opportunity cost. As previously noted, the ROE is an opportunity cost: the prospective return available to investors from alternative investments of similar risk.

The CE method is designed to measure the returns expected to be earned on the original cost book value of similar risk enterprises. Thus, it provides a direct measure of the fair return, since it translates into practice the competitive principle upon which regulation rests.

The CE method normally examines the experienced and/or projected return on book common equity. The logic for examining returns on book equity follows from the use of original cost rate base regulation for public utilities, which uses a utility's book

[14] For example, Value Line uses compound (i.e., geometric) growth rates in its projection. In addition, mutual funds report growth rates on a compound basis.

common equity to determine the cost of capital. This cost of capital is, in turn, used as the fair rate of return which is then applied (multiplied) to the book value of rate base to establish the dollar level of capital costs to be recovered by the utility. This technique is thus consistent with the rate base-rate of return methodology used to set utility rates.

Q. How do you apply the CE methodology in your analysis of OG&E's ROE?

A. I apply the CE methodology by examining realized returns on equity for the groups of proxy utilities, as well as unregulated companies, and evaluating investor acceptance of these returns by reference to the resulting market-to-book ratios ("M/B"). In this manner it is possible to assess the degree to which a given level of return equates to the COC. It is generally recognized for utilities that an M/B of greater than one (i.e. 100 percent) reflect a situation where a company is able to attract new equity capital without dilution (i.e. above book value). As a result, one objective of a fair cost of equity is the maintenance of stock prices at or above book value. There is no regulatory obligation to set rates designed to maintain an M/B significantly above one.

I further note that my CE analysis is based upon market data (through the use of M/Bs) and is thus essentially a market test. As a result, my CE analysis is not subject to the criticisms occasionally made by some who maintain that past earned returns do not represent the cost of capital. In addition, my CE analysis also uses prospective returns and thus is not backward looking.

Q. What time periods do you examine in your CE analysis?

A. My CE analysis considers the experienced ROEs of the proxy groups of utilities for the period 2002-2015 (i.e. the last fourteen years). The CE analysis requires that I examine a relatively long period of time in order to determine trends in earnings over at least a full business cycle. Further, in estimating a fair level of return for a future period, it is important to examine earnings over a diverse period of time in order to avoid any undue influence from unusual or abnormal conditions that may occur in a single year or shorter period. Therefore, in forming my judgment of the current cost of equity, I focused on two periods: 2009-2015 (the current business cycle) and 2002-2008 (the most recent business cycle). I have also considered projected ROEs for 2016 and 2018-2020.

Q. Please describe your CE analysis.

A. Schedule 15 and Schedule 16 contain summaries of experienced ROEs and M/Bs for three groups of companies, while Schedule 17 presents a risk comparison of utilities versus unregulated firms.

Schedule 15 shows the ROEs and M/Bs for the groups of proxy utilities. These can be summarized as follows:

	Parcell Proxy Group	Hevert Proxy Group
Historic ROE		
Mean	9.5-9.6%	9.1-9.3%
Median	9.1-9.5%	9.1-9.3%
Historic M/B		
Mean	139-146%	142-148%
Median	135-145%	136-138%
Prospective ROE		
Mean	9.4-9.8%	9.8-10.4%
Median	9.5%	9.5-10.0%

These results indicate that historic ROEs of 9.1 percent to 9.6 percent have been adequate to produce M/Bs of 135 percent to 148 percent for the groups of utilities. Furthermore, projected returns on equity for 2016 and 2018-2020 are within a range of 9.4 percent to 10.4 percent for the utility groups. These relate to 2015 M/Bs of 150 percent or greater.

Q. Do you also review the earnings of unregulated firms?

A. Yes. As an alternative, I also examine the S&P's 500 Composite group. This is a well recognized group of firms that is widely utilized in the investment community and is indicative of the competitive sector of the economy. Schedule 16 presents the earned ROEs and M/Bs for the S&P 500 group over the past thirteen years (i.e., 2002-2014). As this schedule indicates, over the two business cycle periods, this group's average ROEs ranged from 12.4 percent to 13.6 percent, with average M/Bs ranging between 220 percent and 275 percent.

Q. How can the above information be used to estimate OG&E's ROE?

A. The recent ROE of the proxy utilities and S&P 500 groups can be viewed as an indication of the level of return realized and expected in the regulated and competitive sectors of the economy. In order to apply these returns to the ROE for the proxy utilities, however, it is necessary to compare the risk levels of the utilities and the competitive companies. I do this in Schedule 17, which compares several risk indicators for the S&P 500 group and the utility groups. The information in this schedule indicates that the S&P 500 group is more risky than the utility proxy groups.

Q. What ROE is indicated by your CE analysis?

A. Based on recent ROEs and M/Bs, my CE analysis indicates that the ROE for the proxy utilities is no more than 9.0 percent to 10.0 percent (9.5 percent mid-point). Recent ROEs of 9.1 percent to 9.6 percent have resulted in M/Bs more than 130 percent. Prospective ROEs of 9.4 percent to 10.4 percent have been accompanied by M/Bs over 150 percent. As a result, it is apparent that authorized returns below this level would continue to result in M/Bs of well above 100 percent. As I indicated earlier, the fact that M/Bs substantially exceed 100 percent indicates that historic and prospective ROEs of 9.5 percent reflect earning levels that are well above the actual cost of equity for those regulated companies. I also note that a company whose stock sells above book value can attract capital in a way that enhances the book value of existing stockholders, thus creating a favorable environment for financial integrity. Finally, I note that my 9.0 percent to 10.0 percent CE recommendation generally reflects the actual and prospective ROEs for the proxy groups. I have made no adjustments to these return levels to reflect the high M/Bs.

XI. RETURN ON EQUITY RECOMMENDATION

Q. Please summarize the results of your three ROE analyses.

A. My three ROE analyses produced the following:

	Mid-Point	Range
DCF	8.85%	8.3-9.4%
CAPM	6.85%	6.7-7.0%

CE	9.5%	9.0-10.0%

These results indicate an overall broad range of 6.7 percent to 10.0 percent, which focuses on the respective individual model results. Using mid-point values, the range is 6.85 percent to 9.5 percent. I recommend a ROE range of 8.85 percent to 9.50 percent for OG&E. This range includes my DCF and CE results.

Q. Do you have a specific ROE recommendation?

A. Yes, I do. I am recommending a 9.0 percent ROE for OG&E. I recommend an ROE that is in the lower portion of the ROE range to reflect the following factors:

- OG&E's excessive common equity ratio;
- OG&E's substantial array of riders and other favorable regulatory mechanisms;
- OG&E recovers 43 percent of its revenues through Commission approved riders (which transfer risk from shareholders to ratepayers and mitigate regulatory lag); and
- the continuing level of low interest rates.

Q. It appears that your CAPM results are less than your DCF and CE results. Does this imply that the CAPM results should not be considered in determining the cost of equity for OG&E?

A. No. It is apparent that the CAPM results are less than the DCF and CE results. There are two reasons for the lower CAPM results. First, risk premiums are lower currently than was the case in prior years. This is the result of lower equity returns that have been experienced over the past several years. This is also reflective of a decline in investor expectations of equity returns and risk premiums. Second, the level of interest rates on U.S. Treasury bonds (i.e., the risk free rate) has been lower in recent years. This is partially the result of the actions of the Federal Reserve System to stimulate the economy. This also impacts investor expectations of returns in a negative fashion. I note that, initially, investors may have believed that the decline in Treasury yields was a temporary factor that would soon be replaced by a rise in interest rates. However, this has not been the case as interest rates have remained low and continued to decline for the past five-

plus years. As a result, it cannot be maintained that low interest rates (and low CAPM results) are temporary and do not reflect investor expectations. Consequently, the CAPM results should be considered as one factor in determining the cost of equity for OG&E.

XII. TOTAL COST OF CAPITAL

Q. What is the total cost of capital for OG&E?

A. Schedule 1 reflects the total cost of capital for OG&E using the company's proposed capital structure and embedded cost of debt, as well as my ROE recommendations. The resulting total cost of capital is a range of 7.34 percent to 7.69 percent. Using the 9.0 percent ROE recommendation, I recommend a 7.42 percent COC.

XIII. COMMENTS ON COMPANY TESTIMONY

Q. Have you reviewed the testimony of OG&E witness Robert B. Hevert?

A. Yes, I have. OG&E is requesting a cost of equity for OG&E of 10.25 percent, which is the bottom of Mr. Hevert's recommended range of 10.25 percent to 10.75 percent.

Q. What is the basis for Mr. Hevert's cost of equity range?

A. Mr. Hevert summarizes his cost of equity conclusions on his Exhibits RBH-1, 2, 3, 5 and 6, which are as follows

Constant Growth DCF			
	Mean (Low Growth)	Mean	Mean (High Growth)
30-Day Average Price	8.59%	9.30%	9.98%
90-Day Average Price	8.71%	9.42%	10.10%
180-Day Average Price	8.68%	9.39%	10.06%
Multi-Stage DCF			
	Mean (Low Growth)	Mean	Mean (High Growth)
30-Day Average Price	9.44%	9.63%	9.81%

90-Day Average Price	9.57%	9.77%	9.96%
180-Day Average Price	9.54%	9.73%	9.92%

Capital Asset Pricing Model		
	Bloomberg Derived Market Risk Premium	Value Line Derived Market Risk Premium
Average Bloomberg Beta Coefficient		
Current 30-Year Treasury (2.90%)	9.58%	9.21%
Near-Term Projected 30-Year Treasury (3.48%)	10.16%	9.79%
Average Value Line Beta Coefficient		
Current 30-Year Treasury (2.90%)	10.75%	10.31%
Near-Term Projected 30-Year Treasury (3.48%)	11.33%	11.90%

Bond Yield Plus Risk Premium	
	Return on Equity
Current 30-Year Treasury (2.90%)	10.05%
Near-Term Projected 30-Year Treasury (3.48%)	10.12%
Long-Term Projected 30-Year Treasury (4.90%)	10.58%

Q. Do you have any general comments about Mr. Hevert's testimony and conclusions?

A. Yes, I do. Mr. Hevert's testimony significantly overstates OG&E's cost of equity. Each of his methods, and virtually all of his inputs into those methods, is systematically biased upward in a manner that significantly inflates his cost of equity conclusions. Further, of the 29 cost of equity measures cited in the table above, 24 are less than his 10.25 percent lower bound of his results.

Q. What are your disagreements with Mr. Hevert's constant growth DCF analyses?

A. Mr. Hevert's constant growth DCF analyses are based on 30-day, 90-day, and 180-day average stock prices for the periods ending October 30, 2015, annualized dividends per share as of October 30, 2015 and the average of Value Line, First Call and Zack's EPS

projections. His DCF analyses are applied to his proxy group of nineteen electric utilities.

Mr. Hevert's constant growth DCF analyses are shown on his Exhibit RBH-1. It is apparent from a review of his exhibit that his "Low DCF ROE" for each proxy company reflects the dividend yield and the lowest of the three EPS growth rates he considers. His "Mean DCF ROE" considers the average of all three EPS growth rates and his "High DCF ROE" only considers the highest EPS growth rate for each company. Stated differently, the "High DCF" result considers only the highest of the three EPS growth rates for each company and ignores the other two EPS growth rates. Thus, the "Mean High DCF" result for one proxy company may reflect only the Zacks EPS Growth, while the "Mean High DCF" result for another proxy company may reflect only the Value Line growth result. The prior table shows that none of Mr. Hevert's DCF results are as high as 10.25 percent lower end of his cost of capital conclusions.

Q. Are there any other problems with Mr. Hevert's constant growth DCF analyses?

A. Yes. Even though Mr. Hevert purports to examine three alternative growth rates in his constant growth DCF analyses, in reality each of the three focuses on a single statistic: analysts' EPS forecasts.

Q. Why is it improper to rely exclusively on EPS forecasts in a DCF analysis?

A. There are several reasons why it is not appropriate to rely exclusively on analysts' forecasts in a DCF context. First, it is not realistic to believe that investors rely exclusively on a single factor, such as analysts' forecasts, in making their investment decisions. Investors have an abundance of available information to assist them in evaluating stocks; EPS forecasts are only one of many such statistics.

Second, Value Line – one of Mr. Hevert's sources of EPS projections – publishes both historic and forecasted data, as well as ratios, for a large number of publicly-traded companies. Presumably, both types of information are published for the consideration of its subscribers/investors. Yet Mr. Hevert considers only one factor, the forecast version of EPS, in his analyses.

Third, the vast majority of information available to investors, by both individual companies in the form of annual reports and offering circulars, and by investment publications such as Value Line, is historic data. It is neither realistic nor logical to maintain that investors only consider projected (estimated) data to the exclusion of historic (actual) data.

Fourth, the experience over the past several years should be a clear signal to investors that analysts cannot accurately predict EPS levels. Few, if any, analysts predicted the decline in security prices in the tech market crash of 2000-2002, as well as the financial crisis of 2008 and 2009.[15] Thus, relying only on forecasted EPS levels, while ignoring historic EPS levels, cannot and will not produce accurate results.

In summary, investors are now very much aware of recent inabilities of security analysts to accurately predict EPS growth. These problems clearly call into question the reliance on analysts' forecasts as the only source of growth in a DCF context. As a result, the landscape has changed in recent years and investors have ample reasons to doubt the reliability of such forecasts at the present time. In light of the above, it is problematic to rely exclusively on such forecasts in determining the cost of equity for OG&E.

Q. Are you aware of any recent analyses and comments on the accuracy of analysts' forecasts?

A. Yes, I am. A 2010 study by McKinsey & Company, titled, "Equity Analysts: Still Too Bullish" concludes that "after almost a decade of stricter regulation, analysts' earnings forecasts continue to be excessively optimistic." I have attached a copy of this study as Schedule 18. The significance of this study, as well as the points I raised previously, is that investors should be hesitant to rely exclusively on analysts' forecasts in making investment decisions.

[15] As demonstration of this, see "Security Analysts and their Recommendations", (http://thismatter.com/money/stocks/valuation/security-analysts.htm).

Q. Has the United States Securities and Exchange Commission issued any reports that address the exclusive reliance on analysts' recommendations?

A. Yes. In a 2010 "Investor Alert: Analyzing Analyst Recommendations" the Securities and Exchange Commission ("SEC") made the following statement:

> As a general matter, investors should not rely solely on an analyst's recommendation when deciding whether to buy, hold, or sell a stock. Instead, they should also do their own research – such as reading the prospectus for new companies or for public companies, the quarterly and annual reports filed with the SEC – to confirm whether a particular investment is appropriate for them in light of their individual financial circumstances.

This SEC "Investor Alert" (attached as Schedule 19) also cites the potential conflicts of interest that analysts face.

This "Investor Alert" thus also calls into question the exclusive reliance on analysts' forecasts, as proposed by Mr. Hevert.

Q. What is your response to Mr. Hevert's multi-stage DCF analyses?

A. Mr. Hevert's multi-stage DCF analyses use EPS forecasts as Stage 1 (short-term) and Gross Domestic Product ("GDP") growth as Stage 3 (long-term), with Stage 2 being a transition.

I have previously indicated that his first stage (i.e., EPS forecasts) over-states the cost of equity. In addition, Mr. Hevert's long-term growth rate of 5.22 percent is excessive.

Q. What is the source of this 5.22 percent GDP figure?

A. Mr. Hevert's 5.22 percent long-term growth rate is the result of his combination of 1929-2014 "real growth" of GDP (3.25 percent) and a 1.91 percent inflation rate.

Q. Is there anything inconsistent with Mr. Hevert's use of historic GDP growth in his DCF analyses?

A. Yes, there is. All of Mr. Hevert's growth rates in his constant growth DCF analyses (i.e., EPS growth) reflect projections of future growth. On the other hand, Mr. Hevert only uses historic rates in his real GDP growth input. Apparently, Mr. Hevert believes it is not

proper to use historic growth rates of financial indicators (i.e., EPS growth), but it is proper to use only historic growth rates in his real GDP input.

Q. Are you aware of any projections of GDP growth?

A. Yes, I am. There are at least two sources of projections of GDP growth. These are:

- Social Security Administration (SSA), and
- Energy Information Administration (EIA).

The two organizations cited above are U.S. government-sponsored organizations.

Q. What are the projections of long-term GDP growth by these two organizations?

A. The projections of long-term gross GDP growth by these two organizations are:

SSA-2020-2085-4.32% (see Schedule 20)

EIA-2012-2040-4.2% (see Schedule 20)

Each of these projections is about 80 basis points below the 5.22 percent GDP figure used by Mr. Hevert.

Q. Would it be more appropriate to use historic or projected growth rates of GDP in Mr. Hevert's DCF analysis?

A. It would be appropriate to use projections of GDP growth, since Mr. Hevert is using projections of the other growth rate indicators.

Q. Is it reasonable to believe that investors would expect GDP growth to be 5.22 percent, in spite of the much lower projections by the U.S. government forecasting organizations?

A. No, it is not. Instead, investors will reasonably rely on the government's forecasts of GDP as the most unbiased and reliable estimates.

Q. Are there any other indications that current and future GDP growth may not be as robust as past GDP growth?

A. Yes. I previously indicated that GDP growth in the current economic expansion is lower than has been the case in other expansions over the past several decades. In addition, The

Conference Board's "Global Economic Outlook" projects average annual U.S. real GDP growth to be 2.0 percent or less, from 2015 through 2025.[16] This is well below the 3.25 percent historic (1929-2014) real GDP growth rate utilized by Mr. Hevert. Both of these real GDP figures are lower than the SAA and EIA figures that I discuss above because the real GDP figures are net of (i.e., before) inflation, while the SSA and EIA figures include projected inflation.

Q. Are you aware of any utility regulatory agencies that utilize GDP growth as a component in a DCF analysis?

A. The only regulatory agency of which I am aware that directly and formally uses GDP growth in a DCF context is the Federal Energy Regulatory Commission ("FERC"). The FERC uses a two-stage DCF model in establishing the cost of equity for interstate natural gas pipelines and, more recently, electric utilities. The first stage of the FERC two-stage DCF model uses 5-year EPS forecasts, while the second stage uses GDP projections for 6 to 25+ years into the future.

Q. How much weight does FERC give to the GDP growth rate in its two-stage DCF model?

A. Thirty-three percent.

Q. Are you aware of any regulatory agencies that use historic GDP growth in a DCF context?

A. No, not in the same context as Mr. Hevert.

Q. Do you have any comments concerning Mr. Hevert's CAPM analyses?

A. Yes, I do. I disagree with Mr. Hevert's use of projected interest rates as his risk-free rate CAPM component. I also disagree with his risk premium estimates.

[16] www.conference-board.org/data/globaloutlook.cfm

Q. Why is it not proper to use projected interest rates as the risk-free rate?

A. It is proper to use the current (i.e., actual) yield as the risk-free rate in a CAPM context. This is the case since the current yield is known and measurable and reflects investors' collective assessment of all capital market conditions. Prospective interest rates, in contrast, are not measurable and not achievable. For example, if the current yield on 20-year U.S. Treasury Bonds is about 2.5 percent, this reflects the rate that investors can actually receive on their investment. Investors cannot receive a prospective yield on their investments since such a yield is not actual but rather speculative.

Use of the current risk-free rate in a CAPM context is similar to using the current yield in a DCF context. Analysts do not use prospective stock prices as the basis for the dividend yield in a DCF analysis, as use of prospective stock prices is speculative. Use of current stock prices is appropriate, as are used by Mr. Hevert. Likewise, current levels of interest rates reflect all current information (i.e., the efficient market hypothesis) and should be used as the risk-free rate in the CAPM.

Q. What are your concerns with Mr. Hevert's market risk premium component?

A. Mr. Hevert computes his market risk premium by calculating a constant growth DCF for the S&P 500 companies (using EPS forecasts as growth component) of 13.22 percent and comparing this to current yields on 30-year U.S. Treasury securities. I have previously indicated that his DCF methodology over-states the cost of capital. In addition, his use of U.S. Treasury securities as the baseline for the market risk premium is improper at this time due to the effects of the Federal Reserve's Quantitative Easing on U.S. Treasury yields, which I describe in more detail above.

Q. What are your responses to Mr. Hevert's bond yield plus risk premium analysis?

A. Mr. Hevert's risk premium approach compares the allowed ROEs for electric utilities and 30-Year U.S. Government Bond yields over the period 1980 to October 2015. He applies this regression result to various projected levels of 30-year U.S. Treasury Bonds and correspondingly arrives at his 10.05 percent to 10.58 percent conclusion.

Mr. Hevert's bond yield plus risk premium analysis suffers from the same deficiencies as his market risk premium and CAPM analyses. His use of projected yields

and his use of Treasury Securities as the current measure of the risk premium both overstate OG&E's cost of equity.

Q. Mr. Hevert cites four "additional factors that must be taken into consideration when determining where OG&E's cost of equity falls within the range of results." Do you have any responses to this assertion?

A. Yes, I do. Mr. Hevert has identified four "factors" that he maintains create more risk for OG&E relative to his proxy electric utilities. However, each of these factors is considered by the rating agencies in their assignment of credit ratings to OG&E.

As I indicated previously, OG&E has higher credit ratings, reflecting lower risk, than the typical electric utility. Stated differently, OG&E is perceived to have lower risks than the typical electric utility, including Mr. Hevert's proxy group, in spite of the existence of Mr. Hevert's risk "factors." Consequently, there is no justification for providing OG&E a higher return on equity relative to that of other similar electric utilities.

Q. Can you provide an example of rating agency recognition of those factors in establishing OG&E's security ratings?

A. Yes, I can. As I noted previously, OG&E's security ratings were raised by both Moody's and S&P in 2014, a time in which the Company's capital expenditure and environmental compliance programs had begun. OG&E has maintained these ratings in the three years since. It is the responsibility of the rating agencies to give consideration to all relevant factors in assigning ratings. As a result, it is apparent that OG&E's capital expenditures and environmental compliance programs are reflected in OG&E's single A ratings. As noted previously, OG&E has above-average security rating relative to other electric utilities.

Q. Does Mr. Hevert argue that environmental compliance costs pose additional risks to OG&E?

A. Yes. He argues that OG&E will incur additional costs for environmental compliance in the future, particularly for its coal plants. He also alleges that those costs increase OG&E's investment risk.

Q. Do you agree with Mr. Hevert's argument?

A. No. Utilities have been investing in environmental compliance equipment for decades; there is nothing about the current set of regulations that changes the fundamental risk profile of OG&E. Just as an example, utilities began installing environmental equipment in response to the Clean Air Act shortly after that law was passed in 1970. There is nothing about the current set of environmental regulations that fundamentally changes the risk profile of regulated utilities such as OG&E, as is evidenced by the continuation of OG&E's ratings. In other words, nothing fundamental has changed for companies, such as OG&E, that are subject to rate of return regulations.

Q. Do you agree with the proposition that OG&E should be entitled to a size adjustment?

A. No, I do not. OG&E's ratepayers should not be charged electric rates that reflect an incremental return to reflect the size of the Company. Such an increment is not justified and not appropriate.

Q. Do you have any additional responses to Mr. Hevert's "considerations" of OG&E's business risks?

A. Yes, I do. Mr. Hevert maintains that OG&E has risks associated with cost recovery of environmental regulations and its planned capital investment program. I have previously noted that: (1) OG&E has maintained a high percentage of common equity in its capital structure in recent years, and (2) long-term interest rates are at or near historic low levels. Based upon these factors, it appears appropriate for OG&E to take advantage of those two factors and fund a relatively higher proportion of these above-cited expenses with long-term debt.

Q. Does this conclude your direct testimony?

A. Yes, it does.

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BACKGROUND AND EXPERIENCE PROFILE
DAVID C. PARCELL, MBA, CRRA
PRESIDENT/SENIOR ECONOMIST

EDUCATION

1985	M.B.A., Virginia Commonwealth University
1970	M.A., Economics, Virginia Polytechnic Institute and State University, (Virginia Tech)
1969	B.A., Economics, Virginia Polytechnic Institute and State University, (Virginia Tech)

POSITIONS

2007-Present	President, Technical Associates, Inc.
1995-2007	Executive Vice President and Senior Economist, Technical Associates, Inc.
1993-1995	Vice President and Senior Economist, C. W. Amos of Virginia
1972-1993	Vice President and Senior Economist, Technical Associates, Inc.
1969-1972	Research Economist, Technical Associates, Inc.
1968-1969	Research Associate, Department of Economics, Virginia Polytechnic Institute and State University

ACADEMIC HONORS

Omicron Delta Epsilon - Honor Society in Economics
Beta Gamma Sigma - National Scholastic Honor Society of Business Administration
Alpha Iota Delta - National Decision Sciences Honorary Society
Phi Kappa Phi - Scholastic Honor Society

PROFESSIONAL DESIGNATIONS

Certified Rate of Return Analyst - Founding Member

RELEVANT EXPERIENCE

Financial Economics -- Advised and assisted many Virginia banks and savings and loan associations on organizational and regulatory matters. Testified approximately 25 times before the Virginia State Corporation Commission and the Regional Administrator of National Banks on matters related to branching and organization for banks, savings and loan associations, and consumer finance companies. Advised financial institutions on interest rate structure and loan maturity. Testified before Virginia State Corporation Commission on maximum rates for consumer finance companies.

Testified before several committees and subcommittees of Virginia General Assembly on numerous banking matters.

Clients have included First National Bank of Rocky Mount, Patrick Henry National Bank, Peoples Bank of Danville, Blue Ridge Bank, Bank of Essex, and Signet Bank.

Published articles in law reviews and other periodicals on structure and regulation of banking/financial services industry.

Utility Economics -- Performed numerous financial studies of regulated public utilities. Testified in over 300 cases before some thirty state and federal regulatory agencies.

Prepared numerous rate of return studies incorporating cost of equity determination based on DCF, CAPM, comparable earnings and other models. Developed procedures for identifying differential risk characteristics by nuclear construction and other factors.

Conducted studies with respect to cost of service and indexing for determining utility rates, the development of annual review procedures for regulatory control of utilities, fuel and power plant cost recovery adjustment clauses, power supply agreements among affiliates, utility franchise fees, and use of short-term debt in capital structure.

Presented expert testimony before federal regulatory agencies Federal Energy Regulatory Commission, Federal Power Commission, and National Energy Board (Canada), state regulatory agencies in Alabama, Alaska, Arizona, Arkansas, California, Connecticut, Delaware, District of Columbia, Florida, Georgia, Hawaii, Illinois, Indiana, Kansas, Kentucky, Maine, Maryland, Missouri, Nebraska, Nevada, New Hampshire, New Jersey, New Mexico, Ohio, Oklahoma, Ontario (Canada), Pennsylvania, South Carolina, Texas, Utah, Vermont, Virginia, West Virginia, Washington, Wisconsin, and Yukon Territory (Canada).

Published articles in law reviews and other periodicals on the theory and purpose of regulation and other regulatory subjects.

Clients served include state regulatory agencies in Alaska, Arizona, Delaware, Missouri, North Carolina, Ontario (Canada), and Virginia; consumer advocates and attorneys general in Alabama, Arizona, District of Columbia, Florida, Georgia, Hawaii, Illinois, Indiana, Kansas, Kentucky, Maryland, Nevada, New Mexico, Ohio, Oklahoma, Pennsylvania, South Carolina, Texas, Utah, Vermont, Virginia, and West Virginia; federal agencies including Defense Communications Agency, the Department of Energy, Department of the Navy, and General Services Administration; and various organizations such as Bath Iron Works, Illinois Citizens' Utility Board, Illinois Governor's Office of Consumer Services, Illinois Small Business Utility Advocate, Wisconsin's Environmental Decade, Wisconsin's Citizens Utility Board, and Old Dominion Electric Cooperative.

Insurance Economics -- Conducted analyses of the relationship between the investment income earned by insurance companies on their portfolios and the premiums charged for insurance. Analyzed impact of diversification on financial strength of Blue Cross/Blue Shield Plans in Virginia.

Conducted studies of profitability and cost of capital for property/casualty insurance industry. Evaluated risk of and required return on surplus for various lines of insurance business.

Presented expert testimony before Virginia State Corporation Commission concerning cost of capital and expected gains from investment portfolio. Testified before insurance bureaus of Maine, New Jersey, North Carolina, Rhode Island, South Carolina and Vermont concerning cost of equity for insurance companies.

Prepared cost of capital and investment income return analyses for numerous insurance companies concerning several lines of insurance business. Analyses used by Virginia Bureau of Insurance for purposes of setting rates.

Special Studies -- Conducted analyses which evaluated the financial and economic implications of legislative and administrative changes. Subject matter of analyses include returnable bottles, retail beer sales, wine sales regulations, taxi-cab taxation, and bank regulation. Testified before several Virginia General Assembly subcommittees.

Testified before Virginia ABC Commission concerning economic impact of mixed beverage license.
Clients include Virginia Beer Wholesalers, Wine Institute, Virginia Retail Merchants Association, and Virginia Taxicab Association.

Franchise, Merger & Anti-Trust Economics -- Conducted studies on competitive impact on market structures due to joint ventures, mergers, franchising and other business restructuring. Analyzed the costs and benefits to parties involved in mergers. Testified in federal courts and before banking and other regulatory bodies concerning the structure and performance of markets, as well as on the impact of restrictive practices.

Clients served include Dominion Bankshares, asphalt contractors, and law firms.

Transportation Economics -- Conducted cost of capital studies to assess profitability of oil pipelines, trucks, taxicabs and railroads. Analyses have been presented before the Federal Energy Regulatory Commission and Alaska Pipeline Commission in rate proceedings. Served as a consultant to the Rail Services Planning Office on the reorganization of rail services in the U.S.
Economic Loss Analyses -- Testified in federal courts, state courts, and other adjudicative forums regarding the economic loss sustained through personal and business injury whether due to bodily harm, discrimination, non-performance, or anticompetitive practices. Testified on economic loss to a commercial bank resulting from publication of adverse information concerning solvency. Testimony has been presented on behalf of private individuals and

business firms.

MEMBERSHIPS

American Economic Association
Virginia Association of Economists
Richmond Society of Financial Analysts
Financial Analysts Federation
Society of Utility and Regulatory Financial Analysts

Board of Directors	1992-2000
Secretary/Treasurer	1994-1998
President	1998-2000

RESEARCH ACTIVITY

Books and Major Research Reports

"Stock Price As An Indicator of Performance," Master of Arts Thesis, Virginia Tech, 1970

"Revision of the Property and Casualty Insurance Ratemaking Process Under Prior Approval in the Commonwealth of Virginia," prepared for the Bureau of Insurance of the Virginia State Corporation Commission, with Charles Schotta and Michael J. Ileo, 1971

"An analysis of the Virginia Consumer Finance Industry to Determine the Need for Restructuring the Rate and Size Ceilings on Small Loans in Virginia and the Process by which They are Governed," prepared for the Virginia Consumer Finance Association, with Michael J. Ileo, 1973

State Banks and the State Corporation Commission: A Historical Review, Technical Associates, Inc., 1974

"A Study of the Implications of the Sale of Wine by the Virginia Department of Alcoholic Beverage Control", prepared for the Virginia Wine Wholesalers Association, Virginia Retail Merchants Association, Virginia Food Dealers Association, Virginia Association of Chain Drugstores, Southland Corporation, and the Wine Institute, 1983.

"Performance and Diversification of the Blue Cross/Blue Shield Plans in Virginia: An Operational Review", prepared for the Bureau of Insurance of the Virginia State Corporation Commission, with Michael J. Ileo and Alexander F. Skirpan, 1988.

The Cost of Capital - A Practitioners' Guide, Society of Utility and Regulatory Financial Analysts, 1997 (previous editions in 1991, 1992, 1993, 1994, and 1995).

Papers Presented and Articles Published

"The Differential Effect of Bank Structure on the Transmission of Open Market Operations," Western Economic Association Meeting, with Charles Schotta, 1971

"The Economic Objectives of Regulation: The Trend in Virginia," (with Michael J. Ileo), William and Mary Law Review, Vol. 14, No. 2, 1973

"Evolution of the Virginia Banking Structure, 1962-1974: The Effects of the Buck-Holland Bill", (with Michael J. Ileo), William and Mary Law Review, Vol. 16, No. 3, 1975

"Banking Structure and Statewide Branching: The Potential for Virginia", William and Mary Law Review, Vol. 18, No. 1, 1976

"Bank Expansion and Electronic Banking: Virginia Banking Structure Changes Past, Present, and Future," William and Mary Business Review," Vol. 1, No. 2, 1976

"Electronic Banking - Wave of the Future?" (with James R. Marchand), Journal of Management and Business Consulting, Vol. 1, No. 1, 1976

"The Pricing of Electricity" (with James R. Marchand), Journal of Management and Business Consulting, Vol. 1, No. 2, 1976

"The Public Interest - Bank and Savings and Loan Expansion in Virginia" (with Richard D. Rogers), University of Richmond Law Review, Vol. 11, No. 3, 1977

"When Is It In the 'Public Interest' to Authorize a New Bank?", University of Richmond Law Review, Vol. 13, No. 3, 1979

"Banking Deregulation and Its Implications on the Virginia Banking Structure," William and Mary Business Review, Vol. 5, No. 1, 1983

"The Impact of Reciprocal Interstate Banking Statutes on The Performance of Virginia Bank Stocks", with William B. Harrison, Virginia Social Science Journal, Vol. 23, 1988

"The Financial Performance of New Banks in Virginia", Virginia Social Science Journal, Vol. 24, 1989

"Identifying and Managing Community Bank Performance After Deregulation", with William B. Harrison, Journal of Managerial Issues, Vol. II, No. 2, Summer 1990

"The Flotation Cost Adjustment To Utility Cost of Common Equity - Theory, Measurement and Implementation," presented at Twenty-Fifth Financial Forum, National

Society of Rate of Return Analysts, Philadelphia, Pennsylvania, April 28, 1993.

