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BEFORE THE ARIZONA CORPORATION COMMISSION

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IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	Docket No. E-04204A-09-0206

NOTICE OF FILING DIRECT TESTIMONY

The Residential Utility Consumer Office ("RUCO") hereby provides notice of filing the Direct Testimony of William A. Rigsby, CRRA, and Ben Johnson, Ph.D., in the above-referenced matter.

RESPECTFULLY SUBMITTED this 6th day of November, 2009.

Arizona Corporation Commission
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Daniel W. Pozefsky
Chief Counsel

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UNS ELECTRIC, INC.

DOCKET NO. E-04204A-09-0206

DIRECT TESTIMONY

OF

BEN JOHNSON, Ph.D.

ON BEHALF OF

THE

RESIDENTIAL UTILITY CONSUMER OFFICE

NOVEMBER 6, 2009

TABLE OF CONTENTS

TESTIMONY

OF BEN JOHNSON, PH.D.

On Behalf of

The Residential Utility Consumer Office

Before the

Arizona Corporation Commission

Docket No. E-04204A-09-0206

Introduction

Q. Would you please state your name and address?

A. Ben Johnson, 3854-2 Killearn Court, Tallahassee, Florida.

Q. What is your present occupation?

A. I am a consulting economist and president of Ben Johnson Associates, Inc.®, an economic research firm specializing in public utility regulation.

Q. Have you prepared an appendix that describes your qualifications in regulatory and utility economics?

A. Yes. Appendix A, attached to my testimony, will serve this purpose.

Q. Have you prepared any schedules to be filed with your testimony?

A. Yes, I have prepared Schedules BJ-1 through BJ-10. These schedules were prepared under my supervision and are attached to my testimony.

Q. What is your purpose in making your appearance at this hearing?

A. Our firm has been retained by the Residential Utility Consumer Office ("RUCO") to assist with RUCO's evaluation of UNS Electric, Inc.'s (UNSE's) Application for a rate increase. The purpose of my testimony is to present RUCO's revenue requirement recommendation for UNSE in this proceeding, taking into account my analysis, as well as that of RUCO's rate of return witness Bill Rigsby.

Following this introduction, my testimony has eight sections. In the first section, I briefly summarize the background of this proceeding. In the second section, I discuss UNSE's financial condition and UNSE's credit ratings. In the third section I briefly summarize and discuss UNSE's revenue requirement filing in general terms. In the fourth section, I discuss UNSE's proposal to add the Black Mountain Generating Station to rate base. In the fifth section, I discuss the rate base adjustments proposed by UNSE and I present RUCO's recommendations with respect to each proposed adjustment. In the sixth section, I discuss the income adjustments proposed by the Company and I present RUCO's recommendations with respect to each proposed adjustment. In the seventh section, I discuss the appropriate rate of return to be applied to a fair value rate base. In the eighth and final section, I summarize my conclusions and recommendations.

I. Background

Q. Can you briefly discuss UNSE's most recent rate case?

A. Yes. On December 15, 2006, UNSE filed an application requesting an increase in rates and approval of financing for the purchase of the Black Mountain Generating Station. UNSE requested a revenue increase of $8,468,638, and proposed an adjusted original cost rate base ("OCRB") of $141,036,562 and a fair value rate base of $177,847,579 [Decision 70360, p. 5] Staff and RUCO recommended revenue increases of $3,687,855 and $1,282,144, respectively. [Id.] Staff proposed an OCRB of $130,740,050, and a fair value rate base (FVRB) of $167,551,067. [Id.] RUCO proposed an OCRB of $128,795,088, and a FVRB of $161,635,350. [Id.] The evidentiary hearing was held on 8 days from September 10, 2007 through October 2, 2007. The Commission determined that UNSE had an OCRB of $130,740,050 and a FVRB of $167,551,057. [Id., p. 80] The Commission further determined that the Company was entitled to a revenue increase of $4,018,678, or 2.5% over adjusted test year revenues.[1] [Id.] The Commission ordered the new rates to become effective June 1, 2008. [Id., p. 84]

Q. Can you now briefly discuss the procedural background of this case?

A. Yes. UNSE's initial application for a rate increase was filed with the Commission on April 30, 2009. On May 26, 2009, UNSE filed an Amendment which updated certain financial information in its Application. On May 29, 2009, Staff filed a Letter of Sufficiency in the docket indicating that UNS' application had meet the sufficiency requirements of the Arizona Administrative Code. A Procedural Order was issued on June 18, 2009, setting an evidentiary hearing for February 4, 2010, establishing dates for testimony, and setting a deadline for motions to intervene. On September 1, 2009, RUCO's motion to intervene was granted. On

1 The Commission determined UNSE's adjusted test year revenues to be $158,539,827. [Id., p. 37]

October 1, 2009, the Arizona School Boards Association and the Arizona Association of School Business Officials' motion to intervene was granted.

II. UNSE Financial Situation and Credit Metrics

Q. What information does UNSE provide regarding its financial condition?

A. The Company notes that in the prior rate case, the Commission authorized a return on equity (ROE) of 10%. [UNSE Application, p. 2] The Company claims, however, that in 2008 it earned a ROE of 4.6%, and that it is projected to earn an ROE of only 4.0% in 2009. [Id.] "[I]t is readily apparent that UNS Electric has been under-earning its cost of capital by a wide margin and will continue to do so until appropriate rate relief is granted". [Grant Direct, p. 17] According to UNSE, if the Company is not allowed to earn its cost of capital, UniSoruce Energy (UNSE's parent company) would have no incentive to increase its equity investment, which in turn would force UNSE to become more dependent on debt financing, and could lead to a series of back to back rate cases. [Grant Direct, pp. 19-20] According to the Company, such a scenario would jeopardize its creditworthiness, and increase costs to everyone, including customers. [Id.] "[E]ven a modest decline in financial performance could cause a downgrading of the Company's credit rating to junk bond status". [Grant Direct, p. 9]

Q. Is UNSE's recent financial performance problematic?

A. While there is no expectation that earnings will exactly match the allowed rate of return, it is not in the public interest for the Company to achieve earnings that are far below its cost of capital – particularly if this pattern were to be sustained for several more years into the future.

Q. What rating agencies cover UNSE's debt?

A. According to the Company, a revolving credit facility it shares with UNS Gas, and its senior unsecured debt are both rated by Moody's.

Q. Can you explain how Moody's rates the Company's credit?

A. Yes. As shown below, Moody's has established a series of tiers designated by alphanumeric codes to rate corporate securities.

Moody's Credit Ratings

Investment Grade	Speculative Grade	In Default
Aaa	Ba1	Ca
Aa1	Ba2	C
Aa2	Ba3	
Aa3	B1	
A1	B2	
A2	B3	
A3	Caa1	
Baa1	Caa2	
Baa2	Caa3	
Baa3		

Q. Where does UNSE currently fall within this range?

A. The Company's debt obligations are rated Baa3. [Pritz Direct, p. 3] The credit facility rating was assigned in July 2008 and the rating on the senior notes was assigned in August 2008. [Id.] As you can see in the table above, UNSE is rated on the lowest tier of "investment grade" credit by Moody's. Fortunately, Moody's has assigned a "stable" outlook for the Company. [Id.]

Q. Has Moody's provided any explanation of its rating for UNSE?

A. Yes. Moody's provides the following "ratings rationale":

> The Baa3 rating for the shared guaranteed credit facility is driven by the relatively stable and predictable nature of UNSE's and UNSG's regulated cash flows, as well as their strong combined financial profile which provide the basis of the UES guarantee. For the past several years, cash flow credit metrics at both UNSE and USE have been at or above the ranges demonstrated by electric utilities rated within the Baa range. The rating also considers the traditionally challenging regulatory environment in Arizona, but contemplates recent decisions which appear intended to provide more timely recovery of certain costs.
>
> The rating assumes UNSE and UNSG will be reasonably successful in managing their regulatory relationships with an objective of achieving more timely recovery and an opportunity to earn a fair return. The rating also incorporates an expectation that increasing capital expenditures will be financed in a manner consistent with maintaining current financial strength. [UNSE Exhibit MBP-2]

Moody's provides the following explanation for its rating outlook:

> The stable outlook reflects the relatively stable cash flows anticipated to be generated by UNSE and UNSG and Moody's assumption that increases in the cost of fuel and purchased power will, in fact, be recovered on a relatively timely basis. [Id.]

Q. To what extent does Moody's look at UniSource Energy and UNSE's corporate structure when issuing its rating?

A. That is an issue considered by the agency. Moody's states:

> The rating also recognizes the position of UNSE and UNSG as indirect subsidiaries of UNS through UES. UES is an intermediate holding company with no operations or debt. Debt at UNSE and UNSG is guaranteed by UES, which creates cross-support. UES has not historically received any dividend payments from its utility subsidiaries, and none are anticipated for the foreseeable future. Between 2005 and 2007, UNS contributed approximately $40 million of equity to these subsidiaries in support of their capital programs and to strengthen their balance sheets. [Id.]

Q. What does Moody's say regarding UNSE's credit metrics?

A. Those obviously play a large part in determining a company's rating. For UNSE, Moody's states:

> UNSEs cash flow credit metrics have historically been strong; generally at or above the upper end of the ranges indicated in Moody's rating methodology for electric utilities rated Baa. For example, the ratio of cash from operations excluding changes in working capital (CFO - Pre WC) to Debt (adjusted in accordance with Moody's standard analytical adjustments), has been above 20% for the past several years. Credit metrics are expected to decline somewhat over the next few years, with CFO - Pre WC / Debt moving into the upper teens. The anticipated weakening in metrics reflects the impact of the termination of UNS Electric's full requirements power supply agreement with Pinnacle as well as its continuing growing capital expenditure program. Rating Level of Business Risk
>
> UNSG's credit metrics have also historically remained reasonably stable and generally within the ranges indicated for regulated gas distribution utilities rated Baa in Moody's regulated gas distribution methodology. Metrics are expected to improve modestly if reasonable rate relief occurs in the near-term. [Id.]

Q. Should the Commission be concerned about UNSE's bond rating and credit metrics?

A. Yes, this is a legitimate concern, particularly since the UNSE ratings are currently near the low end of the industry range, and any substantial further degradation could put the Company below the "investment grade" categories. The most obvious reason for concern is the impact of any further downgrading on the interest rates which would be paid by the Company when it needs to raise additional debt capital. As ratings decrease, the required interest on new issuances increases. These increased debt costs lead to higher costs for customers over the life cycle of the debt issuance.

Q. Can you elaborate on the potential adverse impact of an UNSE downgrade?

A. Yes. To fully understand the potential problems, it is helpful to review a few basic facts. First, the market for newly issued junk-rated debt is limited. While there are many junk bonds on the market, many of these were originally issued with higher ratings, and were subsequently downgraded when problems were subsequently encountered by the issuer. While it is possible to issue new debt with a low bond rating, provided the issuer is willing to pay a high enough interest rate, in practice the market for such debt is relatively thin and uncertain, and the cost could actually exceed the cost of equity.

As well, if UNSE were to assume the burden of paying inordinately high interest rates on newly issued debt, it would further reduce the amount of protection offered to its existing creditors, thereby increasing the risk of default or bankruptcy. In turn, this would increase the risk facing stockholders, which would lead to an increase in the cost of equity, making it more difficult to tap the equity markets, and result in a higher allowed return on fair value. Simply stated, a substantial further downgrading could lead to a series of undesirable ripple effects that are difficult to predict in advance, but are not in the best interests of either shareholders or customers, and which should certainly be of concern to the Commission.

Q. Are there aspects of the financial "crisis" which began in September 2008 which ought to be considered in evaluating the potential impact of an UNSE downgrade?

A. Yes. We have recently seen extreme swings in credit markets, triggered by relatively minor changes in the underlying facts. Once perceptions of the credit-worthiness of major institutions like Lehman Brothers or Wachovia turned a bit negative, the shift in perceptions began to feed on itself, leading to rapidly escalating atmosphere of fear and uncertainty, which in turn had very real consequences for these firms and others.

During a financial crisis or tight credit environment, even firms with an investment grade bond rating may find it more difficult than normal to issue additional debt or equity. Having a debt rating toward the low end of the utility industry, the Company may find it difficult to fully fund its planned capital construction program – bearing in mind that merely offering to pay higher than normal interest rates wouldn't necessarily solve the problem, since the very need to offer such high rates could be perceived as a sign of weakness, pushing away more risk-averse investors and making it harder to raise capital in the future.

Absent the ability to access the debt market on a routine basis at attractive interest rates, UNSE would be left with relatively limited and unattractive options. UNSE could slow, or halt, all but the most urgently needed construction projects, but if this were to continue for very long, it could result in a reduction in service reliability, or require extraordinary measures to maintain reliability, such as rolling brownouts during peak hours, or a temporary moratorium on new service connections .

Q. You've painted a rather bleak picture of the potential consequences if a bond downgrading were to occur. Are you suggesting that these risks should dominate the Commission's analysis of the issues in this case?

A. No, not at all. But I wanted to make clear that RUCO recognizes the importance of maintaining a reasonable debt rating, notwithstanding various differences of opinion that may exist concerning the most appropriate resolution of specific issues. That said, I am not by any stretch of the imagination suggesting that the Commission should throw all other concerns overboard or to accept every one of the Company's requests in this case, no matter how excessive or unreasonable, in a misplaced effort to minimize the risk of a downgrading. I believe a vigilant regulatory regime, which forces stockholders to absorb imprudent costs encourages greater efficiency and is ultimately in everyone's best interest.

Arizona has constitutional requirements that require fairness to both consumers and stockholders. As a result, it is certainly possible that the regulatory system may be somewhat less favorable to investors than one that is solely the creation of a legislature that is subjected to intense lobbying by the industries that are regulated. But, this is something the Commission should treat as a given. For regulation to work as intended, management of monopolies cannot be given a blanket promise of immediate, full recovery of any and all costs they have incurred, or anticipate incurring. Instead, it is appropriate to closely scrutinize the Company's application to identify a normalized level of reasonable, prudently incurred costs which are appropriate for consideration in determining rates to be paid by customers.

III. UNS Electric's Filing: An Overview

Q. Can you now summarize UNSE's overall revenue request?

A. Yes. UNSE requests a $13.5 million rate increase, or approximately 7.5% over test year revenues. [Application, p. 2] The requested increase is based in part on adjusted test year sales and expenses during the 2008 test year. However, it also reflects certain post-test year adjustments.

UNSE is also requesting two modifications to its current Purchased Power and Fuel Adjustment Clause ("PPFAC"). First, UNSE is requesting an increase to the interest it is allowed to collect when its PPFAC collections are less than actual purchased power and fuel costs. [Id.] Second, UNSE requests that credit-related costs to support the procurement of wholesale power and natural gas be included in its PPFAC. [Id.]

Finally, UNSE is requesting a post-test year adjustment to include the Black Mountain Generation Station ("BMGS") in rate base. [Id.] An affiliate, UniSource Energy Development Company, currently owns BMGS. The Company is requesting a related rate reclassification that results in an increase in its non-fuel base rate and a corresponding decrease in its power supply base rate; these offsetting rate changes are intended to cancel out, so the impact on the Company's revenues and customer bills will be neutral. [Id., p. 6]

Q. Has UNSE proposed various adjustments to its actual test year results?

A. Yes. UNSE has proposed several adjustments to its test year rate base. The largest adjustment is the proposed inclusion of BMGS in rate base. This adjustment would result in a $61.4 million increase in rate base. [BMGS Schedule B-2] In its "base" filing (i.e., excluding requests related to BMGS), UNSE is proposing certain other adjustments that collectively result in a $11.1 million increase in the rate base. [Schedule B-2] Total adjustments inclusive of BMGS result in a $72.5 million increase in rate base. Similarly, UNSE has proposed numerous adjustments to the actual test year operating income. In its base filing, these adjustments collectively result in a $216,965 net increase to its operating income above the actual level experienced during the test year. [Schedule C-1]

Q. Can you explain the concept of pro forma adjustments, in general terms?

A. Yes. Although terminology can vary, test year adjustments can be classified into various groups, based on the underlying purpose or theoretical basis for making the adjustment. Company witness Kissinger speaks of three major types: normalizations, annualizations and eliminations. He describes normalizing adjustments as follows:

> Normalization adjustments reflect that the recorded test year operating revenues and expenses may not be representative of a normal level for ratemaking purposes. Certain events may have affected recorded transactions in an atypical manner. Moreover, some transactions eligible for reflection in revenue requirements are incurred at intervals less frequent than annually, provide benefits extending beyond a single year, or reoccur in significantly different amounts each year. As a result, the amounts recorded in the test year may not be viewed as "normal," thus

> requiring a restatement for ratemaking purposes. [Kissenger Direct, p. 3]

Mr. Kissinger describes annualization adjustments as follows:

> Annualization adjustments are made to reflect the full, 12-month revenue or expense level of certain components of operating income. Annualization adjustments are typically computed using end-of-test-year quantities, and the most current known and measurable prices and rates. [Id.]