Biography of Myon Edison Bristow, Dictionary of Virginia Biography, Volume 2, 2001.

Exhibit DCP-1
Schedule 1

OKLAHOMA GAS AND ELECTRIC COMPANY
TOTAL COST OF CAPITAL

Item	Amount 1/	Percent	Cost	Weighted Cost
Long-Term Debt	$2,655,459,848	46.69%	5.62% 1/	2.62%
Common Equity	$3,031,797,712	53.31%	8.85% 9.00% 9.50%	4.72% 4.80% 5.06%
Total	$5,687,257,560	100.00%		7.34% 7.42% 7.69%

1/ Amounts and percents of OG&E test year capital and cost of long-term debt, as contained in Company filing.

ECONOMIC INDICATORS

Year	Real GDP* Growth	Industrial Production Growth	Unemploy-ment Rate	Consumer Price Index
		1975 - 1982 Cycle		
1975	-1.1%	-8.9%	8.5%	7.0%
1976	5.4%	10.8%	7.7%	4.8%
1977	5.5%	5.9%	7.0%	6.8%
1978	5.0%	5.7%	6.0%	9.0%
1979	2.8%	4.4%	5.8%	13.3%
1980	-0.2%	-1.9%	7.0%	12.4%
1981	1.8%	1.9%	7.5%	8.9%
1982	-2.1%	-4.4%	9.5%	3.8%
		1983 - 1991 Cycle		
1983	4.0%	3.7%	9.5%	3.8%
1984	6.8%	9.3%	7.5%	3.9%
1985	3.7%	1.7%	7.2%	3.8%
1986	3.1%	0.9%	7.0%	1.1%
1987	2.9%	4.9%	6.2%	4.4%
1988	3.8%	4.5%	5.5%	4.4%
1989	3.5%	1.8%	5.3%	4.6%
1990	1.8%	-0.2%	5.6%	6.1%
1991	-0.5%	-2.0%	6.8%	3.1%
		1992 - 2001 Cycle		
1992	3.0%	3.1%	7.5%	2.9%
1993	2.7%	3.4%	6.9%	2.7%
1994	4.0%	5.5%	6.1%	2.7%
1995	3.7%	4.8%	5.6%	2.5%
1996	4.5%	4.3%	5.4%	3.3%
1997	4.5%	7.3%	4.9%	1.7%
1998	4.2%	5.8%	4.5%	1.6%
1999	3.7%	4.5%	4.2%	2.7%
2000	4.1%	4.0%	4.0%	3.4%
2001	1.1%	-3.4%	4.7%	1.6%
		2002 - 2009 Cycle		
2002	1.8%	0.2%	5.8%	2.4%
2003	2.8%	1.2%	6.0%	1.9%
2004	3.8%	2.3%	5.5%	3.3%
2005	3.3%	3.2%	5.1%	3.4%
2006	2.7%	2.2%	4.6%	2.5%
2007	1.8%	2.5%	4.6%	4.1%
2008	-0.3%	-3.4%	5.8%	0.1%
2009	-2.8%	-11.3%	9.3%	2.7%
		Current Cycle		
2010	2.5%	5.6%	9.6%	1.5%
2011	1.6%	3.0%	8.9%	3.0%
2012	2.2%	2.8%	8.1%	1.7%
2013	1.5%	1.9%	7.4%	1.5%
2014	2.4%	3.7%	6.2%	0.8%
2015	2.4%	1.3%	5.3%	0.7%

*GDP=Gross Domestic Product

Source: Council of Economic Advisors, Economic Indicators, various issues

ECONOMIC INDICATORS

Year	Real GDP* Growth	Industrial Production Growth	Unemployment Rate	Consumer Price Index
2002				
1st Qtr.	2.7%	-3.8%	5.6%	2.8%
2nd Qtr.	2.2%	-1.2%	5.9%	0.9%
3rd Qtr.	2.4%	0.8%	5.8%	2.4%
4th Qtr.	0.2%	1.4%	5.9%	1.6%
2003				
1st Qtr.	1.2%	1.1%	5.8%	4.8%
2nd Qtr.	3.5%	-0.9%	6.2%	0.0%
3rd Qtr.	7.5%	-0.9%	6.1%	3.2%
4th Qtr.	2.7%	1.5%	5.9%	-0.3%
2004				
1st Qtr.	3.0%	2.8%	5.6%	5.2%
2nd Qtr.	3.5%	4.9%	5.6%	4.4%
3rd Qtr.	3.6%	4.6%	5.4%	0.8%
4th Qtr.	2.5%	4.3%	5.4%	3.6%
2005				
1st Qtr.	4.1%	3.8%	5.3%	4.4%
2nd Qtr.	1.7%	3.0%	5.1%	1.6%
3rd Qtr.	3.1%	2.7%	5.0%	8.8%
4th Qtr.	2.1%	2.9%	4.9%	-2.0%
2006				
1st Qtr.	5.4%	3.4%	4.7%	4.8%
2nd Qtr.	1.4%	4.5%	4.6%	4.8%
3rd Qtr.	0.1%	5.2%	4.7%	0.4%
4th Qtr.	3.0%	3.5%	4.5%	0.0%
2007				
1st Qtr.	0.9%	2.5%	4.5%	4.8%
2nd Qtr.	3.2%	1.6%	4.5%	5.2%
3rd Qtr.	2.3%	1.8%	4.6%	1.2%
4th Qtr.	2.9%	1.7%	4.8%	6.4%
2008				
1st Qtr.	-1.8%	1.9%	4.9%	2.8%
2nd Qtr.	1.3%	0.2%	5.3%	7.6%
3rd Qtr.	-3.7%	-3.0%	6.0%	2.8%
4th Qtr.	-8.9%	6.0%	6.9%	-13.2%
2009				
1st Qtr.	-5.3%	-11.6%	8.1%	2.4%
2nd Qtr.	-0.3%	-12.9%	9.3%	3.2%
3rd Qtr.	1.4%	-9.3%	9.6%	2.0%
4th Qtr.	4.0%	-4.5%	10.0%	2.5%
2010				
1st Qtr.	1.6%	2.7%	9.7%	0.9%
2nd Qtr.	3.9%	6.5%	9.7%	-1.2%
3rd Qtr.	2.8%	6.9%	9.6%	2.8%
4th Qtr.	2.8%	6.2%	9.6%	2.8%
2011				
1st Qtr.	-1.5%	5.4%	9.0%	4.8%
2nd Qtr.	2.9%	3.6%	9.0%	3.2%
3rd Qtr.	0.8%	3.3%	9.1%	2.4%
4th Qtr.	4.6%	4.0%	8.7%	0.4%
2012				
1st Qtr.	2.3%	4.5%	8.3%	3.2%
2nd Qtr.	1.6%	4.7%	8.2%	0.0%
3rd Qtr.	2.5%	3.4%	8.1%	4.0%
4th Qtr.	0.1%	2.8%	7.8%	0.0%
2013				
1st Qtr.	1.9%	2.5%	7.7%	2.0%
2nd Qtr.	1.1%	2.0%	7.6%	1.2%
3rd Qtr.	3.0%	2.6%	7.3%	1.6%
4th Qtr.	3.9%	3.3%	7.0%	1.2%
2014				
1st Qtr.	-0.9%	3.2%	6.6%	1.6%
2nd Qtr.	4.6%	4.2%	6.2%	3.6%
3rd Qtr.	4.3%	4.7%	6.1%	0.0%
4th Qtr.	2.1%	4.5%	5.7%	-2.8%
2015				
1st Qtr.	0.6%	3.5%	5.6%	-1.2%
2nd Qtr.	3.9%	1.4%	5.4%	3.2%
3rd Qtr.	2.0%	1.1%	5.2%	-0.1%
4th Qtr.	1.0%	-0.8%	5.0%	0.0%

*GDP=Gross Domestic Product

Source: Council of Economic Advisors, Economic Indicators, various issues.

INTEREST RATES

Year	Prime Rate	US Treasury T Bills 3 Month	US Treasury T Bonds 10 Year	Utility Bonds Aaa	Utility Bonds Aa	Utility Bonds A	Utility Bonds Baa
			1975 - 1982 Cycle				
1975	7.86%	5.84%	7.99%	9.03%	9.44%	10.09%	10.96%
1976	6.84%	4.99%	7.61%	8.63%	8.92%	9.29%	9.82%
1977	6.83%	5.27%	7.42%	8.19%	8.43%	8.61%	9.06%
1978	9.06%	7.22%	8.41%	8.87%	9.10%	9.29%	9.62%
1979	12.67%	10.04%	9.44%	9.86%	10.22%	10.49%	10.96%
1980	15.27%	11.51%	11.46%	12.30%	13.00%	13.34%	13.95%
1981	18.89%	14.03%	13.93%	14.64%	15.30%	15.95%	16.60%
1982	14.86%	10.69%	13.00%	14.22%	14.79%	15.86%	16.45%
			1983 - 1991 Cycle				
1983	10.79%	8.63%	11.10%	12.52%	12.83%	13.66%	14.20%
1984	12.04%	9.58%	12.44%	12.72%	13.66%	14.03%	14.53%
1985	9.93%	7.48%	10.62%	11.68%	12.06%	12.47%	12.96%
1986	8.33%	5.98%	7.68%	8.92%	9.30%	9.58%	10.00%
1987	8.21%	5.82%	8.39%	9.52%	9.77%	10.10%	10.53%
1988	9.32%	6.69%	8.85%	10.05%	10.26%	10.49%	11.00%
1989	10.87%	8.12%	8.49%	9.32%	9.56%	9.77%	9.97%
1990	10.01%	7.51%	8.55%	9.45%	9.65%	9.86%	10.06%
1991	8.46%	5.42%	7.86%	8.85%	9.09%	9.36%	9.55%
			1992 - 2001 Cycle				
1992	6.25%	3.45%	7.01%	8.19%	8.55%	8.69%	8.86%
1993	6.00%	3.02%	5.87%	7.29%	7.44%	7.59%	7.91%
1994	7.15%	4.29%	7.09%	8.07%	8.21%	8.31%	8.63%
1995	8.83%	5.51%	6.57%	7.68%	7.77%	7.89%	8.29%
1996	8.27%	5.02%	6.44%	7.48%	7.57%	7.75%	8.16%
1997	8.44%	5.07%	6.35%	7.43%	7.54%	7.60%	7.95%
1998	8.35%	4.81%	5.26%	6.77%	6.91%	7.04%	7.26%
1999	8.00%	4.66%	5.65%	7.21%	7.51%	7.62%	7.88%
2000	9.23%	5.85%	6.03%	7.88%	8.06%	8.24%	8.36%
2001	6.91%	3.44%	5.02%	7.47%	7.59%	7.78%	8.02%
			2002 - 2009 Cycle				
2002	4.67%	1.62%	4.61%		[1] 7.19%	7.37%	8.02%
2003	4.12%	1.01%	4.01%		6.40%	6.58%	6.84%
2004	4.34%	1.38%	4.27%		6.04%	6.16%	6.40%
2005	6.19%	3.16%	4.29%		5.44%	5.65%	5.93%
2006	7.96%	4.73%	4.80%		5.84%	6.07%	6.32%
2007	8.05%	4.41%	4.63%		5.94%	6.07%	6.33%
2008	5.09%	1.48%	3.66%		6.18%	6.53%	7.25%
2009	3.25%	0.16%	3.26%		5.75%	6.04%	7.06%
			Current Cycle				
2010	3.25%	0.14%	3.22%		5.24%	5.46%	5.96%
2011	3.25%	0.06%	2.78%		4.78%	5.04%	5.57%
2012	3.25%	0.09%	1.80%		3.83%	4.13%	4.86%
2013	3.25%	0.06%	2.35%		4.24%	4.47%	4.98%
2014	3.25%	0.03%	2.54%		4.19%	4.28%	4.80%
2015	3.26%	0.60%	2.14%		4.00%	4.12%	5.03%

[1] Note: Moody's has not published Aaa utility bond yields since 2001.

Sources: Council of Economic Advisors, Economic Indicators; Moody's Bond Record; Federal Reserve Bulletin; various issues.

INTEREST RATES

	Prime Rate	US Treasury T Bills 3 Month	US Treasury T Bonds 10 Year	Utility Bonds Aa	Utility Bonds A	Utility Bonds Baa
2010						
Jan	3.25%	0.06%	3.73%	5.55%	5.77%	6.16%
Feb	3.25%	0.10%	3.69%	5.69%	5.87%	6.25%
Mar	3.25%	0.15%	3.73%	5.64%	5.84%	6.22%
Apr	3.25%	0.15%	3.85%	5.62%	5.81%	6.19%
May	3.25%	0.16%	3.42%	5.29%	5.50%	5.97%
June	3.25%	0.12%	3.20%	5.22%	5.46%	6.18%
July	3.25%	0.16%	3.01%	4.99%	5.26%	5.98%
Aug	3.25%	0.15%	2.70%	4.75%	5.01%	5.55%
Sept	3.25%	0.15%	2.65%	4.74%	5.01%	5.53%
Oct	3.25%	0.13%	2.54%	4.89%	5.10%	5.62%
Nov	3.25%	0.13%	2.76%	5.12%	5.37%	5.85%
Dec	3.25%	0.15%	3.29%	5.32%	5.56%	6.04%
2011						
Jan	3.25%	0.15%	3.39%	5.29%	5.57%	6.06%
Feb	3.25%	0.14%	3.58%	5.42%	5.68%	6.10%
Mar	3.25%	0.11%	3.41%	5.33%	5.56%	5.97%
Apr	3.25%	0.06%	3.46%	5.32%	5.55%	5.98%
May	3.25%	0.04%	3.17%	5.08%	5.32%	5.74%
June	3.25%	0.04%	3.00%	5.04%	5.26%	5.67%
July	3.25%	0.03%	3.00%	5.05%	5.27%	5.70%
Aug	3.25%	0.05%	2.30%	4.44%	4.69%	5.22%
Sept	3.25%	0.02%	1.98%	4.24%	4.48%	5.11%
Oct	3.25%	0.02%	2.15%	4.21%	4.52%	5.24%
Nov	3.25%	0.01%	2.01%	3.92%	4.25%	4.93%
Dec	3.25%	0.02%	1.98%	4.00%	4.33%	5.07%
2012						
Jan	3.25%	0.02%	1.97%	4.03%	4.34%	5.06%
Feb	3.25%	0.08%	1.97%	4.02%	4.36%	5.02%
Mar	3.25%	0.09%	2.17%	4.16%	4.48%	5.13%
Apr	3.25%	0.08%	2.05%	4.10%	4.40%	5.11%
May	3.25%	0.09%	1.80%	3.92%	4.20%	4.97%
June	3.25%	0.09%	1.62%	3.79%	4.08%	4.91%
July	3.25%	0.10%	1.53%	3.58%	3.93%	4.85%
Aug	3.25%	0.11%	1.68%	3.65%	4.00%	4.88%
Sept	3.25%	0.10%	1.72%	3.69%	4.02%	4.81%
Oct	3.25%	0.10%	1.75%	3.68%	3.91%	4.54%
Nov	3.25%	0.11%	1.65%	3.60%	3.84%	4.42%
Dec	3.25%	0.08%	1.72%	3.75%	4.00%	4.56%
2013						
Jan	3.25%	0.07%	1.91%	3.90%	4.15%	4.66%
Feb	3.25%	0.10%	1.98%	3.95%	4.18%	4.74%
Mar	3.25%	0.09%	1.96%	3.90%	4.15%	4.66%
Apr	3.25%	0.06%	1.76%	3.74%	4.00%	4.49%
May	3.25%	0.05%	1.93%	3.91%	4.17%	4.65%
June	3.25%	0.05%	2.30%	4.27%	4.53%	5.08%
July	3.25%	0.04%	2.58%	4.44%	4.68%	5.21%
Aug	3.25%	0.04%	2.74%	4.53%	4.73%	5.28%
Sept	3.25%	0.02%	2.81%	4.58%	4.80%	5.31%
Oct	3.25%	0.06%	2.62%	4.48%	4.70%	5.17%
Nov	3.25%	0.07%	2.72%	4.56%	4.77%	5.24%
Dec	3.25%	0.07%	2.90%	4.59%	4.81%	5.25%
2014						
Jan	3.25%	0.05%	2.86%	4.44%	4.63%	5.09%
Feb	3.25%	0.06%	2.71%	4.38%	4.53%	5.01%
Mar	3.25%	0.05%	2.72%	4.40%	4.51%	5.00%
Apr	3.25%	0.04%	2.71%	4.30%	4.41%	4.85%
May	3.25%	0.03%	2.56%	4.16%	4.26%	4.69%
June	3.25%	0.03%	2.60%	4.23%	4.29%	4.73%
July	3.25%	0.03%	2.54%	4.16%	4.23%	4.66%
Aug	3.25%	0.03%	2.42%	4.07%	4.13%	4.65%
Sept	3.25%	0.02%	2.53%	4.18%	4.24%	4.79%
Oct	3.25%	0.02%	2.30%	3.96%	4.06%	4.67%
Nov	3.25%	0.02%	2.33%	4.03%	4.09%	4.75%
Dec	3.25%	0.04%	2.21%	3.90%	3.95%	4.70%
2015						
Jan	3.25%	0.03%	1.88%	3.52%	3.58%	4.39%
Feb	3.25%	0.03%	1.98%	3.62%	3.67%	4.44%
Mar	3.25%	0.03%	2.04%	3.67%	3.74%	4.51%
Apr	3.25%	0.02%	1.94%	3.63%	3.75%	4.51%
May	3.25%	0.02%	2.20%	4.05%	4.17%	4.91%
June	3.25%	0.04%	2.36%	4.29%	4.39%	5.13%
July	3.25%	0.03%	2.32%	4.27%	4.40%	5.22%
Aug	3.25%	0.09%	2.17%	4.13%	4.25%	5.23%
Sep	3.25%	0.06%	2.17%	4.25%	4.39%	5.42%
Oct	3.25%	0.01%	2.07%	4.13%	4.29%	5.47%
Nov	3.25%	0.13%	2.26%	4.22%	4.40%	5.57%
Dec	3.50%	0.26%	2.24%	4.18%	4.35%	5.55%
2016						
Jan	3.50%	0.25%	2.09%	4.09%	4.27%	5.49%
Feb	3.50%	0.32%	1.78%	3.94%	4.11%	5.28%

Sources: Council of Economic Advisors, Economic Indicators; Moody's Bond Record; Federal Reserve Bulletin; various issues.

STOCK PRICE INDICATORS

	S&P Composite [1]	NASDAQ Composite [1]	DJIA	S&P D/P	S&P E/P
		1975 - 1982 Cycle			
1975			802.49	4.31%	9.15%
1976			974.92	3.77%	8.90%
1977			894.63	4.62%	10.79%
1978			820.23	5.28%	12.03%
1979			844.40	5.47%	13.46%
1980			891.41	5.26%	12.66%
1981			932.92	5.20%	11.96%
1982			884.36	5.81%	11.60%
		1983 - 1991 Cycle			
1983			1,190.34	4.40%	8.03%
1984			1,178.48	4.64%	10.02%
1985			1,328.23	4.25%	8.12%
1986			1,792.76	3.49%	6.09%
1987			2,275.99	3.08%	5.48%
1988	[1]	[1]	2,060.82	3.64%	8.01%
1989	322.84		2,508.91	3.45%	7.41%
1990	334.59		2,678.94	3.61%	6.47%
1991	376.18	491.69	2,929.33	3.24%	4.79%
		1992 - 2001 Cycle			
1992	415.74	$599.26	3,284.29	2.99%	4.22%
1993	451.21	715.16	3,522.06	2.78%	4.46%
1994	460.42	751.65	3,793.77	2.82%	5.83%
1995	541.72	925.19	4,493.76	2.56%	6.09%
1996	670.50	1,164.96	5,742.89	2.19%	5.24%
1997	873.43	1,469.49	7,441.15	1.77%	4.57%
1998	1,085.50	1,794.91	8,625.52	1.49%	3.46%
1999	1,327.33	2,728.15	10,464.88	1.25%	3.17%
2000	1,427.22	2,783.67	10,734.90	1.15%	3.63%
2001	1,194.18	2,035.00	10,189.13	1.32%	2.95%
		2002 - 2009 Cycle			
2002	993.94	1,539.73	9,226.43	1.61%	2.92%
2003	965.23	1,647.17	8,993.59	1.77%	3.84%
2004	1,130.65	1,986.53	10,317.39	1.72%	4.89%
2005	1,207.23	2,099.32	10,547.67	1.83%	5.36%
2006	1,310.46	2,263.41	11,408.67	1.87%	5.78%
2007	1,477.19	2,578.47	13,169.98	1.86%	5.29%
2008	1,220.04	2,161.65	11,252.62	2.37%	3.54%
2009	948.05	1,845.38	8,876.15	2.40%	1.86%
		Current Cycle			
2010	1,139.97	2,349.89	10,662.80	1.98%	6.04%
2011	1,268.89	2,677.44	11,966.36	2.05%	6.77%
2012	1,379.35	2,965.56	12,967.08	2.24%	6.20%
2013	1,462.51	3,537.69	14,999.67	2.14%	5.57%
2014	1,930.67	4,374.31	16,773.99	2.04%	5.25%
2015	2,061.20	4,943.49	17,590.81	2.10%	4.59%

[1] Note: this source did not publish the S&P Composite prior to 1988 and the NASDAQ Composite prior to 1991.

Source: Council of Economic Advisors, Economic Indicators, various issues.

STOCK PRICE INDICATORS

	S&P Composite	NASDAQ Composite	DJIA	S&P D/P	S&P E/P
2004					
1st Qtr.	1,133.29	2,041.95	10,488.43	1.64%	4.62%
2nd Qtr.	1,122.87	1,984.13	10,289.04	1.71%	4.92%
3rd Qtr.	1,104.15	1,872.90	10,129.85	1.79%	5.18%
4th Qtr.	1,162.07	2,050.22	10,362.25	1.75%	4.83%
2005					
1st Qtr.	1,191.98	2,056.01	10,648.48	1.77%	5.11%
2nd Qtr.	1,181.65	2,012.24	10,382.35	1.85%	5.32%
3rd Qtr.	1,225.91	2,144.61	10,532.24	1.83%	5.42%
4th Qtr.	1,262.07	2,246.09	10,827.79	1.86%	5.60%
2006					
1st Qtr.	1,283.04	2,287.97	10,996.04	1.85%	5.61%
2nd Qtr.	1,281.77	2,240.46	11,188.84	1.90%	5.86%
3rd Qtr.	1,288.40	2,141.97	11,274.49	1.91%	5.88%
4th Qtr.	1,389.48	2,390.26	12,175.30	1.81%	5.75%
2007					
1st Qtr.	1,425.30	2,444.85	12,470.97	1.84%	5.85%
2nd Qtr.	1,496.43	2,552.37	13,214.26	1.82%	5.65%
3rd Qtr.	1,490.81	2,609.68	13,488.43	1.86%	5.15%
4th Qtr.	1,494.09	2,701.59	13,502.95	1.91%	4.51%
2008					
1st Qtr.	1,350.19	2,332.91	12,383.86	2.11%	4.55%
2nd Qtr.	1,371.65	2,426.26	12,508.59	2.10%	4.05%
3rd Qtr.	1,251.94	2,290.87	11,322.40	2.29%	3.94%
4th Qtr.	909.80	1,599.64	8,795.61	2.98%	1.65%
2009					
1st Qtr.	809.31	1,485.14	7,774.06	3.00%	0.86%
2nd Qtr.	892.23	1,731.41	8,327.83	2.45%	0.82%
3rd Qtr.	996.68	1,985.25	9,229.93	2.16%	1.19%
4th Qtr.	1,088.70	2,162.33	10,172.78	1.99%	4.57%
2010					
1st Qtr.	1,121.60	2,274.88	10,454.42	1.94%	5.21%
2nd Qtr.	1,135.25	2,343.40	10,570.54	1.97%	6.51%
3rd Qtr.	1,096.39	2,237.97	10,390.24	2.09%	6.30%
4th Qtr.	1,204.00	2,534.62	11,236.02	1.95%	6.15%
2011					
1st Qtr.	1,302.74	2,741.01	12,024.62	1.85%	6.13%
2nd Qtr.	1,319.04	2,766.64	12,370.73	1.97%	6.35%
3rd Qtr.	1,237.12	2,613.11	11,671.47	2.15%	7.69%
4th Qtr.	1,225.65	2,600.91	11,798.65	2.25%	6.91%
2012					
1st Qtr.	1,347.44	2,902.90	12,839.80	2.12%	6.29%
2nd Qtr.	1,350.39	2,928.62	12,765.58	2.30%	6.45%
3rd Qtr.	1,402.21	3,029.86	13,118.72	2.27%	6.00%
4th Qtr.	1,418.21	3,001.69	13,142.91	2.28%	6.07%
2013					
1st Qtr.	1,514.41	3,177.10	14,000.30	2.21%	5.59%
2nd Qtr.	1,609.77	3,369.49	14,961.28	2.15%	5.66%
3rd Qtr.	1,675.31	3,643.63	15,255.25	2.14%	5.61%
4th Qtr.	1,770.45	3,960.54	15,751.96	2.06%	5.42%
2014					
1st Qtr.	1,834.30	4,210.06	16,170.26	2.04%	5.38%
2nd Qtr.	1,900.37	4,195.81	16,603.50	2.06%	5.26%
3rd Qtr.	1,975.95	4,483.51	16,953.85	2.02%	5.37%
4th Qtr.	2,012.04	4,607.88	17,368.36	2.03%	4.97%
2015					
1st Qtr.	2,063.46	4,821.99	17,806.47	2.02%	4.80%
2nd Qtr.	2,094.37	5,029.47	18,007.48	2.05%	4.60%
3rd Qtr.	2,026.14	4,921.81	17,065.52	2.16%	4.72%
4th Qtr.	2,053.17	5,000.70	18,482.97	2.16%	

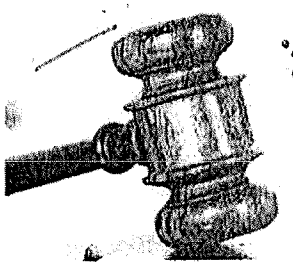
Source: Council of Economic Advisors, Economic Indicators, various issues.

Exhibit DCP-1
Schedule 3

OKLAHOMA GAS & ELECTRIC AND OGE ENERGY CORP. HISTORY OF CREDIT RATINGS

Year	Oklahoma Gas & Electric		OGE Energy	
	S&P	Moody's	S&P	Moody's
2011	BBB+	A2	BBB	Baa1
2012	BBB+	A2	BBB	Baa1
2013	BBB+	A2	BBB	Baa1
2014	A-	A1	BBB+	A3
2015	A-	A1	BBB+	A3

Source: Response to OIEC 7-8.



Regulatory Research Associates
REGULATORY FOCUS

RRA Topical Special Report

March 21, 2012

ADJUSTMENT CLAUSES AND RATE RIDERS

~ A State-By-State Overview ~

The use of adjustment clauses or rate riders to recover certain costs outside of the traditional, sometimes lengthy, rate case process became popular back in the 1970's during the Arab oil embargo, when fuel prices skyrocketed and the utilities had no way to recover their increasing fuel costs in a timely fashion. At that time, the only option for a utility was to file a rate case; however, utility rate proceedings on average take about a year to process, and fuel costs were rising at a rapid rate. Certain states permitted companies to "pancake" rate cases, meaning that the utility could have more than one rate case pending simultaneously, but most states did not. Regardless, during that time period utility earnings came under severe pressure because of the rising costs that could not be recovered in a timely way.

This situation led to the development of the fuel adjustment clause (FAC), essentially a single-issue rate-setting process, whereby a utility is permitted to implement frequent rate adjustments (e.g., monthly, quarterly, semi-annually, annually) associated with changes in its cost of fuel. Additionally, between rate adjustments the utility is generally authorized to defer fuel expenses not being recovered on a current basis in order to offset any effect on earnings from the variation in the cost. The deferral is then recovered from, or refunded to, ratepayers in the next FAC rate adjustment. In some instances the FAC includes a prospective component with a true-up.

Over the ensuing years, the use of adjustment clauses has expanded greatly. Such mechanisms are generally reserved for expenses that are outside the control of the utility or are required by law or rule. In addition to fuel expense, most states allow the cost of purchased power to be reflected in the FAC. Some states now use this type of mechanism to allow utilities to recover environmental compliance costs or conservation costs, or to pass through to customers any revenues that the company may receive from selling excess power or excess gas pipeline capacity in the open market (off-system sales). Some states allow expenses related to renewables to be recovered through a separate charge, and others permit nuclear-related pre-construction costs to be reflected in rates through a capacity cost recovery clause. Another type of adjustment clause is the decoupling mechanism, whereby utilities are able to recover the revenue shortfall caused by conservation efforts or the implementation of energy efficiency projects. Some decoupling mechanisms also account for revenue changes caused by abnormal weather or changes in economic conditions (see RRA's Topical Regulatory Report entitled Decoupling Mechanisms/Straight-Fixed-Variable rate design dated April 5, 2011).

It should be noted that the use of the adjustment clause or rate rider has the effect of shifting the risk associated with the recovery of the expense in question from shareholders to customers, because if the clause operates as designed, the company is able to recover its costs fairly quickly, without any negative effect on the bottom line, and without the expense and delay associated with seeking recovery through the general rate case process.

This study covers the key adjustment clauses and riders used by the largest electric and gas utilities in the 51 jurisdictions covered by RRA. The accompanying table includes footnotes (denoted by "✓*" or "--*") only where a clarification regarding the specific adjustment clause or rider is necessary. Further detail concerning adjustment clauses and riders can be found in each of our Commission Profiles. As indicated in the table, all of these jurisdictions employ some type of adjustment mechanism, with fuel and purchased power recovery clauses clearly the most prevalent. Virtually all electric and gas utilities are permitted to adjust rates, outside of a base rate case, associated with fuel and/or purchased power expenses; the exceptions include: MidAmerican Energy (electric) in Iowa; Kansas City Power & Light (electric) in Missouri (subject to certain limitations); CenterPoint Energy Resources (gas) in Texas; and, PacifiCorp (electric) in Washington. We note that: almost 30 jurisdictions use, or are considering the use of, a rider/adjustment mechanism for new plant investment; at least partial decoupling (conservation and/or weather) is in place in more than 35 jurisdictions; and, riders for renewables expenses are in use in more than 15 jurisdictions.

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Cost Recovery Provisions Key to Investor Owned Utility Ratings and Credit Quality

Evaluating a Utility's Ability to Recover Costs and Earn Returns

Summary

A utility's ability to recover its costs and earn an adequate return are among the most important analytical considerations when assessing utility credit quality and assigning credit ratings. In Moody's Regulated Electric and Gas Utilities Rating Methodology, published in August 2009 (the Rating Methodology), these concepts are incorporated as the second of four key factors utilized to determine credit ratings in the regulated utility sector. The criteria we consider when analyzing this factor include the statutory and regulatory provisions in place to insure full and timely recovery of prudently incurred costs. In their strongest form, these statutory protections provide unquestioned recovery of costs, precluding any possibility of legal challenges to rate increases or cost recovery mechanisms. Such strong statutory protections are most often found in very supportive and protected regulatory environments like Japan and Hong Kong, for example. In the U.S., however, the ability to recover costs and earn returns is much less certain and can be subject to intense public and sometimes political scrutiny, and such provisions vary among state jurisdictions. Consequently, the analysis of a U.S. based utility's cost recovery and return provisions is more complicated. This Special Comment discusses the criteria we use to determine how a utility is scored in the cost recovery and return factor in our ratings methodology.

One of the most referenced, but potentially misleading, indicators used to judge whether a particular utility is recovering its costs and earning an adequate return is its regulatory allowed return on equity. Although a high allowed return on equity can be associated with a higher earned return, this measure cannot be looked at in isolation but must be viewed in relation to a utility's cost recovery provisions that impact actual earned rate of return, like automatic adjustment clauses, the length of rate cases, and the degree of regulatory lag that may occur. Some regulators believe that mechanisms like automatic adjustment clauses materially reduce the business and operating risk of a utility, providing justification for a relatively low allowed rate of return. We believe this is one of several reasons why both allowed and requested ROE's have trended downward over the last two decades.

Moody's views automatic adjustment clauses, the most common of which is for fuel and purchased power, the largest component of utility operating expenses, as supportive of utility credit quality and important in reducing a utility's cash flow volatility, liquidity requirements, and credit risk. Fuel adjustment clauses work to insure that a utility recovers fuel related revenues fairly close to the time it incurs the fuel expense, minimizing the delay in the recovery of these costs. Many of these clauses are annual but they can also be semiannual, quarterly, or monthly. The scope of automatic adjustment clauses has expanded over the years and now covers costs as diverse as transmission, generation, renewable energy, environmental compliance, pensions and bad debt. Generally, the more of these clauses a utility has in place, the stronger its scoring should be on this ratings factor and the lower the credit risk.

Other considerations when analyzing cost recovery include the test year used, regulatory pre-approvals, and the inclusion of construction work in progress (CWIP) in rate base. Forward test years are generally better predictors of future utility conditions than historical test years, and their usage is more likely to reduce regulatory lag. Regulatory pre-approval of major capital expenditures, especially for large, complex projects like new nuclear plants, are also important in the maintenance of utility credit quality. Similarly, the inclusion of CWIP in rate base provides greater regulatory certainty, reduces the chance of rate shock or regulatory disallowance at the end of the construction period, and helps moderate financial pressure on a utility during a capital build cycle. Some of these concepts require a significant departure from the mindset of traditional rate regulation, where costs are typically recovered in rates only after a project is completed and placed into service.