He describes eliminations as follows:

> Elimination adjustments are made to remove out-of-period or non-recurring transactions, or items that are not costs or revenues related to the provision of utility service. Thus, they are not eligible for reflection in revenue requirements. [Id.]

Many of the Company's proposed "annualization" adjustments are designed to bring costs and revenue to an end-of-test year basis, while others update costs beyond the test year, to reflect the impact of additional investment, inflation and cost changes which didn't occur until after the test year. While making "annualization" adjustments for "known and measurable" cost increases is a popular method for dealing with the closely related problems of inflation and regulatory lag, this method tends to be arbitrary and controversial, particularly when attempts are made to select a cut-off date or annualization data that goes beyond the end of the test year. Regardless of how well known or measurable a particular cost change may be, it is difficult to achieve internal consistency and an appropriate "matching" of revenues and costs when the adjustments go beyond the test year.

RUCO believes the Commission should continue to use an historical test year, and it should generally reject ad hoc adjustments stretching well beyond the test year. Even if the Commission were persuaded that a particular utility's financial situation warrants extraordinary measures that go beyond its traditional historical test year approach, I don't believe the best solution is to accept more and more adjustments for "known and measurable" changes, or to extend the cut off date for cost increases farther and farther beyond the end of the test year while leaving revenues frozen at the level which occurred during, or at the end of, the test year.

While it has long been accepted by this Commission and many other regulators, trying to solve a potential problem with inflation by adopting adjustments for "known and measurable" changes to the historic test year is an inherently difficult and controversial process. Should the Commission only consider changes which occurred during the test year? Or, should the Commission go a few weeks, or perhaps 6 months beyond the test year? While it is understandable why the Commission will sometimes go somewhat beyond the end of the test year, in my opinion, this is not the preferred solution to dealing with inflation and attrition. Among other problems, as adjustments stretch farther and farther beyond the test year, it becomes increasingly arbitrary to select a cutoff date; as well, the mismatch between revenues and expenses tends to become increasingly severe, and it becomes harder to ensure that the adjustments are both known and accurately measurable, and that the final result is a realistic and representative snapshot of the Company's operations.

To its credit, in the Company's filing, it mostly focuses on the test year. However, it makes a handful of exceptions in which it proposes adjustments that are calculated with different dates that go well past the end of the test year. No overarching principle has been put forward to justify the particular mix of adjustments and dates, and in my view the end result is not an improvement over an analysis which focuses on the Company's actual operating experience during the test year. There is no assurance that the end result of a series of inconsistent adjustments will be reasonable, or representative of actual conditions that can reasonably be anticipated in the future.

While I will readily concede that at first blush it seems reasonable to extend the cut-off date for known and measurable adjustments to go as far as possible past the end of the test year, this is not a good solution to an inflation or attrition problem, even assuming one exists (something which hasn't been proved in this case). Extending adjustments farther and farther beyond the test year tends to degenerate into an arbitrary, ad hoc, and ultimately unsound process of picking and choosing items to be included in the adjustment process, as well as picking and choosing the dates to be used in developing each of the adjustments. There is no sound theoretical basis for deciding exactly how far to go beyond the test year, yet it is clear that the farther one goes past the test year, the less the Commission will be relying on actual experience, and the more it will be relying on a hypothetical version of what might possibly occur in the future.

As well, the more one goes beyond the actual test year experience, the less confidence can be placed in the underlying premise that the test year represents a realistic, representative snapshot of the Company's actual revenues, costs, and income. By limiting the adjustment process to only consider revenue increases through December 2008, while including a range of cost increases stretching well beyond that date, the Company is proposing a mis-match of revenues and costs with no assurance that the final end result of this mis-matching process is in any way reasonable or accurate.

Rather than debating the merits of each of these adjustments in isolation, one-by-one, or attempting to put forward a different ad hoc mixture of adjustments, my general approach has been to start with a specific cut-off date, and then to remove all of the adjustments that are inconsistent with that cut-off date. More specifically, I recommend using a December 31, 2008 (or January 1, 2009) cut off date (these dates are essentially identical, in my view).

I realize that the Commission might feel some deviation from a strict historical test year may be warranted – e.g. by accepting some of the adjustments related to the first 6 or 9 months beyond the test year. However, rather than pursuing that sort of ad hoc solution, I would recommend the Commission instead use a simpler, more explicit approach. For instance, if the Commission were convinced that the Company's recent weak earnings merit some sort of additional compensation beyond that provided in prior cases, I don't believe ad hoc post-test year adjustments are an appropriate response. Instead, I would suggest using a simpler, more explicit approach, by allowing a slightly higher return on the fair value rate base than would otherwise be approved.

IV. Black Mountain Generating Station

Q. Can you now briefly discuss the Black Mountain Generating Station?

A. Yes. Black Mountain Generating Station (BMGS) is a 90 MW gas turbine generating facility in Northern Arizona. BMGS was recently developed, and is still owned, by UniSource Energy Development Company ("UED"), an affiliate of UNSE. The generating station consists of two LM6000 45 MW combustion turbines. [McKenna Direct, p. 13] These turbines were purchased by UED at a "discounted" price from another utility, which had never used them. [Application, p. 9] BMGS entered service on May 30,2008. [McKenna Direct, p. 13]

In June 2008, UED and UNSE entered into a 5-year Power Purchase Agreement (PPA) under which UED sells all the output of BMGS to UNS Electric. [Exhibit KGK-1, p. 15] Under the terms of the PPA, UNSE pays UED a fixed Capacity Charge of ***CONFIDENTIAL** $855,000 **CONFIDENTIAL*** per month. [See, UED-UNSE PPA, provided on response to Staff DR 1-9] UNSE receives a credit of ***CONFIDENTIAL** $9.50 **CONFIDENTIAL*** for each kW that falls below 90 MW in any month. [Id.] The costs associated with the PPA are recoverable through UNSE's PPFAC.

Q. What does UNSE propose regarding the BMGS??

A. UNSE proposes that UED transfer BMGS to the Company at a cost equaling $62 million, and that this value be added to rate base. [McKenna Direct, p. 16]

> This is the actual current book cost for BMGS and is not a "capped cost" that the Company proposed in its last rate case. UNS Electric proposes to use this actual cost of $62 million as the rate base value of BMGS, if it is included in rate base. [Id.]

UNS Electric proposes that the Commission approve a post-test-year adjustment to rate base and a revenue-neutral-rate reclassification that "reflects the completed cost of this facility upon the transfer of ownership to UNS Electric". [DeConcini Direct, p. 14] UNS Electric would finance the acquisition under the conditions approved by the Commission in UNSE's previous rate case. UNS Electric is authorized to incur up to $40 million of new debt financing and to receive up to $40 million in equity from UniSource Energy, to acquire BMGS. UNS Electric is proposing a rate reclassification that would result in an increase to the Company's non-fuel base rates and a corresponding decrease to UNSE's base power supply rate. [Id.]

Q. Did UNSE make a similar proposal in its last rate case?

A. Yes. UNSE proposed adding BMGS to rate base in Docket No. E-04204A-06-0783. Agreeing with RUCO and Staff, the Commission rejected that proposal as premature. [See, Decision 70360, p. 76] Like Staff, RUCO opposed including BMGS in rate base at that time, because: 1) neither the capital costs nor the operating costs of the plant were known; 2) adoption of the proposal would violate the ratemaking matching principle because customer counts at the time of the plant's completion would be different than the customer counts used in that case for setting rates; 3) the Company's request would violate the ratemaking principle that only "used and useful" plant should be accorded rate recognition; and, 4) there was not sufficient opportunity for close scrutiny of a transaction between affiliated entities. [See, Id.] However, the Commission concluded that there was "a compelling basis on which to encourage UNSE's acquisition of the BMGS". [Id.]

> To provide such encouragement, we will authorize UNSE to implement an accounting order to record any and all of the Company's financial activities associated with the BMGS, as if the BMGS were in rate base as of June 1, 2008. Unless otherwise ordered by the Commission, this accounting order would remain in effect until the effective conclusion of UNSE's next rate case. [Id., p. 76-77]

Q. Why has UNSE not already acquired the BMGS, in response to that encouragement?

A. The Company explains that it has not yet acquired BMGS because it does not have the financial strength to do so in the absence of some greater assurance from the Commission that the cost of the plant will be recovered from customers. It states that it "could simply not acquire an asset as large as BMGS without a commensurate increase in earnings and cash flow." [DeConcini Direct, p. 15] According to the Company, the deferred accounting treatment for BMGS approved by the Commission did not provide enough cash flow relief to "cover the interim cash costs that UNSE Electric would have had to incur to finance the BMGS acquisition". [Id.] Therefore, argues the Company, obtaining financing for the transaction would have been difficult. [Id.] Further, UNSE claims it would have "experienced a substantial decline" in key credit metrics during the interim period between the date when it acquired title to the plant, and the date when its base rates are increased to provide for recovery of the cost of the plant (rather than through the PPAC). [Id.]

Q. Where does BMGS fit into UNSE's overall mix of generation sources?

A. UNSE acquires most of its power through power supply contracts, including the contract for BMGS. The exception is its Valencia generating plant, which has 65 MW of combustion turbine peaking capacity. [McKenna Direct, p. 6] These sources collectively provide

> 70 to 100% of the approximate 475 MW of peak capacity required through May 31, 2010. For the summer (June through September) period of 2009, UNS Electric has 90 to 100% of its peak capacity hedged. The remaining capacity necessary to serve daily peak loads will be purchased

through the short-term daily and real-time markets. [Id.]

If it acquires ownership of BMGS, the Company will more than double the portion of its peak requirements which it meets with its own capacity; however, the majority of its peak requirements will still be met through power supply contracts, and an even larger majority of its energy needs will continue to be acquired through wholesale transactions (neither Valencia nor BMGS are base load plants).

Q. What are the benefits of owning BMGS when compared to purchasing power and peaking capacity on the wholesale market?

A. UNS points primarily to operational benefits, claiming greater flexibility, reliability and efficiency and a superior location. [McKenna, p. 17] Flexibility includes the ability to "utilize its instantaneous, load following and emergency dispatch capabilities". [Id.] Ownership also allows UNSE to address the "intermittency issues of certain types of renewable energy facilities that will be providing power to UNS Electric customers in the future." [Id., p. 18]

Ownership increases reliability, because the Company will have "complete discretion and control over maintenance and operation of the facility for the long term." [Id.] Owning BMGS increases efficiency, by allowing UNSE to "obtain the exact type of unit it needs to meet its requirements" and "better meet its peaking capacity and reserve needs of its supply portfolio on a long-term basis". [Id.] Finally, "because BMGS is located in UNS Electric's load area, it can help to minimize transmission costs and enhance system reliability". [Id.]

Q. What do you recommend regarding UNSE's BMGS request?

A. I recommend the Commission approve this aspect of the Company's filing, for several reasons. First and foremost, UNSE is highly depended on purchased power, with very little of its own generating capacity; this acquisition will improve UNSE's resource mix, making it less subject to the inherent risks associated with nearly exclusive reliance on wholesale markets. The only generating facility currently owned by the Company is the 65 MW gas turbine Valencia unit. The remainder of its 475 MW of peak capacity requirements is served by purchased power, either through purchased power agreements or on the spot market.

Second, the BMGS Combustion Turbines appear to have been acquired at a reasonable cost. In 2006, UED purchased the two LM6000 combustion turbines from Consolidated Edison in New York. The turbines were 2003 vintage units that had never been placed in service. According to UNSE, the purchase price of these units was 50% less than the cost of purchasing two new LM6OOO's from the manufacturer, General Electric. [McKenna Direct, p. 14] While I have not conducted an in-depth prudence analysis, I am not aware of any allegation of imprudence, or any claim that it would not be cost effective, over the life cycle of the plant, for UNSE to own this resource, rather than continuing to purchase power on the wholesale market.

Third, the Company's request for advance approval of the ownership transfer from the affiliate that built the plant is a reasonable one under the current circumstances – considering its small size and limited financial strength, and particularly given the Company's assurance that the ownership transfer will not increase current customer rates. By waiting to transfer ownership until it receives a Commission order granting rate base treatment, a potential problem with regulatory lag is avoided, eliminating a potential burden on stockholders, yet this would be accomplished without unduly burdening customers.

The Company and its affiliates will achieve continuous recovery of the cost of the plant; it currently receives cost recovery through the PPFAC; that treatment will end and base rate treatment will begin at the same time. Providing advanced authorization for this changeover at the time when title is transferred avoids a potentially serious problem with regulatory lag, which is particularly helpful in this situation, given the large size of the investment relative to the Company's small current capitalization. The $62 million cost of the plant is substantial, relative to the Company's $192 million existing total capitalization. [See, Grant Direct, p. 9]

Absent advance approval, the Company might have difficulty borrowing a portion of the funds needed to pay for the plant; similarly, a failure to grant approval of the ownership transfer now that the plant is operating and serving UNSE's customers could reasonably be interpreted by the Company as a possible indication of Commission displeasure or disapproval of the plant. Under those circumstances, it would not be unreasonable for the parent company to decline to make the necessary equity investment required to support the plant – preferring to keep its equity investment, and legal title to the plant, within an unregulated affiliate where it will have the maximum flexibility to decide whether to continue to sell the power to UNSE, to sell power on the open market, or to sell the plant to another owner.

Fourth, adding BMGS to rate base in this proceeding will not harm, and could possibly improve, the Company's credit metrics – something that is in the long term best interests of customers. UNSE's current credit rating from Moody's is Baa3, the lowest investment grade rating assigned by that rating agency. [Id.] Avoiding junk bond status is in the interests of ratepayers. Absent a special effort to overcome the regulatory lag problem, and assurance that the investment will be deemed prudent by the Commission, acquisition of the BMGS plant could jeopardize the Company's investment grade rating. However, acquisition of the BMGS plant will reduce the Company's risk exposure to the wholesale power market, providing it with a more balanced power supply mix, thereby improving its business risk profile, which will be beneficial to its credit outlook over the long term.

As well, the near term acquisition of this plant offers the long term potential for improved financial metrics, which could eventually lead to an improvement in its bond rating. The infusion of as much as $40 million of additional equity capital to support the BMGS investment (which has already been authorized by the Commission) would expand the

Company's balance sheet, ameliorating the impact of the additional debt needed to help finance the plant, and making the Company's financial metrics less susceptible to short term fluctuations in operating expenses. Significantly, the acquisition could improve UNSE's cash flow picture, since customers will continue to pay the full cost of the plant, but a portion of this cost will be reclassified as depreciation. As well, depreciation is a non-cash item, so a portion of the amounts currently being paid by customers will no longer be paid out for purchased power expense; the net result is likely to be an increase in funds from operations, as computed by financial analysts in future years.