Other cost recovery related factors Moody's considers to be favorable to utility credit quality include granting of interim rate relief, which we view as an effective way to accelerate the lengthy and cumbersome rate case process, reduce regulatory lag, and maintain utility cash flow while rate cases are pending. Decoupling mechanisms to "de-link" utility revenues and profits from volumes are essential to credit quality if energy efficiency and demand side management programs become more prevalent in the sector as anticipated. Finally, the option to issue cost recovery bonds to securitize large or unexpected costs, like those from storms, is another way that a utility can recover its costs and avoid the rate shock that could result if such costs are passed on to ratepayers over a limited time frame.

Introduction

In Moody's Rating Methodology, the cost recovery provisions a utility has in place, as well as the return it earns, are important determinants of a utility's rating and overall credit quality. These concepts are incorporated into the ratings methodology as the second of four key factors we use to determine ratings in the regulated electric and gas utility sector. A utility's ability to recover its costs and earn a return represents a significant 25% of the overall weighting[1] of the factors used to determine a utility's credit rating. Unlike Factor 1, Regulatory Framework, which considers the general regulatory environment under which a utility operates and the overall position of a utility within that regulatory environment, Factor 2 addresses in a more specific manner the ability of an individual utility to recover its costs and earn a fair return on invested capital.

1. The factor weightings shown in the rating methodology grid are approximate. The actual weight given to a factor in our assessment of an issuer's credit quality may differ based on the issuer's circumstances, and the scoring does not include every consideration that determines a rating.

TABLE 1

Regulated Electric and Gas Utility Rating Methodology

KEY RATING FACTORS AND WEIGHTINGS
1. Regulatory Framework – 25%
2. Ability to Recover Costs and Earn Returns – 25%
3. Diversification – 10%
4. Financial Strength and Liquidity – 40%

The ability to recover prudently incurred costs in a timely manner is perhaps the single most important credit consideration for regulated electric and gas utilities, especially since the lack of timely recovery of costs has caused severe financial stress for utilities on several occasions. In five of the seven major investor owned utility defaults in the United States over the last 50 years, regulatory disputes culminating in insufficient or delayed rate relief for the recovery of costs and/or capital investments ultimately led to financial pressure and credit rating downgrades. The reluctance to provide rate relief in some cases reflected regulatory commission concerns about the impact of large rate increases on customers as well as concerns about the appropriateness and prudency of the relief being sought by a utility. Currently, given the utility industry's sizable capital expenditure requirements for infrastructure needs and environmental compliance, there is likely to be a growing and ongoing need for rate relief to recover these expenditures, at a time when economic conditions may limit the ability or willingness of regulators to provide this timely rate relief. Regulators also need to balance the amount of rate relief granted to utilities with consumers' ability to absorb these costs.

For regulated utilities, the criteria we consider in assessing Factor 2 include the statutory protections in place to insure full and timely recovery of prudently incurred costs. In their strongest form, these statutory protections provide unquestioned recovery and preclude any possibility of legal or political challenges to rate increases or cost recovery mechanisms. Historically, there should be little evidence of regulatory disallowances or delays to rate increases or cost recovery. These statutory protections are most often found in strongly supportive and protected regulatory environments such as Japan and Hong Kong, for example.

More typically, however, and as is characteristic of most utilities in the U.S. and elsewhere in Asia, the ability to recover costs and earn authorized returns is less certain and subject to public and sometimes political scrutiny. Where automatic cost adjustment clauses or pass-through provisions exist and where there have been only limited instances of regulatory challenges or delays in cost recovery, a utility would likely receive a score in the A category for this factor. Where there may be a greater tendency for a regulator to challenge cost recovery or some history of regulators disallowing or delaying some costs, a utility would likely receive a Baa score for this factor. Where there are no automatic cost recovery provisions, a history of unfavorable rate decisions, a politically charged regulatory environment, or a highly uncertain cost recovery environment, lower scores for this factor would apply.

Most of the utilities in Central and Eastern Europe (CEE) inherited oversized, outdated and underinvested infrastructure, built during previous communist regimes. Furthermore, those infrastructure assets are very often highly depreciated. Therefore, the main regulatory challenges for the CEE region lies rather in the area of full recovery of investment costs, including the establishment of appropriate regulatory asset bases and the determination of reasonable regulatory depreciation levels (which would be included in allowable costs to be recovered), rather than fine-tuning the actual level of return. Indeed, there is a very similar issue confronting South Africa, where there has been a long period of underinvestment in electricity assets. The approach towards the determination of the regulated asset

base and treatment of asset revaluations differ significantly across the developing markets and could impact utilities' ability to generate sufficient funds for future investment in new assets.

The following is a discussion of the key factors we consider when scoring Factor 2, "Ability to Recover Cost and Earn Returns", in our Rating Methodology. The current Factor 2 scoring for the operating utilities in our rated universe is shown in Appendix A. These Factor 2 scores provide in indication of our current thinking. The scores are not intended to be static and continue to be monitored and modified as warranted to reflect changing conditions and circumstances, particularly as new rate cases are decided and cost recovery provisions evolve. In addition, when applied within the context of the Rating Methodology framework grid, the scores shown in Appendix A may be further modified by the use of a "strong" or "weak" designation.

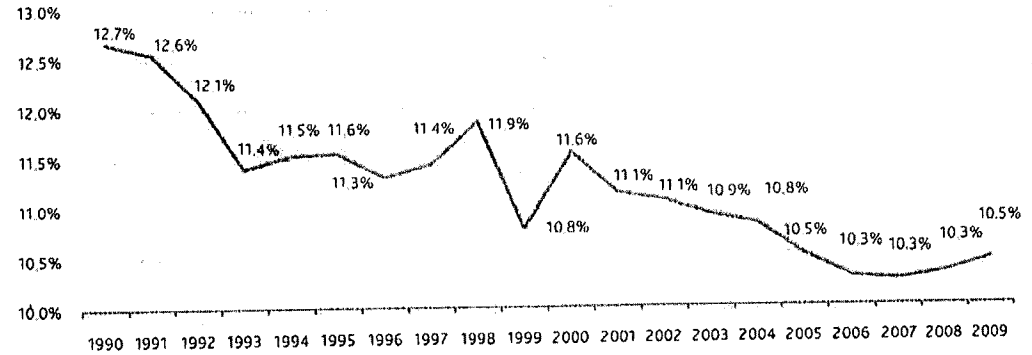
Return on Equity and Regulatory Lag

A utility's allowed return on equity (ROE) is one of the most obvious but potentially misleading statistics used to judge if a utility is recovering its costs and earning an adequate return. High ROE's are typically better than low ROE's, one reason that the timely, forward looking regulation of the Federal Energy Regulatory Commission (FERC) is viewed as more supportive, with ROE's that can be 12% or higher. In theory, if a utility's allowed return on equity is set at a high level, its earned return should also be high, leading to higher equity values, lower costs in relation to revenues, and ultimately higher credit ratings. This framework exists for some investor owned utilities, with high ROE's equating to good earnings and strong metrics, although this is not always the case. Earned ROE's are important in that they help to measure management's ability to operate their utility system within a given regulatory structure. A low allowed ROE is often associated with low earned ROE's, thereby affecting net income, lowering retained cash flow, depressing equity values, and raising financing costs.

However, the relationship between a utility's allowed return on equity and its ability to recover its costs and earn an adequate return is not as simple or clear cut as it may appear. A utility may have a low allowed ROE but be permitted to recover many of its operating costs through automatic adjustment clauses and other trackers, reducing risk and mitigating the impact of a low ROE. On the other hand, a utility may be permitted a high allowed ROE, but because of the higher than average risks associated with operating within this jurisdiction, the absence of such cost recovery provisions, overly long rate cases, or significant regulatory lag, may never actually earn its allowed return. According to the Edison Electric Institute, the average regulatory lag in the utilities industry is 11 months, close to where it has been for most of the last two decades. Adequate liquidity reserves on the part of utilities should mitigate some of the risks associated with regulatory lag.

While it is important to establish a link between a utility's regulatory allowed ROE and its automatic adjustment cost recovery clauses, it is also important to associate its authorized ROE with the sales forecast underlying the return. On its face, a high allowed ROE may appear favorable, although the return may be premised on a historic test year in which a high level of sales was achieved, which may not reoccur. This scenario could occur if there is a subsequent economic recession, unexpected financial shock, or lower usage on the part of the utility's customers due to high electric and/or gas rates or energy conservation. In such a case, a utility with a higher allowed ROE may be no better positioned than a utility with a lower allowed ROE based on a more achievable sales forecast. Allowed ROE's generate headline news, and market participants often gauge, at first blush, a utility's treatment in a rate case by this measure. However, the allowed ROE should not be viewed in isolation, but must be evaluated within the context of a utility's overall cost recovery provisions.

FIGURE 1
Average Awarded Electric ROE



Source: Regulatory Research Associates, a subsidiary of SNL Financial LLC, Edison Electric Institute

While regulatory lag has been stable, the long-term trend in allowed ROE's over the last two decades has been down, with the average allowed ROE falling from the 12% to 13% range in the early 1990's to the 10% to 10.5% range in recent years. In some cases, utility allowed ROE's have dropped below 10%. Not surprisingly, the average requested ROE has exhibited a similar trend, falling from as high as 13.5% in the early 1990's to approximately 11.2% in the first quarter of 2010. While some of the decrease in ROE's can be attributed to falling interest rates over the period, some can also be attributed to the other mechanisms that utilities have put in place to ensure timely cost recovery and maintain adequate returns, many of which are discussed below.

Some regulators view mechanisms such as cost recovery provisions and other automatic cost adjustment clauses as materially reducing the business and operating risk of some utilities, thereby justifying a lower return on equity. While there may be some merit to this argument, the relationship between these mechanisms and return on equity is complicated. Many of these provisions are "earnings neutral" but can have a cash impact, positive or negative, which could affect cash flow coverages and credit quality. Similarly, the increasing prevalence of formula based ratemaking and formula rate plans, where capital projects and other major revenue based changes are automatically incorporated into rates, have also caused some regulatory commissions to approve lower ROE's. However, a well structured formula rate plan could also lead to rate reductions if a utility is earning above its allowed range and in such cases, a lower allowed ROE may not be justified. Using ROE alone as a basis to compare utilities that operate under varying conditions and in different regulatory environments can be problematic and overly simplistic. Other considerations that may lead to widely different ROE's among utilities include the type of utility (whether vertically integrated or transmission and distribution), the mix of plants it operates, the size of its capital expenditure program, the risks associated with operating in a certain jurisdiction or building certain assets, demand and economic conditions within its service territory, and the utility's overall balance of debt and equity.

Fuel, Purchased Power and Other Automatic Cost Adjustment Clauses

Among the most common cost recovery provisions in the regulated utility sector are automatic adjustment clauses and other cost trackers (also referred to as riders or true-ups) for the recovery of

costs outside of traditional base rate cases. The most prevalent type of such clauses are fuel adjustment clauses (FAC's) in the electric sector and purchase gas adjustments (PGA's) in the gas sector. These generally permit automatic changes in rates in response to movements in the price of fuels used in the generation of electricity and in the price of purchased gas for local distribution companies. Moody's views automatic adjustment clauses as supportive of utility credit quality and important in reducing utility cash flow volatility and liquidity requirements. These clauses work to insure that a utility recovers fuel related revenues fairly close to the time it incurs the fuel expense, minimizing the delay in the recovery of these costs. They also reduce the level of regulatory uncertainty for the recovery of these costs by ensuring, through regulatory or statutory means, their recovery up-front.

Important considerations when analyzing such clauses include the frequency of true-up calculations and the period of time over which revenue variances are recovered. For example, Consolidated Edison Company of New York's purchased power cost variances are calculated monthly and recovered or refunded generally within one or two months. Some gas LDC's have quarterly gas cost adjustments; some vertically integrated utilities calculate fuel variances annually and recover these costs the following year, while others may recover some costs over a longer time period. In general, more frequent variance calculations and shorter recovery periods are considered more supportive of credit quality, limiting the potential for the accumulation of large deferral balances, the recovery of which could result in rate shock for consumers, as well as liquidity and working capital stress.

Adjustment Clauses as Regulatory Policy

Fuel adjustment clauses became prevalent in the U.S. in the 1970's when dramatically higher oil prices severely affected the cash flows of several utilities, when the industry was much more reliant on oil as a source of fuel for generation than it is today. During this time, oil prices rose so quickly that traditional base rate proceedings, with their lengthy time schedules, were unable to address cost recovery in a timely manner, severely stressing the cash flows of several utilities. Since that time, most U.S. states have permitted their utilities to automatically adjust fuel related rates outside of a formal base rate proceeding. In Missouri, one of the few states that historically did not have a fuel adjustment clause, legislation was passed in 2005 permitting the Missouri Public Service Commission to implement such a clause. In Ohio, fuel recovery was recently granted to AEP's Ohio Power subsidiary, although Duke Energy Ohio has had one in place for years.

Volume risk and purchase cost adjustments emerged as important regulatory topics in Central and Eastern Europe (CEE) only after the increase in the volatility of energy prices and unprecedented declines of energy consumption caused by the recent recession. The approach of respective CEE regulatory bodies varied from strong opposition to timely adjustments, mostly motivated by social considerations (i.e. Poland, Slovakia), to incorporation of automatic fuel and purchase adjustment mechanisms into regulation. Surprisingly, the regulatory regimes of Baltic countries, where the recession took the greatest toll, showed relatively solid resilience to political interference and allowed the local dominant electric utilities (the Latvian Latvenergo and the Estonian Eesti Energia) to pass through costs from fluctuating fuel input prices, thus allowing them to generate sufficient cash flows even in times of significant economic readjustment; this justifies their scoring of A in this factor.

In Korea, KEPCO's financial performance suffered significant deterioration in 2008 as a result of exposure to contracted high fuel costs and sharp depreciation of the Korean Won. The government stepped in and approved a 4.5% tariff increase and a KRW668 billion one-off subsidy to offset its losses due to high fuel costs and currency devaluation. The government is also considering implementing an automatic cost pass through mechanism in due course.

Automatic adjustment clauses are typically aimed at mitigating the effects of highly variable costs, such as fuel and purchased power, which are typically the largest component of utility operating expenses. These costs have been particularly volatile over the last several years, a time when the industry has become more exposed to both natural gas and coal prices. This exposure was again highlighted in late 2005 when two major hurricanes severely disrupted natural gas production in the Gulf Coast region, leading to a sudden and sustained increase in natural gas prices. Such costs are for the most part out of the utility's control, although some try to manage them by hedging their fuel supply to some degree. However, both the magnitude and volatility of these costs make fuel adjustment clauses one of the more widely used and effective cost recovery mechanisms in the industry.

In some cases, fuel adjustment clauses may be limited in scope or subject to regulatory review to ensure that the costs that are incurred are prudent. Some states allow rate adjustments within certain ranges or bandwidths, with any costs incurred outside of these ranges deferred for recovery in subsequent base rate cases. Cost deferred and recovered through later base rate cases depress cash flow and inevitably add to regulatory lag, a short-term issue that should not negatively affect long-term credit quality

Fuel adjustment clauses, which also include purchased power costs, have also become critical to transmission and distribution utilities that no longer own generation assets following the deregulation of electricity markets in their states. Many of these companies are responsible for procuring power for their retail customers as part of their Provider of Last Resort or POLR obligations and, as a result, are responsible for procuring their generation requirements in the wholesale power markets. The lack of a prompt and timely generation cost adjustment clause or similar pass-through mechanism can have a detrimental effect on transmission and distribution utility cash flows and credit quality.

Automatic adjustment clauses and other pass-through mechanisms have been expanded over the years and now cover costs as diverse as transmission, new generation, renewable energy, environmental compliance costs, demand side management and energy efficiency costs, pensions, and bad debt expenses. These clauses may also be put in place for more unusual or extraordinary costs such as those incurred as a result of hurricanes or ice storms. In some states, changes in interest expense relative to what had been incorporated into existing rates have also been covered by such clauses. Like fuel and purchased power adjustment clauses, these other clauses are likely to increase the likelihood of timely recovery of prudently incurred costs, reduce regulatory uncertainty, and lead to a higher score for a utility's cost recovery factor in our ratings methodology.

Forecast Risk – Historical Versus Forward Test Years

In most utility ratemaking procedures, the selection of a test year is an important consideration in determining both the level of adjustments to rates that may be necessary later and the degree of regulatory lag the may result. A test year is the base year in which a forecast of a utility's operations and investment requirements over a twelve month period is devised. It is supposed to be representative of what costs will be incurred by a utility during an upcoming period, and establish what additional rate adjustments a utility will need to cover costs and earn an adequate rate of return. Depending on the regulatory provisions of a particular state, utilities are generally required to use either a historical test year or a future test year. In some cases, a combination or "hybrid" of these two test year periods can be used, with "known and measurable" adjustments.

A historical test year utilizes a twelve month period before the current rate filing as the basis for determining future rates. Some state regulatory commissions prefer historic tests years because the information used in determining rates is based on actual data that can be easily measured and analyzed.

However, in situations where industry conditions are changing rapidly, such as when costs are increasing or capital expenditures growing, historical test years are generally less useful as an accurate data point for setting future rates. In addition, the use of historical test years can contribute to regulatory lag in that a utility must usually file another rate case to recover those costs not accurately predicted with the use of the historical test year. As a result, utilities that use historical test years typically do not earn their allowed rate of return on an ongoing basis and experience persistent regulatory lag in the recovery of costs.

The use of a forward (or future) test year, while not a perfect predictor of future utility revenue requirements, strives to use the most timely and up-to-date information available in setting rates. Forward test years are typically based on forecasts of future costs and expenses, often leading to a high degree of scrutiny by regulators on the financial models and assumptions used in creating these forecasts. While all forecasts have limitations, forward test years are generally better predictors of future utility conditions than historical test years, especially where there are rapidly changing industry conditions. Forward test years can better incorporate current and expected economic conditions, a utility's capital expenditure budget going forward, and projected changes to a utility's customer base or load growth forecasts, for example. Moreover, forward test years help to reduce regulatory lag and ensure that a utility earns closer to its allowed rate of return. As a result, from a credit standpoint, Moody's views the use of forward test years as more supportive of utility credit quality than historical test years.

Regulatory Pre-Approvals

The utilities industry is in the midst of a substantial capital expenditure program, with significant investment planned in all aspects of its business, including generation, transmission, and distribution, as well as for substantial environmental compliance expenditures. Because of the size and complexity of many of these projects, Moody's places a high degree of emphasis on the regulatory certainty for the recovery of such costs, which is critical for the maintenance of utility credit quality. For some of these projects, especially when considering added uncertainty related to the economy and the timing of future laws and regulations related to carbon, it will be viewed as a significant credit positive if utilities are able to obtain regulatory support for recovery in advance. This would serve to limit regulatory risk associated with eventual disallowance or nonrecovery of already expended costs. Some U.S. states, including Idaho, Iowa, Virginia, and Wisconsin, have passed legislation pre-approving some generation costs and outlining cost recovery provisions for new plant construction, which Moody's considers to be a positive regulatory development for the utilities in those states. In India, the construction of Ultra Mega Power Projects do not have any cost recovery provisions, but are rather based on competitive tariff structures. Pre-approval of purchased power agreements would also be considered positively from a credit standpoint.

Approval of future project capital expenditures in advance requires a significant departure from the mindset of traditional rate regulation, where costs are typically recovered in rates only after a project is completed and placed into service. In order for a state regulatory commission to pre-approve costs for a large and complex project, it is necessary for the commission and commission staff to gain an understanding of the project, including the need for the project, the construction budget, and the financing plan. Some projects underway right now, such as new nuclear construction, are expensive, complex, and multi-year in scope, and may not have been undertaken at all if regulators were not on board with the prudency of their projected costs and timetable in advance.

Regulatory pre-approval of utility capital expenditures may include incentives, mandated completion dates, or caps on the aggregate amount of recovery, giving state regulators some control over the ultimate costs and thus limiting ratepayer exposure in the event there are cost overruns or delays. In some cases, utilities may seek pre-approval for capital expenditures on a regular basis, such as annually or semi-annually, throughout the project's construction period. For example, for the recovery of costs related to Georgia Power's new nuclear construction project at its Vogtle plant site, the utility files a semi-annual construction monitoring report with the Georgia Public Service Commission (GPSC), with the GPSC reviewing and approving project costs on an ongoing basis. South Carolina Electric & Gas has a similar arrangement with the South Carolina Public Service Commission (SCPSC) for new nuclear construction at its Summer plant site. In order for such a pre-approval arrangement to be effective, however, state commissions need to have the time, ability, and resources to properly evaluate a complex project's construction progress, as well as any potential delays or problems that may arise. The Indiana Utility Regulatory Commission, for example, has an engineer advising them on Duke Indiana's Edwardsport project. Moody's views such collaborative utility-regulatory commission relationships as positive and important in insuring that prudent project costs are eventually recovered. They also serve to limit, but not fully protect against, the risk that there will be significant stranded, disallowed or otherwise unrecovered expenditures.

Construction Work in Progress (CWIP) in Rate Base/Concurrent Recovery

"Construction work in progress" (CWIP) represents the cost of capital projects that are under construction but not yet in service and considered "used-and-useful" in the provision of electric and/or gas service. Under traditional utility ratemaking, these costs cannot be included in customer rates until a project is completed and fully operational. However, because of the long lead times and large cost of many utility construction projects, some utilities are permitted by regulators to include CWIP in rate base, allowing it to earn a cash return on the project while it is under construction. The alternative would be for a utility to accumulate the financing costs on CWIP over the construction period (called "allowance for funds used during construction" or AFUDC) and include them in rates when the project is completed. Proponents of this approach generally argue that it is appropriate for utility ratepayers to pay only for projects that are in use and currently benefiting them through the provision of electricity and/or gas.

Moody's views the inclusion of CWIP in rate base as supportive of utility credit quality. It helps moderate the financial pressure of the incremental construction related debt by providing a cash return during lengthy, sometimes uncertain, and potentially delayed construction periods. It also allows a project's costs to be gradually incorporated into rates rather than all at once at the conclusion of construction, when a large and potentially unpopular one-time rate increase may be required. The resulting rate shock could lead to further delays in the recovery of these costs or political/legislative intervention aimed at limiting or denying utility cost recovery altogether.

It should be noted that not all CWIP recovery provisions are the same. Some state regulatory commissions only allow a portion of CWIP to be included in rate base, some only allow a debt return, while others allow a full weighted average cost of capital return. From a credit perspective, inclusion of all CWIP in rate base at a full weighted average cost of capital return would be considered the most supportive CWIP recovery provision.

Whether to allow CWIP in rate base became a significant issue several years ago, particularly during the last round of nuclear construction in the 1970's, when a number of utilities were engaged in major nuclear construction projects and substantial cost overruns were commonplace. This was also an era of

high inflation and high interest rates, exacerbating the rate impact of allowing CWIP in rate base. Because of this experience, a few states actually passed laws prohibiting utilities from including CWIP in rate base, some of which are still on the books today. The issue has again come to the forefront with the advent of major new nuclear construction in the U.S., and also because of large capital expenditure plans for transmission, renewable energy projects, integrated gasification combined-cycle (IGCC) plants, and environmental compliance requirements. Although the treatment of CWIP by individual state regulatory commissions varies, most states do allow for the inclusion of some or all of CWIP in rate base, a credit positive. Those states that do not allow the inclusion of CWIP in rate base, either by law or by recent commission decision, are listed below.

TABLE 2
States Not Allowing CWIP in Rate Base

LEGALLY PROHIBITED	DENIED BY COMMISSION
Connecticut	Arizona
Missouri	Nebraska
New Hampshire	Oklahoma
Oregon	Rhode Island
Pennsylvania	

The inclusion of CWIP in rate base is an especially important credit supportive measure for those utilities in the process of constructing new nuclear plants. In Georgia and Florida, for example, legislation passed over the last few years allows utilities in both states to earn a cash return on CWIP for new nuclear construction. For Georgia Power, the inclusion of CWIP in rate base and the recovery of financing costs on its new Vogtle nuclear construction project reduced the project's in-service cost to $4.5 billion from $6.4 billion. Similarly, in South Carolina, the Public Service Commission has authorized South Carolina Electric & Gas to earn a cash return on CWIP associated with new nuclear construction in that state. In contrast, in early 2009, Ameren subsidiary AmerenUE suspended efforts to build a new nuclear plant in Missouri after legislation allowing CWIP in rate base was not passed by the Missouri General Assembly.

As previously mentioned, the less favorable alternative to inclusion of CWIP in rate base from a credit standpoint is allowance for funds used during construction (AFUDC) accounting treatment for construction projects. With AFUDC, capital projects do not earn a cash return during the construction phase, but do when they become used and useful. Because of the long lead times and large cost of many utility construction projects, this can place great financial and liquidity pressure on utilities. Under AFUDC accounting conventions, a utility's earnings are made whole by non-cash earnings, offsetting the incremental debt and equity capital costs incurred to finance the projects. While there is no earnings impact on a utility income statement, cash flow generally lags while debt mounts, a credit negative. Some opponents to AFUDC treatment argue that rate payers generally face a larger one-time rate increase under this approach than if CWIP treatment was applied.

Interim Rate Relief

Because of the length of base rate cases, with many lasting 12 months and some as long as 18 months, interim rate relief is often an effective way to accelerate rate relief, reduce regulatory lag, and maintain utility cash flow while rate cases are pending. While some states allow utilities to petition for interim

rate relief, others only permit such relief in extraordinary or emergency situations, limiting its use to unusually dire circumstances. Interim rate relief is also difficult for state regulators to grant when there are poor economic conditions in a utility's service territory, and some requests for interim rate relief are declined for these reasons. Because interim rate relief has a positive impact on utility cash flows and coverage metrics and reduces regulatory lag, Moody's views interim rate relief as a positive credit consideration. The existence of a maximum timeframe for decisions on interim (or general) rate cases is another important credit consideration. If there is no statutory time limit for rendering such rate case decisions, regulatory lag can result.

In Florida, utilities may request an interim rate increase only if they have petitioned the Florida Public Service Commission (FPSC) for a permanent base rate increase. In its most recent rate case, for example, Progress Energy Florida requested and was granted an interim rate increase to recover the costs of repowering one of its generating units to natural gas from oil. The interim rates were put in effect during the course of the base rate proceeding, which in Florida takes about nine months. Interim rates are credited back to customers, with interest, if the FPSC determines in its final rate decision that the interim rates were not justified. In Hawaii, interim rates must be enacted within 11 months of filing, but there is no statutory time limit for a final decision. As such, the majority of Hawaiian Electric rate decisions in recent years have been interim decisions.

In West Virginia, Appalachian Power and Wheeling Power, both subsidiaries of American Electric Power (AEP), requested an interim rate increase of $180 million in April 2009, out of an overall $442 million rate increase request, for fuel, purchased power, and environmental compliance project expenses. Because of sharply higher fuel costs, the company was paying more for fuel than it was receiving in existing rates and hoped the interim rates would offset a growing fuel underrecovery. On June 4, 2009, the Public Service Commission of West Virginia denied the request, citing the potential for financial hardship on customers, especially during currently difficult economic times. The denial of interim rate relief is considered a credit negative in that it added to fuel underrecoveries and increased regulatory lag at the utilities.

Volume Risk and Decoupling

There has been a great deal of emphasis and attention in recent years given to energy efficiency and demand side management programs aimed at reducing the consumption of electricity and natural gas both because of environmental concerns and for economic reasons. For utilities these efforts represent a potential threat to cost recovery because under traditional rate of return regulation, utility revenues are a function of the volume of power and energy is sold, i.e. all or a portion of the utility's fixed costs are recovered through volumetric charges. Consequently, utilities that are dependent on volume are, in fact, economically motivated to encourage higher energy usage instead of conservation and energy efficiency. Decoupling is aimed at "de-linking" a utility's revenues and profits from volume and at the same time compensating utilities for promoting less energy use.

Decoupling has become more prevalent over the last year since the Federal government's economic stimulus bill was passed in February 2009. That bill provides significant funding to states to promote and encourage energy efficiency programs, but only in the event there are incentives in place for utilities themselves to encourage and promote such programs. There are still relatively few states with decoupling measures in place for electric utilities, although they have been more common for gas utilities. Moody's views decoupling measures as important to the maintenance of utility credit quality in states where energy efficiency and demand side management programs could put pressure on utility sales volumes, operating margins, and cash flow coverage metrics.

TABLE 3

Selected States With Decoupling Measures in Place

ELECTRIC DECOUPLING	GAS DECOUPLING
California	Arkansas
Connecticut	California
Idaho	Colorado
Maryland	Illinois
Massachusetts	Indiana
Michigan	Maryland
New Hampshire	Massachusetts
New York	Michigan
Oregon	Minnesota
Vermont	New Jersey
	New York
	Nevada
	North Carolina
	Ohio
	Oregon
	Utah
	Virginia
	Washington
	Wisconsin
	Wyoming

The state of California was at the forefront of states adopting decoupling as far back as 1982, when it put an Electric Revenue Adjustment Mechanism in place, which de-linked utility revenues from utility sales to promote energy conservation. Other states have introduced decoupling more recently, including Idaho, Maryland, Massachusetts, and New York. Some states have partial decoupling measures in place, such as New Hampshire, which allows decoupling for generation and transmission, but not for distribution. Hawaii has recently approved a decoupling mechanism, which is most similar to the California model, but it has yet to be fully implemented into electric rates. Many more states are considering decoupling measures and Moody's expects such measures to become increasingly prevalent as energy efficiency and demand side management programs are increasingly emphasized.

Cost Recovery Bonds (Securitization)

Since the late 1990's, legislatively approved stranded cost, storm cost, and other cost recovery bonds have been issued to reimburse utilities for costs related to deregulation, hurricanes, environmental compliance, and energy supply. In its simplest form, a securitization is a type of irrevocable rate order that authorizes and dedicates a stream of cash flow to service bonds issued to reimburse utilities for specific costs. Such bonds were originally issued to compensate utilities for stranded costs following the deregulation of the energy markets in some states several years ago. More recently, storm-related securitizations have been completed following active hurricane seasons in 2004, 2005 and 2008 along

the Gulf Coast region and in Florida. Securitization bonds have also been issued to finance environmental compliance costs in West Virginia.

Cost recovery bonds represent another way that regulatory commissions and state legislatures can assure that a utility receives adequate recovery for sometimes large and unanticipated capital expenditures, while avoiding the rate shock that could result from passing through all these costs over a limited time frame. Instead, cost recovery bonds allow these costs to be spread out and financed over a multi-year period. Customers benefit from the low financing costs that characterize such bonds, since the special purpose entities issuing the bonds are typically rated Aaa, and the utility is reimbursed for the costs it incurred fairly quickly when the bonds are issued, reducing regulatory lag. However, Moody's notes that some storm cost recovery bonds have been issued as long as two to three years after the costs have been incurred, in some cases due to the need to pass legislation authorizing such bonds. Such legislation is necessary to insure that the collection of the cost recovery bond surcharge is statutorily protected, irrevocable, and non-bypassable. Moody's views utilities that have the option of issuing cost recovery bonds in the event of large, unexpected, or extraordinary costs more favorably from a credit point of view.

Conclusion

Cost recovery provisions and a utility's ability to earn an adequate return are important considerations in determining credit quality and credit ratings in the regulated utility sector, so much so that they account for a significant 25% weighting when determining utility credit ratings under our Rating Methodology. Among the provisions we consider when judging this factor include a utility's ability to earn its allowed return on equity, which must be examined in conjunction with its actual earned return on equity resulting from its overall cost recovery provisions. These provisions could include automatic adjustment clauses, the use of a forward test year, regulatory pre-approval of major capital expenditures, construction work in progress (CWIP) in rate base, interim rate relief, decoupling, and the option of issuing cost recovery or securitized bonds to recovery large or unexpected costs. The presence of most or all of these provisions is likely to lead to a higher score for the cost recovery and earned return factor in our ratings methodology.

FEBRUARY 3, 2014

INFRASTRUCTURE

MOODY'S
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SECTOR COMMENT

US utility sector upgrades driven by stable and transparent regulatory frameworks

Rate this Research

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- We recently upgraded most US investor-owned utilities and many of their holding companies due to our view that the US regulatory environment has improved over the past several years. Most of the companies placed on review for upgrade in November 2013[1] were upgraded in late January 2014, and most by one notch. Please see Appendix A for a list of companies that were upgraded.
- US regulated utilities appear financially secure, thanks to their suite of transparent and timely cost and investment recovery mechanisms. When compared with other regulatory environments in developed countries[2], the overall regulatory environment for US utilities has steadily improved over the past few years and is expected to remain supportive and constructive for at least the next 3-5 years.
- A more favorable regulatory environment allows US regulated utilities to generate relatively stable and predictable revenue and cash flow, which can support a material amount of leverage. But most US utilities maintain a conservative capital structure, where the ratios of debt to EBITDA and cash flow to debt hover in the 4.0x and 20% range, respectively. Key financial ratios are likely to decline over the next few years, as interest rates rise and tax payments increase with the expiration of bonus depreciation.
- US utilities own and operate enormous, capital intensive, long-lived critical infrastructure assets. They are often one of the larger companies residing in a particular state, they pay big property taxes and employ lots of people. The importance of utilities to state and local governments is not lost on elected officials, and utilities maintain very effective constituency outreach programs.
- Utilities have demonstrated strong, stable access to the capital markets. Utilities do not maintain high cash balances, but their committed credit facilities are typically syndicated across several banks and contain few, if any, borrowing constraints. However, a combination of significant capital investments and sizable shareholder dividends that are typically well beyond the cash generated from operations means that utilities are generally in a negative free cash flow position.
- A handful of companies placed on review in late 2013 were not upgraded. Some of the reasons include sizable non-utility businesses with higher business risk, or a large amount of debt at the holding company as a percentage of total consolidated debt. For a few issuers, ratings weren't upgraded because these companies were viewed as being appropriately positioned at their existing rating category, relative to their rated peers.