V. Rate Base Adjustments

Q. Can you briefly describe the Company's first proposed rate base adjustment - the Acquisition Discount Adjustment?

A. Yes. In August, 2003, UniSource Energy purchased Citizens Communications Company's Arizona electric utility assets. UniSource paid less than book value for the assets, resulting in a "acquisition discount", or "negative acquisition premium". According to witness Dukes, Unisource paid $104.3 million less than the original cost of Citizen's electric assets. [Dukes Direct, p. 10] GAAP accounting requires this amount to be shown on the Company's books as a negative acquisition adjustment. However, when reviewing the proposed acquisition, the Commission approved a settlement agreement that included a negative acquisition adjustment of just $93.6 million, which is roughly 10% less than the actual amount booked. [See, Decision 66028, p. 8] The Acquisition Discount Adjustment

> takes the GAAP discount and reduces it to the value of the discount authorized by the Commission. Put another way, the GAAP discount must be eliminated for ratemaking purposes, thus increasing its original

> cost rate base. This increased rate base must then be reduced by the value of the agreed upon discount. Overall, this adjustment results in a net increase to rate base. [Dukes Direct, pp. 10-11]

Q. Did UNSE request a similar adjustment in its last rate case?

A. Yes. UNSE proposed an acquisition adjustment, which was not opposed by any party. [See, Decision 70360, p. 14]

Q. What is your conclusion with regard to the Acquisition Discount Adjustment?

A. I recommend approving this adjustment. As a general rule, assets are appropriately put into the original cost rate base at the amount expended when the asset was originally devoted to public service (less accumulated depreciation). It is reasonable to make an exception in this case, since the Company voluntarily agreed to less favorable regulatory treatment as part of a Settlement. I would also point out that the public interest is well served by adjusting the rate base downward by less than the full amount of the negative acquisition adjustment. This regulatory treatment effectively rewards the Company's stockholders for negotiating a favorable acquisition price – a result that greatly benefits customers relative to paying the full depreciated original cost, or an even greater amount, as is more typically the case.

Q. Can you now discuss the Company's second rate base adjustment - the Post Test Year Non-Revenue Plant in Service?

A. Yes. UNSE proposes to include 85 items in rate base that had not been placed into service by the end of the test year. [See, UNSE response to Staff DR 4.9] However, according to UNSE, the Company invested "every single dollar in this adjustment" before the end of the test year. [Dukes Direct, pp. 11-12] "These investments were not in service by the end of the test year, but will be in service when rates established in this case go into effect". [Id., p. 12]

Q. Did the Company propose any post test year adjustments to rate base in its last rate case?

A. Yes. In its 2007 rate case, UNSE requested the inclusion of construction work in progress (CWIP) in rate base. Alternatively, the Company requested the inclusion of post test year plant in rate base. [See, Decision 7360, p. 9] In that proceeding, UNSE argued that the majority of the CWIP expenditures "will not produce new revenue or reduce the Company's expenses but, instead, will improve service reliability for both new and existing customers". [Id., p. 6] The Commission noted that the few times CWIP had been allowed in rate base involved extraordinary circumstances, and concluded that "UNSE is not faced with an extraordinary situation that would justify inclusion of CWIP in rate base because the plant required to serve new customers will help produce revenues". [Id., p. 8]

The Commission further concluded that the Company could mitigate the effect of the CWIP investment through the accrual of AFUDC; allowing CWIP would undermine the balancing of test year revenues and expenses; and, regulatory lag can be both a benefit and determent to UNSE. [Id.] With regard to the Company's post test-year plant request, the Commission concluded that "post-test-year plant should not be included in rate base for the same reasons stated above with respect to the Company's request for CWIP". [Id., p. 9] The Commission further explained:

> This issue is virtually identical to that raised in the UNS Gas case (Decision No. 7001 1 , at 7-8). As we stated in that Decision, "although the Commission has allowed post-test-year plant in several prior cases involving water companies, it appears that the issue was developed on the record in those proceedings in a manner that afforded assurance that a mismatch of revenues did not occur" (Id.) For example, in Decision No. 66849 (March 19, 2004), we stated that "we do not believe that adoption of this method would result in a mismatch because the post-test-year plant additions are revenue neutral (i.e., not funded by CIAC or AIAC)" (Id. at 5). In the instant case, however, the Company's request appears to

> be simply a fallback to its CWIP position, and there is no development of the record to support inclusion of the post-test-year plant. ... Even if we were inclined to recognize post-test-year plant in this case, there is not a sufficient basis upon which to evaluate the reasonableness of the request (i.e., whether a mismatch would exist). We therefore deny the Company's proposal on this issue. [Id.]

Q. Can you describe the post-test year investments UNSE hopes to include in rate base in this proceeding?

A. Essentially, it is requesting rate base treatment for the portion of UNSE's CWIP balance, as of the end of the test year, which UNSE considers "non-revenue producing". [See, attachment provided by UNSE in response to Staff DR 4.9] It includes investments in intangibles, as well as transmission, distribution and general plant assets. [Id.]

Q. What is UNSE's basis for including these investments in its proposed rate base?

A. UNSE contends that, given anticipated future rate cases, "UNS Electric would not begin recovering its investment for over 3.5 years after the investments were made to serve existing customers. " [Dukes Direct, p. 12] Further, UNSE claims that it's request is reasonable because it is limited to "revenue neutral plant". [Id., p. 13]

Q. Do you agree with UNSE's proposal to include these investments in rate base, or this "revenue neutral" characterization?

A. No. First, it isn't clear what is meant by the term "revenue neutral" in this context. The effect of including these items in rate base certainly is not revenue neutral – it increases the rate base, and if it were approved, this proposal would increase revenues received by the Company and the bills paid by customers. Furthermore, there is nothing extraordinary about these investments; aside from being labeled "revenue-neutral" (whatever that means), these assets are not unlike many other assets that are routinely acquired by utilities in the ordinary course of business, benefiting both existing and future customers.

They include investments that should improve the Company's efficiency and help reduce operating expenses (e.g., "Project to replace existing work order, facilities data base & facilities mapping system with improved GPS based work order and mapping system"). They include investments that are necessary to accommodate growth (e.g., "Blanket account for line & service extensions to commercial businesses"), which will presumably be accompanied by future growth in revenues as well. They even include investments that may be reimbursed by third parties (e.g., "Damage to company facilities for which repair or replacement cost is billed to outside entities who cause the damage."). The list of proposed post-test year assets includes investments that are quite ordinary (e.g., "Specific project to construct a new warehouse with provisions for offices and material storage".

It is not a question of whether these investments are worthwhile, but whether they require extraordinary post-test year treatment. I see no evidence that special treatment is warranted in this case. The Commission should bear in mind that the Company will ultimately receive reimbursement for the cost of all of these investments from its customers. In fact, many of these investments will be paid for using internally generated cash flows received from customers through the allowance for depreciation which is included in existing rates. As well, even if an investment is financed with externally acquired funds, the cost of financing those investments will often be paid for through growth in revenues from increases in the sale of energy to existing customers as well as increases in the number of customers. To the extent any investments are not sufficiently offset through growth, depreciation, or reduced operating expenses, any resulting shortfall that might arise will be short lived, since they will be included in the rate base developed in future rate cases.

Second, as a matter of sound public policy, RUCO believes the Commission should continue to use an historical test year, and it should reject proposals to include in rate base a long list of investments which were not placed into service until well beyond the test year. UNSE claims that all of these investments will be in service by the time new rates will likely go into effect, but that is not a valid criteria for judging the merit of this proposal, since it is not proposing to adjust for growth in revenues that occurred after the end of the test year.

Third, it is inappropriate to modify the test year for some, but not all, of the impacts of post-test year events. For instance, it is impossible to know precisely how these assets will impact the Company's operating costs. In some cases, there may be additional maintenance and other costs; in other cases, costs may actually decline as a result of these investments, as older equipment is reinforced with new additions that increase reliability, or reduce the need to incur extraordinary labor costs to provide reliable service as the existing facilities near overload conditions, or it becomes feasible to operate more efficiently using better capital equipment and facilities.

In general, as new transmission and distribution facilities are added to the system it becomes feasible to serve load growth, which allows the Company to earn additional revenues. Yet, the Company has not made any adjustments for increased revenues associated with customer and sales growth which will be accommodated by, or occur contemporaneously with completion of these various projects. There is no justification for violating the matching principle by reaching well beyond the test year to the cost of these various projects while ignoring the accumulation of additional depreciation after the test year, as well as the offsetting benefit of operating cost decreases and revenue increases which will occur during contemporaneously with completion of these various projects. I believe it is preferable to adopt a uniform, consistent cut-off date as of the end of the test year.

Q. Can you now discuss the Company's third proposed rate base adjustment - Accumulated

Deferred Income Taxes?

A. UNSE reduced rate base by $684,777 to account for Accumulated Deferred Income Taxes. [Schedule B-2, p. 2] Company witness Kissinger explains this adjustment:

> The adjustment reduces rate base for the computed balance of Accumulated Deferred Income Taxes, a source of non-investor capital, based on adjusted test year rate base and operating results and the Company's existing income tax ratemaking authority. ... This reflects the ADIT associated with assets owned by UNS Electric at the end of the test year, and the results of operations for the test year. There are no incremental effects included for any potential future events. [Kissinger Direct, pp. 4-7]

I have included this adjustment in the $2,028,227 deferred taxes amount shown on line 10 of BJ-2.

Q. Can you now discuss the Company's fourth proposed rate base adjustment - Working Capital?

A. The Company reduced its rate base by $3.8 million as an allowance for negative working capital. [Schedule B-2, p. 2] Company witness Dukes explains this adjustment:

> The Working Capital adjustment was computed in two pieces. First, as indicated on page2 of Schedule B-5, the recorded end-of-test-year balances for Materials and Supplies, and Prepayments are adjusted to reflect the 13-month average monthly balances, in recognition of the variability in the monthly balances of the accounts. This is consistent with the treatment of such accounts in prior rate cases. Second, Working Capital is adjusted for the reflection in rate base of a measure of Cash Working Capital, developed through the preparation of a comprehensive lead-lag study. [Dukes Direct, p. 14]

While I have not undertaken a detailed, independent review of the Company's working capital needs, the Company's working capital allowance appears reasonable, and I have included it on line 12 of BJ-2, along with an amount related to BMGS, as shown on line 12 of BJ-3.

VI. Income Adjustments

Q. Let's discuss UNSE's proposed income adjustments. Can you begin by commenting on UNSE's first income adjustment?

A. UNSE's first income adjustment, "Retail Revenue and Purchased Power Annualization" is intended to adjust the test year revenues and expenses to reflect the impact of current rates, which went into effect mid-year 2008. This $11.7 million adjustment to operating income includes a $10.7 million increase in electric sales revenue, and a $956,469 decrease in purchased power expenses. [See, Schedule C]

Absent the revenue adjustment, the test year results would reflect a mixture of the previously approved rates and those that were in effect prior to the last rate case, making it difficult to compute the amount of any rate increase that might be warranted in this case, relative to current rates.

UNSE explains the purchased power expense adjustment as follows:

> It is necessary to maintain the operating income neutrality of the PPFAC process. The PPFAC process allows for recovery of all eligible fuel, purchased power and purchased transmission cost ("PPFAC eligible cost") without profit. The amount included in revenue in the form of base power supply charges and PPFAC charges must be equal to the amount of PPFAC eligible cost reflected within expenses. Thus when we annualize the revenue to reflect the PPFAC rate as of June 1, 2008, we must also annualize the PPFAC eligible cost to be equivalent. [Dukes Direct, p. 17]

Q. What is your conclusion regarding this adjustment?

A. As with many of the proposed adjustments, I primarily focused on the ratemaking theory underlying the Company's proposal. I concluded that it is reasonable to make an adjustment of this type, in order to keep the base rates and PPFAC rates in synch, and to maintain an appropriate matching between revenues and expenses. Accordingly, I have included this adjustment in my recommended revenue requirements, as shown on BJ-7, page 1 in column (B). As with other proposed adjustments that I accepted for purposes of developing my revenue requirement recommendations, I am not vouching for the Company's calculations, and I reserve the right to comment further on those calculations, at a later point in the proceeding.

Q. Can you now discuss UNSE's second income adjustment - Wholesale Revenue and Purchased Power?

A. This adjustment includes a $10.1 million decrease to Sales for Resale revenue, and a corresponding $10.1 million decrease to Fuel and Purchased power expenses. [Schedule C] This adjustment is designed to ensure that any profits on wholesale transactions are credited to customers through the PPFAC. UNSE explains:

> For book purposes the revenue associated with wholesale sales is recorded and 100% of that is also booked as a PPFAC regulatory liability (ultimately to credit customers through the PPFAC). There are also expenses associated with producing those revenues and those are expensed as incurred. Without adjustment the profit on those sales would flow through the income statement. Therefore an adjustment is made to the Company's actual books to bring the expenses up to the revenue level. By making that adjustment, there is no operating income from wholesale transactions. That "profit" is maintained in the PPFAC regulatory liability, which is then credited to customers through the PPFAC. So, the PPFAC rate reflects any profit in wholesale transactions and reduces the ultimate cost to customers. Therefore, we take the cost and the revenue out of the test year (which zero themselves out) because the profit on wholesale transactions is already reflected in the PPFAC rates... [Dukes Direct, p. 18]

Q. What do you conclude regarding this adjustment?

A. This adjustment also appears to be appropriate and consistent with the Commission's past policy. Accordingly, I have included it on BJ-7, page 1 in column (C).

Q. Can you now discuss UNSE's third income adjustment - Weather Normalization?

A. This adjustment is intended to restate the test year results as if perfectly normal weather conditions had occurred. UNSE's analysis indicates that during the test year weather was slightly hotter than normal, resulting in sales that were slightly greater than normal. [Erdwurm Direct, p. 9] Accordingly, UNSE made negative adjustments to revenues and expenses, for a net $186,687 reduction in operating income. [Schedule C]

Q. What do you conclude regarding the weather adjustment?

A. A similar adjustment was unopposed and accepted by the Commission in UNSE's last rate case. This type of adjustment is consistent with the underlying purpose of using a historical test year, which is simply a device for analyzing the normal level of revenues and costs which can be expected in the future. Therefore, I have included this adjustment in developing my recommended revenue requirements, as shown on BJ-7, page 1 in column (D).

Q. Can you now discuss UNSE's fourth income adjustment - Customer Energy Annualization & Customer Demand Normalization?

A. This adjustment restates test year bills and volumes "to be consistent with the number of customers on the system at the end of the test year". [Erdwurm Direct, p. 10] UNSE's customer count adjustment results in a 11,151,325 reduction in kWh. [Id., p. 11] This 0.7% reduction in kWh results in a $1.7 million decrease in operating income. [Schedule C-2]

Q. What do you conclude regarding this adjustment?

A. A similar adjustment was unopposed and accepted by the Commission in UNSE's last rate case. As well, this type of adjustment is appropriate if the Commission is going to use an end-of-year rate base, as has been its typical practice. Hence, in developing my recommended revenue requirement, I have incorporated the adjustment amount proposed by the Company, as shown on BJ-7, page 1 in column (E).

Q. Can you now discuss UNSE's fifth income adjustment - Normalization of Revenues and Expenses for Fuel and PPFAC?

A. This adjustment normalizes test year PPFAC-eligible costs and revenues to the average rate included in UNSE's April 1, 2009 PPFAC submission.

> That submission results in an overall system average recovery rate for fuel, purchased power and purchased transmission cost at $0.067738 per kWh of sold energy when applied to test year billing determinants. This is 21% less than the overall system average rate of $0.086191 billed within rates from January lst, 2008 through December 31st, 2008. [Dukes Direct, p. 19]

The adjustment modifies test year operations to reflect the Company's most recent estimation of fuel, purchased power and purchased transmission expenses, with the intent of synchronizing the base rate calculations with the PPFAC rate calculations. The result is a $10.2 million reduction in operating income. [Schedule C] UNSE explains that the net result of all its PPFAC adjustments is "income neutral".

> Adjusted retail revenues for customer charges and delivery charges reflect the most recent rates that went into effect June 1, 2008 applied to the customer levels at the end of the test year and usage levels adjusted for normal weather. And the PPFAC eligible revenues and PPFAC eligible cost are based on the overall average rate effective June 1,2009, applied to the test year adjusted customer and consumption levels. Thus the PPFAC eligible revenue and PPFAC eligible cost have "zero" impact on operating income (no rate increase impact), but establish an overall base cost of fuel, purchased power and purchased transmission of $0.067738 per kWh - which is our best estimate of the cost at this point in time. [Dukes Direct, p. 19]

Q. What do you conclude regarding this adjustment?

A. As I understand it, this adjustment will have no net impact on customer bills, and is designed to synchronize the base rates with the most recent PPFAC submission by the Company. This adjustment appears to be consistent with past Commission practice, and I have included it in my recommended revenue requirements, as shown on BJ-7, page 1 in column (F).

Q. Can you now discuss UNSE's sixth income adjustment - CARES Discounts?

A. According to the Company, this normalization adjustment is required because "subscription to the CARES program is increasing". [Erdwurm Direct, p. 18] The $61,797 adjustment increases the test year level of discount to $752,265, which "better approximates discounts that will prevail when rates are in effect". [Id.]

Q. What do you conclude regarding this adjustment?

A. Although the process by which UNSE calculated this adjustment is not entirely clear to me, it appears that Company has estimated an increase in the CARES discount based on an increase in the number of customers who were receiving the benefit of this discount as of the end of the year. Assuming I have interpreted the calculations correctlty, the adjustment does not go beyond the end of the test year, and it appears reasonable. Accordingly, I have included it in my recommended revenue requirements, as shown on BJ-7, page 1 in column (G).

Q. Can you now discuss UNSE's sixth income adjustment - Demand Side Management (DSM) Revenues and Expense?

A. In the Company's last rate case, it proposed a Demand-Side Management ("DSM') adjustor mechanism to recover costs of its DSM programs. UNSE and Staff agreed that the mechanism would be used to fund 100 percent of its expanded Low Income Weatherization ("LIW") program costs, and 25 percent of the other DSM program costs. [See, Decision 70360, p. 57] The Commission initially set the DSM adjustor at $0.000583 per kWh, and decided the amount would be adjusted annually on June 1 of each year. [p. 57]

In this proceeding, UNSE has adjusted revenues and expenses for a net $168,787 increase in operating revenues. The Company explains: "This adjustment excludes from test year revenue and expenses the activity directly related to the DSM adjustor mechanism approved in Commission Decision No. 70360". [Dukes Direct, p. 20]

Q. What do you conclude regarding the DSM adjustment?

A. This adjustment appears reasonable, and I have included it in developing my recommended revenue requirements, as shown on BJ-7, page 1 in column (F).

Q. Can you now discuss UNSE's seventh income adjustment - Payroll Expense?

A. This adjustment consists of a $220,252 increase to operating expenses. [Schedule C] In calculating this adjustment, UNSE used end of test-year employee levels, and a mixture of 2009 and estimated 2010 wage levels.

> The Payroll Expense adjustment is intended to reflect in operating expenses an annualized level of salaries and wages based on current rates of pay and the number of employees on the UNS Electric payroll at the end of the test-year. That annualized level is then adjusted for the known pay rate increase that will go into effect January 1, 2009 and the estimated pay rate increase that will go into effect January 1,2010. [Dukes Direct, pp. 20-21]

Q. What is your conclusion regarding this adjustment?

A. I disagree with the portion of this adjustment that includes estimated pay increases that won't go into effect until far beyond the end of the test year. I do not object to including the January 1, 2009 pay increase, since this helps synchronize this cost with other aspects of the test year calculations, but it is not appropriate to include the second portion of the adjustment.

Accordingly, I have incorporated a similar adjustment in my revenue requirement analysis, but it uses the December 31, 2008 employee levels in conjunction with wage levels that went into effect the next day, on January 1, 2009. This modified adjustment results in a $79,628 increase to operating expenses, as shown on BJ-7, page 2 in column (I), rather than the $220,252 increase proposed by the Company.

Q. Can you now discuss UNSE's eighth income adjustment - Payroll Tax Expense?

A. UNSE explains:

> The Payroll Tax Expense adjustment was computed in a manner similar to, and consistent with, the payroll adjustment. An annualized level of payroll taxes was computed using current payroll tax rates, the same end-of-test-year employee levels and current salary rates that were used in the payroll adjustment. [Dukes Direct, p. 21]

The proposed adjustment consists of a $55,054 increase to operating expenses. [Schedule C]

Q. What is your conclusion regarding this adjustment?

A. I don't dispute the underlying premise of this adjustment, but have modified it to be consistent with my modifications to the payroll expenses adjustment. In other words, I used December 31, 2008 employees levels, and the wage levels that went into effect in January, 2009. This modified adjustment results in a $35,430 increase to operating expenses, as shown on BJ-7, page 2 in column (J).

Q. Can you now discuss UNSE's ninth income adjustment - Pension and Benefits?

A. This adjustment is "intended to reflect in operating expenses a level of pension and benefits expense reflecting the end-of-test-year work force, current pension and benefit actuarial expense level, and a normal level of business activity". [Dukes Direct, p. 22] The adjustment includes pensions, the Company's share of contributions to the employees' 401(k) plan, and current medical costs. [Id.] The adjustment consists of a $220,252 increase to expenses. [Schedule C]

The adjustment was calculated as the difference between actual test year expense, and the level of expense estimated for 2009. [See, Income - Pension & Benefits 12-08.xls provided in response to Staff's second set of data requests] Essentially, UNSE has replaced actual 2008 expenses with anticipated 2009 expenses.

Q. What is your conclusion regarding this adjustment?

A. I recommend against this adjustment. It is reasonable to rely on the actual pensions and benefits expenses during the test year, and it isn't appropriate to estimate the level of costs that will be incurred during 2009.

Q. Can you now discuss UNSE's tenth income adjustment - Post Retirement Medical?

A. Witness Dukes explains: "The Post Retirement Medical adjustment is intended to reflect in operating expenses a level of post retirement medical payments reflecting the end-of-test-year work force level.". [Dukes Direct, p. 22] The adjustment consists of a $161,929 increase to expenses. [Schedule C]

Q. What is your conclusion regarding this adjustment?

A. This adjustment appears reasonable and consistent with past Commission practice, and I have included it in developing my recommended revenue requirements, as shown on BJ-7, page 2 in column (L).

Q. Can you now discuss UNSE's eleventh income adjustment - Rate Case Expense?

A. The adjustment consists of a $138,890 increase to expenses. [Schedule C] UNSE explains:

> The Rate Case Expense adjustment addresses the outside costs already incurred, and expected to be incurred, in connection with this rate case. This amount is an estimate of the anticipated final cost and will be updated before this proceeding concludes. The adjustment amortizes the balance to expense over three years. This is the approximate time period between when UNS Electric filed this rate case and when the next rate case will likely occur. The adjustment also reflects the collection of the anticipated remaining balance of rate case expense allowed to be recovered in the last UNS Electric Rate Order. That remaining balance will also be amortized over the anticipated life of rates in this case. [Dukes Direct, p. 23]

To calculate this adjustment, UNSE assumes $500,000 in rate case expenses annualized over 3 years, for an annual expense of $166,667. [See, Income - Rate Case Expense 12-08.xls provided in response to Staff's 2nd set of data requests] UNSE then adds $30,556 as the remaining amount of rate case expense approved in the last rate case, and subtracts $58,333 as the amount of rate case expense approved in the last rate case which had already been collected during the test year. [Id.] The net result is the $138,890 decrease in operating income.

Q. What is your conclusion regarding this adjustment?

A. In the prior rate case, UNSE calculated rate case expenses based on an assumed $600,000 cost. The Commission concluded that was an excessive amount of assumed rate case expense, and approved an adjustment that assumed $300,000 in rate case expenses instead. [Decision 70360, p. 24] This rate case was filed just 2 years after the prior rate case filing. This proceeding involves many of the same company witnesses, and many of the same issues. Given the commonality of witnesses and issues, I see no reason why the Company's rate case expenses should increase sharply above the level found reasonable in the prior case. Accordingly, I have used the Company's methodology, but have assumed a lower level of rate case expense of $300,000. To the extent the Company chooses to spend more than this amount, the excess amount should be the responsibility of the stockholders, and not borne by customers. As shown on BJ-7, page 2 in column (M), this results in a $72,223 increase to operating expenses.

Q. Can you now discuss UNSE's twelfth income adjustment - Bad Debt Expense?

A. Yes. This adjustment consists of a $436,441 decrease to operating expenses. Consistent with the methodology approved in the last rate case, UNSE developed a bad debt expense ratio based on the average annual bad debt expense for the years 2006-2008, and average annual unadjusted retail revenues for 2006-2008. UNSE then applies this ratio to test year revenues adjusted for revenue annualization, customer annualization, weather normalization, the PPFAC revenue adjustment, and CARES discounts. [See, Income - Bad Debt Expense 12-08.xls provided in response to Staff's 2nd set of data requests] Since actual bad debt expense was significantly greater in 2008 than 2006 and 2007, the averaging method results in a downward adjustment to test year expenses.

Q. What is your conclusion regarding this adjustment?

A. The adjustment is reasonable, and appears to be calculated in a manner consistent with the Commission's order in the prior rate case. Bad debt expense increased during 2008, as the economy turned down and more customers had trouble paying their bills. Hopefully, this problem will be short lived, and as the economy stabilizes bad debt expense will return to a more normal level. In any event, it is reasonable to normalize this expense to eliminate the impact of short term fluctuations, just as revenues are normalized to eliminate the impact of weather fluctuations. Accordingly, I included this adjustment on BJ-7, page 2 in column (N).

Q. Can you now discuss UNSE's thirteenth income adjustment - Interest on Customer Deposits?

A. This adjustment consists of a $145,701 decrease to operating expenses. [Schedule C] This is described as a normalizing adjustment "to reflect the currently applicable interest rate and balance of customer deposits as of the end of the test year." [Dukes Direct, p. 24]

Q. What is your conclusion regarding this adjustment?

A. This type of adjustment is appropriate, in order to synchronize the level of interest on customer deposits with the end of the test-year rate base, and other adjustments that are tied to this cut off date. Accordingly, I recommend the Commission approve this adjustment. I have incorporated this adjustment into BJ-7, page 2 in column (O).adjst

Q. Can you now discuss UNSE's fourteenth income adjustment - Workers Compensation?

A. Yes. This adjustment consists of a $115,528 decrease to operating expenses. [Schedule C] It is designed to "to normalize the workers compensation expense level within the test year to an expected recurring level". [Dukes Direct, p. 24] UNSE further explains:

> This adjustment reduces the test year level to reflect a three year average for the expense which has fluctuated between a credit of $4 thousand in one of those years and as much as $212 thousand in expense in another. [Id.]

Q. What is your conclusion regarding this adjustment?

A. This adjustment appears to be calculated in a manner consistent with the approach approved by the Commission in the previous rate case, and I have included it in developing my recommended revenue requirements, as shown on BJ-7, page 2 in column (P).

Q. Can you now discuss UNSE's sixteenth income adjustment- Miscellaneous Expenses?

A. Yes. This adjustment consists of a $342,454 decrease to operating expenses. [Schedule C]

> This adjustment removes test-year expenses that should not be included

> in revenue requirements because they are for out-of-period activity, not reflective of test-year activity and/or should not be recovered from customers. Also included in this adjustment is an increase to test year postage expense to reflect the postage rate increases that went into effect May 12, 2008 and May 11, 2009. Additionally, the normalization of outside legal cost is contained within this adjustment. [Dukes Direct, p. 25]

Outside legal costs were normalized to reflect a three-year average. [Id.] UNSE explains:

> In this case, the test year activity did not fairly reflect a normal and recurring level, prior to adjustment, the test year contained $141 thousand in outside legal costs related to the last UNS Electric rate case filing that were disallowed recovery of and thus written off within the test year. Once that adjustment is made the test year level is only $28 thousand, which is not reflective of normal and recurring levels. In 2005, 2006 and 2007 the Company spent $128, $106 and $181 thousand respectively, on outside legal costs, excluding UNS Electric rate case activity. That results in a three-year average of $138 thousand which is reflective of normal and recurring levels and is consistent with expected spending levels. [Id.]

This adjustment also excludes a portion of certain organizational dues. Specifically, UNSE removes 1% of USWAG dues, and 16% of EEI dues.

Q. What is your conclusion regarding this adjustment?

A. While the general thrust of the adjustment is reasonable, I disagree with the amount.

To begin with, I disagree with UNSE's exclusion of just 1% of USWAG does and 16% of EEI dues. Neither exclusion is sufficient, in my opinion. I say this for two primary reasons. First, a large, but indeterminate, portion of these organizations' activities are designed to influence government policy, both directly (supporting industry lobbying and public relations efforts with respect to Congress and various State and Federal agencies) and indirectly (through various types of policy studies and research which support those efforts). The Company has focused on a narrow subset of this overall range of activities – those which are most directly related to influencing legislation, but the entire range of activities is primarily the responsibility of, and for the benefit of, stockholders.

Second, these organization's activities would continue whether or not UNSE or any other Arizona utility belongs to the organization, or contributes to the budget for these activities. Thus, it is hard to say these costs are necessary for the Company to incur, or that membership offers any significant benefits to the Company's ratepayers. Taking both of these problems into account, I recommend that ratepayers be required to bear no more than a reasonable portion of these dues. While the specific split between stockholders and ratepayers is a matter of discretion for the Commission, in preparing my recommendations I have excluded 40% of the cost, consistent with RUCO's position in the pending UNS Gas rate case.

With regard to the adjustment for legal costs, I agree it is reasonable to use a "normalized" level of legal expense, and I don't object to using a relatively brief, recent period to develop an estimate of the ongoing, normal level of cost. However, the Company used a 3 year average that excluded the test year. In my view, it would be more appropriate to use an average that includes the recent 2008 level of legal expenses, and it would be appropriate to exclude the cost of the prior rate case. More specifically, I recommend using an average of the Company's 2006, 2007 and 2008 legal expenses, excluding costs associated with the prior rate case, which are being dealt with separately.

I have also modified the postage portion of this adjustment. My revised postage calculations include the portion related to the postage rate increase that went into effect during the test year, but I have excluded the portion related to the May 2009 postage increase, since this went into effect well beyond the end of the test year. My recommended adjustment is shown on BJ-7, page 2 in column (Q).

Q. Can you now discuss UNSE's seventeenth income adjustment- A&G Expense Capitalized?

A. Yes. This adjustment consists of a $229,429 decrease to operating expenses. [Schedule C] UNSE states that the adjustment is necessary to "normalize the level of administrative and general charges capitalized during the test year". [Dukes Direct, p. 25]

> The charges capitalized are for services performed by personnel in support areas like Information Services, Plant Accounting, and Operational Systems Support. A study was performed during the test year to evaluate the time spent by these service areas in support of capital activities. A new capitalization rate was determined and put into effect in the first quarter of 2009. This new rate was used to normalize test year activity and more properly reflect the known capitalization rate going forward. [Id., pp. 25-26]

Q. What is your conclusion regarding this adjustment?

A. This adjustment appears reasonable. I have included it in my recommended revenue requirements, as shown on BJ-7, page 3 in column (R).

Q. Can you now discuss UNSE's eighteenth income adjustment- Depreciation and Property Tax for Post Test Year Non-Revenue Producing Plant in Service?

A. This adjustment consists of a $442,526 increase to operating expenses. [Schedule C] UNSE does not provide a discussion of this adjustment. However, it appears to be directly related to the supposedly "non-revenue producing" plant investment the Company proposes to add to rate base, which was not in service during the test year. I recommend the Commission disallow this adjustment, consistent with my recommendation regarding rejection of the proposed addition to rate base.

Q. Can you now discuss UNSE's nineteenth income adjustment- Depreciation & Amortization Annualization?

A. This adjustment consists of a $507,792 decrease to operating expenses. [Schedule C] UNSE explains:

> The Depreciation Expense adjustment is computed to reflect in pro forma operating expense an annual depreciation amount based on depreciable plant in service as of the end of the test year and book depreciation rates as presented in detail in the testimony of witness Dr. Ronald E. White. The calculation of the adjustment properly considers the effects of depreciation associated with vehicles that are charged to clearing accounts or expense categories other than depreciation. This adjustment does not include any amounts related to BMGS. The depreciation expense requested for BMGS is presented separately. [Kissinger Direct, p. 7]

Q. What do you conclude regarding this adjustment?

A. This adjustment appears reasonable, and I recommend the Commission accept it. I have included it in my recommended revenue requirements, as shown on BJ-7, page 3 in column (T).

Q. Can you now discuss UNSE's twentieth income adjustment- Property Tax Expense?

A. Yes. This adjustment consists of a $7,358 decrease to operating expenses. [Schedule C] The adjustment is based in part on the assessment ratio that won't go into effect until January 1, 2010. [Kissinger Direct, p. 8]

Q. What do you conclude regarding this adjustment?

A. By using the 2010 assessment ratio, this adjustment goes too far beyond the test year. I have developed an alternative adjustment, as shown on BJ-7, page 3 in column (U), which uses the 22% assessment ratio, which is applicable "from and after December 31, 2008 through December 31, 2009". [See, page 20 of Income - Property Tax Expense 12-08_bates.pdf, provided in response to Staff's 2nd set of data requests]

Q. Can you now discuss UNSE's final income adjustment- Income Taxes?

A. This adjustment is intended to reflect the Company's final adjusted operating revenues, expenses and rate base. The Company explains that it is computed in two parts.