1 See press release: Moody's places ratings of most US regulated utilities on review for upgrade, November 08,2013.

2 For example: Australia, Canada, Japan, South Korea and the United Kingdom.

Supportive regulatory frameworks

Over the past few years, the US regulatory environment has been very supportive of utilities. We think this is partly a function of regulators acknowledging that their utility infrastructure needs a material amount of ongoing investment for maintenance, refurbishment and renovation purposes. Utility infrastructure is necessary to facilitate a growing economy, and since utility investments help create jobs, utilities have been able to garner support from both politicians and regulators to authorize prudently incurred investments in these critical assets. We also think regulators prefer to regulate financially healthy utilities. Recent legislation that helps utilities recover their costs and investments in a more timely manner are evidenced in Virginia, South Carolina, Florida and Illinois.

We think political risks are also manageable, in part, because elected officials are increasingly viewing their local utilities as a reliable source of investment into the local infrastructure. Investments bring jobs, and employment growth helps the economy. This is part of the "virtuous circle" for regulated utilities, and we see a few more years of continued smooth sailing, where elected officials, their regulators, consumer groups and utilities share a common understanding with respect to strengthening this infrastructure sector.

From a practical perspective, a few regulatory hot spots of contentiousness will flare up over our rating horizon, but it is unclear at this time as to which utilities might be affected. We have generally seen such situations result in outcomes that were difficult for utilities but not punitive, and they have generally been isolated incidents rather than a broad pandemic. As a result, we continue to keep an eye on the magnitude of rate increases, and how likely those rates can be absorbed by the service territory or market before consumers become intolerant, in order to identify utilities that are exceptions to the generally positive regulatory environment.

Stable and predictable financial profile

A transparent suite of timely recovery mechanisms helps utilities generate stable and predictable revenues and cash flows, which can support a material amount of leverage. But most US utilities maintain a relatively solid capital structure, where the ratios of debt to EBITDA and cash flow to debt hovers in the 4.0x and 20% range, respectively. Key financial ratios are likely to decline over the next few years, as interest rates rise and tax payments increase with the expiration of bonus depreciation.

In the table below, we illustrate the sector's financial stability by showing the historical medians for most of the companies included in our US utility rated universe. We show the 4-year (2009 – 2012) and 2-year (2011 – 2012) average medians by rating category. We also include the latest twelve months ended September 2013. In general, lower debt to EBITDA and dividend payout ratios correspond with higher credit ratings, as do higher cash flow to debt ratios. We note that A1 rated companies invest more heavily in their assets, relative to depreciation and amortization (D&A). Because we show these financial ratios by rating category, the rating category might include different kinds of companies included in our peer groups. For example, the Baa1 rating category might include parent holding companies (which also include hybrid integrated companies), vertically integrated, transmission and distribution, local gas distribution or transmission only companies.

EXHIBIT 1

US regulated utilities – selected financial ratios, by rating category (medians)

	Debt / EBITDA			CFO / debt			Dividend payout			Cap Ex / D&A		
Rating	4-yr avg	2-yr avg	LTM	4-yr avg	2-yr avg	LTM	4-yr avg	2-yr avg	LTM	4-yr avg	2-yr avg	LTM
A1	2.7	2.8	3.0	31%	32%	25%	35%	33%	39%	2.4	2.7	2.7
A2	3.3	3.3	3.5	27%	26%	22%	67%	70%	64%	1.8	1.9	2.0
A3	3.9	4.0	4.0	22%	23%	22%	56%	67%	52%	2.1	1.9	2.2
Baa1	4.1	4.2	4.0	19%	20%	19%	61%	64%	52%	1.8	1.9	2.2
Baa2	4.3	4.3	4.5	17%	17%	17%	56%	56%	78%	1.7	1.9	2.1
Baa3	4.2	4.4	4.3	18%	17%	18%	120%	91%	99%	1.3	1.5	1.4

We also examined the broad peer group of utilities by sector classification. For example, we looked at the selected financial ratios for parent holding companies, vertically integrated utilities, transmission and distribution utilities and natural gas local distribution companies. We note that the financial ratios by sector classification means that both A3 and Baa3 rated companies might be included in the "Vertically Integrated" peer group and in other peer groups. We observe that the ratio of cash flow to debt is better for the utilities than it is for the parent holding companies[3].

EXHIBIT 2

US regulated utilities – selected financial ratios, by sector classification

		Debt / EBITDA			CFO / debt			Dividend payout			Cap Ex / D&A		
Sector		4-yr avg	2-yr avg	LTM	4-yr avg	2-yr avg	LTM	4-yr avg	2-yr avg	LTM	4-yr avg	2-yr avg	LTM
Holding companies	Median	4.5	4.7	4.4	18%	18%	17%	68%	69%	69%	2.3	2.3	2.5
	Total	4.1	4.3	4.2	19%	19%	18%	67%	73%	78%	2.0	2.1	2.1
LDC's	Median	4.0	4.0	4.1	24%	22%	22%	75%	70%	76%	2.0	2.2	3.1
	Total	3.5	3.5	3.4	26%	25%	23%	60%	61%	58%	2.1	2.3	2.5
T&D (electric or gas)	Median	4.0	3.7	4.2	21%	22%	20%	97%	88%	57%	1.6	1.9	1.5
	Total	3.7	3.7	3.7	22%	22%	20%	92%	86%	67%	1.5	1.8	1.9
Transmission	Median	2.3	2.3	2.5	37%	33%	26%	82%	92%	71%	5.7	6.4	6.4
	Total	3.9	3.9	4.1	20%	19%	16%	80%	83%	58%	4.7	5.3	5.5
Vertically Integrated	Median	3.7	3.7	3.7	22%	23%	20%	53%	59%	56%	2.0	2.0	2.1
	Total	3.6	3.6	3.6	23%	23%	23%	59%	64%	68%	2.1	2.1	2.1

[3] See Appendix A for a table of selected financial ratios by sector classification, by rating

Critical infrastructure assets

US utilities own and operate enormous, capital intensive, long-lived critical infrastructure assets. They are often cited as being one of the larger companies residing in a particular state, pay big property taxes and employ lots of people. The importance of utilities to state and local governments is not lost on elected officials, and utilities maintain very effective constituency outreach programs[4].

EXHIBIT 3

US regulated utilities – selected financial data, by rating category ($ billions)

	Revenues			EBITDA			CFO			Debt		
Rating	4-yr avg	2-yr avg	LTM	4-yr avg	2-yr avg	LTM	4-yr avg	2-yr avg	LTM	4-yr avg	2-yr avg	LTM
Medians												
A1	$2.6	$2.7	$2.8	$0.8	$0.8	$0.8	$0.6	$0.7	$0.6	$2.1	$2.2	$2.4
A2	$1.6	$1.5	$1.4	$0.4	$0.5	$0.5	$0.4	$0.4	$0.4	$1.5	$1.6	$1.7
A3	$1.7	$1.7	$1.7	$0.4	$0.5	$0.5	$0.4	$0.4	$0.4	$1.7	$1.8	$1.9
Baa1	$1.6	$1.6	$1.6	$0.4	$0.4	$0.5	$0.3	$0.4	$0.4	$1.7	$1.8	$1.9
Baa2	$1.6	$1.6	$1.6	$0.8	$0.5	$0.5	$0.3	$0.4	$0.4	$2.0	$2.1	$2.3
Baa3	$1.7	$1.7	$1.6	$0.5	$0.5	$0.5	$0.4	$0.4	$0.4	$2.2	$2.2	$2.3
Total												
A1	$50.3	$50.2	$51.3	$15.8	$16.3	$17.5	$13.2	$13.7	$14.2	$50.7	$54.8	$58.3
A2	$86.4	$85.4	$86.6	$25.6	$27.1	$29.0	$22.2	$23.6	$22.8	$86.6	$92.0	$98.9
A3	$151.3	$154.0	$166.8	$47.5	$49.9	$54.2	$39.3	$42.5	$45.3	$187.3	$199.4	$221.6
Baa1	$468.5	$473.4	$499.6	$144.4	$150.8	$160.0	$117.3	$125.7	$130.9	$576.9	$610.6	$668.0
Baa2	$1.7	$1.6	$1.6	$32.7	$32.2	$40.4	$25.5	$26.9	$27.1	$125.1	$129.1	$135.8
Baa3	$5.4	$5.6	$5.6	$17.6	$18.8	$18.2	$1.7	$1.8	$1.8	$81.3	$89.6	$94.8

EXHIBIT 4

US regulated utilities – selected financial data, by sector classification ($ billions)

		Revenue			EBITDA			CFO			Total Debt		
Sector		4-yr avg	2-yr avg	LTM	4-yr avg	2-yr avg	LTM	4-yr avg	2-yr avg	LTM	4-yr avg	2-yr avg	LTM
Holding companies	Median	$4.0	$4.1	$4.5	$1.1	$1.1	$1.2	$0.9	$1.0	$0.9	$5.2	$5.3	$5.2
	Total	$337.4	$342.1	$358.4	$106.3	$109.7	$121.9	$84.7	$89.8	$92.1	$437.5	$467.0	$509.5
LDC's	Median	$0.7	$0.7	$0.6	$0.1	$0.2	$0.2	$0.1	$0.1	$0.1	$0.6	$0.6	$0.6
	Total	$26.8	$25.7	$26.0	$5.9	$6.3	$6.5	$5.4	$5.4	$5.1	$20.5	$22.0	$22.3
T&D (electric or gas)	Median	$1.4	$1.2	$1.1	$0.3	$0.4	$0.3	$0.3	$0.3	$0.3	$1.3	$1.3	$1.4
	Total	$74.7	$70.5	$67.3	$21.3	$21.8	$22.5	$16.8	$17.7	$16.5	$78.1	$80.0	$84.2
Transmission	Median	$0.3	$0.3	$0.3	$0.2	$0.2	$0.2	$0.1	$0.1	$0.1	$0.4	$0.5	$0.6
	Total	$2.0	$2.2	$2.5	$1.4	$1.5	$1.7	$1.1	$1.1	$1.2	$5.5	$6.0	$7.1
Vertically Integrated	Median	$1.7	$1.7	$1.7	$0.5	$0.5	$0.5	$0.4	$0.4	$0.4	$1.7	$1.8	$1.9
	Total	$195.3	$197.9	$202.7	$60.1	$62.9	$65.5	$49.2	$52.4	$53.6	$215.9	$227.7	$237.5

[4] See Appendix B for a table of selected financial data, by sector classification by rating

Strong, Stable access to capital

Our view of the supportive US utility regulatory environments resulted in several rating upgrades where companies attained an A2 rating from A3, or Baa2 from Baa3. Consistent with these long term rating changes, some utilities also achieved a change in their short-term commercial paper (CP) ratings. For more information on the linkage between long term ratings and short term ratings, please see Moody's Rating Symbols and Definitions.

EXHIBIT 5

Selected companies that received short-term commercial paper rating changes*

Name	Sector	Old Rating	New Rating	Rating Outlook	Short term Rating
Questar Corporation	Holdco	A3	A2	Stable	P-1 from P-2
Wisconsin Energy Corporation	Holdco	A3	A2	Stable	P-1 from P-2
DTE Gas Company	LDC	A3	A2	Stable	P-1 from P-2
Northern Illinois Gas Company	LDC	A3	A2	Stable	P-1 from P-2
Peoples Gas Light and Coke Company	LDC	A3	A2	Stable	P-1 from P-2
Consolidated Edison Company of New York, Inc.	T&D (electric or gas)	A3	A2	Stable	P-1 from P-2
PECO Energy Company	T&D (electric or gas)	A3	A2	Stable	P-1 from P-2
Public Service Electric and Gas Company	T&D (electric or gas)	A3	A2	Stable	P-1 from P-2
Atmos Energy Corporation	LDC	Baa1	A2	Stable	P-1 from P-2
DTE Electric Company	Vertically Integrated	A3	A2	Stable	P-1 from P-2
Northern States Power Company (Minnesota)	Vertically Integrated	A3	A2	Stable	P-1 from P-2
Northern States Power Company (Wisconsin)	Vertically Integrated	A3	A2	Stable	P-1 from P-2
Southern California Edison Company	Vertically Integrated	A3	A2	Stable	P-1 from P-2
Piedmont Natural Gas Company, Inc.	LDC	A3	A2	Stable	P-1 from P-2
South Jersey Gas Company	LDC	A3	A2	Stable	P-1 from P-2
Vectren Utility Holdings, Inc.	Vertically Integrated	A3	A2	Stable	P-1 from P-2
Virginia Electric and Power Company	Vertically Integrated	A3	A2	Stable	P-1 from P-2
Pinnacle West Capital Corporation	Holdco	Baa2	Baa1	Stable	P-2 from P-3
Ameren Corporation	Holdco	Baa3	Baa2	Stable	P-2 from P-3
NiSource Finance	Holdco	Baa3	Baa2	Stable	P-2 from P-3
Union Electric Company	Vertically Integrated	Baa2	Baa1	Stable	P-2 from P-3
Kansas City Power & Light Greater MO Op.	Vertically Integrated	Baa3	Baa2	Stable	P-2 from P-3

*Not all short-term ratings are listed here. Instead, we show a list of upgrades associated with the short term commercial paper rating. This list does not include utilities that may have had short-term ratings on industrial development bonds, such as Duke Indiana and Duke Carolinas. In Duke's case, both companies had their short-term IDB ratings upgraded (both VMIG and Prime ratings), but are not included on our list, but are available on the individual company's press releases.

Utility credit facilities are usually unsecured, so we tend to examine the few instances of secured revolving credits more closely . In many cases, security for credit facilities was initially granted when the utility incurred financial stress and/or was rated below investment grade. Similar to first mortgage bonds, secured credit facilities at the utility level are mostly viewed as having a materially lower risk of incurring any losses given a default. As a result, the costs and fees for secured credit facilities are typically lower than unsecured credit facilities, which regulators may view in a positive light, although we typically view utilities with secured credit facilities as possessing somewhat less financial flexibility.

One of the big credit positives that unsecured credit facilities provide utilities is the "ability" to raise capital or secure continued liquidity through a secured facility. This is a type of financial flexibility that can be useful for utilities experiencing a period of financial distress, since the security may be

granted in exchange for accommodations from lenders such as an increase in facility size, longer maturities, or easing of financial covenants or other terms.

EXHIBIT 6

Selected companies with secured credit facilities

Name	Sector	Old	New	Outlook	Comment
Avista Corp.	Vertically Integrated	Baa2	Baa1	Stable	Secured Revolver
Consumers Energy Company	Vertically Integrated	Baa1	A3	Stable	Secured Revolver
Oncor Electric Delivery Company LLC	T&D (electric or gas)	Baa3	Baa3	Stable	Secured Revolver
Puget Energy, Inc.	Holdco	Ba1	Baa3	Stable	Cross - Over / secured rev.
UNS Energy Corporation	Holdco	Baa3	Baa2	Stable	Secured Revolver
Westar Energy, Inc.	Holdco	Baa2	Baa1	Stable	Secured Revolver

Notable upgrades

Two companies were upgraded by 2-rating notches, Edison International (EIX: A3 stable) and Western Massachusetts Electric Company (WMECO: A3 stable). Prospectively, both companies are increasing the stability and predictability of their revenues and cash flows, because they are becoming more regulated.

EXHIBIT 7

Selected companies with 2 notch rating upgrades

Name	Sector	Old	New	Outlook
Atmos Energy Corporation	LDC	Baa1	A2	Stable
Edison International	Holdco	Baa2	A3	Stable
Western Massachusetts Electric Company	T&D (electric or gas)	Baa2	A3	Stable

For EIX, the increase in regulated revenues and cash flows (as a percentage of the total) will result from the divestiture of its risky non-utility businesses. In this case, EIX has benefitted because the former merchant generation operations at Edison Mission Energy (EME not rated) are no longer part of the consolidated entity, and we view the litigation risk from suits by EME creditors as manageable for EIX.

With the recent completion of a large transmission project in December 2013, WMECO is increasing the portion of its revenues derived from FERC-regulated transmission only assets. The FERC regulatory environment is viewed as being both transparent and predictable over the long term, with a very timely suite of cost recovery mechanisms and a reasonable assurance of a guaranteed return.

Four companies crossed over to the investment grade rating category from the non-investment grade category. Three are parent holding companies, all of which own solid investment grade utility operating subsidiaries.

EXHIBIT 8

Selected companies that crossed-over into investment grade from non-investment grade

Name	Sector	Old	New	Outlook
PNM Resources, Inc.	Holdco	Ba1	Baa3	Positive
Entergy Texas, Inc.	Vertically Integrated	Ba1	Baa3	Stable
Puget Energy, Inc.	Holdco	Ba1	Baa3	Stable
IPALCO	Holdco	Ba1	Baa3	Stable

For Entergy Texas Inc (ET: Baa3 stable), where we think Texas regulation is less favorable for non-ERCOT, vertically integrated utilities than they are on the unbundled transmission and distribution utilities, we see a steadily improving financial profile, including a sustainable production of cash flow to debt in the low-teen's, at a minimum. However, ET has the most most challenging regulatory relations of all the Texas utilities.

Puget Energy's (PE: Baa3 Stable)cross over to investment grade reflects an expectation for sustained improvement in the company's financials, due to supportive regulatory treatment. For example, the most recent rate case decision for its utility Puget Sound Energy, Inc. (PSE: Baa1, stable) by the Washington Utilities and Transportation Commission's (WUTC) allowance for a full electric and gas revenue decoupling mechanism and a series of predetermined annual delivery rate increases, including cost escalation factors.

Five issuers in two corporate families, Cleco Corporation (Cleco: Baa2, positive) and PNM Resources Inc. (PNM: Baa3, positive), continue to exhibit materially favorable regulatory or financial trends, reflected in the positive rating outlooks assigned at the conclusion of our review. For the remainder of the companies, stable rating outlooks were the norm.

EXHIBIT 9

Selected companies with positive rating outlooks

Name	Sector	Old	New	Outlook	Comment
Cleco Corporation	Holdco	Baa3	Baa2	Positive	
Cleco Power LLC	Vertically Integrated	Baa2	Baa1	Positive	
PNM Resources, Inc.	Holdco	Ba1	Baa3	Positive	Cross - Over
Texas-New Mexico Power Company	T&D (electric or gas)	Baa2	Baa1	Positive	
Public Service Company of New Mexico	Vertically Integrated	Baa3	Baa2	Positive	

For PNM, as soon as its San Juan Generating Station environmental compliance requirement is resolved, or close to it, and assuming financial metrics remain consistent with our expectations, additional rating upgrades could be considered. For Cleco, the positive outlooks reflect our expectation that Cleco Power LLC (CNL: Baa1, positive) will receive a constructive outcome on its latest regulatory filing, including the extension of its formula rate plan for another five-year period. This would follow the December 2013 approval received from the Louisiana Public Service Commission to transfer the Coughlin power plant to CLN.

EXHIBIT 10

Selected companies still on review for possible upgrade

Name	Sector	Old	New	Outlook	Comment
Brooklyn Union Gas Company	LDC	A3	A3	RUR - up	
Key Span Gas East Corp	LDC	A3	A3	RUR - up	
Niagara Mohawk Power Corp	T&D (electric or gas)	A3	A3	RUR - up	
New England Power Corp	T&D (electric or gas)	A3	A3	RUR - up	

Companies not upgraded

For some holding companies with material non-utility businesses, rating upgrades were constrained. Our analysis was heavily influenced by the size, composition and strategy of those non-utility businesses. We widened the notching between some parent holding companies and their operating subsidiaries, especially if there was significant non-utility subsidiary debt or parent holding company debt. Negative rating consequences might also hold back the rating at the utility subsidiary, since parent holding company debt could be viewed as a proxy for utility subordinated debt or preferred stock.

As part of our review process, several corporate families are now characterized by a wider rating notching differential between the parent and one or more utility subsidiaries.

EXHIBIT 11

Parent holding companies with a three notch differential from one or more subsidiaries

Parent	Rating	Subsidiary	Rating	Notch differential
NextEra	Baa1	Florida Power & Light	A1	3
Sempra	Baa1	San Diego Gas & Electric	A1	3
Exelon Corp	Baa2	PECO Energy	A2	3
Dominion Resources	Baa2	VEPCO / DomGas	A2	3
PS Enterprises Group	Baa2	Public Service Electric & Gas	A2	3
Southern Company	Baa1	Alabama Power	A1	3
Integrys Energy	Baa1	Wisconsin Public Service	A1	3
Duquesne Light Holdgs.	Baa3	Duquesne Light Company	A3	3

In the table below, we show the utilities and holdcos that were placed on review for upgrade but were not upgraded. For these companies, ratings were confirmed at their existing rating categories[5].

EXHIBIT 12

Selected companies that were not upgraded

Name	Sector	Old	New	Outlook	Summary Rationale
American Transmission Company LLC	Transmission	A1	A1	Stable	Credit supportive FERC regulation already incorporated
Madison Gas and Electric Company	Vertically Integrated	A1	A1	Stable	Credit supportive regulation already incorporated
NSTAR Electric Company	T&D (electric or gas)	A2	A2	Stable	Credit supportive regulation already incorporated
International Transmission Company	Transmission	A3	A3	Stable	Credit supportive FERC regulation already incorporated
ITC Midwest LLC	Transmission	A3	A3	Stable	Credit supportive FERC regulation already incorporated
Michigan Electric Transmission Company, LLC	Transmission	A3	A3	Stable	Credit supportive FERC regulation already incorporated
Otter Tail Power Company	Vertically Integrated	A3	A3	Stable	Supportive regulation already incorporated
Integrys Energy Group, Inc.	Holdco	Baa1	Baa1	Stable	Non-utility business / Holdco debt
ITC Great Plains LLC	Transmission	Baa1	Baa1	Stable	Credit supportive FERC regulation already incorporated
Hawaiian Electric Company, Inc.	Vertically Integrated	Baa1	Baa1	Stable	Declining metrics, higher leverage
Duke Energy Kentucky, Inc.	Vertically Integrated	Baa1	Baa1	Stable	Declining metrics, higher leverage
Dominion Resources Inc.	Holdco	Baa2	Baa2	Stable	Non-utility business / Holdco debt
Hawaiian Electric Industries, Inc.	Holdco	Baa2	Baa2	Stable	Declining metrics, higher leverage
LG&E and KU Energy LLC	Holdco	Baa2	Baa2	Stable	Holdco debt
Bay State Gas Company	LDC	Baa2	Baa2	Stable	Supportive regulation already incorporated

[5] See Appendix C for a table of selected companies that were not placed on review for upgrade on 8 November 2013.

EXHIBIT 12

Selected companies that were not upgraded

Name	Sector	Old	New	Outlook	Summary Rationale
ITC Holdings Corp.	Transmission	Baa2	Baa2	Stable	Credit supportive FERC regulation already incorporated
Entergy Arkansas, Inc.	Vertically Integrated	Baa2	Baa2	Stable	Supportive regulation already incorporated
Kentucky Power Company	Vertically Integrated	Baa2	Baa2	Stable	Supportive regulation already incorporated
Duquesne Light Holdings, Inc.	Holdco	Baa3	Baa3	Stable	Non-utility business / Holdco debt
Pepco Holdings, Inc.	Holdco	Baa3	Baa3	Stable	Holdco debt
PPL Corporation	Holdco	Baa3	Baa3	Stable	Holdco debt
Atlantic City Electric Company	T&D (electric or gas)	Baa2	Baa2	Stable	Supportive regulation already incorporated

For a few companies, such as Madison Gas and Electric Company (MG&E: A1, stable) and NSTAR Electric Company (NSTAR Electric: A2, stable), their ratings already captured our view about the credit supportiveness of their regulatory environment and they exhibit prospective financials that are commensurate with their rating category. Their ratings also compare well with similarly rated utilities that operate in commensurately sized metro areas. The same can be said for Otter Tail Power Company (OTP: A3, stable), where we confirmed the utility at A3 and upgraded the parent holding company Otter Tail Corporation (OTC: Baa2, stable) to Baa2, thus narrowing the notching differential between the parent and the subsidiary.

The FERC regulated transmission companies, namely American Transmission Company LLC (ATC: A, stable) and ITC Holdings Corp. (ITC: Baa2, stable) and its operating subsidiaries, were not upgraded because the credit supportive FERC regulatory framework is already sufficiently incorporated into our credit analysis. Moreover, unlike most state regulatory jurisdictions, which are improving, we see the FERC maintaining a relatively steady level of supportiveness, which is high.

We summarize the rationale behind our rating confirmations for the rest of the companies in the pages that follow.

American Transmission Company (A1, stable)

The rating confirmation for American Transmission Company (ATC) reflects our view of the supportive regulatory framework of the FERC. We believe ATC's A1 issuer rating is well positioned reflecting the relatively stable and predictable cash flows supported by a federal regulatory framework governed by the FERC that promotes a tariff framework that allows timely recovery of operating and investment costs. The rating also considers ATC's low business risk profile, which is characterized by limited exposure to demand volatility and solid market position. The rating is constrained by ATC's small size, lack of geographic diversification, financial metrics that are weak for the rating but mitigated by the favorable FERC regulatory framework and the funding requirements associated with the company's significant capital expenditure program.

Our view of the supportive federal regulatory framework governed by the FERC is balanced against the current Section 206 complaint filed against the regional rate used by Transmission Owners in the Midcontinent Independent System Operator, Inc. (MISO) in November 2013. To date, FERC has taken no action on this complaint, which the TOs have filed a motion to dismiss. While it is too early in the process to determine the ultimate credit impact of any final outcome from the Section 206 complaint on ATC, we believe the final resolution of a similar Section 206 complaint filed at FERC currently being litigated against TOs in the New England ISO will provide some clarity on how similar cases will be treated going forward as to FERC's policies on these matters. We expect a final resolution by the FERC on the New England Section 206 complaint by the second quarter of 2014.

Given that ATC's credit metrics are expected to continue to be weak for its rating, ongoing favorable regulatory support provided by the FERC regulatory construct represents an essential factor in ATC's ability to maintain its financial strength.

ITC Holdings Corp (Baa2, stable) & subsidiaries

The rating confirmation for ITC Holdings Corp (ITC) and its subsidiaries reflects our view of the supportive regulatory framework of the FERC. We believe ITC Holdings' Baa2 senior unsecured rating is well positioned reflecting the relatively stable and predictable cash flows provided by its electric transmission operating subsidiaries and a solid market position. The Baa2 rating is constrained by the significant amount of debt maintained at the parent level and consolidated credit metrics that are weak for the rating but mitigated by the favorable FERC regulatory framework. The rating also considers the significant capital expenditure program currently being undertaken at ITC Holdings' operating subsidiaries.

Our view of the supportive federal regulatory framework governed by the FERC is balanced against the current Section 206 complaint filed against the regional rate used by Transmission Owners in the MISO including ITC's MISO-based subsidiaries (ITC Transmission, METC and ITC Midwest) in November 2013. To date, FERC has taken no action on this complaint, which the TOs have filed a motion to dismiss. While it is too early in the process to determine the ultimate credit impact of any final outcome from the Section 206 complaint on ITC's MISO-based subsidiaries, we believe the final resolution of a similar Section 206 complaint filed at FERC currently being litigated against the TOs in the New England ISO will provide some clarity on how similar cases will be treated going forward as to FERC's policies on these matters. We expect a final resolution by the FERC on the New England Section 206 complaint by the second quarter of 2014. Given that ITC's credit metrics are expected to continue to be weak for its rating, ongoing favorable regulatory support provided by the FERC regulatory construct represents an essential factor in ITC's ability to maintain its financial strength.

The ratings of ITC's subsidiaries reflect the same supportive FERC regulatory framework that provides a robust set of timely recovery mechanisms and healthy returns resulting in strong credit metrics. However, ITC's subsidiary ratings are constrained by the significant leverage at its parent, ITC Holdings, Corp. ITC has historically issued debt at the parent level to finance acquisitions, which accounts for approximately 70% of total parent level debt, as well as to finance equity infusions to its transmission subsidiaries. This holdco/opco financing approach used within the industry creates a benefit of double leverage by having higher equity ratios at the utility subsidiaries. As of September 30, 2013, parent level debt represented approximately 54% of ITC's consolidated debt. ITC has indicated it expects to continue funding its operations with internally generated cash, revolving credit facilities and long-term debt at the operating subsidiaries and parent as necessary.

Madison Gas &Electric Company (A1, stable)

The rating confirmation of MG&E's rating reflects our view that the utility already capture the regulatory environment in Wisconsin as above average relative to its integrated utility peers. The rating further acknowledges that MG&E's credit metrics have historically been strong for the rating category but are expected to soften as the company funds its near term capital expenditure program with a mix of internally generated funds and incremental debt, but should remain in line with comparable A1 rated utilities. Finally, the rating captures MG&E's comparatively small and concentrated service territory relative to the other utilities in the same rating category.

NSTAR Electric Company (A2, stable)

The rating confirmation of NSTAR Electric reflects our view that the regulatory environment in Massachusetts is slightly above average for T&D utilities, and those associated benefits have already been incorporated with NSTAR's current rating. The rating further acknowledges that NSTAR Electric's credit metrics are commensurate with the mid range of the A-rating category and that it compares well relative to other A2-rated transmission and distribution peers operating in a single metro area. It also captures that NSTAR Electric has a standalone $450 million committed credit facility and that the utility's historical ability to report significant amounts of positive free cash flow has diminished in recent years.

Otter Tail Power Company (A3, stable)

The rating confirmation of OTP reflects the overall credit supportive regulatory environments which the utility currently operates; a robust suite of recovery mechanisms that provide timely recovery of prudent costs and investments; and reasonably diverse service territory spread across three states. The rating also factors in the expected slight decline in financial metrics due to the current substantial capex program to grow rate base, including sizeable investments in transmission assets, as well as the continued pressure from material upstream dividend distributions to help the parent meet its somewhat aggressive dividend policy.

Duke Energy Kentucky, Inc (Baa1, stable)

The rating confirmation of Duke Energy Kentucky, Inc. reflects adequate but declining financial metrics, increasing capital expenditures, and anticipated higher debt levels that offset the generally credit supportive regulatory environment in Kentucky. The utility's cash flow pre-working capital to debt ratio has fallen from the 25% range in 2011 and prior years to the 20% range more recently, and is likely to fall into the high teens as debt levels rise. The utility has not filed for a rate increase in several years and has no immediate plans to file a base rate case. Duke Energy Kentucky Inc's small size and status as a subsidiary of Baa1 rated Duke Energy Ohio, which was not placed on review for upgrade in November, are also rating constraints.

Hawaiian Electric Industries, Inc. (Baa2, stable) and utility subsidiary

The rating confirmation of Hawaiian Electric Company, Inc. (HECO: Baa1, stable) reflects a weak financial profile. The ratings of Hawaiian Electric Industries, Inc (HEI: Baa2, stable)) at current levels reflect the relatively stable earnings and cash flow historically provided by both the vertically integrated utility businesses at HECO and the stable banking operations at American Savings Bank. The ratings also recognize the challenges at HECO and its subsidiaries, which have some of the highest retail electric rates in the country. The utility operations face heavy pressure from regulators and stakeholders to reduce rates and dependence on fuel oil. While rate reduction initiatives involving infrastructure improvements and new generation may present investment opportunities for the utilities, they also present the potential for under-recovery. HEI projects $2.9 billion of capital expenditures at the utilities over the next five years, which is sizable compared with the total authorized rate base of $2.2 billion. HECO benefits from a robust suite of regulatory mechanisms to mitigate this risk, including the revenue adjustment mechanism (RAM), which allows for rate base additions in between rate cases. The banking subsidiary, which provides about one-third of operating income to HEI, is managing well through the housing downturn and the low net interest margin environment.

Integrys Energy Group (Baa1, stable)

The confirmation of Integrys Energy Group's (Integrys: Baa1, stable) rating takes into consideration the company's sizable non-regulated energy marketing business, currently making up about 10-15% of consolidated earnings as well as the substantial amount of debt held at the parent. Today's rating action assumes Integrys' management will keep holding company debt around 30% of consolidated debt, while maintaining the size of its unregulated segment at current levels. It further assumes that management would take necessary actions to address any deterioration in its business risk profile if required in the future.

Bay State Gas Company (Baa2, stable)

The rating confirmation of Bay State Gas Company (Bay State: Baa2, stable) reflects the inter-company relationship with its parent, NiSource. This intercompany relationship constrains Bay State's rating at the parent rating level because Bay State's debt is being guaranteed by its Baa2 rated parent.

Dominion Resources Inc. (Baa2 stable)

The rating confirmation of Dominion Resources Inc (Dominion: Baa2, stable) reflects high leverage at the parent holding company. We also see weak near term cash flow generation at the non-utilities businesses; a sustained period of high capital investments, much of which is associated with a risky, multi-year construction program to construct an LNG export terminal (which will also create some asset concentration risk), and; a more welcoming stance towards corporate financial engineering, which contribute to a more complex capital structure and a net reduction of financial flexibility.

Duquesne Light Holdings, Inc (Baa3, stable)

The rating confirmation of Duquesne Light Holdings, Inc (DLH: Baa3, stable)) reflects the high level of parent company debt and unregulated operations which do not benefit from our more favorable view of the US regulatory environment.

Pepco Holdings Inc. (Baa3, stable) and subsidiary

The rating confirmation of Pepco Holdings Inc.'s (PHI: Baa3, stable) reflects meaningful parent company debt and an aggressive dividend payout policy primarily funded through incremental debt issuances prevented upward movement in its rating.

Despite generally improving regulatory environments across the US, Atlantic City Electric Company's (ACE: Baa2, stable) regulatory construct has not benefitted from similar developments. For instance, unlike the majority of its sister utilities, ACE does have access to a decoupling mechanism that would improve the predictability of its earnings by eliminating fluctuations based on weather and changes in customer usage patterns. Furthermore, ACE continues to wrestle with significant lag in its earnings which keep the company's financial metrics squarely in the mid-Baa range.