> The first part is pro forma current income tax expense, the tax liability computed as though an actual income tax return was being prepared on final adjusted test year taxable operating income. For this purpose, it was necessary to identify all operating book-tax differences ("Schedule M items"), both timing and permanent, and then recompute based on adjusted test year operating revenues and expenses, if necessary. The tax deduction for interest was computed using a synchronization methodology reflecting final adjusted rate base and the weighted cost of debt in the capital structure. The second part of the income tax calculation is deferred income tax expense. Deferred income taxes are computed on the Schedule M items representing timing differences for which the Company has obtained normalization ratemaking authority from the Commission as previously described in my testimony. [Kissinger Direct, p. 8]

Q. What do you conclude regarding this adjustment?

A. The basic approach the Company is using seems reasonable. I have used a similar approach in computing my income tax adjustment, on BJ-7, page 3 in column (V), modified to be consistent with my other recommendations.

Q. Are there any other expense related adjustments you would like to discuss?

A. Yes. First, while I have not quantified specific adjustments related to Incentive Compensation, Stock-Based Compensation, and the Supplemental Executive Retirement Plan (SERP), RUCO's position on these expenses is well known to the Commission. As a matter of sound public policy, RUCO continues to urge the Commission to disallow all Stock-Based Compensation Expenses and SERP expenses, and to disallow 50% of Incentive Compensation Expenses. The effect of this policy is to place responsibility for these costs on stockholders, rather than ratepayers. The rationale for this policy is set forth in detail in the testimony of Ralph Smith, filed on behalf of RUCO in the pending UNS Gas rate case.

Second, RUCO believes it would appropriate, again as a matter of sound public policy, to exclude a portion of purchased power and fuel related costs from the Company's PPFAC, in order to provide an incentive for management to aggressively control these costs, and to manage its power and fuel acquisition process as efficiently as possible. Historically, the Company has acquired nearly all of its energy from a single supplier (Arizona Public Service Company), and so arguably there was not a great need for an incentive mechanism in the PPFAC. However, the Company plans to begin purchasing more power on the wholesale market, and it plans to produce more of its power using its own generating facilities. Accordingly, I recommend adopting a 90/10 sharing mechanism for UNSE that is like the one utilized by APS.

VII. Fair Value Rate of Return

Q. The Commission's traditional method of calculating a rate of return for application to a fair value rate base was recently addressed by the Arizona courts. Can you briefly explain that proceeding, and how it relates to this case?

A. On September 30, 2005 the Commission issued Decision No. 68176 granting a rate increase to Chaparral City Water Company. ("Chaparral") In accordance with longstanding precedent, the Commission multiplied the weighted average cost of capital (WACC) by the original cost rate base (OCRB) to estimate the needed operating income. [Decision 68176, pp. 26-28] The Commission then divided that required level of operating income by the fair value rate base (FVRB) to arrive at a fair rate of return. [Id., p. 28] The fair rate of return was then applied to the FVRB to determine operating income for rate making purposes. Chaparral subsequently filed an appeal with the Arizona Court of Appeals that, among other things, has resulted in the Commission rethinking its approach to developing the rate of return it applies to the FVRB.

Q. Did the Court of Appeals address the methodology for determining a fair rate of return?

A. Yes. First, the court recognized that the Arizona Constitution gives the Commission "exclusive and plenary" authority to prescribe rates for public utilities within the state. [Chaparral City Water Company v. ACC, 1 CA-CC 05-0002, Memorandum Decision, p. 5] However, the court also noted that the state Constitution specifically requires the Commission to ascertain the "fair value" of the utility's property. [Id., p. 6]. Article 15, Section 14 of the Arizona Constitution states:

> The corporation commission shall, to aid it in the proper discharge of its duties, ascertain the fair value of the property within the state of every public service corporation doing business therein; and every public service corporation doing business within the state shall furnish to the commission all evidence in its possession, and all assistance in its power, requested by the commission in aid of the determination of the value of the property within the state of such public service corporation.

The court stated that this provision has been interpreted as requiring the Commission to determine the fair value of the utility's property, and to use that finding as the rate base in setting rates. [Id., citing Simms v. Round Valley Light & Power Co., 294 P. 2nd at 382] The court noted that the Arizona Constitution does not define fair value, but stated that it is "generally recognized as being based on both original cost and reproduction cost". [Id., p. 4, f.n. 4]

On appeal, Chaparral argued that operating income should be determined by multiplying the FVRB by the rate of return, and that "the rate of return is generally equal to a utility's weighted cost of capital". [See, Id., p. 7] The Commission responded by asserting that it was not bound to use the weighted average cost of capital as the rate of return to be applied to

FVRB. The court agreed, stating:

> If the Commission determines that the cost of capital analysis is not the appropriate methodology to determine the rate of return to be applied to the FVRB, the Commission has the discretion to determine the appropriate methodology. [Id., p. 13]

The court also noted that "rates of return vary, depending upon the type of rate base used". [Id., p. 7, f.n. 5] However, the Court of Appeals found that the Commission's method for determining operating income ignored fair value rate base, in violation of the Arizona Constitution.

> Here, the Commission determined Chaparral City's operating income based on the OCRB and then mathematically calculated a corresponding rate of return had the income been based on the FVRB. Under this method, Chaparral City's operating income, and therefore its revenue requirements and rates, were based not on the fair value of its property, but on its OCRB, which does not comport with the Arizona Constitution. [Id., p. 12]

Accordingly, the court remanded the matter to the Commission for further determination.

Q. What did the Commission decide on remand?

A. On July 28, 2008, the Commission issued Decision No. 70441, in which it stated:

> Our previous method was a shorthand method of ensuring that inflation would only influence one piece of the ratemaking formula - the rate of return. However, the Court of Appeals has made it clear that, under our constitution, the "inflation component" belongs in the FVRB. Accordingly, in order to avoid over-counting the effect of inflation, it is necessary for us to ensure that the rate of return does not also carry an inflation component. [Decision No. 70441, p. 33]

The Commission noted that there are many methods that could be used to determine an appropriate FVROR, including the methods advocated by Staff and RUCO in the Chaparral case. [Id., p. 34] Staff's method "adjusts the cost of capital to reflect the cost of the portion of the capital structure that is funded by neither debt nor equity, but exists due to inflation". [Id.] RUCO's method "analyzes the inflation contained in the estimates of cost of equity and adjusts the cost of capital to eliminate the inflation component". [Id.] Ultimately, the Commission used a method similar to the one I recommended on behalf of RUCO, but with a significant modification, which limited its scope. [Id.]

Q. Are there other methods available for the Commission to deal with this issue in this proceeding?

A. Yes. The Commission has several methods to choose from, including: the method I recommended on behalf of RUCO in the Chaparral remand proceeding; the modified method that was subsequently adopted by the Commission in the Chaparral remand proceeding; and three other methods, which have been advocated by Staff in various proceedings.

Q. Can you describe the method that was recommended by RUCO in the Chaparral remand case?

A. Yes. As I explained in that proceeding, in jurisdictions where the rate base is entirely based on original cost data, it is common practice to apply a rate of return which is based upon the weighted average cost of capital, derived in large part using accounting data (e.g. debt and equity amounts; embedded interest rates). In contrast, where the rate of return will be applied to the current value of the utility's property, a lower return is appropriate – one that provides the utility with an opportunity to recover its actual capital costs, without overcompensating for inflation.

A rate of return that is fair to both customers and stockholders can be derived from the weighted average cost of capital by simply subtracting an amount related to the rate of inflation, thereby preventing a double counting of compensation for inflation. For example, assume the weighted average cost of capital is 7.50%, and the relevant inflation rate is 2.5%, then a fair return on the fair value rate base would be 5.00%, or thereabouts.

Q. Why is it appropriate to remove inflation from the rate of return?

A. A typical cost of capital, which includes inflation, cannot be applied to the fair value rate base because this would result in a double counting of inflation. A fair value valuation of the rate base tends to be higher than an original cost valuation, because it also reflects the impact of inflation and other factors which tend to contribute to an upward growth in value over time. Economists have long recognized that inflation and other factors which increase the value of an investment will significantly impact an investment's expected return. In turn, these factors affect the present value of the investment. To fully understand this relationship, it is necessary to realize that growth in the value of an investment is a component of the total return achieved by the investor. Indeed, for many so-called growth stocks which pay little or no dividends, virtually the entire return received by the investor results from growth in the market value of the stock (capital gains). The same principle applies to the value of rental property in areas where real estate prices (and/or rents) are escalating – investors will take into account the anticipated growth in the value of their investment – similar to the way growth stocks are evaluated.

Similarly, if the income being generated by a particular investment is expected to grow over time (e.g. rents are increasing), that will tend to push up the current market value of an investment. Investors will accept a lower current return from an investment, if they have reason to believe the return will increase over time.

The current market value of an investment is determined by the net effect of multiple factors, including the current annual income or return (in dollars), expected changes in that income or return, and expected changes in the value of the investment. Thus, real estate investors in areas where demand is growing will often purchase property with an extremely low or negative current cash return, because they anticipate profiting from future growth. Similarly, investors might construct a new office building, despite the fact that the rent payments during the first few years will actually be less than their direct expenses (interest, utilities, taxes, etc.), indicating a negative current level of return – if they expect rents, and/or the value of the property, to increase sufficiently in the future. Investors take into account all aspects of anticipated returns, including past and future trends in market rents, as well as anticipated growth in the value of the building. If the growth expectations are strong enough, investors will accept extremely low or negative returns during the early years, because they anticipate earning an adequate return over the entire life cycle of their investment.

Since the dollar magnitude of the fair value rate base is larger than an original cost rate base, reflecting past growth in the value of the utility's property, and since the future income stream can reasonably be expected to increase in the future, due to inflation and other factors which tend to push up property values as time passes, a 5.00% return on fair value is likely to provide investors with as large a total return (over time) as a 7.50% return applied to an original cost rate base. The exact amounts received by investors may differ somewhat, and they certainly will differ during any specific year, but the key point is that investors will have as strong an opportunity to recover their capital costs and to earn a competitive return through the application of a 5.00% return on an escalating estimate of fair value as with a 7.50% return on the original cost. The regulatory goal of simulating the effects of competitive markets, and compensating investors for the impact of inflation, can be achieved either way.

Q. Can you explain in greater detail why a fair rate of return applied to a fair value rate base is less than the percentage return which would normally be applied to an original cost rate

base?

A. Yes. If the return is going to be fair to customers as well as to stockholders, it must be lower than the weighted average cost of capital. The same percentage figure cannot be appropriate for application to both the original cost and to the replacement cost of the utility's property, unless these two cost measures happen to be nearly the same.

Another way of seeing why this conclusion is valid is to start with the competitive market result, which is widely accepted as the appropriate standard for utility regulation in nearly all jurisdictions, regardless of whether they use original cost or fair value in developing their rate base calculations. Utilities in Arizona and other states are all competing for investment capital that is being provided in a national market. If the same percentage rates of return were applied to fair value rate bases in Arizona as are applied to original cost rate bases in all other jurisdictions, it is self evident that Arizona investors would be overcompensated.

If the same cost of capital were applied to a fair value rate base as is applied to original cost rate bases in other jurisdictions, Arizona utilities would be provided with an opportunity to earn windfall profits, in comparison with the treatment of utilities in other states, where firms are only given the opportunity to earn a normal, competitive return.

While the Arizona Constitution requires use of a fair value rate base, and that may influence the specific rate of compensation provided to any specific utility during any specific year, it is not necessary or appropriate to provide Arizona utilities with earnings that consistently exceed those earned, on average, by utilities in other states (or which consistently exceed the earnings of the average unregulated firm which operates in competitive markets, adjusted for differences in risk). Yet just such a consistent differential would occur if the same rate of return were applied to fair value in Arizona and to original cost in other jurisdictions.

Aside from differences in risk, the long term average compensation provided to utility investors in Arizona should be roughly equivalent to that paid to investors in other enterprises –

assuming comparable levels of risk. Investors in Arizona and in other states should all be given a reasonable opportunity to earn a normal return – a return which is consistent with competitive market levels.

I made that last statement in terms of the long term average, because there could be differences in timing, due to differences in the rate base valuation methodology. The return on investment provided in a fair value rate jurisdiction might be somewhat lower in the initial years, and higher in the later years of any given investment, relative to the timing of the returns received in an original cost jurisdiction, just as investors in growth stocks receive more of their return in later years, as dividends increase, or upon sale of the stock. While the year-to-year pattern of cash flows might differ somewhat depending on the specific rate base methodology, the overall long term average level of compensation paid to investors should be very similar, regardless of whether the rate base is based upon original cost, or fair value.

Consistent with this line of reasoning, it is clear that the appropriate magnitude of the difference between the appropriate rate of return in an original cost jurisdiction and the fair rate of return in a fair value jurisdiction is closely related to the rate of growth in the utility's fair value rate base relative to the original cost of its property. The more rapidly fair value is growing relative to original cost, the less need there is to immediately provide a high level of current income in the form of high percentage return for application to the fair value rate base. This is exactly what we observe in the stock market, where investors are satisfied with relatively lower levels of current income and dividends in growth industries, where the value of the stock and the anticipated future level of dividends are expected to grow over time.

Q. Can you now describe the modified method the Commission used in the Chaparral case?

A. The Commission held:

> Although we believe that the cost of debt may reflect the effects of

> inflation, we are not convinced that the evidence presented in this proceeding is developed sufficiently to make that determination with certainty. Accordingly, while we agree with RUCO that the WACC should be adjusted to remove the inflation component, we believe that the appropriate adjustment in this case is to adjust only the cost of equity component of the WACC. [Id., pp. 36-37]

The Commission used a "conservative" inflation estimate of 2.00%, but it only removed the inflation component from the cost of equity component of the WACC. [Id., p. 37]

Q. Can you now describe some other methods that can be used in developing a fair rate of return to apply to the fair value rate base?

A. Yes. In the Chaparral remand proceeding, Staff recommended developing a "fair value capital structure", and assigning cost rates to the various components. Staff recommended assigning a zero cost to the "fair value increment" (The amount by which fair value exceeds OCRB) [See, Decision 70441, p. 14] Staff explained that since this portion was not financed by investors, a zero cost would be appropriate. [Id.]

Staff presented a second alternative on October 3rd, 2008 through Staff witness Gordon Fox, who presented testimony in the most recent Chaparral rate case. Mr. Fox noted that on remand in the Chaparral case, the Commission did not reduce the cost of debt for inflation "due to inadequacies in the record". [Fox Direct, Docket W-02113A-07-0551, p. 5] Mr. Fox concludes (correctly) that inflation is a component of the cost of debt (interest rates tend to increase as inflationary expectations increase). "Accordingly, Staff recommends a FVROR that includes an adjustment to remove the inflation component, i.e., an "accretion return" from the cost of debt". [Id.] However, Staff only removed half of the inflation component from capital costs, because FVRB is computed by averaging OCRB and RCND.

> The OCRB includes no inflation factor. Thus, if the inflation adjustment is made for the entire inflation component of capital costs, the downward

> adjustment to the FVROR will be greater than the upward inflation recognized in the FVRB for reasons other than market forces. As a result of this lack of symmetry, when the FVROR is multiplied by the FVRB to compute operating income, the calculation will be skewed downward. Removing only half of the inflation component from the equity and debt costs maintains symmetry between the FVROR and the FVRB. [Id., p. 8]

A third method advocated by Staff is similar to its first method described above, except that rather than assigning a zero cost rate to the fair value increment, Staff would assign a cost equal to half the rate of inflation.

Q. Several of the methods described above include an inflation component. To the extent inflation is going to be considered, what inflation factor would you suggest using?

A. This is a matter of judgment; the Commission can exercise sound discretion in determining the most appropriate inflation factor to subtract from the weighted average cost of capital. Numerous data series are available as indicators of historical inflation rates, including the data published by the Bureau of Labor Statistics for the annual rate of change in the Gross Domestic Product Deflator, as well as annual changes in consumer prices and various measures of producer prices. Expected future inflation rates are obviously of vital importance in this context, so it is appropriate to consider a forward looking view of inflation. However, it is also reasonable to consider historical inflation, since this contributed to increases in the current fair value of the utility's property. A useful measure of investor inflation expectations can be derived by comparing yields on Treasury Inflation-Protected Securities (TIPS) and other securities issued by the Treasury Department with similar liquidity and duration. TIPS are bonds issued by the U.S. Treasury which are sometimes called "linkers", because they are "linked" to the actual rate of inflation.

TIPS are issued twice a year, in January and July. The principal amount that is paid back to the holder upon maturity is periodically increased, based on the CPI-All Consumer Items. Like most government bonds, the TIPS coupon rate (percentage return) is constant, but these particular securities are unique because they generate an increasing flow of interest payments. TIPs pay interest twice a year, based upon a fixed rate that is multiplied by the inflation-adjusted principal. The end result is that investors are protected against inflation both with respect to the value of their investment, and with respect to the income they receive.

Thus, for example, if the interest rate on a TIP Security is 5%, its cost is $100, and cumulative total amount of inflation from the time of issuance until maturity is 20%, the value of the investment would increase to $120 at maturity. The 5% interest rate would be applied to the increasing principal amount, eventually reaching the level of 5% of $120 – approximately 20% more than the initial payment level.

At maturity, the securities are redeemed at the greater of their inflation-adjusted principal or the original par amount at the time they were issued. TIPS provide yet another example that illustrates one of the key points in my testimony – that the percentage rate of return earned by an investment that grows in value over time will normally be lower than the analogous return paid on an investment that does not grow over time. The fact that these securities offer significantly different percentage returns is further proof of this fundamental point. But, these securities are also of interest because they provide useful insights into investor expectations concerning inflation.

It is well established in the academic literature that the difference between the yield on a TIP and the yield on a comparable government security that is not linked to inflation can be used to estimate investors' future inflation expectations. In fact, UNSE uses such an approach to estimate inflation in this proceeding.

Q. What inflation rate did UNSE calculate?

A. UNSE developed an estimate of long term inflation of 2.1%. [Pritz Direct, p. 11] This estimate was derived from several data series published by the Federal Reserve Bank of Cleveland: 20-year TIPS Derived Expected Inflation; 10-year TIPs Derived Expected Inflation; and, Adjusted 10-year TIPs Derived Expected Inflation. [Id., pp. 10-11; STF Pritz adjusted tips inflation 2006 to 2009.xls] The last series includes an adjustment to account for the liquidity differences between TIPs treasuries and other treasuries, but it was discontinued by the Federal Reserve Bank of Cleveland in October, 2008 because the "extreme rush to liquidity" was affecting the accuracy of the series. http://www.clevelandfed.org/research/data/tips/index.cfm]

In developing its estimate, UNSE relied on an average of recent Adjusted 10-year TIPs Derived Expected Inflation rates, and a single recent 20-year TIPS Derived Expected Inflation rate for its estimate of the long term inflation rate.

> In light of the current uncertainty in the financial markets, I recommend averaging two figures to arrive at an estimate of long-term inflation expectations. The first figure is the average adjusted implied inflation rate for the period from January 2007 through August 2008, representative of expectations prior to the disruption in the financial markets. That figure is 2.68%. The second figure is the February 2009 unadjusted implied inflation based on 20-year treasuries, 1.52%. The average of these two figures is 2.1%. [Pritz Direct, p. 11]

Q. What is your recommendation concerning the appropriate inflation rate to use in developing the fair rate of return?

A. In my opinion, it would be reasonable to use a 2.1% inflation rate. However, I don't think the rate should be based purely on forward looking expectations, as the Company has done. Under the current circumstances, there isn't a great difference between historic inflation and forward looking inflation estimates, but as a matter of theory, I believe it is appropriate to give some weight to both views of inflation. While I agree the 2.1% inflation rate is reasonable, I have a fundamental disagreement with slashing the rate in half, as the Company suggests, and the Commission staff has proposed in the recent Chaparral proceeding.

The Company doesn't provide any explanation or justification for cutting the inflation rate in half, but from my reading of the Staff's testimony in the recent Chaparral case, I get the impression this method is based, at least in part, on the fact that reproduction costs are only given half weight in the fair value rate base calculations, while original cost (which does not escalate with inflation) is also given half weight. In my view, this does not provide adequate justification for simply slashing the inflation rate in half.

While it is true that reproduction cost is only given half weight in developing the FVRB, reproduction cost does not escalate at the inflation rate; to the contrary, reproduction costs tend to grow faster than the rate of inflation, because they don't fully consider the favorable impact of technological changes, increasing economies of scale, and other sources of increased efficiency and cost savings – factors which tend to hold back the pace at which prices escalate over time.

Technological improvements and other sources of cost savings are one of the reasons why the Commission doesn't rely entirely on reproduction cost in developing fair value, and instead weights reproduction cost with original cost. As well, it's important to realize that technological improvements and other sources of cost savings are considered in developing the GDP deflator and most other measures of inflation. In other words, the 2.1% inflation rate developed by the Company is a relatively low percentage figure, because it takes into account the beneficial effects of technological changes and other sources of cost savings which ameliorate or offset other factors which tend to push up reproduction costs. Since the 2.1% inflation rate is relatively modest, it isn't necessary to cut this rate in half in order to develop an appropriate net figure for use in this context.

Q. What fair value rate of return is the Company proposing?

A. Company witness Grant recommends a 6.88% rate of return to be applied to UNSE's fair value rate base. [Grant Direct, p. 13] The primary explanation provided regarding the development of this rate is the following:

> This ROR, when applied to the Company's FVRB of $265 million, produces an overall rate increase that would provide UNS Electric with a reasonable opportunity to earn its cost of capital, to support its creditworthiness and to attract capital on reasonable terms. [Id.]

Elsewhere in the Company's testimony, it explained that this 6.88% figure is less than the percentage figure that would be developed by starting with its estimate of the WACC and adopting the method adopted by the Commission in the Chaparral remand case (which it estimates works out to 8.08%), or the alternative method proposed by the Staff in the more recent Chaparral case, cutting the inflation rate in half, (which it estimates works out to a FVROR of 7.99%).

Q. Have you prepared an analysis of the five methods you described above in comparison with RUCO's estimate of the weighted average cost of capital and the requested rate of return proposed by the Company?

A. Yes. This analysis is shown on my schedule BJ-10. Under "Method 1" I show the impact of using the 9.25% cost of equity and other WACC inputs presented in the testimony of RUCO witness Bill Rigsby, and subtracting an inflation rate of 2.1%. The result of this methodology, which is the one I presented in the Chaparral remand proceeding, results in a fair value rate of return of 5.96%.

"Method 2" shows the effect of using the procedure adopted by the Commission in that proceeding, in which the inflation rate is only subtracted from the equity cost component; it results in a fair value rate of return of 7.10%.

The other three approaches I discuss above, which have been proposed by the Staff in various contexts, are shown as Methods 3, 4 and 5 of BJ-10. These three methods result in a fair value rates of return of 5.39%, 5.80%, and 7.01%, respectively.

Q. What do you recommend concerning the fair return on fair value in this proceeding?

A. I recommend the Commission begin by evaluating all of the methods presented on BJ-10. The Commission can use its discretion to set a fair return on fair value, provided that it reasonably b balances the interests of both ratepayers and customers, and in so doing it gives the Company a reasonable opportunity to recover its cost of capital, and earn a reasonable return on its invested capital. These various methods result in returns on fair value ranging from 5.39% to 7.01%, with a midpoint of 6.20% and an average of 6.25%. The greatest weight should be given to Method 1, because it is the most theoretically sound approach. I recognize that the Commission has discretion in adopting the allowed return on fair value, and it may want to give at some limited consideration to other methods, resulting in a slightly higher or lower return. But, using Method 1, as I recommend, with Mr. Rigsby's recommended weighted average cost of capital, a fair return on fair value is computed to be 5.96%, as shown on BJ-10.

VIII. Conclusions and Recommendations

Q. Can you now please briefly summarize your recommendations?

A. Yes. The effect of my recommendations, as well as Bill Rigsby's cost of capital analysis, is set forth on Schedule BJ-1 of my exhibit. If the Commission were to accept all of my recommendations, the original cost rate base would be approximately $229.9 million; similarly the RCND rate base would be approximately $411.4 million. The fair value rate base would be approximately $320.7 million, assuming the Commission follows its traditional 50/50 weighting of original cost and RCND. These figures compare to the Company's rate base proposals of $237.2 million, $418.7 million, and $327.9 million, for original cost, RCND and fair value, respectively.

If the Commission were to accept all of my recommendations, after taking into account my recommended pro forma adjustments, the test year operating income would be $16.3 million, which compares to the Company's proposed operating income of $15.7 million. If the Commission were to adopt RUCO witness Rigsby's 9.25% estimate of the cost of equity and his overall weighted average cost of capital of 8.06%, applying my recommended 5.96% fair rate of return to a fair value rate base of approximately $320.7 million, the required operating income is approximately $19.1 million. This analysis suggests a test year operating income deficiency of $2.8 million. This compares to the Company's calculated income deficiency of $8.3 million.

Q. What increase in revenues is implied by this income deficiency calculation?

A. Applying the Company's gross revenue conversion factor to this test year income deficiency results in a base rate revenue increase of approximately $4.5 million. This compares to the Company's proposed revenue increase of $13.5 million.

Q. Does this conclude your testimony, prefiled on November 6, 2009?

A. Yes, it does.

Appendix A

Qualifications

Present Occupation

Q. What is your present occupation?

A. I am a consulting economist and President of Ben Johnson Associates, Inc.®, a firm of economic and analytic consultants specializing in the area of public utility regulation.

Educational Background

Q. What is your educational background?

A. I graduated with honors from the University of South Florida with a Bachelor of Arts degree in Economics in March 1974. I earned a Master of Science degree in Economics at Florida State University in September 1977. The title of my Master's Thesis is a "A Critique of Economic Theory as Applied to the Regulated Firm." Finally, I graduated from Florida State University in April 1982 with the Ph.D. degree in Economics. The title of my doctoral dissertation is "Executive Compensation, Size, Profit, and Cost in the Electric Utility Industry."

Clients

Q. What types of clients employ your firm?

A Much of our work is performed on behalf of public agencies at every level of government involved in utility regulation. These agencies include state regulatory commissions, public counsels, attorneys general, and local governments, among others. We are also employed by various private organizations and firms, both regulated and unregulated. The diversity of our clientele is illustrated below.

Regulatory Commissions

Alabama Public Service Commission—Public Staff for Utility Consumer Protection
Alaska Public Utilities Commission
Arizona Corporation Commission
Arkansas Public Service Commission
Connecticut Department of Public Utility Control
District of Columbia Public Service Commission
Idaho Public Utilities Commission
Idaho State Tax Commission
Iowa Department of Revenue and Finance
Kansas State Corporation Commission
Maine Public Utilities Commission
Minnesota Department of Public Service
Missouri Public Service Commission
National Association of State Utility Consumer Advocates
Nevada Public Service Commission
New Hampshire Public Utilities Commission
North Carolina Utilities Commission—Public Staff
Oklahoma Corporation Commission
Ontario Ministry of Culture and Communications
Staff of the Delaware Public Service Commission
Staff of the Georgia Public Service Commission
Texas Public Utilities Commission
Virginia State Corporation Commission
Washington Utilities and Transportation Commission

West Virginia Public Service Commission—Division of Consumer Advocate
Wisconsin Public Service Commission
Wyoming Public Service Commission

Public Counsels

Arizona Residential Utility Consumers Office
Colorado Office of Consumer Counsel
Colorado Office of Consumer Services
Connecticut Consumer Counsel
District of Columbia Office of People's Counsel
Florida Public Counsel
Georgia Consumers' Utility Counsel
Hawaii Division of Consumer Advocacy
Illinois Small Business Utility Advocate Office
Indiana Office of the Utility Consumer Counselor
Iowa Consumer Advocate
Maryland Office of People's Counsel
Minnesota Office of Consumer Services
Missouri Public Counsel
New Hampshire Consumer Counsel
Ohio Consumer Counsel
Pennsylvania Office of Consumer Advocate
Utah Department of Business Regulation—Committee of Consumer Services

Attorneys General

Arkansas Attorney General
Florida Attorney General—Antitrust Division
Idaho Attorney General
Kentucky Attorney General
Michigan Attorney General

Minnesota Attorney General

Nevada Attorney General's Office of Advocate for Customers of Public Utilities

South Carolina Attorney General

Utah Attorney General

Virginia Attorney General

Washington Attorney General

Local Governments

City of Austin, TX

City of Corpus Christi, TX

City of Dallas, TX

City of El Paso, TX

City of Galveston, TX

City of Norfolk, VA

City of Phoenix, AZ

City of Richmond, VA

City of San Antonio, TX

City of Tucson, AZ

County of Augusta, VA

County of Henrico, VA

County of York, VA

Town of Ashland, VA

Town of Blacksburg, VA

Town of Pecos City, TX

Other Government Agencies

- Canada—Department of Communications
- Hillsborough County Property Appraiser
- Provincial Governments of Canada
- Sarasota County Property Appraiser
- State of Florida—Department of General Services
- United States Department of Justice—Antitrust Division
- Utah State Tax Commission

Regulated Firms

- Alabama Power Company
- Americall LDC, Inc.
- BC Rail
- CommuniGroup
- Florida Association of Concerned Telephone Companies, Inc.
- LDDS Communications, Inc.
- Louisiana/Mississippi Resellers Association
- Madison County Telephone Company
- Montana Power Company
- Mountain View Telephone Company
- Nevada Power Company
- Network I, Inc.
- North Carolina Long Distance Association
- Northern Lights Public Utility
- Otter Tail Power Company
- Pan-Alberta Gas, Ltd.
- Resort Village Utility, Inc.
- South Carolina Long Distance Association

Stanton Telephone
Teleconnect Company
Tennessee Resellers' Association
Westel Telecommunications
Yelcot Telephone Company, Inc.

<u>Other Private Organizations</u>

Arizona Center for Law in the Public Interest
Black United Fund of New Jersey
Casco Bank and Trust
Coalition of Boise Water Customers
Colorado Energy Advocacy Office
East Maine Medical Center
Georgia Legal Services Program
Harris Corporation
Helca Mining Company
Idaho Small Timber Companies
Independent Energy Producers of Idaho
Interstate Securities Corporation
J.R. Simplot Company
Merrill Trust Company
MICRON Semiconductor, Inc.
Native American Rights Fund
PenBay Memorial Hospital
Rosebud Enterprises, Inc.
Skokomish Indian Tribe
State Farm Insurance Company
Twin Falls Canal Company
World Center for Birds of Prey

Prior Experience

Q. Before becoming a consultant, what was your employment experience?

A. From August 1975 to September 1977, I held the position of Senior Utility Analyst with Office of Public Counsel in Florida. From September 1974 until August 1975, I held the position of Economic Analyst with the same office. Prior to that time, I was employed by the law firm of Holland and Knight as a corporate legal assistant.

Q. In how many formal utility regulatory proceedings have you been involved?

A. As a result of my experience with the Florida Public Counsel and my work as a consulting economist, I have been actively involved in approximately 400 different formal regulatory proceedings concerning electric, telephone, natural gas, railroad, and water and sewer utilities.

Q. Have you done any independent research and analysis in the field of regulatory economics?

A. Yes, I have undertaken extensive research and analysis of various aspects of utility regulation. Many of the resulting reports were prepared for the internal use of the Florida Public Counsel. Others were prepared for use by the staff of the Florida Legislature and for submission to the Arizona Corporation Commission, the Florida Public Service Commission, the Canadian Department of Communications, and the Provincial Governments of Canada, among others. In addition, as I already mentioned, my Master's thesis concerned the theory of the regulated firm.

Q. Have you testified previously as an expert witness in the area of public utility regulation?

A. Yes. I have provided expert testimony on more than 250 occasions in proceedings before state courts, federal courts, and regulatory commissions throughout the United States and in Canada. I have presented or have pending expert testimony before 35 state commissions, the Interstate Commerce Commission, the Federal Communications Commission, the District of Columbia Public Service Commission, the Alberta, Canada Public Utilities Board, and the Ontario Ministry of Culture and Communication.