Kentucky Power Company (Baa2, stable)

The rating confirmation of Kentucky Power Company (KEPCO: Baa2, stable) reflects the high leverage, a large capital expenditure program and weak financial metrics. The settlement outcome of last October clears the path to complete the transfer of the Mitchell Plant (including considerations of potential greenhouse initiatives), and the conversion of the Big Sandy Unit 1 to natural gas. KEPCO'S financial metrics for LTM third-quarter 2013, are reasonably within the range for the rating

category. However, on a forward looking basis, a large capital expenditure program and increased leverage will contribute to weaker financial metrics such as CFO pre-WC to debt averaging between 12-14% and CFO pre WC – Div to debt between 9-11%.

Entergy Arkansas, Inc. (Baa2, stable)

The rating confirmation of Entergy Arkansas Inc. (EA: Baa2, stable) reflects less favorable rate case outcomes in May 2010 and December 2013. Arkansas operates under traditional rate of return regulation rather than the more credit supportive formula rate plans in place in Louisiana and Mississippi, where Entergy's other large subsidiaries operate. The rate of return regulation contributes to regulatory lag at EA. Under Arkansas regulation, the test year is either fully historical or 6 months historical and 6 months projected. However, there are fuel and certain other riders that help offset some aspects of the lag.

LTM third-quarter 2013 metrics are consistent with that of fiscal year end 2012, with Cash Flow Interest Coverage of 4.5x and CFO pre-WC to debt of 13%. According to Moody's adjusted projections, EA will be able to maintain appropriate metrics for the rating, including CFO pre-WC to debt, and CFO pre-WC – Div to debt of around 16% and 14% respectively.

PPL Corporation (Baa3, stable)

The rating confirmation of PPL Corporation (PPL: Baa3, stable) reflects the upgrades of its US regulated utilities, which represent 31% of consolidated earnings, but these upgrades were not sufficient to shift PPL's consolidated credit profile as their financial metrics remain weak for its rating category. LKE did not receive an upgrade because of the high debt level at LKE relative to the consolidated LKE. Moreover, because there is free movement of cash between PPL and LKE, PPL has a constraining effect on LKE's ratings.

INFRASTRUCTURE AND PROJECT FINANCE

MOODY'S
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SECTOR IN-DEPTH
10 MARCH 2015

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US Regulated Utilities

Lower Authorized Equity Returns Will Not Hurt Near-Term Credit Profiles

The credit profiles of US regulated utilities will remain intact over the next few years despite our expectation that regulators will continue to trim the sector's profitability by lowering its authorized returns on equity (ROE). Persistently low interest rates and a comprehensive suite of cost recovery mechanisms ensure a low business risk profile for utilities, prompting regulators to scrutinise their profitability, which is defined as the ratio of net income to book equity. We view cash flow measures as a more important rating driver than authorized ROEs, and we note that regulators can lower authorized ROEs without hurting cash flow, for instance by targeting depreciation, or through special rate structures. Regulators can also adjust a utility's equity capitalization in its rate base. All else being equal, we think most utilities would prefer a thicker equity base and a lower authorized ROE over a small equity layer and a high authorized ROE.

» **More timely cost recovery helps offset falling ROEs.** Regulators continue to permit a robust suite of mechanisms that enable utilities to recoup prudently incurred operating costs, including capital investments such as environment related or infrastructure hardening expenditures. Strong cost recovery is credit positive because it ensures a stable financial profile. Despite lower authorized ROEs, we see the sector maintaining a ratio of Funds From Operations (FFO) to debt near 20%, a level that continues to support strong investment-grade ratings.

» **Utilities' cash flow is somewhat insulated from lower ROEs.** Net income represents about 30% - 40% of utilities' cash flow, so lower authorized returns won't necessarily affect cash flow or key financial credit ratios, especially when the denominator (equity) is rising. Regulators set the equity layer when capitalizing rate base, and the equity layer multiplied by the authorized ROE drives the annual revenue requirements. Across the sector, the ratio of equity to total assets has remained flat in the 30% range since 2007.

» **Utilities' actual financial performance remains stable.** Earned ROEs, which typically lag authorized ROEs, have not fallen as much as authorized returns in recent years. Since 2007, vertically integrated utilities, transmission and distribution only utilities, and natural gas local distribution companies have maintained steady earned ROE's in the 9% - 10% range. Holding companies with primarily regulated businesses also earned ROEs of around 9% - 10%, while returns for holding companies with diversified operations, namely unregulated generation, have fallen from 11% (over the past seven year average) to around 9% today.

Robust Suite of Cost Recovery Mechanisms Is Credit Positive

Over the past few years, the US regulatory environment has been very supportive of utilities. We think this is partly because regulators acknowledge that utility infrastructure needs a material amount of ongoing investment for maintenance, refurbishment and renovation. Utilities have also been able to garner support from both politicians and regulators for prudent investment in these critical assets because it helps create jobs, spurring economic growth. We also think regulators prefer to regulate financially healthy utilities.

Across the US, we continue to see regulators approving mechanisms that allow for more timely recovery of costs, a material credit positive. These mechanisms, which keep utilities' business risk profile low compared to most industrial corporate sectors, include: formulaic rate structures; special purpose trackers or riders; decoupling programs (which delink volumes from revenue); the use of future test years or other pre-approval arrangements. We also see a sustained increase in the frequency of rate case filings.

A supportive regulatory environment translates into a more transparent and stable financial profile, which in turn results in reasonably unfettered access to capital markets - for both debt and equity. Today, we think utilities enjoy an attractive set of market conditions that will remain in place over the next few years. By themselves, neither a slow (but steady) decline in authorized profitability, nor a material revision in equity market valuation multiples, will derail the stable credit profile of US regulated utilities.

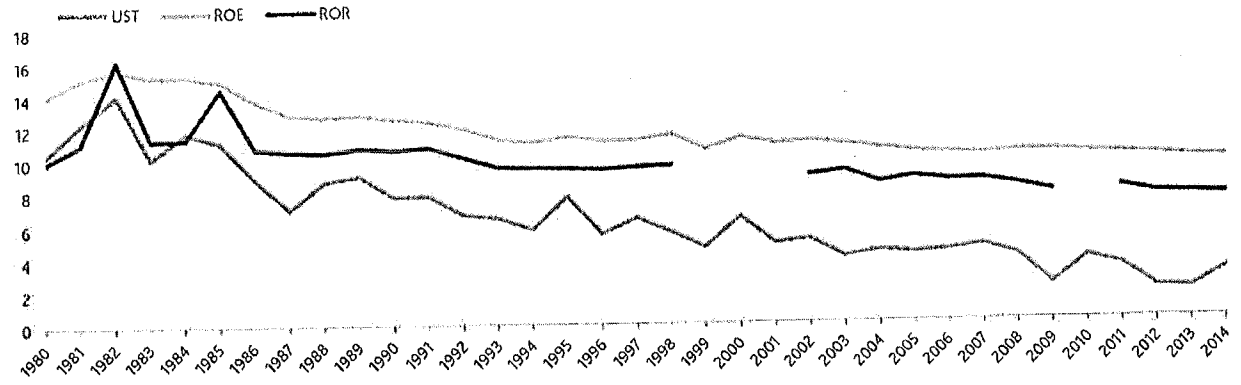
Cost recovery will help offset falling ROEs

Robust cost recovery mechanisms will help ensure that US regulated utilities' credit quality remains intact over the next few years. As a result, falling authorized ROEs are not a material credit driver at this time, but rather reflect regulators' struggle to justify the cost of capital gap between the industry's authorized ROEs and persistently low interest rates. We also see utilities struggling to defend this gap, while at the same time recovering the vast majority of their costs and investments through a variety of rate mechanisms.

In the table below, we show the US Treasury 10-year yield, which has steadily fallen from the 5% range in the summer of 2007 to the 2% range today. US utilities benefit from these lower interest rates because they borrow approximately $50 billion a year. For some utilities, a lower cost of debt translates directly into a higher return on equity, as long as their rate structure includes an embedded weighted average cost of capital (and the utilities can stay out of a general rate case proceeding).

Exhibit 1

Regulators hold up their end of the bargain by limiting reduction in return on equity (ROE) and overall rate of return (ROR) when compared with the decline in US Treasury 10-year yields



SOURCE: SNL Financial, LP, Moody's

This publication does not announce a credit rating action. For any credit ratings referenced in this publication, please see the ratings tab on the issuer/entity page on www.moodys.com for the most updated credit rating action information and rating history.

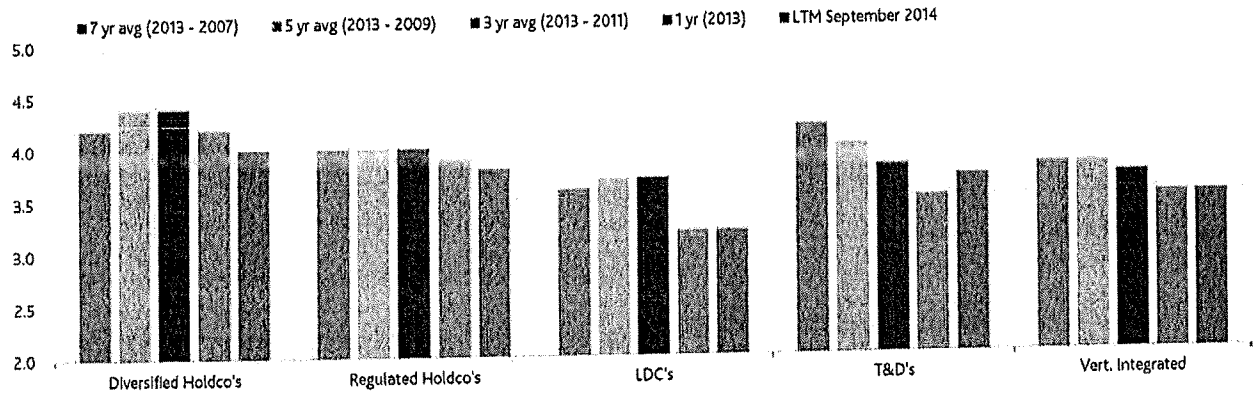
As utilities increasingly secure more up-front assurance for cost recovery in their rate proceedings, we think regulators will increasingly view the sector as less risky. The combination of low capital costs, high equity market valuation multiples (which are better than or on par with the broader market despite the regulated utilities' low risk profile), and a transparent assurance of cost recovery tend to support the case for lower authorized returns, although because utilities will argue they should rise, or at least stay unchanged.

One of the arguments for keeping authorized ROEs steady is that lowering them would make utilities less attractive to providers of capital. Utility holding companies assert that they would rather invest in higher risk-adjusted opportunities than in a regulated utility with sub-par return prospects. We see a risk that this argument could lead to a more contentious regulatory environment, a material credit negative. We do not think this scenario will develop over the next few years.

Our default and recovery data provides strong evidence that regulated utilities are indeed less risky (from the perspective of a probability of default and expected loss given default, as defined by Moody's) than their non-financial corporate peers. On a global basis, we nonetheless see a material amount of capital looking for regulated utility investment opportunities, and the same is true in the US despite, despite a lower authorized return. This is partly because investors can use holding company leverage to increase their actual equity returns, by borrowing capital at today's low interest rates and investing in the equity of a regulated utility.

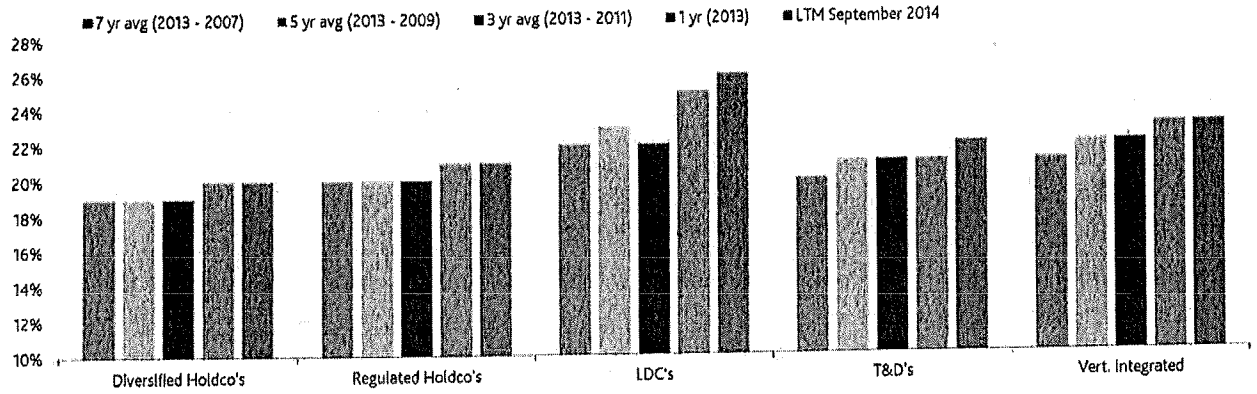
Despite the reduction in authorized ROEs, US utilities are thankful to their regulators for the robust suite of timely cost recovery mechanisms which allow them to recoup prudently incurred operating costs such as fuel, as well as some investment expenses. These recovery mechanisms drive a stable and transparent dividend policy, which translates into historically very high equity multiples. Moreover, cost recovery helps keep the sector's overall financial profile stable, thereby supporting strong investment-grade ratings.

Exhibit 2
With better recovery mechanisms, the ratio of debt-to-EBITDA can rise, modestly, without negatively impacting credit profiles



SOURCE: Company filings; Moody's

Exhibit 3
The ratio of Funds From Operations to debt is rising, a material credit positive,
but the rise is partly funded by bonus depreciation and deferred taxes, which will eventually reverse



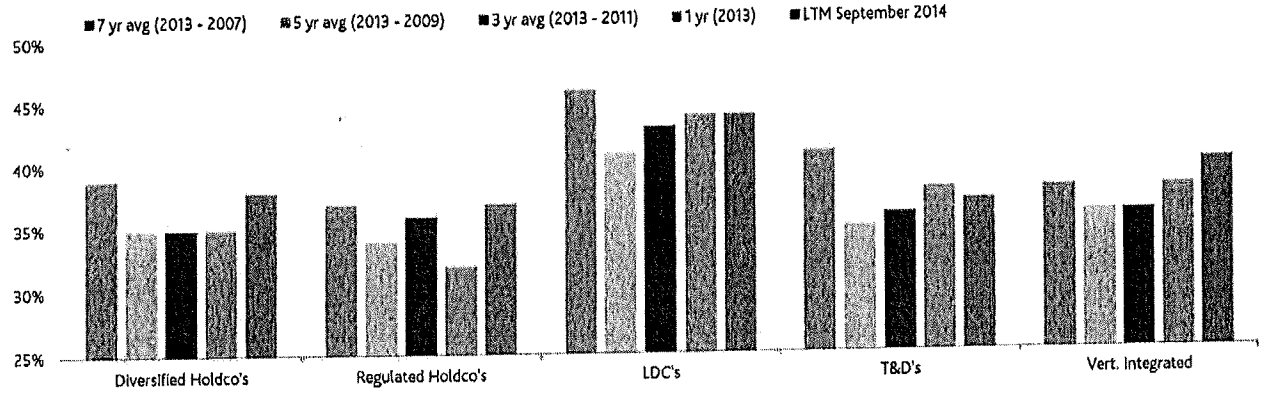
SOURCE: Company filings; Moody's

Utilities' cash flow is somewhat insulated from declining ROEs

Across all our utility group sub-sectors (see Appendix), net income -- the numerator in the calculation of ROE – accounts for between 30% - 40% of cash flow. While net income is important, cash flow exerts a much greater influence over creditworthiness. This is primarily because cash flow takes into account depreciation and amortization expenses, along with other deferred tax adjustments. We note that deferred taxes have risen over the past few years, in part due to bonus depreciation elections, which will eventually reverse. From a credit perspective, there is a difference between the nominal amount of net income, which goes into cash flow, and the relationship of net income to book equity (a measure of profitability).

In the chart below, we highlight the ratio of net income to cash flow from operations (CFO) for our selected peer groups. Across all of the sectors, the longer term historical average of net income to CFO has fallen compared with the late 2000s, but has been rising over the more recent past. This is partly a function of deferred taxes, which have become a larger component of CFO over the past decade.

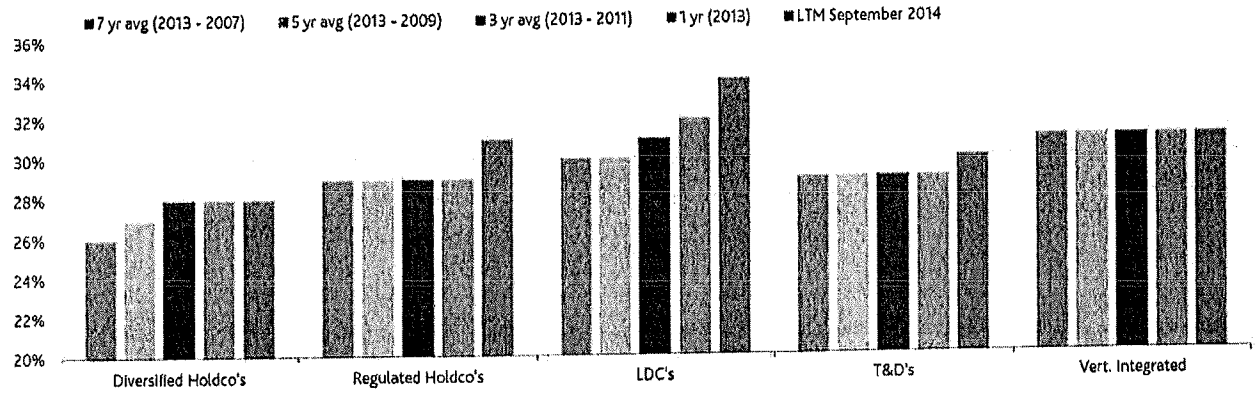
Exhibit 4
Net income as a % of cash flow from operations has been steadily rising (since 2011)



SOURCE: Company filings, Moody's

We can also envisage scenarios where regulators seek to achieve a reduction in authorized ROEs without harming credit profiles by focusing on utilities' equity layer. In the chart below, we illustrate median equity as a percentage of total assets for our selected peer groups. In our illustration, utilities will benefit from acquisition related goodwill on one hand, and impairments on the other.

Exhibit 5
Equity as a % of total assets, not capitalization, includes both goodwill and impairments



SOURCE: Company filings; Moody's

Utilities' actual financial performance remains stable

Earned ROE's, as reported by utilities and adjusted by Moody's, have been relatively flat over the past few years, despite the decline in authorized ROEs. This means utilities are closer to earning their authorized equity returns, which is positive from an equity market valuation perspective.

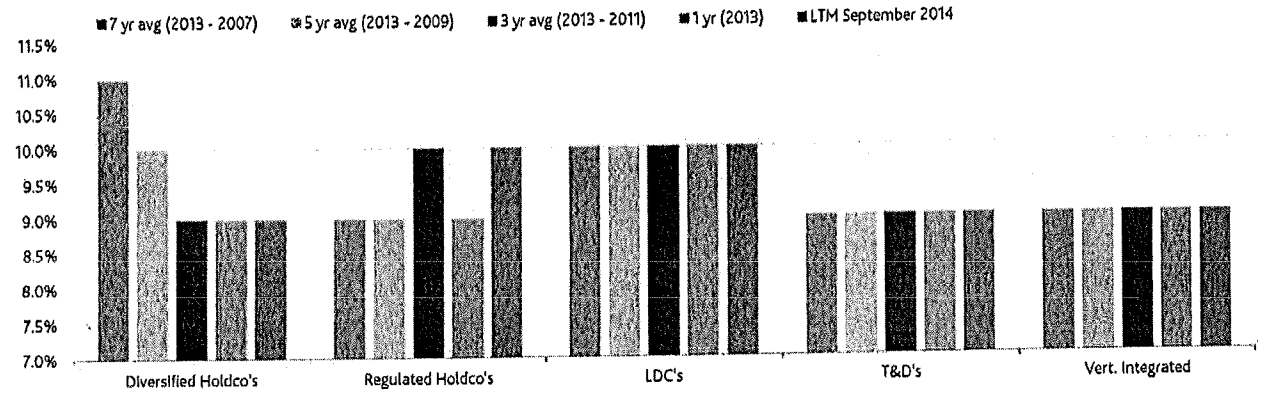
The authorized ROE is a popular focal point in many regulatory rate case proceedings. In addition, many regulatory jurisdictions look to established precedents that rely on various methodologies to determine an appropriate ROE, such as the capital asset pricing model or discounted cash flow analysis. In some jurisdictions where formulaic based rate structures point to lower ROEs for a longer projected period of time, regulators are incorporating a view that today's interest rate environment is "artificially" being held low.

Regardless, we think interest rates will go up, eventually. When they do, we also think authorized ROEs will trend up as well. However, just as authorized ROEs declined in a lagging fashion when compared to falling interest rates, we expect authorized ROEs to rise in a lagging fashion when interest rates rise.

Depending on alternative sources of risk-adjusted capital investment opportunities, this could spell trouble for utilities. For now, utilities can enjoy their (historically) high equity valuations, in terms of dividend yield and price-earnings ratios.

Exhibit 6

GAAP adjusted earned ROE's are relatively flat across all sub-sectors except Holding Companies with Diversified Operations, while the lower-risk LDC sector is outperforming



NOTE: GAAP adjusted ROE, not regulated ROE, does not adjust for goodwill or impairments.

Source: Company filings; Moody's

OKLAHOMA GAS & ELECTRIC
CAPITAL STRUCTURE RATIOS
2011 - 2015
($000)

YEAR	COMMON EQUITY	LONG-TERM DEBT 1/	SHORT-TERM DEBT
2011	$2,494,000	$2,039,200	$0
	55.0%	45.0%	0.0%
	55.0%	45.0%	
2012	$2,703,100	$2,050,300	$0
	56.9%	43.1%	0.0%
	56.9%	43.1%	
2013	$2,829,300	$2,300,200	$87,200
	54.2%	44.1%	1.7%
	55.2%	44.8%	
2014	$3,004,200	$2,655,300	$0
	53.1%	46.9%	0.0%
	53.1%	46.9%	
2015	$3,155,700	$2,655,600	$0
	54.3%	45.7%	0.0%
	54.3%	45.7%	

1/ Includes long-term debt within one year.

Note: Percentages may not total 100.0% due to rounding.

Source: Response to OIEC 7-7.

OGE ENERGY CORP.
CAPITAL STRUCTURE RATIOS
2011 - 2015
($000)

YEAR	COMMON EQUITY	LONG-TERM DEBT 1/	SHORT-TERM DEBT
2011	$2,819,300 48.3% 50.7%	$2,737,100 46.9% 49.3%	$277,100 4.8%
2012	$3,072,400 48.4% 51.9%	$2,848,600 44.8% 48.1%	$430,900 6.8%
2013	$3,037,100 51.7% 55.9%	$2,400,100 40.8% 44.1%	$439,600 7.5%
2014	$3,244,400 53.2% 54.1%	$2,755,300 45.2% 45.9%	$98,000 1.6%
2015	$3,326,000 53.8% 54.7%	$2,755,600 44.5% 45.3%	$105,500 1.7%

1/ Includes long-term debt within one year.

Source: Response to OIEC 7-7.

Exhibit DCP-1
Schedule 9

AUS UTILITY REPORTS
ELECTRIC UTILITY GROUPS
AVERAGE COMMON EQUITY RATIOS

Year	Electric	Combination Electric and Gas
2011	47%	46%
2012	47%	46%
2013	48%	47%
2014	47%	47%
2015		

Note: Averages include short-term debt.

Source: AUS Utility Reports.

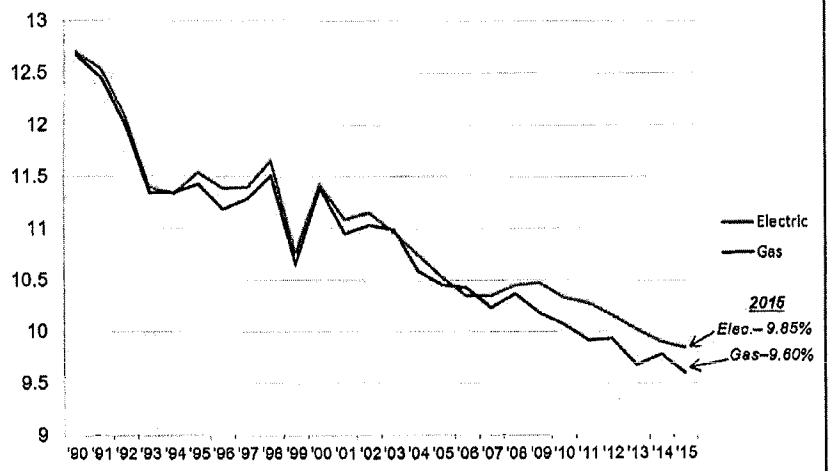
Regulatory Research Associates
REGULATORY FOCUS

January 14, 2016*

MAJOR RATE CASE DECISIONS--CALENDAR 2015

The average return on equity (ROE) authorized electric utilities was 9.85% in 2015, compared to 9.91% in 2014. There were 30 electric ROE determinations in 2015, versus 38 in 2014. We note that the data includes several surcharge/rider generation cases in Virginia that incorporate plant-specific ROE premiums. Virginia statutes authorize the State Corporation Commission to approve ROE premiums of up to 200 basis points for certain generation projects (see the Virginia Commission Profile). Excluding these Virginia surcharge/rider generation cases from the data, the average authorized electric ROE was 9.58% in 2015 compared to 9.76% in 2014. The average ROE authorized gas utilities was 9.6% in 2015 compared to 9.78% in 2014. There were 16 gas cases that included an ROE determination in 2015, versus 26 in 2014. The 2014 averages do not include a Feb. 20, 2014 New York Public Service Commission steam rate decision for Consolidated Edison Co. of New York that adopted a 9.3% ROE.

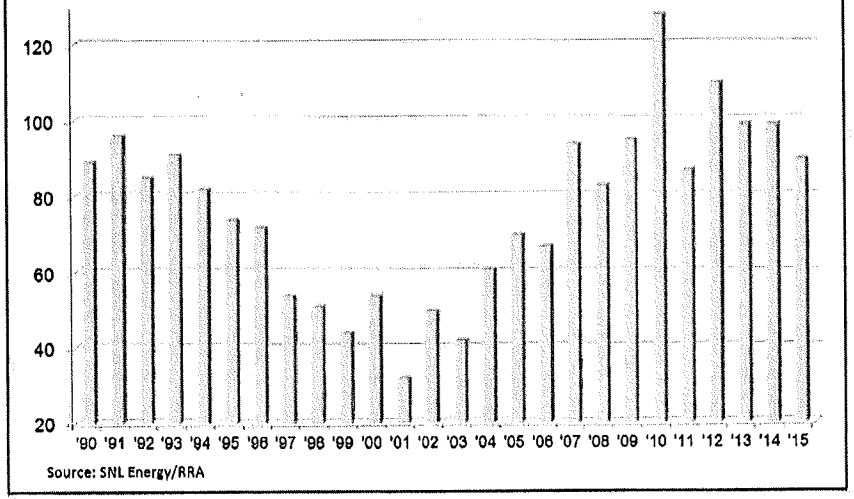
Graph 1: Average Authorized ROEs – Electric and Gas Rate Decisions



Source: SNL Energy/RRA

As shown in Graph 2 below, after reaching a low in the early-2000s, the number of rate case decisions for energy companies has generally increased over the last several years, peaking in 2010 at more than 125 cases.

Graph 2: Volume of Electric and Gas Rate Case Decisions



Source: SNL Energy/RRA

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Since 2010, the number of cases has moderated somewhat but has approximated 90 or more in the last five calendar years. There were 90 electric and gas rate cases resolved in 2015, 99 in both 2014 and 2013, 110 in 2012, and 87 in 2011. The number of rate cases decided in 2015 declined slightly from the level of activity in 2014, but this level remains robust compared to the late-1990s/early-2000s. Increased costs for environmental compliance (including the CO_2 reduction mandates), generation and delivery infrastructure upgrades and expansion, renewable generation mandates, and employee benefits argue for the continuation of an active rate case agenda over the next few years. In addition, if the Federal Reserve continues its policy initiated in December 2015 to gradually raise the federal funds rate, utilities eventually would face higher capital costs and would need to initiate rate cases to reflect the higher capital costs in rates.

We note that this report utilizes the simple mean for the return averages. In addition, the average equity returns indicated in this report reflect the cases decided in the specified time periods and are not necessarily representative of the returns actually earned by utilities industry wide.

As a result of electric industry restructuring, certain states unbundled electric rates and implemented retail competition for generation. Commissions in those states now have jurisdiction only over the revenue requirement and return parameters for delivery operations (which we footnote in our chronology beginning on page 5), thus complicating historical data comparability. We note that since 2008, interest rates declined significantly, and average authorized ROEs have declined modestly. We also note the increased utilization of limited issue rider proceedings that allow utilities to recover certain costs outside of a general rate case and typically incorporate previously-determined return parameters.

The table on page 3 shows the average ROE authorized in major electric and gas rate decisions annually since 1990, and by quarter since 2011, followed by the number of observations in each period. The tables on page 4 indicate the composite electric and gas industry data for all major cases summarized annually since 2001 and by quarter for the past eight quarters. The individual electric and gas cases decided in 2015 are listed on pages 5-9, with the decision date shown first, followed by the company name, the abbreviation for the state issuing the decision, the authorized rate of return (ROR), ROE, and percentage of common equity in the adopted capital structure. Next we indicate the month and year in which the adopted test year ended, whether the commission utilized an average or a year-end rate base, and the amount of the permanent rate change authorized. The dollar amounts represent the permanent rate change ordered at the time decisions were rendered. Fuel adjustment clause rate changes are not reflected in this study.

The table below tracks the average equity return authorized for all electric and gas rate cases combined, by year, for the last 26 years. As the table indicates, since 1990 the authorized ROEs have generally trended downward, reflecting the significant decline in interest rates and capital costs that has occurred over this time frame. The combined average equity returns authorized for electric and gas utilities in each of the years 1990 through 2015, and the number of observations for each year are as follows:

1990	12.69%	(75)	2003	10.98%	(47)
1991	12.51	(80)	2004	10.67	(39)
1992	12.06	(77)	2005	10.50	(55)
1993	11.37	(77)	2006	10.39	(42)
1994	11.34	(59)	2007	10.30	(76)
1995	11.51	(49)	2008	10.42	(67)
1996	11.29	(42)	2009	10.36	(68)
1997	11.34	(24)	2010	10.28	(100)
1998	11.59	(20)	2011	10.21	(59)
1999	10.74	(29)	2012	10.08	(93)
2000	11.41	(24)	2013	9.92	(71)
2001	11.05	(25)	2014	9.86	(63)
2002	11.10	(43)	2015	9.76	(46)

Please note: Historical data provided in this report may not match data provided on RRA's website due to certain differences in presentation, including the treatment of cases that were withdrawn or dismissed.

Dennis Sperduto

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Average Equity Returns Authorized January 1990 - December 2015

		Electric Utilities		Gas Utilities	
Year	**Period**	**ROE %**	**(# Cases)**	**ROE %**	**(# Cases)**
1990	Full Year	12.70	(44)	12.67	(31)
1991	Full Year	12.55	(45)	12.46	(35)
1992	Full Year	12.09	(48)	12.01	(29)
1993	Full Year	11.41	(32)	11.35	(45)
1994	Full Year	11.34	(31)	11.35	(28)
1995	Full Year	11.55	(33)	11.43	(16)
1996	Full Year	11.39	(22)	11.19	(20)
1997	Full Year	11.40	(11)	11.29	(13)
1998	Full Year	11.66	(10)	11.51	(10)
1999	Full Year	10.77	(20)	10.66	(9)
2000	Full Year	11.43	(12)	11.39	(12)
2001	Full Year	11.09	(18)	10.95	(7)
2002	Full Year	11.16	(22)	11.03	(21)
2003	Full Year	10.97	(22)	10.99	(25)
2004	Full Year	10.75	(19)	10.59	(20)
2005	Full Year	10.54	(29)	10.46	(26)
2006	Full Year	10.36	(26)	10.43	(16)
2007	Full Year	10.36	(39)	10.24	(37)
2008	Full Year	10.46	(37)	10.37	(30)
2009	Full Year	10.48	(39)	10.19	(29)
2010	Full Year	10.37	(61)	10.15	(39)
	1st Quarter	10.32	(13)	10.10	(5)
	2nd Quarter	10.12	(10)	9.88	(5)
	3rd Quarter	10.36	(8)	9.65	(2)
	4th Quarter	10.34	(11)	9.88	(4)
2011	**Full Year**	**10.29**	(42)	**9.92**	(16)
	1st Quarter	10.84	(12)	9.63	(5)
	2nd Quarter	9.92	(13)	9.83	(8)
	3rd Quarter	9.78	(8)	9.75	(1)
	4th Quarter	10.10	(25)	10.07	(21)
2012	**Full Year**	**10.17**	(58)	**9.94**	(35)
	1st Quarter	10.28	(14)	9.57	(3)
	2nd Quarter	9.84	(7)	9.47	(6)
	3rd Quarter	10.06	(7)	9.60	(1)
	4th Quarter	9.91	(21)	9.83	(11)
2013	**Full Year**	**10.03**	(49)	**9.68**	(21)
	1st Quarter	10.23	(8)	9.54	(6)
	2nd Quarter	9.83	(5)	9.84	(8)
	3rd Quarter	9.87	(12)	9.45	(6)
	4th Quarter	9.78	(13)	10.28	(6)
2014	**Full Year**	**9.91**	**(38)**	**9.78**	**(26)**
	1st Quarter	10.37	(9)	9.47	(3)
	2nd Quarter	9.73	(7)	9.43	(3)
	3rd Quarter	9.40	(2)	9.75	(1)
	4th Quarter	9.62	(12)	9.68	(9)
2015	**Year-to-Date**	**9.85**	**(30)**	**9.60**	**(16)**

Electric Utilities--Summary Table

	Period	ROR %	(# Cases)	ROE %	(# Cases)	Eq. as % Cap. Struc.	(# Cases)	Amt. $ Mil.	(# Cases)
2001	Full Year	8.93	(15)	11.09	(18)	47.20	(13)	14.2	(21)
2002	Full Year	8.72	(20)	11.16	(22)	46.27	(19)	-475.4	(24)
2003	Full Year	8.86	(20)	10.97	(22)	49.41	(19)	313.8	(12)
2004	Full Year	8.44	(18)	10.75	(19)	46.84	(17)	1,091.5	(30)
2005	Full Year	8.30	(26)	10.54	(29)	46.73	(27)	1,373.7	(36)
2006	Full Year	8.24	(24)	10.36	(26)	48.67	(23)	1,465.0	(42)
2007	Full Year	8.22	(38)	10.36	(39)	48.01	(37)	1,401.9	(46)
2008	Full Year	8.25	(35)	10.46	(37)	48.41	(33)	2,899.4	(42)
2009	Full Year	8.23	(38)	10.48	(39)	48.61	(37)	4,192.3	(58)
2010	Full Year	7.99	(59)	10.37	(61)	48.45	(54)	5,567.7	(78)
2011	Full Year	8.00	(43)	10.29	(42)	48.26	(42)	2,853.5	(56)
2012	Full Year	7.95	(51)	10.17	(58)	50.55	(52)	3,131.5	(69)
2013	Full Year	7.66	(45)	10.03	(49)	49.25	(43)	3,326.6	(61)
	1st Quarter	7.71	(6)	10.23	(8)	51.08	(8)	251.4	(9)
	2nd Quarter	7.77	(2)	9.83	(5)	49.12	(4)	92.5	(6)
	3rd Quarter	7.55	(11)	9.87	(12)	50.12	(11)	651.5	(16)
	4th Quarter	7.56	(13)	9.78	(13)	50.29	(12)	1,058.4	(20)
2014	**Full Year**	**7.60**	**(32)**	**9.91**	**(38)**	**50.28**	**(35)**	**2,053.8**	**(51)**
	1st Quarter	7.74	(10)	10.37	(9)	51.91	(9)	203.7	(11)
	2nd Quarter	7.04	(9)	9.73	(7)	47.83	(6)	819.4	(17)
	3rd Quarter	7.85	(3)	9.40	(2)	51.08	(3)	379.6	(5)
	4th Quarter	7.22	(13)	9.62	(12)	48.24	(12)	484.3	(19)
2015	**Year-To-Date**	**7.38**	**(35)**	**9.85**	**(30)**	**49.54**	**(30)**	**1,887.0**	**(52)**

Gas Utilities--Summary Table

	Period	ROR %	(# Cases)	ROE %	(# Cases)	Eq. as % Cap. Struc.	(# Cases)	Amt. $ Mil.	(# Cases)
2001	Full Year	8.51	(6)	10.95	(7)	43.96	(5)	114.0	(11)
2002	Full Year	8.80	(20)	11.03	(21)	48.29	(18)	303.6	(26)
2003	Full Year	8.75	(22)	10.99	(25)	49.93	(22)	260.1	(30)
2004	Full Year	8.34	(21)	10.59	(20)	45.90	(20)	303.5	(31)
2005	Full Year	8.25	(29)	10.46	(26)	48.66	(24)	458.4	(34)
2006	Full Year	8.51	(16)	10.43	(16)	47.43	(16)	444.0	(25)
2007	Full Year	8.12	(32)	10.24	(37)	48.37	(30)	813.4	(48)
2008	Full Year	8.48	(30)	10.37	(30)	50.47	(30)	884.8	(41)
2009	Full Year	8.15	(28)	10.19	(29)	48.72	(28)	475.0	(37)
2010	Full Year	7.95	(38)	10.15	(39)	48.56	(38)	816.7	(50)
2011	Full Year	8.09	(18)	9.92	(16)	52.49	(14)	436.3	(31)
2012	Full Year	7.98	(30)	9.94	(35)	51.13	(32)	263.9	(41)
2013	Full Year	7.39	(20)	9.68	(21)	50.60	(20)	494.9	(38)
	1st Quarter	7.67	(6)	9.54	(6)	51.14	(6)	22.2	(9)
	2nd Quarter	7.74	(7)	9.84	(8)	52.12	(8)	62.2	(12)
	3rd Quarter	7.24	(7)	9.45	(6)	48.68	(7)	329.1	(11)
	4th Quarter	7.97	(7)	10.28	(6)	52.35	(7)	115.5	(16)
2014	**Full Year**	**7.65**	**(27)**	**9.78**	**(26)**	**51.11**	**(28)**	**529.0**	**(48)**
	1st Quarter	6.41	(2)	9.47	(3)	50.41	(2)	168.7	(9)
	2nd Quarter	7.29	(3)	9.43	(3)	50.71	(3)	34.9	(8)
	3rd Quarter	7.35	(1)	9.75	(1)	42.01	(1)	103.9	(8)
	4th Quarter	7.54	(10)	9.68	(9)	50.40	(10)	180.1	(13)
2015	**Year-To-Date**	**7.34**	**(16)**	**9.60**	**(16)**	**49.93**	**(16)**	**487.6**	**(38)**

ELECTRIC UTILITY DECISIONS

Date	Company (State)	ROR %	ROE %	Common Eq. as % Cap. Str.	Test Year & Rate Base	Amt. $ Mil.
1/23/15	PacifiCorp (WY)	7.41	9.50	51.43	6/15-A	20.2
2/4/15	Monongahela Power/Potomac Ed. (WV)	--	--	--	12/13	124.3 (B,1)
2/18/15	Virginia Electric and Power (VA)	7.88	11.00	52.03	3/16-A	36.9 (LIR,B,2)
2/24/15	Public Service Co. of Colorado (CO)	7.55	9.83	56.00	12/13-YE	-39.4 (I,B)
3/2/15	Black Hills Power (SD)	7.76	--	--	9/13-A	6.9 (I,B)
3/12/15	Virginia Electric and Power (VA)	8.40	12.00	52.03	3/16-A	-6.4 (LIR,B,3)
3/12/15	Virginia Electric and Power (VA)	7.88	11.00	52.03	3/16-A	11.4 (LIR,B,4)
3/12/15	Virginia Electric and Power (VA)	7.88	11.00	52.03	3/16-A	5.8 (LIR,B,5)
3/18/15	Jersey Central Power & Light (NJ)	8.01	9.75	50.00 (Hy)	12/11-YE	-115.0 (D)
3/25/15	PacifiCorp (WA)	7.30	9.50	49.10 (Hy)	12/13-A	9.6
3/26/15	Northern States Power-Minnesota (MN)	7.37	9.72	52.50	12/14-A	149.4 (R,I,Z)
2015	***1ST QUARTER: AVERAGES/TOTAL***	**7.74**	**10.37**	**51.91**		**203.7**
	OBSERVATIONS	**10**	**9**	**9**		**11**
4/9/15	Metropolitan Edison (PA)	--	--	--	4/16	105.7 (D,B)
4/9/15	Pennsylvania Electric (PA)	--	--	--	4/16	107.8 (D,B)
4/9/15	Pennsylvania Power (PA)	--	--	--	4/16	25.5 (D,B)
4/9/15	West Penn Power (PA)	--	--	--	4/16	95.2 (D,B)
4/14/15	Public Service Oklahoma (OK)	7.63	--	--	7/13-YE	-4.8 (I,B)
4/21/15	Virginia Electric & Power (VA)	7.88	11.00	52.03	8/16-A	60.5 (LIR,Z,B,6)
4/23/15	Wisconsin Public Service (MI)	6.01	10.20	--	12/15	4.0 (Z,B)
4/29/15	Union Electric (MO)	7.60	9.53	51.76	3/14-YE	121.5
5/1/15	Cross Texas Transmission (TX)	6.11	9.60	40.00	9/14-YE	30.9 (B,D,7)
5/26/15	Appalachian Pow./Wheeling Pow. (WV)	7.38	9.75	47.16	12/13-A	123.5
6/15/15	Northern States Power-Minnesota (SD)	7.22	--	--	12/13-A	15.2 (I,B)
6/17/15	Central Hudson Gas & Electric (NY)	6.62	9.00	48.00	6/16-A	15.3 (D,B,8)
6/17/15	Consolidated Edison of New York (NY)	6.91	9.00	48.00	12/16-A	0.00 (D,B,9)
6/22/15	Kentucky Power (KY)	--	--	--	9/14	-23.0 (B)
6/24/15	Empire District Electric (MO)	--	--	--	4/14	17.1 (B)
6/30/15	Kentucky Utilities (KY)	--	--	--	6/16	125.0 (B)
6/30/15	Louisville Gas & Electric (KY)	--	--	--	6/16	0.0 (B)
2015	***2ND QUARTER: AVERAGES/TOTAL***	**7.04**	**9.73**	**47.83**		**819.4**
	OBSERVATIONS	**9**	**7**	**6**		**17**
7/7/15	Mississippi Power (MS)	--	--	--	--	0.0 (LIR,10)
9/2/15	Kansas City Power & Light (MO)	7.53	9.50	50.09	3/14-YE	89.7 (11)
9/10/15	Kansas City Power & Light (KS)	7.44	9.30	50.48	6/14-YE	40.1 (11)
9/23/15	South Carolina Electric & Gas (SC)	8.57	--	52.66	6/15-YE	64.5 (LIR,12)
9/24/15	Westar Energy (KS)	--	--	--	9/14	185.3 (B)
2015	***3RD QUARTER: AVERAGES/TOTAL***	**7.85**	**9.40**	**51.08**		**379.6**
	OBSERVATIONS	**3**	**2**	**3**		**5**

ELECTRIC UTILITY DECISIONS (continued)

Date	Company (State)	ROR %	ROE %	Common Eq. as % Cap. Str.	Test Year & Rate Base	Amt. $ Mil.
10/15/15	Orange & Rockland Utilities (NY)	7.10	9.00	48.00	10/16-A	9.3 (B,D,13)
10/29/15	NorthWestern Corp. (SD)	7.24	--	--	9/14-A	40.7 (I,B)
11/5/15	Southern California Edison (CA)	--	--	--	12/15-A	-450.4 (Z)
11/19/15	Consumers Energy (MI)	6.18	10.30	41.50 *	5/16-A	126.4 (I,Z)
11/19/15	PPL Electric Utilities (PA)	--	--	--	12/16	124.0 (D,B)
11/19/15	Wisconsin Public Service (WI)	8.24	10.00	50.47	12/16-A	-7.9
11/23/15	Virginia Electric and Power (VA)	--	--	--	12/14	0.0 (14)
12/3/15	Mississippi Power (MS)	6.68	9.23	49.73	5/16-A	126.1 (LIR,I,B)
12/3/15	Northern States Power-Wisconsin (WI)	7.81	10.00	52.49	12/16-A	7.6
12/9/15	Ameren Illinois (IL)	7.65	9.14	50.00	12/14-YE	95.1 (D)
12/9/15	Commonwealth Edison (IL)	7.05	9.14	46.25	12/14-YE	-65.5 (D)
12/11/15	DTE Electric (MI)	5.70	10.30	38.03 *	6/16-A	238.2 (I)
12/15/15	Portland General Electric (OR)	7.51	9.60	50.00	12/16-A	70.4 (B,15)
12/17/15	PECO Energy (PA)	--	--	--	12/16	127.0 (D,B)
12/17/15	Southwestern Public Service (TX)	7.88	9.70	51.00 (Hy)	6/14-YE	-4.0
12/18/15	Avista Corp. (ID)	7.42	9.50	50.00	12/14-A	1.7 (B)
12/22/15	Georgia Power (GA)	--	--	--	12/16	19.1 (LIR,16)
12/23/15	PacifiCorp (ID)	--	--	--	--	10.2 (LIR,17)
12/30/15	PacifiCorp (WY)	7.40	9.50	51.44	12/15-A	16.3 (R)
2015	***4TH QUARTER: AVERAGES/TOTAL***	**7.22**	**9.62**	**48.24**		**484.3**
	OBSERVATIONS	**13**	**12**	**12**		**19**
2015	***YEAR-TO-DATE: AVERAGES/TOTAL***	**7.38**	**9.85**	**49.54**		**1,887.0**
	OBSERVATIONS	**35**	**30**	**30**		**52**

GAS UTILITY DECISIONS

Date	Company (State)	ROR %	ROE %	Common Eq. as % Cap. Str.	Test Year & Rate Base	Amt. $ Mil.
1/13/15	Consumers Energy (MI)	--	10.30	--	12/15	45.0 (I,B)
1/14/15	Indiana Gas (IN)	--	--	--	6/14-YE	5.7 (LIR,18)
1/14/15	Southern Indiana Gas & Electric (IN)	--	--	--	6/14-YE	1.5 (LIR,18)
1/21/15	North Shore Gas (IL)	6.26	9.05	50.48	12/15-A	3.5 (R)
1/21/15	Peoples Gas Light & Coke (IL)	6.56	9.05	50.33	12/15-A	71.1 (R)
1/26/15	Piedmont Natural Gas (NC)	--	--	--	10/14	26.6 (LIR,19)
1/27/15	Atmos Energy (KS)	--	--	--	9/14-YE	0.3 (LIR,20)
1/27/15	Northern States Power-Minnesota (MN)	--	--	--	12/15	14.7 (LIR,21)
1/28/15	Northern Indiana Public Service (IN)	--	--	--	6/14-YE	0.3 (LIR,22)
2015	***1ST QUARTER: AVERAGES/TOTAL***	**6.41**	**9.47**	**50.41**		**168.7**
	OBSERVATIONS	**2**	**3**	**2**		**9**
4/7/15	Delta Natural Gas (KY)	--	--	--	12/14-YE	1.3 (LIR,23)
4/9/15	Avista Corporation (OR)	7.52	9.50	51.00	12/15-A	5.3 (B)
5/11/15	Atmos Energy (TN)	7.73	9.80	53.13	5/16-A	0.7 (B)
5/13/15	Missouri Gas Energy (MO)	--	--	--	2/15-YE	2.8 (LIR,24)
5/20/15	Laclede Gas (MO)	--	--	--	2/15-YE	5.5 (LIR,24)
6/17/15	Central Hudson Gas & Electric (NY)	6.62	9.00	48.00	6/16-A	1.8 (B,25)
6/26/15	Liberty Utilities EnergyNorth (NH)	--	--	--	3/14	10.5 (I,B,26)
6/30/15	Louisville Gas & Electric (KY)	--	--	--	6/16	7.0 (B)
2015	***2ND QUARTER: AVERAGES/TOTAL***	**7.29**	**9.43**	**50.71**		**34.9**
	OBSERVATIONS	**3**	**3**	**3**		**8**
7/22/15	Indiana Gas (IN)	--	--	--	12/14-YE	5.5 (LIR,18)
7/22/15	Southern Indiana Gas & Electric (IN)	--	--	--	12/14-YE	3.2 (LIR,18)
7/28/15	Atmos Energy (TX)	--	--	--	12/14-YE	52.6 (I,B,27)
8/21/15	Columbia Gas of Virginia (VA)	7.35	9.75	42.01	12/13	25.2 (I,B)
8/25/15	CenterPoint Energy Resources (TX)	--	--	--	9/14	4.9 (B)
9/16/15	Liberty Utilities (Midstates N.G.) (MO)	--	--	--	5/15	0.3 (LIR,28)
9/23/15	Atmos Energy (KY)	--	--	--	9/16-YE	3.8 (LIR,23)
9/29/15	ENSTAR Natural Gas (AK)	--	--	--	12/14	8.4 (I,B,Z)
2015	***3RD QUARTER: AVERAGES/TOTAL***	**7.35**	**9.75**	**42.01**		**103.9**
	OBSERVATIONS	**1**	**1**	**1**		**8**

GAS UTILITY DECISIONS (continued)

Date	Company (State)	ROR %	ROE %	Common Eq. as % Cap. Str.	Test Year & Rate Base	Amt. $ Mil.
10/7/15	Bay State Gas (MA)	7.75	9.55	53.54	12/14-YE	32.8 (B,29)
10/13/15	Mountaineer Gas (WV)	7.96 (E)	9.75	45.50 (E)	9/14-A	7.7 (B,30)
10/15/15	Orange and Rockland Utilities (NY)	7.10	9.00	48.00	10/16-A	27.5 (B,31)
10/30/15	NSTAR Gas (MA)	7.72	9.80	52.10	12/13-YE	15.8
11/4/15	CenterPoint Energy Resources (OK)	8.64	--	49.86	12/14-YE	0.9 (32)
11/5/15	Kansas Gas Service (KS)	--	--	--	6/15-YE	2.5 (20)
11/19/15	Wisconsin Public Service (WI)	7.80	10.00	50.47	12/16-A	-6.2
12/1/15	Piedmont Natural Gas (NC)	--	--	--	9/15	16.5 (LIR,19)
12/3/15	Columbia Gas of Pennsylvania (PA)	--	--	--	12/16	28.0 (B)
12/3/15	Northern States Power-Wisconsin (WI)	7.81	10.00	52.49	12/16-A	4.2
12/9/15	Ameren Illinois (IL)	7.65 (B)	9.60 (B)	50.00 (B)	12/16-A	44.5
12/11/15	Michigan Gas Utilities (MI)	5.51	9.90	52.00	12/16	3.4 (B)
12/18/15	Avista Corp. (ID)	7.42	9.50	50.00	12/14-A	2.5 (B)
2015	***4TH QUARTER: AVERAGES/TOTAL***	**7.54**	**9.68**	**50.40**		**180.1**
	OBSERVATIONS	**10**	**9**	**10**		**13**
2015	***YEAR-TO-DATE: AVERAGES/TOTAL***	**7.34**	**9.60**	**49.93**		**487.6**
	OBSERVATIONS	**16**	**16**	**16**		**38**

FOOTNOTES

A- Average
B- Order followed stipulation or settlement by the parties. Decision particulars not necessarily precedent-setting or specifically adopted by the regulatory body.
COC- Case involved only the determination of cost-of-capital parameters.
CWIP- Construction work in progress
D- Applies to electric delivery only
DCt Date certain rate base valuation
E- Estimated
F- Return on fair value rate base
Hy- Hypothetical capital structure utilized
I- Interim rates implemented prior to the issuance of final order, normally under bond and subject to refund.
LIR Limited-issue rider proceeding
M- "Make-whole" rate change based on return on equity or overall return authorized in previous case.
R- Revised
Te- Temporary rates implemented prior to the issuance of final order.
U- Double leverage capital structure utilized.
W- Case withdrawn
YE- Year-end
Z- Rate change implemented in multiple steps.
* Capital structure includes cost-free items or tax credit balances at the overall rate of return.

(1) Consolidated rate proceeding for Monongahela Power and Potomac Edison, whose rate schedules were combined.
(2) Increase authorized through a surcharge, Rider W, which reflects in rates the investment in the Warren County Power Station.
(3) This proceeding determines the revenue requirement for Rider B, which is the mechanism through which the company recovers costs associated with its plan to convert the Altavista, Hopewell, and Southampton Power Stations to burn biomass fuels.
(4) Represents rate increase associated with the company's Rider R proceeding, which is the mechanism through which the company recovers the investment in the Bear Garden generating facility.
(5) This proceeding determines the revenue requirement for Rider S, which recognizes in rates the company's investment in the Virginia City Hybrid Energy Center.

FOOTNOTES (continued)

(6) This proceeding determines the revenue requirement for Rider BW, which recognizes in rates the company's investment in the Brunswick Generating Station. A $10.1 million increase became effective Sept. 1, 2015, and an incremental $50.5 million is to be implemented May 1, 2016.
(7) Indicated rate increase is for base rates and reflects the transfer to base rates of $30.1 million that was being collected through the company's interim transmission cost of service adjustment mechanism. The net overall rate increase is $0.8 million.
(8) The approved final Joint Proposal provides for the company to implement a $15.3 million electric rate increase, effective July 1, 2015, based on a 9% return on equity (48% of capital) and a 6.62% overall return, a $16 million increase on July 1, 2016, based on the same return parameters, and a $14.1 million increase on July 1, 2017, that reflects a 9% return on equity (48% of capital) and a 6.58% overall return.
(9) Joint Proposal adopted that extends the company's existing rate plan by one year through 12/31/16. Rates were not changed.
(10) On 7/7/15, the PSC issued an order on remand directing the company to cease collecting CWIP-related rate increases effective 7/20/15, and to submit a refund plan. This PSC action is the result of a 2/12/15 Mississippi Supreme Court decision that reversed and remanded the PSC's 3/5/13 decision in the proceeding that had authorized the company a two-step $156 million rate increase related to the Kemper generation plant.
(11) Approved settlements did not address rate-of-return issues.
(12) Case involves company's request for a cash return on incremental V.C. Summer Units 2 and 3 CWIP and incorporates the 11% ROE that was initially authorized in 2009 for use in Summer CWIP-related proceedings.
(13) The approved joint settlement provides for a $9.3 million electric rate increase on 11/1/15, and an $8.8 million increase on 11/1/16. The approved rate changes incorporate a 9% return on equity (48% of capital) and overall returns of 7.1% (in rate year one) and 7.06% (in rate year two).
(14) Proceeding reviewed earnings levels for the 2013-2014 biennium versus the 10% ROE authorized in the previous review. By law, no prospective rate change was permissible in this case. The Commission calculated the company had earned a 10.89% ROE, and ordered $19.7 million of refunds.
(15) A $14.7 million base rate reduction became effective 1/1/16. An $85.1 million base rate increase is to be implemented in mid-2016, provided the Carty generation station achieves commercial operation by 7/31/16.
(16) Case represents recovery of a cash return on 2016 CWIP and a preliminary true-up of the cash return on 2015 CWIP for Plant Vogtle Units 3 and 4 under the company's legislatively-enabled nuclear construction cost recovery tariff.
(17) Limited-issue proceeding to reflect updated net power costs.
(18) Proceeding to establish the rates to be charged to customers under the company's "compliance and system improvement adjustment" mechanism.
(19) Case involves the company's Integrity Management Rider.
(20) Case involves the company's gas system reliability surcharge rider.
(21) Case represents the company's first filing under its Gas Utility Infrastructure Cost Rider.
(22) This is the initial proceeding to establish the rates to be charged to customers under the company's transmission, distribution, and storage system improvement charge rate adjustment mechanism.
(23) Case represents an annual update to the company's pipe replacement program rider.
(24) Case represents an update to the company's semi-annual infrastructure system replacement surcharge rider.
(25) The approved final Joint Proposal provides for the company to implement a $1.8 million gas rate increase, effective July 1, 2015, based on a 9% return on equity (48% of capital) and a 6.62% overall return, a $4.6 million increase on July 1, 2016, based on the same return parameters, and a $4.4 million increase on July 1, 2017, that reflects a 9% return on equity (48% of capital) and a 6.58% overall return.
(26) Indicated $10.5 million rate increase excludes a $1.9 million "step" increase for capital additions that was effective July 1, 2015.
(27) Rate change ratified by cities in Atmos' Mid-Tex Division.
(28) Case represents annual update to company's infrastructure system replacement surcharge rider.
(29) Two step rate increase authorized. A $32.8 million first-step increase was implemented on 11/1/15, and an incremental second-step incremental increase of up to $3.6 million to become effective on 11/1/16.
(30) Settlement did not specify the equity ratio or ROR; in a demonstration filing, the PSC Staff calculated a 45.5% equity ratio and 7.96% ROR.
(31) The approved settlement provides for a three-year gas rate plan under which gas rates are to increase $27.5 million effective 11/1/15, $4.4 million effective Nov. 1, 2016, and $6.7 million effective Nov. 1, 2017. The approved rate changes incorporate a 9% return on equity (48% of capital) and overall returns of 7.1% (in rate year one) and 7.06% (in rate years two and three).
(32) Case involves the company's performance based ratemaking mechanism.

Dennis Sperduto

Exhibit DCP-1
Schedule 11

PROXY COMPANIES
BASIS FOR SELECTION

Company	Market Capitalization ($ millions)	Percent Reg Electric Revenues	Common Equity Ratio	Value Line Safety	S&P Stock Ranking	S&P Bond Rating	Moody's Bond Rating
OGE Energy	$5,800,000	100%	54%	1	A-	BBB+	A3
Parcell Proxy Group							
ALLETE	$2,400,000	88%	56%	2	A-	A-	A3
Alliant Energy	$6,500,000	81%	48%	2	B+	A-	A2/A3
Ameren Corp	$9,200,000	81%	52%	2	B	BBB+/BBB	Baa1
Avista Corp	$2,000,000	68%	49%	2	A-	A-	Baa1
El Paso Electric	$1,400,000	100%	47%	2	B	BBB+	Baa1
IDACORP	$2,900,000	100%	55%	2	A	A-	A3
Pinnacle West Capital	$6,600,000	100%	59%	1	B+	BBB	A3/Baa1
SCANA Corp	$8,000,000	53%	47%	2	A	BBB+	Baa1/Baa2
Westar Energy	$4,500,000	100%	50%	2	A-	A-	A3/Baa1
			51%				
Hevert Proxy Group							
ALLETE, Inc.	$2,400,000	88%	56%	2	A-	A-	A3
Alliant Energy Corporation	$6,500,000	81%	48%	2	B+	A-	A2/A3
Ameren Corporation	$ 9,200,000	81%	52%	2	B	BBB+/BBB	Baa1
American Electric Power	$26,000,000	82%	51%	2	A-	BBB/BBB-	Baa1
Avista Corporation	$ 2,000,000	68%	49%	2	A-	A-	Baa1
CMS Energy Corporation	$ 8,800,000	62%	31%	2	B	BBB+/BBB	A3/Baa1
Dominion Resources	$43,000,000	60%	35%	2	B	A-	A3/Baa1
DTE Energy Corporation	$13,000,000	43%	50%	2	A-	A-/BBB+	A2/A3
Empire District Electric Company	$975,000	91%	49%	2	B+	A-	Baa1
Great Plains Energy Inc.	$ 3,800,000	100%	51%	3	B	BBB	Baa2
IDACORP, Inc.	$ 2,900,000	100%	55%	2	A	A-	A3
NorthWestern Corporation	$ 2,400,000	68%	47%	3	A+	NR	A3
Otter Tail Corporation	$ 975,000	51%	54%	3	B	BBB-	Baa2
Pinnacle West Capital Corp.	$ 6,600,000	100%	59%	1	B+	BBB	A3/Baa1
PNM Resources, Inc.	$ 2,000,000	100%	51%	3	B	BBB	Baa2
Portland General Electric Co.	$ 2,700,000	100%	47%	2	NR	A-	A3
SCANA Corporation	$ 8,000,000	53%	47%	2	A-	BBB+	Baa1/Baa2
Westar Energy, Inc.	$ 4,500,000	100%	50%	2	A-	A-	A3/Baa1
Xcel Energy Inc.	$17,000,000	81%	47%	1	A-	A-	A3
			49%				

Sources: AUS Utility Reports, Value Line.

PROXY COMPANIES
DIVIDEND YIELD

COMPANY	Qtr DPS	December 2015 -- February 2016 DPS	HIGH	LOW	AVERAGE	YIELD
Parcell Proxy Group						
ALLETE	$0.520	$2.08	$54.96	$47.93	$51.45	4.0%
Alliant Energy	$0.588	$2.35	$70.25	$58.13	$64.19	3.7%
Ameren Corp	$0.425	$1.70	$48.22	$41.33	$44.78	3.8%
Avista Corp	$0.343	$1.37	$39.30	$33.00	$36.15	3.8%
El Paso Electric	$0.295	$1.18	$43.40	$35.32	$39.36	3.0%
IDACORP	$0.510	$2.04	$73.82	$65.03	$69.43	2.9%
OGE Energy	$0.275	$1.10	$27.81	$23.37	$25.59	4.3%
Pinnacle West Capital	$0.625	$2.50	$71.40	$60.70	$66.05	3.8%
SCANA Corp	$0.545	$2.18	$66.90	$55.50	$61.20	3.6%
Westar Energy	$0.360	$1.44	$46.67	$40.00	$43.34	3.3%
Average						**3.6%**
Hevert Proxy Group						
ALLETE, Inc.	$0.520	$2.08	$54.96	$47.93	$51.45	4.0%
Alliant Energy Corporation	$0.588	$2.35	$70.25	$58.13	$64.19	3.7%
Ameren Corporation	$0.425	$1.70	$48.22	$41.33	$44.78	3.8%
American Electric Power	$0.560	$2.24	$63.90	$54.08	$58.99	3.8%
Avista Corporation	$0.343	$1.37	$39.30	$33.00	$36.15	3.8%
CMS Energy Corporation	$0.310	$1.24	$40.79	$34.18	$37.49	3.3%
Dominion Resources	$0.700	$2.80	$72.20	$64.54	$68.37	4.1%
DTE Energy Corporation	$0.730	$2.92	$87.84	$77.35	$82.60	3.5%
Empire District Electric Company	$0.260	$1.04	$33.75	$22.18	$27.97	3.7%
Great Plains Energy Inc.	$0.263	$1.05	$29.88	$25.57	$27.73	3.8%
IDACORP, Inc.	$0.510	$2.04	$73.82	$65.03	$69.43	2.9%
NorthWestern Corporation	$0.480	$1.92	$60.76	$51.95	$56.36	3.4%
Otter Tail Corporation	$0.313	$1.25	$29.39	$25.20	$27.30	4.6%
Pinnacle West Capital Corp.	$0.625	$2.50	$71.40	$60.70	$66.05	3.8%
PNM Resources, Inc.	$0.220	$0.88	$33.34	$27.90	$30.62	2.9%
Portland General Electric Co.	$0.300	$1.20	$40.48	$35.04	$37.76	3.2%
SCANA Corporation	$0.545	$2.18	$66.90	$55.50	$61.20	3.6%
Westar Energy, Inc.	$0.360	$1.44	$46.67	$40.00	$43.34	3.3%
Xcel Energy Inc.	$0.320	$1.28	$40.42	$34.33	$37.38	3.4%
Average						**3.6%**

Source: Yahoo! Finance.

PROXY COMPANIES
RETENTION GROWTH RATES

COMPANY	2011	2012	2013	2014	2015	Average	2016	2017	2018-'20	Average
Parcell Proxy Group										
ALLETE	2.9%	2.3%	2.2%	2.5%	4.0%	2.8%	3.0%		3.5%	3.3%
Alliant Energy	3.3%	3.9%	4.9%	4.3%	4.5%	4.2%	4.5%		4.5%	4.5%
Ameren Corp	2.8%	3.0%	1.9%	2.9%	3.0%	2.7%	3.5%		4.5%	4.0%
Avista Corp	3.1%	0.8%	2.9%	2.4%	2.5%	2.3%	2.5%		2.5%	2.5%
El Paso Electric	10.0%	6.3%	4.9%	4.8%	3.5%	5.9%	3.5%		5.0%	4.3%
IDACORP	6.5%	5.7%	5.6%	5.4%	4.5%	5.5%	4.0%		3.5%	3.8%
OGE Energy	7.7%	7.2%	7.3%	6.5%	4.0%	6.5%	4.0%		3.0%	3.5%
Pinnacle West Capital	2.8%	4.1%	4.1%	3.5%	3.5%	3.6%	3.5%		3.5%	3.5%
SCANA Corp	3.6%	3.9%	4.1%	4.9%	4.5%	4.2%	4.5%	4.5%	5.0%	4.7%
Westar Energy	2.7%	4.0%	4.2%	4.3%	4.5%	3.9%	4.5%		5.0%	4.8%
Average						**4.2%**				**3.9%**
Hevert Proxy Group										
ALLETE, Inc.	2.9%	2.3%	2.2%	2.5%	4.0%	2.8%	3.0%		3.5%	3.3%
Alliant Energy Corporation	3.3%	3.9%	4.9%	4.3%	4.5%	4.2%	4.5%		4.5%	4.5%
Ameren Corporation	2.8%	3.0%	1.9%	2.9%	3.0%	2.7%	3.5%		4.5%	4.0%
American Electric Power	4.2%	3.5%	3.7%	3.8%	4.5%	3.9%	4.0%		4.0%	4.0%
Avista Corporation	3.1%	0.8%	2.9%	2.4%	2.5%	2.3%	2.5%		2.5%	2.5%
CMS Energy Corporation	5.6%	5.0%	5.2%	5.0%	5.5%	5.3%	5.5%		5.0%	5.3%
Dominion Resources	4.0%	3.5%	4.2%	3.3%	2.9%	3.6%	3.5%	3.0%	5.0%	3.8%
DTE Energy Corporation	3.4%	3.5%	2.7%	5.2%	3.5%	3.7%	3.5%		4.0%	3.8%
Empire District Electric Company	4.1%	1.9%	2.7%	2.9%	2.0%	2.7%	2.0%		3.0%	2.5%
Great Plains Energy Inc.	2.0%	2.2%	3.2%	2.7%	1.5%	2.3%	3.0%		3.0%	3.0%
IDACORP, Inc.	6.5%	5.7%	5.6%	5.4%	4.5%	5.5%	4.0%		3.5%	3.8%
NorthWestern Corporation	4.7%	3.2%	3.5%	3.8%	3.0%	3.6%	4.0%		4.0%	4.0%
Otter Tail Corporation	0.0%	0.0%	1.2%	2.2%	2.0%	1.1%	3.0%		5.0%	4.0%
Pinnacle West Capital Corp.	2.8%	4.1%	4.1%	3.5%	3.5%	3.6%	3.5%		3.5%	3.5%
PNM Resources, Inc.	3.3%	3.8%	3.7%	3.2%	3.5%	3.5%	3.5%		3.5%	3.5%
Portland General Electric Co.	4.1%	3.5%	2.9%	4.6%	3.5%	3.7%	4.5%		4.0%	4.3%
SCANA Corporation	3.6%	3.9%	4.1%	4.9%	4.5%	4.2%	4.5%	4.5%	5.0%	4.7%
Westar Energy, Inc.	2.7%	4.0%	4.2%	4.3%	4.5%	3.9%	4.5%		5.0%	4.8%
Xcel Energy Inc.	4.3%	4.7%	4.5%	4.5%	4.0%	4.4%	4.0%		4.0%	4.0%
Average						**3.5%**				**3.8%**

Source: Value Line Investment Survey.