Q. What types of companies have you analyzed?

A. My work has involved more than 425 different telephone companies, covering the entire spectrum from AT&T Communications to Stanton Telephone, and more than 55 different electric utilities ranging in size from Texas Utilities Company to Savannah Electric and Power Company. I have also analyzed more than 30 other regulated firms, including water, sewer, natural gas, and railroad companies.

Teaching and Publications

Q. Have you ever lectured on the subject of regulatory economics?

A. Yes, I have lectured to undergraduate classes in economics at Florida State University on various subjects related to public utility regulation and economic theory. I have also addressed conferences and seminars sponsored by such institutions as the National Association of Regulatory Utility Commissioners (NARUC), the Marquette University College of Business Administration, the Utah Division of Public Utilities and the University of Utah, the Competitive Telecommunications Association (COMPTEL), the

International Association of Assessing Officers (IAAO), the Michigan State University Institute of Public Utilities, the National Association of State Utility Consumer Advocates (NASUCA), the Rural Electrification Administration (REA), North Carolina State University, and the National Society of Rate of Return Analysts.

Q. Have you published any articles concerning public utility regulation?

A. Yes, I have authored or co-authored the following articles and comments:

"Attrition: A Problem for Public Utilities—Comment." *Public Utilities Fortnightly*, March 2, 1978, pp. 32-33.

"The Attrition Problem: Underlying Causes and Regulatory Solutions." *Public Utilities Fortnightly*, March 2, 1978, pp. 17-20.

"The Dilemma in Mixing Competition with Regulation." *Public Utilities Fortnightly,* February 15, 1979, pp. 15-19.

"Cost Allocations: Limits, Problems, and Alternatives." *Public Utilities Fortnightly,* December 4, 1980, pp. 33-36.

"AT&T is Wrong." *The New York Times,* February 13, 1982, p. 19.

"Deregulation and Divestiture in a Changing Telecommunications Industry," with Sharon D. Thomas. *Public Utilities Fortnightly*, October 14, 1982, pp. 17-22.

"Is the Debt-Equity Spread Always Positive?" *Public Utilities Fortnightly,* November 25, 1982, pp. 7-8.

"Working Capital: An Evaluation of Alternative Approaches." *Electric Rate-Making,* December 1982/January 1983, pp. 36-39.

"The Staggers Rail Act of 1980: Deregulation Gone Awry," with Sharon D. Thomas. *West Virginia Law Review,* Coal Issue 1983, pp. 725-738.

"Bypassing the FCC: An Alternative Approach to Access Charges." *Public Utilities Fortnightly*, March 7, 1985, pp. 18-23.

"On the Results of the Telephone Network's Demise—Comment," with Sharon D. Thomas. *Public Utilities Fortnightly*, May 1, 1986, pp. 6-7.

"Universal Local Access Service Tariffs: An Alternative Approach to Access Charges." In *Public Utility Regulation in an Environment of Change,* edited by Patrick C. Mann and Harry M. Trebing, pp. 63-75. Proceedings of the Institute of Public Utilities Seventeenth Annual Conference. East Lansing, Michigan: Michigan State University Public Utilities Institute, 1987.

With E. Ray Canterbery. Review of *The Economics of Telecommunications: Theory and Policy* by John T. Wenders. *Southern Economic Journal* 54.2 (October 1987).

"The Marginal Costs of Subscriber Loops," A Paper Published in the Proceedings of the Symposia on Marginal Cost Techniques for Telephone Services. The National Regulatory Research Institute, July 15-19, 1990 and August 12-16, 1990.

With E. Ray Canterbery and Don Reading. "Cost Savings from Nuclear Regulatory Reform: An Econometric Model." *Southern Economic Journal,* January 1996.

Professional Memberships

Q. Do you belong to any professional societies?

A. Yes. I am a member of the American Economic Association.

UNS ELECTRIC, INC.
DOCKET NO. E-04204A-09-0206
TABLE OF CONTENTS TO BJ SCHEDULES

UNS ELECTRIC, INC.
BMGS ADJUSTED TEST YEAR ENDED DECEMBER 31, 2008
ACC JURISDICTIONAL REVENUE REQUIREMENTS

DOCKET NO. E-04204A-09-0206
SCHEDULE BJ-1

LINE NO.	DESCRIPTION	(A) RUCO ORIGINAL COST	(B) RUCO RCND	(C) RUCO FAIR VALUE
1	ADJUSTED RATE BASE	$229,945,361	$411,422,319	$320,683,840
2	ADJUSTED OPERATING INCOME	16,335,782	16,335,782	16,335,782
3	CURRENT RATE OF RETURN (L2 / L1)	7.10%	3.97%	5.09%
4	REQUIRED OPERATING INCOME (L5 * L1)	18,533,596		19,112,757
5	REQUIRED RATE OF RETURN	8.06%		5.96%
6	OPERATING INCOME DEFICIENCY (L4 - L2)	2,197,814		2,776,974
7	GROSS REVENUE CONVERSION FACTOR	1.6363		1.6363
8	REVENUE REQUIREMENT	$3,596,283		**$4,543,963**

REFERENCES:
COLUMN (A): RUCO SCHEDULES BJ-2, BJ-7, BMGS SCHEDULE A1
COLUMN (B): RUCO SCHEDULES BJ-4, BMGS SCHEDULE A1
COLUMN (C): JOHNSON TESTIMONY, BMGS SCHEDULE A1

UNS ELECTRIC, INC.
BMGS ADJUSTED TEST YEAR ENDED DECEMBER 31, 2008
ORIGINAL COST RATE BASE

DOCKET NO. E-04204/
SCHEDULE BJ-2

LINE NO.	DESCRIPTION	(A) AS FILED TOTAL COMPANY	(B) RUCO ADJUSTMENTS TOTAL COMPANY	(C) RUCO AS ADJUSTED TOTAL COMPANY
1	GROSS UTILITY PLANT IN SERVICE	$454,177,170	$55,716,067	$509,893,237
2	Less: Accumulated depreciation & amortization	193,348,359	1,009,199	194,357,558
3	NET UTILITY PLANT IN SERVICE	**$260,828,811**	**$54,706,868**	**$315,535,679**
	CITIZENS ACQUISITION ADJUSTMENT			
4	Citizens Acquisition Discount	$(93,273,341)		(93,273,341)
5	Less: Accum. Amort. - Citizens Acq. Discount	$(20,876,317)		(20,876,317)
6	NET CITIZENS ACQUISITION DISCOUNT	**(72,397,024)**		**(72,397,024)**
7	TOTAL NET UTILITY PLANT	**188,431,787**	**61,970,352**	**250,402,139**
	DEDUCTIONS:			
8	Customer advances for construction	(12,605,744)		(12,605,744)
9	Customer deposits	(4,064,671)		(4,064,671)
10	Accumulated Deferred Income Taxes	(2,028,227)		(2,028,227)
11	TOTAL DEDUCTIONS	**$(18,698,642)**		(18,698,642)
	ADDITIONS:			
12	Allowance for working capital	$6,085,768	$(580,420)	$5,505,348
13	Regulatory assets			
14	Regulatory Liabilities			
15	TOTAL ADDITIONS	6,085,768	(580,420)	5,505,348
16	TOTAL ORGINAL COST RATE BASE	**$175,818,913**	**$54,126,448**	**$229,945,361**

REFERENCES:
COLUMN (A): RUCO SCHEDULE BJ-3
COLUMN (B): RUCO SCHEDULE BJ-3
COLUMN (C): RUCO SCHEDULE BJ-3

UNS ELECTRIC, INC.
BMGS ADJUSTED TEST YEAR ENDED DECEMBER 31, 2008
ORIGINAL COST RATE BASE ADJUSTMENTS: TOTAL COMPANY

DOCKET NO. E-04204A-09-0206
SCHEDULE BJ-3

LINE NO.	DESCRIPTION	(A) Adjusted (Original) at End of Test Period	(B) BMGS Adjustments (a)	(C) BMGS Adjusted At *End of Test* Period	(D) OTHER RUCO ADJUSTMENTS	(E) RUCO ADJUSTED
1	GROSS UTILITY PLANT IN SERVICE	$454,177,170	$62,979,551	$517,156,721	$(7,263,484)	$509,893,237
2	Less: Accumulated depreciation & amortization	193,348,359	1,009,199	194,357,558	-	194,357,558
3	NET UTILITY PLANT IN SERVICE	**$260,828,811**	**$61,970,352**	**$322,799,163**	**$(7,263,484)**	**$315,535,679**
	CITIZENS ACQUISITION ADJUSTMENT					
4	Citizens Acquisition Discount	(93,273,341)		(93,273,341)		(93,273,341)
5	Less: Accum. Amort. - Citizens Acq. Discount	(20,876,317)		(20,876,317)		(20,876,317)
6	NET CITIZENS ACQUISITION DISCOUNT	**(72,397,024)**		**(72,397,024)**		**(72,397,024)**
7	TOTAL NET UTILITY PLANT	**188,431,787**	**61,970,352**	**250,402,139**		**250,402,139**
	DEDUCTIONS:					
8	Customer advances for construction	(12,605,744)		(12,605,744)		(12,605,744)
9	Customer deposits	(4,064,671)		(4,064,671)		(4,064,671)
10	Accumulated Deferred Income Taxes	(2,028,227)		(2,028,227)		(2,028,227)
11	TOTAL DEDUCTIONS	**(18,698,642)**		**(18,698,642)**		**(18,698,642)**
	ADDITIONS:					
12	Allowance for working capital	6,085,768	(580,420)	5,505,348		5,505,348
13	Regulatory assets	-				
14	Regulatory Liabilities	-				
15	TOTAL ADDITIONS	6,085,768	(580,420)	5,505,348		5,505,348
15	TOTAL ORGINAL COST RATE BASE	**$175,818,913**	**$61,389,932**	**$237,208,845**	**$(7,263,484)**	**$229,945,361**

REFERENCES:
COLUMN (A): COMPANY BMGS SCHEDULE B2 P1
COLUMN (B): COMPANY BMGS SCHEDULE B2 P1
COLUMN (C): (A)+(B)

UNS ELECTRIC, INC.
BMGS ADJUSTED TEST YEAR ENDED DECEMBER 31, 2008
RCND RATE BASE

DOCKET NO. E-04204A-09-0206
SCHEDULE BJ-4

LINE NO.	DESCRIPTION	(A) ADJUSTED RCND RATE BASE	(B) RUCO ADJUSTMENTS	(C) RUCO AS ADJUSTED
1	GROSS UTILITY PLANT IN SERVICE	$844,301,155	$58,572,449	$902,873,604
2	Less: Accumulated depreciation & amortization	$367,590,759	$1,054,932	$368,645,691
3	NET UTILITY PLANT IN SERVICE	$476,710,396	$57,517,517	$534,227,913
	CITIZENS ACQUISITION ADJUSTMENT			
4	Citizens Acquisition Discount	$(130,469,005)		$(130,469,005)
5	Less: Accum. Amort. - Citizens Acq. Discount	$(27,773,948)		$(27,773,948)
6	NET CITIZENS ACQUISITION DISCOUNT	$(102,695,057)		$(102,695,057)
7				
8	TOTAL NET UTILITY PLANT	$374,015,339	$64,781,001	$438,796,340
9				
10	DEDUCTIONS:			
11	Customer advances for construction	$(17,555,056)		$(35,110,112)
12	Customer deposits	$(4,064,671)		$(8,129,342)
	Accumulated Deferred Income Taxes	$(3,996,158)		$(7,992,316)
13				
	TOTAL DEDUCTIONS	$(25,615,885)		$(25,615,885)
14	ADDITIONS:			
15	Allowance for working capital	$6,085,768	$(580,420)	$5,505,348
16	Regulatory assets			
17	Regulatory Liabilities			
18	TOTAL ADDITIONS	6,085,768	(580,420)	5,505,348
19	TOTAL RCND RATE BASE	$354,485,222	$56,937,097	$411,422,319

REFERENCES:
COLUMN (A): BMGS COMPANY SCHEDULE B1
COLUMN (B): BJ-3
COLUMN (C): COLUMN (A) + COLUMN (B)

UNS ELECTRIC, INC.
BMGS ADJUSTED TEST YEAR ENDED DECEMBER 31, 2008
RCND RATE BASE ADJUSTMENTS: ACC

DOCKET NO. E-04204A-09-0206
SCHEDULE BJ-5

LINE NO.	DESCRIPTION	(A) RCND Adjusted (Original) at End of Test Period (a) (b)	(B) BMGS Adjustments (c)	(C) BMGS Adjusted At End of Test Period	(D) OTHER RUCO ADJUSTMENTS	(E) RUCO AS ADJUSTED
1	GROSS UTILITY PLANT IN SERVICE	$844,301,155	$65,835,933	$910,137,088	$(7,263,484)	$902,873,604
2	Less: Accumulated depreciation & amortization	367,590,759	1,054,932	368,645,691		368,645,691
3	NET UTILITY PLANT IN SERVICE	**$476,710,396**	**$64,781,001**	**$541,491,397**	**$(7,263,484)**	**$534,227,913**
	CITIZENS ACQUISITION ADJUSTMENT					
4	Citizens Acquisition Discount	(130,469,005)		(130,469,005)		(130,469,005)
5	Less: Accum. Amort. - Citizens Acq. Discount	(27,773,948)		(27,773,948)		(27,773,948)
6	NET CITIZENS ACQUISITION DISCOUNT	**(102,695,057)**		**(102,695,057)**		**(102,695,057)**
7						
8	TOTAL NET UTILITY PLANT	**374,015,339**	**64,781,001**	**438,796,340**		**438,796,340**
9						
10	DEDUCTIONS:					
11	Customer advances for construction	(17,555,056)		(17,555,056)		(35,110,112)
12	Customer deposits	(4,064,671)		(4,064,671)		(8,129,342)
	Accumulated Deferred Income Taxes	(3,996,158)		(3,996,158)		(7,992,316)
13	TOTAL DEDUCTIONS	**$(25,615,885)**		**$(25,615,885)**		**$(25,615,885)**
14	ADDITIONS:					
15	Allowance for working capital	6,085,768	(580,420)	5,505,348		5,505,348
16	Regulatory assets					-
17	Regulatory Liabilities					-
18	TOTAL ADDITIONS	**$6,085,768**	**$(580,420)**	**$5,505,348**	**$-**	**$5,505,348**
19	TOTAL RCND RATE BASE	**$354,485,222**	**$64,200,581**	**$418,685,803**	**$(7,263,484)**	**$411,422,319**

REFERENCES:
COLUMN (A): COMPANY BMGS SCHEDULE B3 P1, COLUMN (a) (b)
COLUMN (B): COMPANY BMGS SCHEDULE B3 P1, COLUMN (c)
COLUMN (C): COMPANY BMGS SCHEDULE B3 P1
COLUMN (D): *Post Test Year Adjustment Staff DR 4.9*
COLUMN (E): (C)+(D)

UNS ELECTRIC, INC.
BMGS ADJUSTED TEST YEAR ENDED DECEMBER 31, 2008
OPERATING INCOME

DOCKET NO. E-04204A-09-0206
SCHEDULE BJ-6

LINE NO.	DESCRIPTION	(A) AS FILED TOTAL COMPANY	(B) RUCO ADJUSTMENTS TOTAL COMPANY	A+B (C) RUCO AS ADJUSTED TOTAL COMPANY
	ELECTRIC OPERATING REVENUES			
0	Electric Retail Revenues	$181,638,915	$(22,358,469)	$159,280,446
2	Sales for Resale	10,168,115	(10,168,115)	
3	Other Operating Revenue	3,103,658	(1,458,039)	1,645,619
4	Total Operating Revenues	**$194,910,688**	**$(33,984,623)**	**$160,926,065**
	OPERATING EXPENSES:			
5	Fuel, Purchased Power & Transmission	$143,362,723	$(43,019,937)	$100,342,786
6	Other Operations and Maintenance Expense	21,569,849	(1,469,430)	20,100,419
7	Depreciation and Amortization	14,429,415	1,141,704	15,571,119
8	Taxes Other than Income Taxes	3,680,634	579,459	4,260,093
9	Income Taxes	2,081,685	2,234,181	4,315,866
10	Total Operating Expenses	**$185,124,306**	**$(40,534,023)**	**$144,590,283**
11	OPERATING INCOME	**$9,786,382**	**$6,549,400**	**$16,335,782**