PROXY COMPANIES
PER SHARE GROWTH RATES

COMPANY	5-Year Historic Growth Rates				Est'd '12-'14 to '18-'20 Growth Rates			
	EPS	DPS	BVPS	Average	EPS	DPS	BVPS	Average
Parcell Proxy Group								
ALLETE	1.0%	2.0%	5.0%	2.7%	6.5%	3.0%	5.0%	4.8%
Alliant Energy	6.5%	6.5%	3.5%	5.5%	6.0%	4.5%	4.0%	4.8%
Ameren Corp	-4.5%	-6.0%	-3.5%	neg	7.0%	3.5%	3.5%	4.7%
Avista Corp	6.5%	11.5%	4.0%	7.3%	5.0%	4.0%	3.5%	4.2%
El Paso Electric	6.5%		8.0%	7.3%	3.5%	5.0%	4.5%	4.3%
IDACORP	10.0%	5.5%	6.0%	7.2%	1.0%	6.0%	4.0%	3.7%
OGE Energy	8.0%	4.5%	9.0%	7.2%	3.0%	10.0%	4.0%	5.7%
Pinnacle West Capital	8.0%	3.0%	2.0%	4.3%	4.0%	3.5%	3.5%	3.7%
SCANA Corp	4.0%	2.0%	5.0%	3.7%	4.5%	3.5%	5.5%	4.5%
Westar Energy	9.0%	3.5%	3.5%	5.3%	6.0%	3.0%	5.0%	4.7%
Average				**5.6%**				**4.5%**
Hevert Proxy Group								
ALLETE, Inc.	1.0%	2.0%	5.0%	2.7%	6.5%	3.0%	5.0%	4.8%
Alliant Energy Corporation	6.5%	6.5%	3.5%	5.5%	6.0%	4.5%	4.0%	4.8%
Ameren Corporation	-4.5%	-6.0%	-3.5%	neg	7.0%	3.5%	3.5%	4.7%
American Electric Power	1.5%	4.0%	4.5%	3.3%	5.0%	5.0%	4.5%	4.8%
Avista Corporation	6.5%	11.5%	4.0%	7.3%	5.0%	4.0%	3.5%	4.2%
CMS Energy Corporation	12.0%	23.5%	4.0%	13.2%	5.5%	6.5%	5.5%	5.8%
Dominion Resources	2.5%	7.0%	2.0%	3.8%	8.0%	8.0%	5.0%	7.0%
DTE Energy Corporation	8.0%	4.0%	4.0%	5.3%	5.0%	5.5%	4.5%	5.0%
Empire District Electric Company	5.0%	-4.5%	2.0%	0.8%	3.0%	2.0%	2.5%	2.5%
Great Plains Energy Inc.	2.5%	-8.5%	2.5%	neg	5.0%	6.0%	3.0%	4.7%
IDACORP, Inc.	10.0%	5.5%	6.0%	7.2%	1.0%	6.0%	4.0%	3.7%
NorthWestern Corporation	8.0%	3.0%	5.5%	5.5%	6.5%	6.5%	5.5%	6.2%
Otter Tail Corporation	2.0%	0.0%	-4.5%	neg	9.0%	1.5%	3.5%	4.7%
Pinnacle West Capital Corp.	8.0%	3.0%	2.0%	4.3%	4.0%	3.5%	3.5%	3.7%
PNM Resources, Inc.	23.5%		1.0%	12.3%	9.0%	10.0%	3.5%	7.5%
Portland General Electric Co.	3.0%	2.5%	2.0%	2.5%	6.0%	5.5%	4.0%	5.2%
SCANA Corporation	4.0%	2.0%	5.0%	3.7%	4.5%	3.5%	5.5%	4.5%
Westar Energy, Inc.	9.0%	3.5%	3.5%	5.3%	6.0%	3.0%	5.0%	4.7%
Xcel Energy Inc.	6.0%	3.5%	4.5%	4.7%	4.5%	6.0%	4.0%	4.8%
Average				**5.5%**				**4.9%**

Source: Value Line Investment Survey.

PROXY COMPANIES
DCF COST RATES

COMPANY	ADJUSTED YIELD	HISTORIC RETENTION GROWTH	PROSPECTIVE RETENTION GROWTH	HISTORIC PER SHARE GROWTH	PROSPECTIVE PER SHARE GROWTH	FIRST CALL EPS GROWTH	AVERAGE GROWTH	DCF RATES
Parcell Proxy Group								
ALLETE	4.1%	2.8%	3.3%	2.7%	4.8%	6.0%	3.9%	8.0%
Alliant Energy	3.8%	4.2%	4.5%	5.5%	4.8%	6.7%	5.1%	8.9%
Ameren Corp	3.9%	2.7%	4.0%	neg	4.7%	5.6%	4.2%	8.1%
Avista Corp	3.9%	2.3%	2.5%	7.3%	4.2%	5.0%	4.3%	8.1%
El Paso Electric	3.1%	5.9%	4.3%	7.3%	4.3%	7.0%	5.7%	8.8%
IDACORP	3.0%	5.5%	3.8%	7.2%	3.7%	4.0%	4.8%	7.8%
OGE Energy	4.4%	6.5%	3.5%	7.2%	5.7%	1.8%	4.9%	9.3%
Pinnacle West Capital	3.9%	3.6%	3.5%	4.3%	3.7%	4.1%	3.8%	7.7%
SCANA Corp	3.6%	4.2%	4.7%	3.7%	4.5%	5.4%	4.5%	8.1%
Westar Energy	3.4%	3.9%	4.8%	5.3%	4.7%	5.3%	4.8%	8.2%
Mean	3.7%	4.2%	3.9%	5.6%	4.5%	5.1%	4.6%	**8.3%**
Median	3.8%	4.1%	3.9%	5.5%	4.6%	5.3%	4.6%	**8.1%**
Composite - Mean		7.9%	**7.6%**	**9.3%**	8.2%	8.8%	8.3%	
Composite - Median		7.9%	**7.7%**	**9.3%**	8.4%	9.1%	8.4%	
Hevert Proxy Group								
ALLETE, Inc.	4.1%	2.8%	3.3%	2.7%	4.8%	6.0%	3.9%	8.0%
Alliant Energy Corporation	3.8%	4.2%	4.5%	5.5%	4.8%	6.7%	5.1%	8.9%
Ameren Corporation	3.9%	2.7%	4.0%	neg	4.7%	5.6%	4.2%	8.1%
American Electric Power	3.9%	3.9%	4.0%	3.3%	4.8%	4.6%	4.1%	8.0%
Avista Corporation	3.9%	2.3%	2.5%	7.3%	4.2%	5.0%	4.3%	8.1%
CMS Energy Corporation	3.4%	5.3%	5.3%	13.2%	5.8%	7.2%	7.3%	10.8%
Dominion Resources	4.2%	3.6%	3.8%	3.8%	7.0%	6.5%	4.9%	9.1%
DTE Energy Corporation	3.6%	3.7%	3.8%	5.3%	5.0%	5.5%	4.6%	8.3%
Empire District Electric Company	3.8%	2.7%	2.5%	0.8%	2.5%	5.0%	2.7%	6.5%
Great Plains Energy Inc.	3.9%	2.3%	3.0%	neg	4.7%	6.9%	4.2%	8.1%
IDACORP, Inc.	3.0%	5.5%	3.8%	7.2%	3.7%	4.0%	4.8%	7.8%
NorthWestern Corporation	3.5%	3.6%	4.0%	5.5%	6.2%	5.6%	5.0%	8.5%
Otter Tail Corporation	4.7%	1.1%	4.0%	neg	4.7%	6.0%	3.9%	8.6%
Pinnacle West Capital Corp.	3.9%	3.6%	3.5%	4.3%	3.7%	4.1%	3.8%	7.7%
PNM Resources, Inc.	3.0%	3.5%	3.5%	12.3%	7.5%	9.3%	7.2%	10.2%
Portland General Electric Co.	3.2%	3.7%	4.3%	2.5%	5.2%	5.7%	4.3%	7.5%
SCANA Corporation	3.6%	4.2%	4.7%	3.7%	4.5%	5.4%	4.5%	8.1%
Westar Energy, Inc.	3.4%	3.9%	4.8%	5.3%	4.7%	5.3%	4.8%	8.2%
Xcel Energy Inc.	3.5%	4.4%	4.0%	4.7%	4.8%	4.8%	4.5%	8.1%
Mean	3.7%	3.5%	3.8%	5.5%	4.9%	5.7%	4.7%	**8.3%**
Median	3.8%	3.6%	4.0%	5.0%	4.8%	5.6%	4.5%	**8.1%**
Composite - Mean		**7.2%**	7.5%	9.2%	8.6%	**9.4%**	8.3%	
Composite - Median		**7.4%**	7.8%	8.8%	8.6%	**9.3%**	8.2%	

Note: negative values not used in calculations.

Sources: Prior pages of this schedule.

STANDARD & POOR'S 500 COMPOSITE
20-YEAR U.S. TREASURY BOND YIELDS
RISK PREMIUMS

Year	EPS	BVPS	ROE	20-YEAR T-BOND YIELD	RISK PREMIUM
1977		$79.07			
1978	$12.33	$85.35	15.00%	7.90%	7.10%
1979	$14.86	$94.27	16.55%	8.86%	7.69%
1980	$14.82	$102.48	15.06%	9.97%	5.09%
1981	$15.36	$109.43	14.50%	11.55%	2.95%
1982	$12.64	$112.46	11.39%	13.50%	-2.11%
1983	$14.03	$116.93	12.23%	10.38%	1.85%
1984	$16.64	$122.47	13.90%	11.74%	2.16%
1985	$14.61	$125.20	11.80%	11.25%	0.55%
1986	$14.48	$126.82	11.49%	8.98%	2.51%
1987	$17.50	$134.04	13.42%	7.92%	5.50%
1988	$23.75	$141.32	17.25%	8.97%	8.28%
1989	$22.87	$147.26	15.85%	8.81%	7.04%
1990	$21.73	$153.01	14.47%	8.19%	6.28%
1991	$16.29	$158.85	10.45%	8.22%	2.23%
1992	$18.86	$149.74	12.22%	7.29%	4.93%
1993	$21.89	$180.88	13.24%	7.17%	6.07%
1994	$30.60	$193.06	16.37%	6.59%	9.78%
1995	$33.96	$216.51	16.58%	7.60%	8.98%
1996	$38.73	$237.08	17.08%	6.18%	10.90%
1997	$39.72	$249.52	16.33%	6.64%	9.69%
1998	$37.71	$266.40	14.62%	5.83%	8.79%
1999	$48.17	$290.68	17.29%	5.57%	11.72%
2000	$50.00	$325.80	16.22%	6.50%	9.72%
2001	$24.70	$338.37	7.44%	5.53%	1.91%
2002	$27.59	$321.72	8.36%	5.59%	2.77%
2003	$48.73	$367.17	14.15%	4.80%	9.35%
2004	$58.55	$414.75	14.98%	5.02%	9.96%
2005	$69.93	$453.06	16.12%	4.69%	11.43%
2006	$81.51	$504.39	17.03%	4.68%	12.35%
2007	$66.17	$529.59	12.80%	4.86%	7.94%
2008	$14.88	$451.37	3.03%	4.45%	-1.42%
2009	$50.97	$513.58	10.56%	3.47%	7.09%
2010	$77.35	$579.14	14.16%	4.25%	9.91%
2011	$86.95	$613.14	14.59%	3.81%	10.78%
2012	$86.51	$666.97	13.52%	2.40%	11.12%
2013	$100.20	$715.84	14.49%	2.86%	11.63%
2014	$102.31	$726.96	14.18%	3.33%	10.85%
Average					**6.85%**

Source: Standard & Poor's Analysts' Handbook, Ibbotson Associates Handbook.

PROXY COMPANIES
CAPM COST RATES

COMPANY	RISK-FREE RATE	BETA	RISK PREMIUM	CAPM RATES
Parcell Proxy Group				
ALLETE	2.43%	0.80	5.75%	7.0%
Alliant Energy	2.43%	0.80	5.75%	7.0%
Ameren Corp	2.43%	0.75	5.75%	6.7%
Avista Corp	2.43%	0.80	5.75%	7.0%
El Paso Electric	2.43%	0.75	5.75%	6.7%
IDACORP	2.43%	0.80	5.75%	7.0%
OGE Energy	2.43%	0.95	5.75%	7.9%
Pinnacle West Capital	2.43%	0.75	5.75%	6.7%
SCANA Corp	2.43%	0.75	5.75%	6.7%
Westar Energy	2.43%	0.75	5.75%	6.7%
Mean				**7.0%**
Median				**6.9%**
Hevert Proxy Group				
ALLETE, Inc.	2.43%	0.80	5.75%	7.0%
Alliant Energy Corporation	2.43%	0.80	5.75%	7.0%
Ameren Corporation	2.43%	0.75	5.75%	6.7%
American Electric Power	2.43%	0.70	5.75%	6.5%
Avista Corporation	2.43%	0.80	5.75%	7.0%
CMS Energy Corporation	2.43%	0.75	5.75%	6.7%
Dominion Resources	2.43%	0.70	5.75%	6.5%
DTE Energy Corporation	2.43%	0.75	5.75%	6.7%
Empire District Electric Company	2.43%	0.70	5.75%	6.5%
Great Plains Energy Inc.	2.43%	0.85	5.75%	7.3%
IDACORP, Inc.	2.43%	0.80	5.75%	7.0%
NorthWestern Corporation	2.43%	0.70	5.75%	6.5%
Otter Tail Corporation	2.43%	0.85	5.75%	7.3%
Pinnacle West Capital Corp.	2.43%	0.75	5.75%	6.7%
PNM Resources, Inc.	2.43%	0.80	5.75%	7.0%
Portland General Electric Co.	2.43%	0.80	5.75%	7.0%
SCANA Corporation	2.43%	0.75	5.75%	6.7%
Westar Energy, Inc.	2.43%	0.75	5.75%	6.7%
Xcel Energy Inc.	2.43%	0.65	5.75%	6.2%
Mean				**6.8%**
Median				**6.7%**

Sources: Value Line Investment Survey, Standard & Poor's Analysts' Handbook, Federal Reserve.

20-year Treasury Bonds

Month	Rate
Dec. 2015	2.61%
Jan. 2016	2.49%
Feb. 2016	2.20%
Average	2.43%

PROXY COMPANIES
RATES OF RETURN ON AVERAGE COMMON EQUITY

COMPANY	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2002-2008 Average	2009-2015 Average	2016	2018-20
Parcell Proxy Group																		
ALLETE			12.7%	12.0%	13.2%	13.4%	11.4%	7.3%	8.2%	9.5%	8.7%	8.4%	8.6%	9.6%	12.5%	8.6%	8.0%	9.0%
Alliant Energy	5.7%	7.6%	8.5%	10.3%	9.4%	11.4%	10.2%	7.5%	10.8%	10.3%	1.0%	11.4%	11.5%	11.6%	9.0%	9.2%	11.5%	11.5%
Ameren Corp	10.8%	12.2%	10.0%	10.3%	8.5%	9.3%	8.8%	8.4%	8.5%	7.6%	8.0%	7.7%	8.8%	8.7%	10.0%	8.2%	9.5%	10.5%
Avista Corp	4.5%	6.7%	4.6%	5.8%	8.8%	4.1%	7.6%	8.4%	8.5%	8.6%	6.4%	8.7%	8.1%	7.9%	6.0%	8.1%	8.0%	8.5%
El Paso Electric	6.3%	6.5%	6.3%	6.7%	10.5%	11.9%	11.4%	9.4%	11.7%	13.0%	11.4%	10.0%	9.5%	8.3%	8.5%	10.5%	8.0%	9.5%
IDACORP	7.1%	4.2%	8.2%	7.3%	9.4%	7.1%	8.0%	9.3%	9.8%	10.5%	9.9%	10.1%	10.2%	9.6%	7.3%	9.9%	9.0%	8.5%
OGE Energy	11.1%	13.2%	12.7%	12.5%	15.0%	14.7%	13.0%	12.9%	13.5%	14.0%	13.2%	13.2%	12.5%	10.6%	13.2%	12.8%	10.5%	11.0%
Pinnacle West Capital	8.6%	8.3%	8.2%	6.7%	9.2%	8.5%	6.1%	6.8%	9.3%	8.7%	9.8%	9.9%	9.2%	9.6%	7.9%	9.0%	9.5%	9.5%
SCANA Corp	11.7%	12.4%	12.6%	12.4%	10.9%	11.0%	11.5%	10.7%	10.5%	10.0%	10.2%	10.5%	11.1%	10.6%	11.8%	10.5%	10.5%	10.0%
Westar Energy	5.0%	10.6%	7.7%	9.6%	11.1%	10.0%	6.7%	6.3%	8.6%	8.2%	9.5%	9.8%	9.7%	9.0%	8.7%	8.7%	9.5%	9.5%
Average	7.9%	9.1%	9.2%	9.4%	10.6%	10.1%	9.5%	8.7%	9.9%	10.0%	8.8%	10.0%	9.9%	9.6%	**9.5%**	**9.6%**	**9.4%**	**9.8%**
Median	7.1%	8.3%	8.4%	10.0%	10.0%	10.5%	9.5%	8.4%	9.6%	9.8%	9.7%	10.0%	9.6%	9.6%	**9.1%**	**9.5%**	**9.5%**	**9.5%**
Hevert Proxy Group																		
ALLETE, Inc.			12.7%	12.0%	13.2%	13.4%	11.4%	7.3%	8.2%	9.5%	8.7%	8.4%	8.6%	9.6%	12.5%	8.6%	8.0%	9.0%
Alliant Energy Corporation	5.7%	7.6%	8.5%	10.3%	9.4%	11.4%	10.2%	7.5%	10.8%	10.3%	1.0%	11.4%	11.5%	11.6%	9.0%	9.2%	11.5%	11.5%
Ameren Corporation	10.8%	12.2%	10.0%	10.3%	8.5%	9.3%	8.8%	8.4%	8.5%	7.6%	8.0%	7.7%	8.8%	8.7%	10.0%	8.2%	9.5%	10.5%
American Electric Power	12.3%	12.4%	12.7%	11.9%	12.2%	11.7%	11.6%	11.0%	9.3%	10.7%	9.7%	9.9%	9.9%	10.5%	12.1%	10.1%	10.0%	10.0%
Avista Corporation	4.5%	6.7%	4.6%	5.8%	8.8%	4.1%	7.6%	8.4%	8.5%	8.6%	6.4%	8.7%	8.1%	7.9%	6.0%	8.1%	8.0%	8.5%
CMS Energy Corporation	nmf	nmf	7.2%	10.4%	6.2%	6.6%	12.1%	8.3%	11.8%	12.5%	12.7%	13.2%	13.2%	13.7%	8.5%	12.2%	13.5%	13.5%
Dominion Resources	14.9%	12.0%	12.9%	9.4%	14.3%	12.2%	18.1%	14.7%	14.7%	13.5%	14.3%	16.1%	15.3%	15.6%	13.4%	14.9%	15.0%	19.0%
DTE Energy Corporation	13.7%	9.7%	8.1%	10.2%	7.5%	7.7%	7.5%	8.7%	9.6%	9.1%	9.2%	8.6%	11.1%	9.5%	9.2%	9.4%	9.5%	10.0%
Empire District Electric Company	8.4%	8.7%	5.7%	6.2%	9.2%	6.9%	7.4%	7.5%	7.4%	8.1%	7.9%	8.6%	8.7%	7.4%	7.5%	7.9%	7.5%	8.5%
Great Plains Energy Inc.	15.6%	16.6%	16.9%	13.7%	9.8%	10.6%	5.9%	4.9%	7.3%	5.8%	6.2%	7.3%	6.8%	5.8%	12.7%	6.3%	7.5%	7.5%
IDACORP, Inc.	7.1%	4.2%	8.2%	7.3%	9.4%	7.1%	8.0%	9.3%	9.8%	10.5%	9.9%	10.1%	10.2%	9.6%	7.3%	9.9%	9.0%	8.5%
NorthWestern Corporation					6.4%	6.9%	8.4%	9.4%	9.6%	10.9%	9.3%	9.5%	10.3%	9.3%		9.8%	9.5%	10.0%
Otter Tail Corporation	15.2%	12.0%	10.8%	11.6%	10.4%	10.4%	5.9%	3.7%	2.1%	2.7%	6.9%	9.4%	10.3%	10.2%	10.9%	6.5%	11.0%	12.5%
Pinnacle West Capital Corp.	8.6%	8.3%	8.2%	6.7%	9.2%	8.5%	6.1%	6.8%	9.3%	8.7%	9.8%	9.9%	9.2%	9.6%	7.9%	9.0%	9.5%	9.5%
PNM Resources, Inc.	6.3%	6.7%	7.9%	8.6%	8.4%	3.4%	0.5%	3.1%	4.8%	5.8%	6.6%	6.9%	7.0%	7.1%	6.0%	5.9%	7.5%	9.5%
Portland General Electric Co.					5.9%	11.5%	6.5%	6.2%	8.0%	9.0%	8.3%	7.7%	9.1%	8.2%	8.0%	8.1%	9.0%	9.0%
SCANA Corporation	11.7%	12.4%	12.6%	12.4%	10.9%	11.0%	11.5%	10.7%	10.5%	10.0%	10.2%	10.5%	11.1%	10.6%		10.5%	10.5%	10.0%
Westar Energy, Inc.	5.0%	10.6%	7.7%	9.6%	11.1%	10.0%	6.7%	6.3%	8.6%	8.2%	9.5%	9.8%	9.7%	9.0%	8.7%	8.7%	9.5%	9.5%
Xcel Energy Inc.	2.8%	10.0%	9.8%	9.1%	9.8%	9.3%	9.7%	9.5%	9.5%	10.1%	10.4%	10.2%	10.3%	10.2%	8.6%	10.0%	10.0%	10.5%
Average	9.5%	10.0%	9.7%	9.7%	9.5%	9.1%	8.6%	8.0%	8.9%	9.0%	8.7%	9.7%	10.0%	9.7%	**9.3%**	**9.1%**	**9.8%**	**10.4%**
Median	8.6%	10.0%	8.5%	10.2%	9.4%	9.3%	8.0%	8.3%	9.3%	9.1%	9.2%	9.5%	9.9%	9.6%	**9.1%**	**9.3%**	**9.5%**	**10.0%**

Source: Calculations made from data contained in Value Line Investment Survey.

PROXY COMPANIES
MARKET TO BOOK RATIOS

COMPANY	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2002-2008 Average	2009-2015 Average
Parcell Proxy Group																
ALLETE			322%	212%	219%	195%	156%	113%	127%	138%	136%	152%	151%	145%	221%	137%
Alliant Energy	110%	97%	120%	131%	155%	173%	131%	102%	131%	147%	162%	170%	198%	198%	131%	158%
Ameren Corp	163%	162%	161%	172%	164%	159%	122%	83%	81%	92%	106%	125%	152%	149%	158%	113%
Avista Corp	85%	94%	111%	15%	135%	127%	110%	94%	106%	119%	123%	125%	143%	141%	97%	122%
El Paso Electric	140%	120%	148%	176%	179%	179%	134%	102%	134%	164%	163%	16%	158%	151%	154%	127%
IDACORP	134%	112%	125%	122%	139%	132%	104%	94%	113%	119%	123%	136%	159%	158%	124%	129%
OGE Energy	147%	154%	178%	187%	205%	197%	145%	139%	180%	197%	204%	231%	228%	185%	173%	195%
Pinnacle West Capital	116%	114%	130%	130%	129%	127%	100%	90%	113%	125%	141%	153%	158%	161%	121%	134%
SCANA Corp	137%	158%	171%	179%	167%	158%	141%	121%	134%	135%	152%	154%	160%	160%	159%	145%
Westar Energy	67%	109%	132%	142%	139%	140%	107%	91%	111%	119%	133%	138%	155%	155%	119%	129%
Average	122%	124%	160%	147%	163%	159%	125%	103%	123%	136%	144%	140%	166%	160%	**146%**	**139%**
Median	134%	114%	140%	157%	160%	159%	127%	98%	120%	130%	139%	145%	158%	157%	**141%**	**135%**
Hevert Proxy Group																
ALLETE, Inc.			322%	212%	219%	195%	156%	113%	127%	138%	136%	152%	151%	145%	221%	137%
Alliant Energy Corporation	110%	97%	120%	131%	155%	173%	131%	102%	131%	147%	162%	170%	198%	198%	131%	158%
Ameren Corporation	163%	162%	161%	172%	164%	159%	122%	83%	81%	92%	106%	125%	152%	149%	158%	113%
American Electric Power	138%	124%	155%	165%	161%	190%	145%	112%	118%	128%	134%	145%	162%	167%	154%	138%
Avista Corporation	85%	94%	111%	15%	135%	127%	110%	94%	106%	119%	123%	125%	143%	141%	97%	122%
CMS Energy Corporation	137%	80%	90%	125%	142%	177%	127%	117%	148%	170%	192%	218%	239%	254%	125%	191%
Dominion Resources	158%	180%	196%	242%	229%	256%	238%	186%	207%	235%	272%	313%	362%	352%	214%	275%
DTE Energy Corporation	145%	142%	132%	140%	134%	143%	101%	91%	116%	121%	137%	153%	170%	172%	134%	137%
Empire District Electric Company	132%	133%	144%	148%	149%	150%	122%	100%	127%	128%	124%	131%	150%	144%	140%	129%
Great Plains Energy Inc.	163%	198%	218%	189%	181%	173%	113%	73%	87%	89%	97%	102%	116%	116%	176%	97%
IDACORP, Inc.	134%	112%	125%	122%	139%	132%	104%	94%	113%	119%	123%	136%	159%	158%	124%	129%
NorthWestern Corporation					160%	147%	109%	105%	122%	138%	146%	159%	174%	167%		144%
Otter Tail Corporation	245%	209%	185%	183%	178%	200%	167%	108%	120%	123%	152%	196%	196%	185%	195%	154%
Pinnacle West Capital Corp.	116%	114%	130%	130%	129%	127%	100%	90%	113%	125%	141%	153%	158%	161%	121%	134%
PNM Resources, Inc.	95%	93%	124%	147%	134%	125%	72%	50%	68%	86%	100%	109%	130%	127%	113%	96%
Portland General Electric Co.					153%	140%	101%	83%	97%	109%	117%	131%	145%	149%		119%
SCANA Corporation	137%	158%	171%	179%	167%	158%	141%	121%	134%	135%	152%	154%	160%	160%	159%	145%
Westar Energy, Inc.	67%	109%	132%	142%	139%	140%	107%	91%	111%	119%	133%	138%	155%	155%	119%	129%
Xcel Energy Inc.	113%	113%	132%	139%	150%	154%	127%	121%	135%	143%	156%	157%	165%	171%	133%	150%
Average	134%	132%	156%	152%	159%	161%	126%	102%	119%	130%	142%	156%	173%	172%	**148%**	**142%**
Median	136%	119%	132%	147%	153%	154%	122%	100%	118%	125%	136%	152%	159%	160%	**138%**	**136%**

Source: Calculations made from data contained in Value Line Investment Survey.

Exhibit DCP-1
Schedule 16

STANDARD & POOR'S 500 COMPOSITE RETURNS AND MARKET-TO-BOOK RATIOS 2002 - 2014

YEAR	RETURN ON AVERAGE EQUITY	MARKET-TO BOOK RATIO
2002	8.4%	295%
2003	14.2%	278%
2004	15.0%	291%
2005	16.1%	278%
2006	17.0%	277%
2007	12.8%	284%
2008	3.0%	224%
2009	10.6%	187%
2010	14.2%	208%
2011	14.6%	207%
2012	13.5%	214%
2013	14.5%	237%
2014	14.2%	268%
Averages:		
2002-2008	12.4%	275%
2009-2014	13.6%	220%

Source: Standard & Poor's Analyst's Handbook, 2015 edition.

RISK INDICATORS

COMPANY	VALUE LINE SAFETY	VALUE LINE BETA	VALUE LINE FINANCIAL STRENGTH		S& P STOCK RANKING	
Parcell Proxy Group						
ALLETE	2	0.80	A	4.00	A-	3.67
Alliant Energy	2	0.80	A	4.00	B+	3.33
Ameren Corp	2	0.75	A	4.00	B	3.00
Avista Corp	2	0.80	A	4.00	A-	3.67
El Paso Electric	2	0.75	B++	3.67	B	3.00
IDACORP	2	0.80	B++	3.67	A	4.00
OGE Energy	2	0.95	A	4.00	A-	3.67
Pinnacle West Capital	1	0.75	A+	4.33	B+	3.33
SCANA Corp	3	0.75	B++	3.67	A	4.00
Westar Energy	2	0.75	B++	3.67	A-	3.67
	2.0	0.79	A	3.90	B+/A-	3.53
Hevert Proxy Group						
ALLETE, Inc.	2	0.80	A	4.00	A-	3.67
Alliant Energy Corporation	2	0.80	A	4.00	B+	3.33
Ameren Corporation	2	0.75	A	4.00	B	3.00
American Electric Power	2	0.70	A	4.00	A-	3.67
Avista Corporation	2	0.80	A	4.00	A-	3.67
CMS Energy Corporation	2	0.75	B++	3.67	B	3.00
Dominion Resources	2	0.70	B++	3.67	B	3.00
DTE Energy Corporation	2	0.75	B++	3.67	A-	3.67
Empire District Electric Company	2	0.70	B++	3.67	B+	3.33
Great Plains Energy Inc.	3	0.85	B+	3.33	B	3.00
IDACORP, Inc.	2	0.80	B++	3.67	A	4.00
NorthWestern Corporation	3	0.70	B+	3.33	A+	4.33
Otter Tail Corporation	3	0.85	B+	3.33	B	3.00
Pinnacle West Capital Corp.	1	0.75	A+	4.33	B+	3.33
PNM Resources, Inc.	3	0.80	B	3.00	B	3.00
Portland General Electric Co.	2	0.80	B++	3.67	NR	
SCANA Corporation	3	0.75	B++	3.67	A	4.00
Westar Energy, Inc.	2	0.75	B++	3.67	A-	3.67
Xcel Energy Inc.	1	0.65	A	4.00	A-	3.67
Average	2.2	0.76	B++	3.72	B+/A-	3.46

RISK INDICATORS

GROUP	VALUE LINE SAFETY	VALUE LINE BETA	VALUE LINE FIN STR	S & P STK RANK
S & P's 500 Composite	2.7	1.05	B++	B
Parcell Proxy Group	2.0	0.79	A	B+/A-
Hevert Proxy Group	2.2	0.76	B++	B+/A-

Sources: Value Line Investment Survey, Standard & Poor's Stock Guide.

Definitions:

Safety rankings are in a range of 1 to 5, with 1 representing the highest safety or lowest risk.

Beta reflects the variability of a particular stock, relative to the market as a whole. A stock with a beta of 1.0 moves in concert with the market, a stock with a beta below 1.0 is less variable than the market, and a stock with a beta above 1.0 is more variable than the market.

Financial strengths range from C to A++, with the latter representing the highest level.

Common stock rankings range from D to A+, with the later representing the highest level.

McKinsey on Finance

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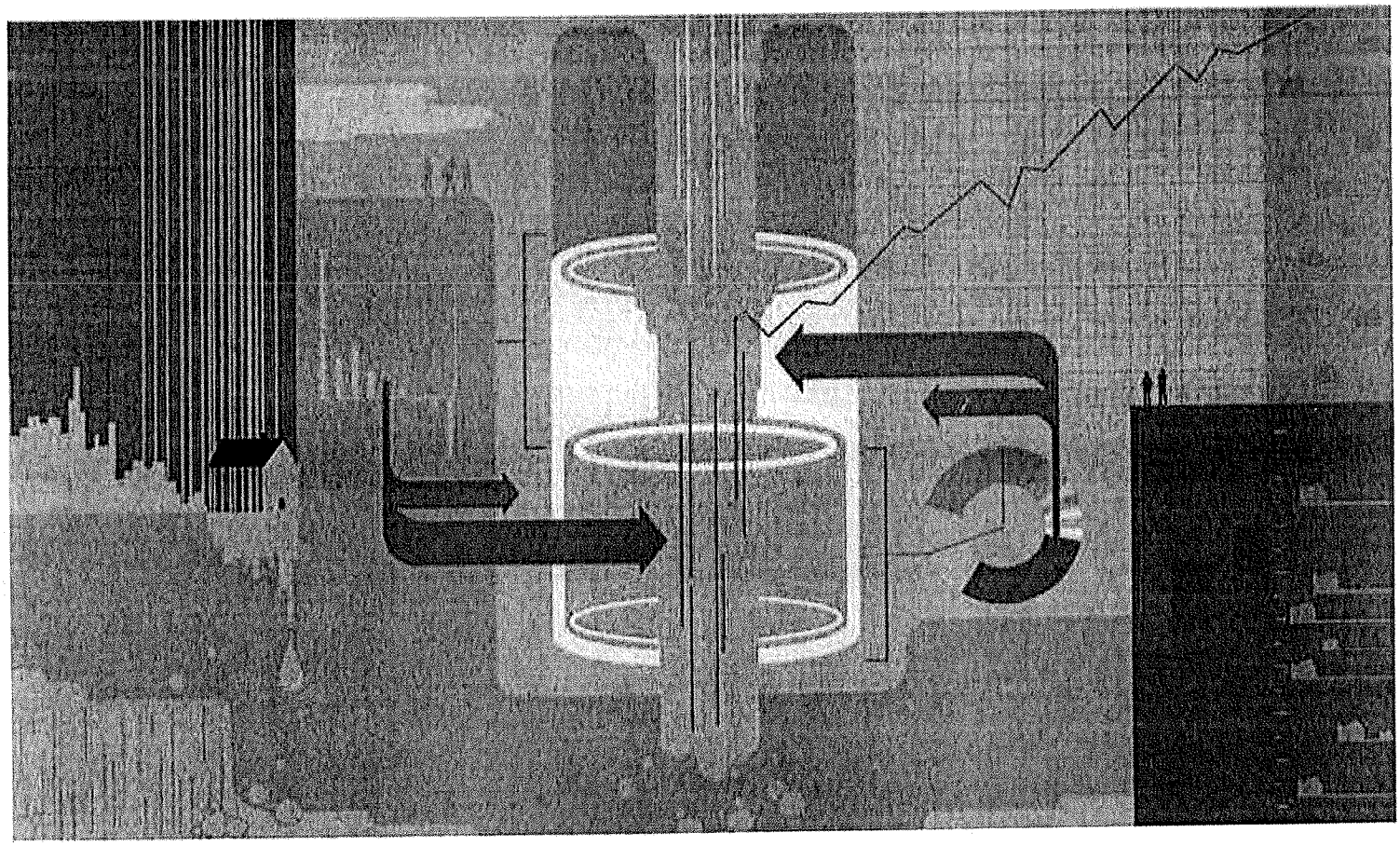
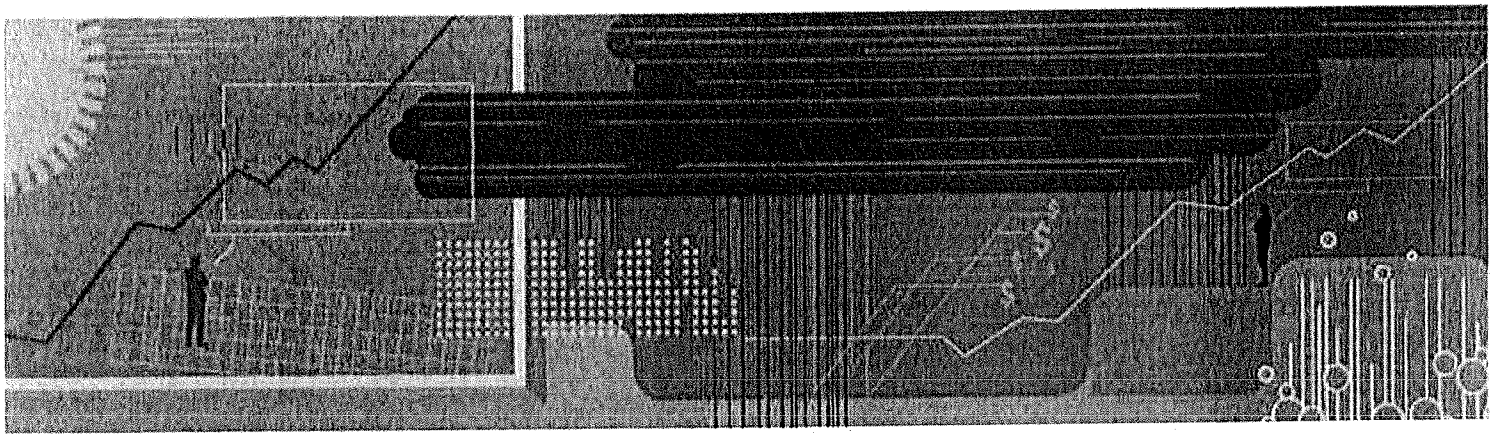
Spring 2010

Perspectives on
Corporate Finance
and Strategy





Equity analysts: Still too bullish

After almost a decade of stricter regulation, analysts' earnings forecasts continue to be excessively optimistic.

Marc H. Goedhart, Rishi Raj, and Abhishek Saxena

No executive would dispute that analysts' forecasts serve as an important benchmark of the current and future health of companies. To better understand their accuracy, we undertook research nearly a decade ago that produced sobering results. Analysts, we found, were typically overoptimistic, slow to revise their forecasts to reflect new economic conditions, and prone to making increasingly inaccurate forecasts when economic growth declined.[1]

Alas, a recently completed update of our work only reinforces this view—despite a series of rules and regulations, dating to the last decade, that were intended to improve the quality of the analysts' long-term earnings forecasts, restore investor confidence in them, and prevent conflicts of interest.[2] For executives, many of whom go to great lengths to satisfy Wall Street's expectations in their financial reporting and long-term strategic moves, this is a cautionary tale worth remembering.

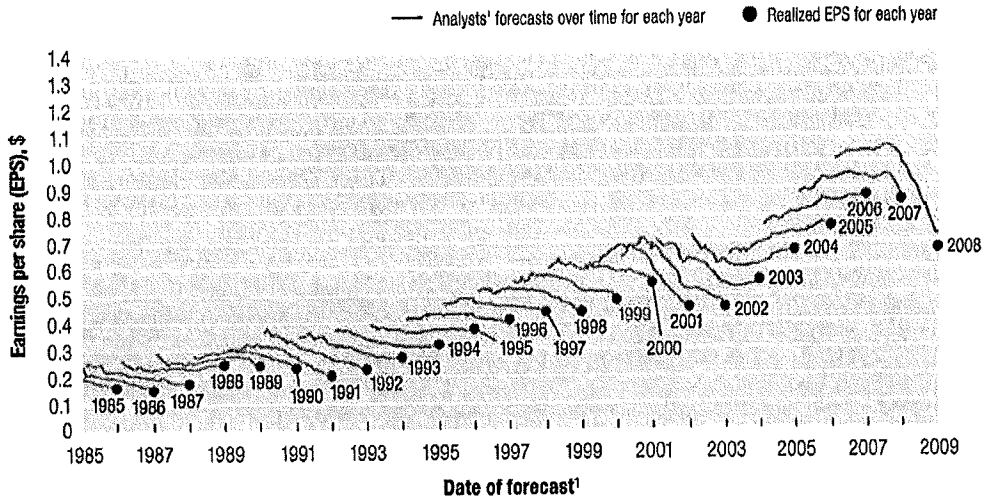
Exceptions to the long pattern of excessively optimistic forecasts are rare, as a progression of consensus earnings estimates for the S&P 500 shows (Exhibit 1). Only in years such as 2003 to 2006, when strong economic growth generated actual earnings that caught up with earlier predictions, do forecasts actually hit the mark.

Exhibit 1

Off the mark

With few exceptions, aggregate earnings forecasts exceed realized earnings per share.

S&P 500 companies



[1]Monthly forecasts.

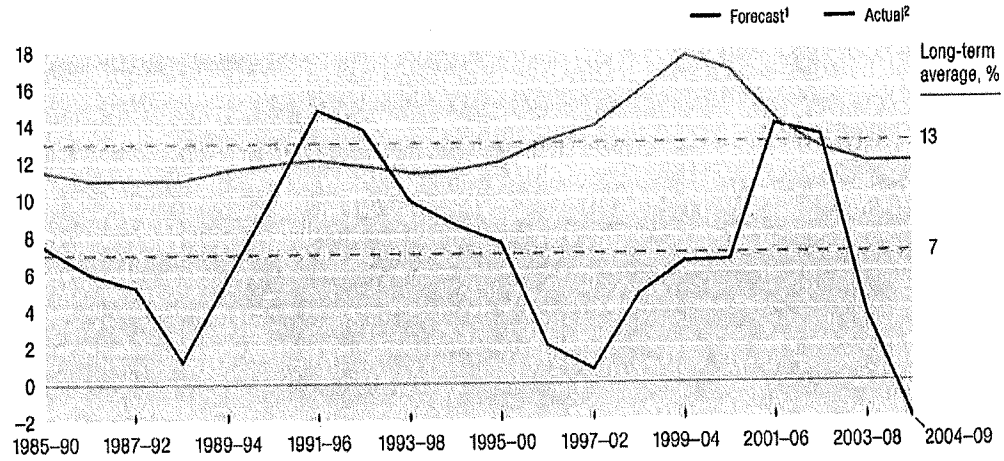
Source: Thomson Reuters I/B/E/S Global Aggregates; McKinsey analysis

Exhibit 2

Overoptimistic

Actual growth surpassed forecasts only twice in 25 years—both times during the recovery following a recession.

Earnings growth for S&P 500 companies, 5-year rolling average, %



[1]Analysts' 5-year forecasts for long-term consensus earnings-per-share (EPS) growth rate. Our conclusions are same for growth based on year-over-year earnings estimates for 3 years.

[2]Actual compound annual growth rate (CAGR) of EPS; 2009 data are not yet available, figures represent consensus estimate as of Nov 2009.

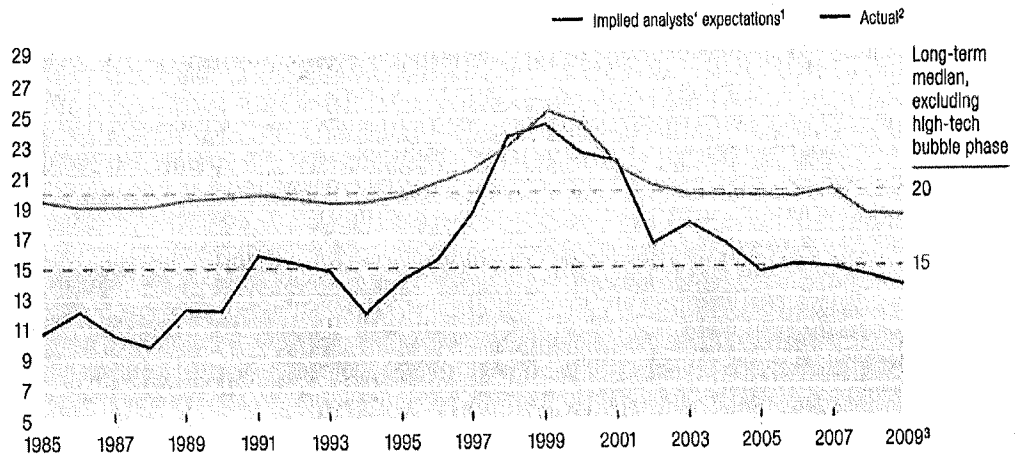
Source: Thomson Reuters I/B/E/S Global Aggregates; McKinsey analysis

Exhibit 3

Less giddy

Capital market expectations are more reasonable.

Actual P/E ratio vs P/E ratio implied by analysts' forecasts, S&P 500 composite index



[1]P/E ratio based on 1-year-forward earnings-per-share (EPS) estimate and estimated value of S&P 500. Estimated value assumes: for first 5 years, EPS growth rate matches analysts' estimates then drops smoothly over next 10 years to long-term continuing-value growth rate; continuing value based on growth rate of 6%; return on equity is 13.5% (long-term historical median for S&P 500), and cost of equity is 9.5% in all periods.
[2]Observed P/E ratio based on S&P 500 value and 1-year-forward EPS estimate.
[3]Based on data as of Nov 2009.

Source: Thomson Reuters I/B/E/S Global Aggregates; McKinsey analysis

This pattern confirms our earlier findings that analysts typically lag behind events in revising their forecasts to reflect new economic conditions. When economic growth accelerates, the size of the forecast error declines; when economic growth slows, it increases.[3] So as economic growth cycles up and down, the actual earnings S&P 500 companies report occasionally coincide with the analysts' forecasts, as they did, for example, in 1988, from 1994 to 1997, and from 2003 to 2006.

Moreover, analysts have been persistently overoptimistic for the past 25 years, with estimates ranging from 10 to 12 percent a year,[4] compared with actual earnings growth of 6 percent.[5] Over this time frame, actual earnings growth surpassed forecasts in only two instances, both during the earnings recovery following a recession (Exhibit 2). On average, analysts' forecasts have been almost 100 percent too high.[6]

Capital markets, on the other hand, are notably less giddy in their predictions. Except during the market bubble of 1999–2001, actual price-to-earnings ratios have been 25 percent lower than implied P/E ratios based on analyst forecasts (Exhibit 3). What's more, an actual forward P/E ratio[7] of the S&P 500 as of November 11, 2009—14—is consistent with long-term earnings growth of 5 percent.[8] This assessment is more

reasonable, considering that long-term earnings growth for the market as a whole is unlikely to differ significantly from growth in GDP,[9] as prior McKinsey research has shown.[10] Executives, as the evidence indicates, ought to base their strategic decisions on what they see happening in their industries rather than respond to the pressures of forecasts, since even the market doesn't expect them to do so.

[1] Marc H. Goedhart, Brendan Russell, and Zane D. Williams, "Prophets and profits," mckinseyquarterly.com, October 2001.

[2] US Securities and Exchange Commission (SEC) Regulation Fair Disclosure (FD), passed in 2000, prohibits the selective disclosure of material information to some people but not others. The Sarbanes–Oxley Act of 2002 includes provisions specifically intended to help restore investor confidence in the reporting of securities' analysts, including a code of conduct for them and a requirement to disclose knowable conflicts of interest. The Global Settlement of 2003 between regulators and ten of the largest US investment firms aimed to prevent conflicts of interest between their analyst and investment businesses.

[3] The correlation between the absolute size of the error in forecast earnings growth (S&P 500) and GDP growth is –0.55.

[4] Our analysis of the distribution of five-year earnings growth (as of March 2005) suggests that analysts forecast growth of more than 10 percent for 70 percent of S&P 500 companies.

[5] Except 1998–2001, when the growth outlook became excessively optimistic.

[6] We also analyzed trends for three-year earnings-growth estimates based on year-on-year earnings estimates provided by the analysts, where the sample size of analysts' coverage is bigger. Our conclusions on the trend and the gap vis-à-vis actual earnings growth does not change.

[7] Market-weighted and forward-looking earnings-per-share (EPS) estimate for 2010.

[8] Assuming a return on equity (ROE) of 13.5 percent (the long-term historical average) and a cost of equity of 9.5 percent—the long-term real cost of equity (7 percent) and inflation (2.5 percent).

[9] Real GDP has averaged 3 to 4 percent over past seven or eight decades, which would indeed be consistent with nominal growth of 5 to 7 percent given current inflation of 2 to 3 percent.

[10] Timothy Koller and Zane D. Williams, "What happened to the bull market?" mckinseyquarterly.com, November 2001.

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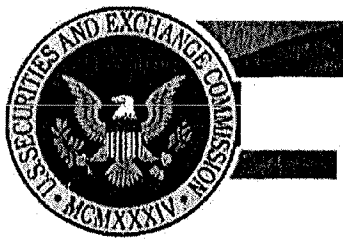

Analyzing Analyst Recommendations

Research analysts study publicly traded companies and make recommendations on the securities of those companies. Most specialize in a particular industry or sector of the economy. They exert considerable influence in today's marketplace. Analysts' recommendations or reports can influence the price of a company's stock—especially when the recommendations are widely disseminated through television appearances or through other electronic and print media. The mere mention of a company by a popular analyst can temporarily cause its stock to rise or fall—even when nothing about the company's prospects or fundamentals has recently changed.

Analysts often use a variety of terms—buy, strong buy, near-term or long-term accumulate, near-term or long-term over-perform or under-perform, neutral, hold—to describe their recommendations. But the meanings of these terms can differ from firm to firm. Rather than make assumptions, investors should carefully read the definitions of all ratings used in each research report. They should also consider the firm's disclosures regarding what percentage of all ratings fall into either "buy," "hold/neutral," and "sell" categories.

While analysts provide an important source of information in today's markets, investors should understand the potential conflicts of interest analysts might face. For example, some analysts work for firms that underwrite or own the securities of the companies the analysts cover. Analysts themselves sometimes own stocks in the companies they cover—either directly or indirectly, such as through employee stock-purchase pools in which they and their colleagues participate.

As a general matter, investors should not rely solely on an analyst's recommendation when deciding whether to buy, hold, or sell a stock. Instead, they should also do their own research—such as reading the prospectus for new companies or for public companies, the quarterly and annual reports filed with the SEC—to confirm whether a particular investment is appropriate for them in light of their individual financial circumstances. This alert discusses the potential conflicts of interest analysts face, describes the New York Stock Exchange (NYSE) and FINRA rules concerning analyst recommendations, and provides tips for researching investments.

Who Analysts Are and Who They Work for

Analysts historically have served an important role, promoting the efficiency of our markets by ferreting out facts and offering valuable insights on companies and industry trends. Analysts generally fall into one of three categories:

Sell-side analysts typically work for full-service broker-dealers and make recommendations on the securities they cover. Many of the more popular sell-side analysts work for prominent brokerage firms that also provide investment banking services for corporate clients—including companies whose securities the analysts cover.

Buy-side analysts typically work for institutional money managers—such as mutual funds, hedge funds, or investment advisers—that purchase securities for their own accounts. They counsel their employers on which securities to buy, hold, or sell and stand to make money when they make good calls.

Independent analysts typically aren't associated with firms that underwrite the securities they cover. They often sell their research reports on a subscription or other basis. Some firms that have discontinued their investment banking operations now market themselves as more independent than multi-service firms, emphasizing their lack of conflicts of interest.

Potential Conflicts of Interest

Many analysts work in a world with built-in conflicts of interest and competing pressures. On the one hand, sell-side firms want their individual investor clients to be successful over time because satisfied long-term investors are a key to a firm's long-term reputation and success. A well-respected investment research team is an important service to customers.

At the same time, however, several factors can create pressure on an analyst's independence and objectivity. The existence of these factors does not necessarily mean that the research analyst is biased. But investors should take them into account before making an investment decision. Some of these factors include:

- **Investment Banking Relationships**—When companies issue new securities, they hire investment bankers for advice on structuring the deal and for help with the actual offering. Underwriting a company's securities offerings and providing other investment banking services can bring in more money for firms than revenues from brokerage operations or research reports. Here's what an investment banking relationship may mean:

    1. **The analyst's firm may be underwriting the offering**—If so, the firm has a substantial interest—both financial and with respect to its reputation—in assuring that the offering is successful. Analysts are often an integral part of the investment banking team for initial public offerings—assisting with "due diligence" research into the company, participating in investor road shows, and helping to shape the deal. Upbeat research reports and positive recommendations published after the offering is completed may "support" new stock issued by a firm's investment banking clients.

    2. **Client companies prefer favorable research reports**—Unfavorable analyst reports may hurt the firm's efforts to

nurture a lucrative, long-term investment banking relationship. An unfavorable report might alienate the firm's client or a potential client and could cause a company to look elsewhere for future investment banking services.

3. **Positive reports attract new clients**—Firms must compete with one another for investment banking business. Favorable analyst coverage of a company may induce that company to hire the firm to underwrite a securities offering. A company might be unlikely to hire an underwriter to sell its stock if the firm's analyst has a negative view of the stock.

- **Brokerage Commissions**—Brokerage firms usually don't charge for their research reports. But a positive-sounding analyst report can help firms make money indirectly by generating more purchases and sales of covered securities—which, in turn, result in additional brokerage commissions.

- **Analyst Compensation**—Brokerage firms' compensation arrangements can put pressure on analysts to issue positive research reports and recommendations. For example, some firms link compensation and bonuses—directly or indirectly—to the number of investment banking deals the analyst lands or to the profitability of the firm's investment banking division.

- **Ownership Interests in the Company**—An analyst, other employees, and the firm itself may own significant positions in the companies an analyst covers. Analysts may also participate in employee stock-purchase pools that invest in companies they cover. And in a growing trend called "venture investing," an analyst's firm or colleagues may acquire a stake in a start-up by obtaining discounted, pre-IPO shares. These practices allow an analyst, the firm he or she works for, or both to profit, directly or indirectly, from owning securities in companies the analyst covers.

Disclosure and Recent Rule Changes

The rules of the NYSE and FINRA require analysts in some circumstances to disclose certain conflicts of interest when recommending the purchase or sale of a specific security. On May 10, 2002, the SEC approved proposed changes to these rules, strengthening the disclosures that analysts and firms must make. The NYSE and FINRA decided upon an implementation schedule of between 60 and 180 calendar days for the new rules in order to provide reasonable time periods for firms to develop and implement policies, procedures and systems to comply with the new requirements. These rules implement key structural reforms aimed at increasing analysts' independence and further managing conflicts of interest. They also require increased disclosure of conflicts in research reports and public appearances. Key provisions of the rules include the following:

- **No Promises of Favorable Research** — NYSE and FINRA rules now prohibit analysts from offering a favorable research rating or specific price target to induce investment banking business from companies. The rule changes also impose "quiet periods" that bar a firm that is acting as manager or co-manager of a

securities offering from issuing a report on a company within 40 days after an initial public offering or within 10 days after a secondary offering for an inactively traded company.

Significance of the Change: Promising research coverage to a company will not be as attractive if the research may not be issued within the initial days following the offering.

- **Limitations on Relationships and Communications** — The rule changes prohibit research analysts from being supervised by the investment banking department. In addition, investment banking personnel are prohibited from discussing research reports with analysts prior to distribution, unless staff from the firm's legal/compliance department monitor those communications. Analysts are also prohibited from sharing draft research reports with the target companies, other than to check facts after approval from the firm's legal/compliance department.

  Significance of the Change: These provisions help protect research analysts from influences that could impair their objectivity and independence.

- **Analyst Compensation** — The rule changes bar securities firms from tying an analyst's compensation to specific investment banking transactions. Furthermore, if an analyst's compensation is based on the firm's general investment banking revenues, that fact must be disclosed in the firm's research reports.

  Significance of the Change: Prohibiting compensation from specific investment banking transactions significantly curtails a potentially major influence on research analysts' objectivity.

- **Firm Compensation** — The rule changes require a securities firm to disclose in a research report if it managed or co-managed a public offering of equity securities for the company or if it received any compensation for investment banking services from the company in the past 12 months. A firm also must disclose if it expects to receive or intends to seek compensation for investment banking services from the company during the next 3 months.

  Significance of the Change: Requiring securities firms to disclose compensation from investment banking clients can alert investors to potential biases in their recommendations.

- **Restrictions on Personal Trading by Analysts** — The rule changes bar analysts and members of their households from investing in a company's securities

prior to its initial public offering if the company is in the business sector that the analyst covers. In addition, the rule changes require "blackout periods" that prohibit analysts from trading securities of the companies they follow for 30 days before and 5 days after they issue a research report about the company, and also prohibits analysts from trading against their most recent recommendations—subject to exceptions for unanticipated significant changes in the personal financial circumstances of the beneficial owner of a research analyst account.

Significance of the Change: Prohibiting analysts from trading around the time they issue research reports should reduce conflicts arising from personal financial interests.

- **Disclosures of Financial Interests in Covered Companies** — The rule changes require analysts to disclose if they own shares of recommended companies. Firms are also required to disclose if they own 1% or more of a company's equity securities as of the previous month end.

  Significance of the Change: Requiring analysts and securities firms to disclose financial interests can alert investors to potential biases in their recommendations.

- **Disclosures in Research Reports Regarding the Firm's Ratings** — The rule changes require firms to clearly explain in research reports the meaning of all ratings terms they use, and this terminology must be consistent with its plain meaning. Additionally, firms must provide the percentage of all the ratings that they have assigned to buy / hold / sell categories and the percentage of investment banking clients in each category. Firms are also required to provide a graph or chart that plots the historical price movements of the security and indicates those points at which the firm initiated and changed ratings and price targets for the company.

  Significance of the Change: These disclosures will assist investors in deciding what value to place on a securities firm's ratings and provide them with better information to assess its research.

- **Disclosures During Public Appearances by Analysts** — The rule changes require disclosures from analysts during public appearances, such as television or radio interviews. Guest analysts will have disclose if they or their firm have a position in the stock; if the company is an investment banking client of the firm; if the analyst or a member of the analyst's household is an officer, director or advisory board member of the

recommended issuer; and other material conflicts.

> **Significance of the Change**: This disclosure will inform investors who learn of analyst opinions and ratings through the media — rather than in written research reports — of analyst and firm conflicts.

What Conflicts May Mean to You

The fact that an analyst—or the analyst's firm—may have a conflict of interest does not mean that his or her recommendation is flawed or unwise. But it's a fact you should know and consider in assessing whether the recommendation is wise *for you*.

It's up to you to educate yourself to make sure that any investments you choose match your goals and tolerance for risk. Remember that analysts generally do not function as your financial adviser when they make recommendations—they're not providing individually tailored investment advice, and they're not taking your personal circumstances into consideration.

Uncovering Conflicts

In addition to paying close attention to the disclosures that firms and analysts make, here are some steps you can take to assess whether and to what extent analyst conflicts may exist:

Identify the Underwriter

Before you buy, confirm whether the analyst's firm underwrote a recommended company's stock by looking at the prospectus, which is part of the registration statement for the offering. Note that firms are required to disclose in research reports whether they managed or co-managed a public offering. You'll find a list of the lead or managing underwriters on the front cover of both the preliminary and final copies of the prospectus. By convention, the name of the lead underwriter—the firm that stands to make the most money on the deal—will appear first, and any co-managers will generally be listed second in alphabetical order. Other firms participating in the deal will be listed only in the "Underwriting" or "Plan of Distribution" sections of the final supplement to the prospectus. You can search for registration statements using the SEC's EDGAR database at www.sec.gov/edgar.shtml. The final supplement to the prospectus will appear in EDGAR as a "424" filing.

Research Ownership Interests

A company's registration statement and its annual report on Form 10-K will tell you who the beneficial owners of more than five percent of a class of equity securities are. Research reports on a company must disclose whether the securities firm issuing the report (or any of its affiliates) beneficially owns one percent or more of any class of common equity securities of the subject company. The issuer's registration statement will also tell you

about private sales of the company's securities during the past three years. In addition to the disclosure requirements in the new rules, you may be able to ascertain ownership by checking the following SEC forms:

- **Schedules 13D and 13G**—Any person who acquires a beneficial ownership of more than five percent must file a Schedule 13D. Schedule 13G is a much abbreviated version of Schedule 13D that is only available for use by a limited category of "persons," such as banks, broker-dealers, or insurance companies.

- **Forms 3, 4, and 5**—Officers, directors, and beneficial owners of more than 10 percent must report their holdings—and any changes in their holdings—to the SEC on Forms 3, 4, and 5.

- **Form 144**—If an analyst or a firm holds "restricted" securities from the company—meaning those acquired in an unregistered, private sale from the issuer or its affiliates—then investors can find out whether the analyst or the firm recently sold the stock by researching their Form 144 filings.

As of November 4, 2002, all statements of beneficial ownership on Schedules 13D and 13G (including those relating to the securities of foreign private issuers) must be submitted electronically using the SEC's EDGAR system. If you can't find a form on EDGAR, please refer to information on "How to Request Public Documents" at http://www.sec.gov/answers/publicdocs.htm. Or check the "Quotes" section of the Nasdaq Stock Market's website at http://quotes.nasdaq.com/

Unlock the Mystery of "Lock-ups"

If the analyst's firm acquired ownership interests through venture investing, the shares generally will be subject to a "lock-up" agreement during and after the issuer's initial public offering. Lock-up agreements prohibit company insiders—including employees, their friends and family, and venture capitalists—from selling their shares for a set period of time without the underwriter's permission. While the underwriter can choose to end a lock-up period early—whether because of market conditions, the performance of the offering, or other factors—lock-ups generally last for 180 days after the offering's registration statement becomes effective.

After the lock-up period ends, the firm may be able to sell the stock. If you're considering investing in a company that has recently conducted an initial public offering, you'll want to check whether a lock-up agreement is in effect and when it expires or if the underwriter waived any lock-up restrictions. This is important information because a company's stock price may be affected by the prospect of lock-up shares being sold into the market when the lock-up ends. It is also a data point you can

consider when assessing research reports issued just before a lock-up period expires—which are sometimes known as "booster shot" reports.

To find out whether a company has a lock-up agreement, check the "Underwriting" or "Plan of Distribution" sections of the prospectus. That's where companies must disclose that information. You can contact the company's shareholder relations department to ask for its prospectus, or use the SEC's EDGAR database if the company has filed its prospectus electronically. If you can't find a form on EDGAR, please refer to information on "How to Request Public Documents" at http://www.sec.gov/answers/publicdocs.htm. There are also commercial websites you can use for free that track when companies' lock-up agreements expire. The SEC does not endorse these websites and makes no representation about any of the information or services contained on these websites.

How You Can Protect Yourself

We advise all investors to do their homework before investing. If you purchase a security solely because an analyst said the company was one of his or her "top picks," you may be doing yourself a disservice. Especially if the company is one you've never heard of, take time to investigate:

- When assessing a firm's research report of a company, be sure to read all of the disclosures about the firm and analysts' conflicts of interest and the types of research recommendations that the firm has made.
- Research the company's financial reports using the SEC's EDGAR database at http://www.sec.gov/edgar.shtml, or call the company for copies. If you can't analyze them on your own, ask a trusted professional for help.
- Find out if a lock-up period is about to expire or whether the underwriter waived it. While that may not necessarily affect your decision to buy, it may put an analyst recommendation in perspective.
- Confirm whether the analyst's firm underwrote one of the company's recent stock offerings—especially its IPO.
- Learn as much as you can about the company by reading independent news reports, commercial databases, and reference books. Your local library may have these and other resources.
- Talk to your broker or financial adviser and ask questions about the company and its prospects. But bear in mind that if your broker's firm issued a positive report on a company, your broker will be hard-pressed to contradict it. Be sure to ask your broker whether a particular investment is suitable for you in light of your

financial circumstances.

Above all, always remember that even the soundest recommendation from the most trust-worthy analyst may not be a good choice for you. That's one reason we caution investors never to rely solely on an analyst's recommendation when buying or selling a stock. Before you act, ask yourself whether the decision fits with your goals, your time horizon, and your tolerance for risk. Know what you're buying—or selling—and why.

http://www.sec.gov/investor/pubs/analysts.htm

We have provided this information as a service to investors. It is neither a legal interpretation nor a statement of SEC policy. If you have questions concerning the meaning or application of a particular law or rule, please consult with an attorney who specializes in securities law.

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Modified: 08/30/2010

LONG-TERM PROJECTIONS OF GROSS DOMESTIC PRODUCT GROWTH

Social Security Administration

Year	Real GDP	GDP Index	Nominal GDP
2020	2.70%	2.30%	5.00%
2021	2.60%	2.30%	4.90%
2022	2.40%	2.30%	4.70%
2023	2.20%	2.30%	4.50%
2024	2.20%	2.30%	4.50%
2025	2.20%	2.30%	4.50%
2026	2.20%	2.30%	4.50%
2027	2.20%	2.30%	4.50%
2028	2.20%	2.30%	4.50%
2029	2.20%	2.30%	4.50%
2030	2.10%	2.30%	4.40%
2031	2.10%	2.30%	4.40%
2032	2.10%	2.30%	4.40%
2033	2.10%	2.30%	4.40%
2034	2.10%	2.30%	4.40%
2035	2.10%	2.30%	4.40%
2036	2.10%	2.30%	4.40%
2037	2.10%	2.30%	4.40%
2038	2.10%	2.30%	4.40%
2039	2.10%	2.30%	4.40%
2040	2.20%	2.30%	4.50%
2041	2.20%	2.30%	4.50%
2042	2.20%	2.30%	4.50%
2043	2.20%	2.30%	4.50%
2044	2.20%	2.30%	4.50%
2045	2.10%	2.30%	4.40%
2046	2.10%	2.30%	4.40%
2047	2.10%	2.30%	4.40%
2048	2.10%	2.30%	4.40%
2049	2.10%	2.30%	4.40%
2050	2.10%	2.30%	4.40%
2051	2.10%	2.30%	4.40%
2052	2.10%	2.30%	4.40%
2053	2.10%	2.30%	4.40%
2054	2.10%	2.30%	4.40%
2055	2.10%	2.30%	4.40%
2056	2.10%	2.30%	4.40%
2057	2.10%	2.30%	4.40%
2058	2.10%	2.30%	4.40%
2059	2.10%	2.30%	4.40%
2060	2.00%	2.30%	4.30%
2061	2.00%	2.30%	4.30%
2062	2.00%	2.30%	4.30%
2063	2.00%	2.30%	4.30%
2064	2.00%	2.30%	4.30%
2065	2.00%	2.10%	4.10%
2066	2.00%	2.10%	4.10%
2067	2.00%	2.10%	4.10%
2068	2.00%	2.10%	4.10%
2069	2.00%	2.10%	4.10%
2070	2.00%	2.10%	4.10%
2071	2.00%	2.10%	4.10%
2072	2.00%	2.10%	4.10%
2073	2.00%	2.10%	4.10%
2074	2.00%	2.10%	4.10%
2075	2.00%	2.10%	4.10%
2076	2.00%	2.10%	4.10%
2077	2.00%	2.10%	4.10%
2078	2.00%	2.10%	4.10%
2079	2.00%	2.10%	4.10%
2080	2.00%	2.10%	4.10%
2081	2.00%	2.10%	4.10%
2082	2.00%	2.10%	4.10%
2083	2.00%	2.10%	4.10%
2084	2.00%	2.10%	4.10%
2085	2.00%	2.10%	4.10%
2086	2.00%	2.00%	4.00%
2087	2.00%	2.00%	4.00%
2088	2.00%	2.00%	4.00%
Average			**4.32%**

Source: 2015 OASDI Trustees Report.

LONG-TERM PROJECTIONS OF GROSS DOMESTIC PRODUCT GROWTH

Energy Information Administration

Annual Growth (2012-2040):

Real GDP	2.4%
GDP Chain-type Price Index	1.8%
Nominal GDP Growth	**4.2%**

Source: Energy Information Administration, Annual Energy Outlook 2015 with Projections to 2040.