REFERENCES:
COLUMN (A): COMPANY SCHEDULE C1, UNADJUSTED
COLUMN (B): BJ-7, P3 (AB)
COLUMN (C): COLUMN (A) + COLUMN (B)

UNS ELECTRIC, INC.
BMGS ADJUSTED TEST YEAR ENDED DECEMBER 31, 2008
OPERATING INCOME ADJUSTMENTS: TOTAL COMPANY

DOCKET NO. E-04204A-09-0206
SCHEDULE BJ-7

LINE NO.	DESCRIPTION	(A) AS FILED TOTAL COMPANY	Retail Revenue & Purchased Power Annualization (B)	Wholesale Rev & Purch Power (C)	Weather Normalization (D)	Customer Energy Annualization & Customer Demand Normalization (E)	Normalization of Rev & Exp for Fuel and PPFAC (F)	CARES Discounts (G)	DSM & Renewables Revenue & Expense (H)	Payroll Expense (I)
	ELECTRIC OPERATING REVENUES									
0	Electric Retail Revenues	$181,638,915	$10,733,456		$(1,017,300)	$(2,820,565)	$(29,192,263)	(61,797)		
2	Sales for Resale	10,168,115		(10,168,115)						
3	Other Operating Revenue	3,103,658							(1,458,039)	
4	Total Operating Revenues	$194,910,688	$10,733,456	$(10,168,115)	$(1,017,300)	$(2,820,565)	$(29,192,263)	$(61,797)	$(1,458,039)	$-
	OPERATING EXPENSES:									
5	Fuel, Purchased Power & Transmission	$143,362,723	(956,469)	(10,168,115)	(830,613)	(1,079,814)	(19,024,147)			
6	Other Operations and Maintenance Expense	21,569,849							(1,617,113)	79,628
7	Depreciation and Amortization	14,429,415								
8	Taxes Other than Income Taxes	3,680,634							(9,713)	
9	Income Taxes	2,081,685								
10	Total Operating Expenses	$185,124,306	$(956,469)	$(10,168,115)	$(830,613)	$(1,079,814)	$(19,024,147)	$-	$(1,626,826)	$79,628
11	OPERATING INCOME	$9,786,382	$11,689,925	$-	$(186,687)	$(1,740,751)	$(10,168,116)	$(61,797)	$168,787	$(79,628)

REFERENCES:
COLUMN (A): COMPANY SCHEDULE C1, COLUMN (a)
COLUMN (B): COMPANY SCHEDULE C2 P1
COLUMN (C): COMPANY SCHEDULE C2 P1
COLUMN (D): COMPANY SCHEDULE C2 P1
COLUMN (E): COMPANY SCHEDULE C2 P1
COLUMN (F): COMPANY SCHEDULE C2 P1
COLUMN (G): COMPANY SCHEDULE C2 P1
COLUMN (H): COMPANY SCHEDULE C2 P2
COLUMN (I): COMPANY WORKPAPER "Income – Payroll Expenses 12-08.xls"
RUCO adjustment eliminates the 3% factor associated with the expected 2010 pay increases.

UNS ELECTRIC, INC.
BMGS ADJUSTED TEST YEAR ENDED DECEMBER 31, 2008
SUMMARY OF OPERATING ADJUSTMENTS (000'S)

LINE NO.	DESCRIPTION	Payroll Tax Expense (J)	Pension & Benefits (K)	Post Retirement Medical (L)	Rate Case Expense (M)	Bad Debt Expense (N)	Interest on Customer Deposits (O)	Workers Compensation (P)	Miscellaneous Expenses (Q)
	ELECTRIC OPERATING REVENUES								
1	Revenues from Base Rates								
2	Revenues from Surcharges								
3	Other Electric Revenues								
4	Total Electric Operating Revenues								
	OPERATING EXPENSES:								
5	Fuel, Purchased Power & Transmission								
6	Other Operations and Maintenance Expense			161,929	72,223	(436,441)	(145,701)	(115,528)	(397,462)
7	Depreciation and Amortization								
8	Taxes Other than Income Taxes	35,430							(10,495)
9	Income Taxes								
10	Total Operating Expenses	$35,430	$-	$161,929	$72,223	$(436,441)	$(145,701)	$(115,528)	$(407,957)
11	OPERATING INCOME	$(35,430)	$-	$(161,929)	$(72,223)	$436,441	$145,701	$115,528	$407,957

REFERENCES:
COLUMN (J): COMPANY WORKPAPER "Income – Payroll Tax Expenses 12-08.xls"
RUCO adjustment uses payroll expenses which excludes the 3% factor associated with the expected 2010 pay increases.
COLUMN (K): DENY
COLUMN (L): COMPANY SCHEDULE C2 P2
COLUMN (M): COMPANY WORKPAPER "Income – Rate Case Expenses 12-08.xls"
RUCO adjustment assumes rate case expenses of $300,000
COLUMN (N): COMPANY SCHEDULE C2 P3
COLUMN (O): COMPANY SCHEDULE C2 P3
COLUMN (P): COMPANY SCHEDULE C2 P3
COLUMN (Q): COMPANY SCHEDULE C2 P3 AND SUPPORTING WORKPAPERS
RUCO adjustment eliminates 40% of USWAG and EEI dues; normalizes legal expenses based actual 2006-2008 expenses; and eliminates the 5/12/09 postage increase

UNS ELECTRIC, INC.
BMGS ADJUSTED TEST YEAR ENDED DECEMBER 31, 2008
SUMMARY OF OPERATING ADJUSTMENTS (000'S)

DOCKET NO. E-04204A-09-0206
SCHEDULE BJ-7

LINE NO.	DESCRIPTION	A&G Expense Capitalized (R)	Depr & Property Tax for Post TY Non-Rev. Plant in Service (S)	Depr & Amort Expense Annualization (T)	Property Tax Expense (U)	Income Taxes (V)	BMGS PPA Adjustment (W)	BGMS O&M Expense (X)	BMGS Depr & Amort Expense Annalization (Y)	BMGS Property Tax Expense (Z)	BMGS Income Taxes (AA)	Synchronize Income Taxes (AB)	SUM OF BJ7, PAGES 1 THROUGH 3 (AC) RUCO ADJUSTED TOTAL COMPANY
	ELECTRIC OPERATING REVENUES												
0	Revenues from Base Rates												(22,358,469)
2	Revenues from Surcharges												(10,168,115)
3	Other Electric Revenues												(1,458,039)
4	Total Electric Operating Revenues												$(33,984,623)
	OPERATING EXPENSES:												
5	Fuel, Purchased Power & Transmission						(10,960,779)						(43,019,937)
6	Other Operations and Maintenance Expense	(229,429)						1,158,464					(1,469,430)
7	Depreciation and Amortization			(507,792)					1,649,496				1,141,704
8	Taxes Other than Income Taxes				144,026					420,211			579,459
9	Income Taxes					39,582					2,079,821	114,778	2,234,181
10	Total Operating Expenses	$(229,429)	$-	$(507,792)	$144,026	$39,582	$(10,960,779)	$1,158,464	$1,649,496	$420,211	$2,079,821	$114,778	$(40,534,023)
11	OPERATING INCOME	$229,429	$-	$507,792	$(144,026)	$(39,582)	$10,960,779	$(1,158,464)	$(1,649,496)	$(420,211)	$(2,079,821)	$(114,778)	$6,549,400

REFERENCES:
COLUMN (R): COMPANY SCHEDULE C2 P3
COLUMN (S): DENY
COLUMN (T): COMPANY SCHEDULE C2 P3
COLUMN (U): COMPANY WORKPAPER "Income – Property Tax Expense 12-08.xls"
RUCO adjustment uses 22% assessment ratio effective 1/1/09
COLUMN (V): COMPANY SCHEDULE C2 P3
COLUMN (W): COMPANY BMGS SCHEDULE C2 P1
COLUMN (X): COMPANY BMGS SCHEDULE C2 P1
COLUMN (Y): COMPANY BMGS SCHEDULE C2 P1
COLUMN (Z): COMPANY WORKPAPER "Income – Property Tax Expense 12-08.xls"
RUCO adjustment uses 22% assessment ratio effective 1/1/09
COLUMN (AA): COMPANY BMGS SCHEDULE C2 P1
COLUMN (AB): SUM BJ 7 PAGES 1 THROUGH 3

UNS ELECTRIC, INC.
BMGS ADJUSTED TEST YEAR ENDED DECEMBER 31, 2008
COST OF CAPITAL

DOCKET NO. E-04204A-09-0206
SCHEDULE BJ-8

LINE NO.	TYPE OF CAPITAL	(A) PERCENT	(B) COST RATE	(C) WEIGHTED AVG. COST RATE
1	COMMON EQUITY	45.76%	9.25%	4.23%
2	TOTAL DEBT	54.24%	7.05%	3.82%
3	TOTALS	100.00%		8.06%

REFERENCES:
WAR-1

.ECTRIC, INC.
ADJUSTED TEST YEAR ENDED DECEMBER 31, 2008
.TING INCOME ADJUSTMENT: SYNCHRONIZE INCOME TAXES

DOCKET NO. E-04204A-09-0206
SCHEDULE BJ-9

DESCRIPTION	TOTAL COMPANY AMOUNT	REFERENCE
FEDERAL INCOME TAXES:		
OPERATING INCOME BEFORE INCOME TAXES	$20,651,648	SCHEDULE BJ-6, LINE 4 – (LINES 5 THROUGH 8)
LESS:		
ARIZONA STATE TAX	826,316	LINE 11
INTEREST EXPENSE	8,792,927	NOTE (a)
FEDERAL TAXABLE INCOME	11,032,406	LINE 1 - LINES 2 & 3
FEDERAL INCOME TAX RATE	31.630%	BMSG SCHEDULE C3
FEDERAL INCOME TAX EXPENSE	3,489,550	LINE 4 X LINE 5
STATE INCOME TAXES:		
OPERATING INCOME BEFORE INCOME TAXES	20,651,648	LINE 1
LESS:		
INTEREST EXPENSE	8,792,927	LINE 17
STATE TAXABLE INCOME	11,858,721	LINE 7 - LINE 8
STATE TAX RATE	6.968%	BMSG SCHEDULE C3
STATE INCOME TAX EXPENSE	826,316	LINE 9 X LINE 10
TOTAL INCOME TAXES	4,315,866	LINE 6 + LINE 11
INCOME TAXES PER COMPANY	4,201,088	COMPANY SCHEDULE. C-1
ADJUSTMENT	$\boxed{\$114,778}$	LINE 12 - LINE 13

NOTE (a)
INTEREST SYCHRONIZATION

ADJUSTED RATE BASE	$229,945,361	BJ-2
WEIGHTED COST OF DEBT	3.82%	BJ-8
INTEREST EXPENSE	$8,792,927	

UNS ELECTRIC, INC.
FVROR CALCULATIONS

DOCKET NO. E-04204A-09-0206
SCHEDULE BJ-10

Method 1

LINE NO.	TYPE OF CAPITAL	(A) CAPITALIZATION	(B) PERCENT	(C) COST RATE	(D) INFLATION COMPONENT	(E) MODIFIED COST RATE	(F) WEIGHTED AVG. COST RATE
1	COMMON EQUITY	83,755,000	45.76%	9.25%	2.10%	7.15%	3.27%
2	TOTAL DEBT	99,272,000	54.24%	7.05%	2.10%	4.95%	2.68%
3	TOTALS	183,027,000	100.00%				5.96%

Method 2

LINE NO.	TYPE OF CAPITAL	(A) CAPITALIZATION	(B) PERCENT	(C) COST RATE	(D) INFLATION COMPONENT	(E) MODIFIED COST RATE	(F) WEIGHTED AVG. COST RATE
4	COMMON EQUITY	83,755,000	45.76%	9.25%	2.10%	7.15%	3.27%
5	TOTAL DEBT	99,272,000	54.24%	7.05%	0.00%	7.05%	3.82%
6	TOTALS	183,027,000	100.00%				7.10%

Method 3

LINE NO.	TYPE OF CAPITAL	(A) CAPITALIZATION	(B) PERCENT	(C) COST RATE	(D) INFLATION COMPONENT	(E) MODIFIED COST RATE	(F) WEIGHTED AVG. COST RATE
7	COMMON EQUITY	83,755,000	30.59%	9.25%	0.00%	9.25%	2.83%
8	TOTAL DEBT	99,272,000	36.26%	7.05%	0.00%	7.05%	2.56%
9	FVRB INCREMENT	90,738,479	33.14%	0.00%	0.00%	0.00%	0.00%
10	TOTALS	273,765,479	100.00%				5.39%

Method 4

LINE NO.	TYPE OF CAPITAL	(A) CAPITALIZATION	(B) PERCENT	(C) COST RATE	(D) INFLATION COMPONENT	(E) MODIFIED COST RATE	(F) WEIGHTED AVG. COST RATE
11	COMMON EQUITY	83,755,000	30.59%	9.25%	0.00%	9.25%	2.83%
12	TOTAL DEBT	99,272,000	36.26%	7.05%	0.00%	7.05%	2.56%
13	FVRB INCREMENT	90,738,479	33.14%	1.25%	0.00%	1.25%	0.41%
14	TOTALS	273,765,479	100.00%				5.80%

Method 5

LINE NO.	TYPE OF CAPITAL	(A) CAPITALIZATION	(B) PERCENT	(C) COST RATE	(D) INFLATION COMPONENT	(E) MODIFIED COST RATE	(F) WEIGHTED AVG. COST RATE
15	COMMON EQUITY	83,755,000	45.76%	9.25%	1.05%	8.20%	3.75%
16	TOTAL DEBT	99,272,000	54.24%	7.05%	1.05%	6.00%	3.25%
17	TOTALS	183,027,000	100.00%				7.01%

UNS ELECTRIC, INC.

DOCKET NO. E-04204A-09-0206

DIRECT TESTIMONY

OF

WILLIAM A. RIGSBY, CRRA

ON BEHALF OF

THE

RESIDENTIAL UTILITY CONSUMER OFFICE

NOVEMBER 6, 2009

TABLE OF CONTENTS

INTRODUCTION

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

A. My Name is William A. Rigsby. I am a Public Utilities Analyst V employed by the Residential Utility Consumer Office ("RUCO") located at 1110 W. Washington, Suite 220, Phoenix, Arizona 85007.

Q. Please describe your qualifications in the field of utilities regulation and your educational background.

A. I have been involved with utilities regulation in Arizona since 1994. During that period of time I have worked as a utilities rate analyst for both the Arizona Corporation Commission ("ACC" or "Commission") and for RUCO. I hold a Bachelor of Science degree in the field of finance from Arizona State University and a Master of Business Administration degree, with an emphasis in accounting, from the University of Phoenix. I have also been awarded the professional designation, Certified Rate of Return Analyst ("CRRA") by the Society of Utility and Regulatory Financial Analysts ("SURFA"). The CRRA designation is awarded based upon experience and the successful completion of a written examination. Appendix I, which is attached to this testimony, further describes my educational background and also includes a list of the rate cases and regulatory matters that I have been involved with.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present recommendations that are based on my analysis of UNS Electric, Inc.'s ("UNSE" or "Company") application for a permanent rate increase ("Application") for the Company's electric distribution operations in Mohave and Santa Cruz Counties. UNSE filed the Application with the ACC on April 30, 2009. The Company has chosen the operating period ending December 31, 2008 for the test year in this proceeding.

Q. Briefly describe UNSE.

A. UNSE is a wholly owned subsidiary of UniSource Energy Services, which is owned by UniSource Energy Corporation ("UniSource" or "Parent"), an Arizona corporation, based in Tucson, that is publicly traded on the New York Stock Exchange ("NYSE")'. UniSource is also the parent company of Tucson Electric Power, the second largest investor owned electric utility in the state. In addition to the electric distribution operations of UNS, UniSource also provides electric utilities distribution service through its other subsidiary UNS Gas, Inc., to customers in Northern Arizona and Santa Cruz County.

Q. Please explain your role in RUCO's analysis of UNSE's Application.

A. I reviewed UNSE's Application and performed a cost of capital analysis to determine a fair rate of return on the Company's invested capital. In addition to my recommended capital structure, my direct testimony will present my recommended costs of common equity and my recommended cost of long-term debt (the Company has no short-term debt or preferred stock). The recommendations contained in this testimony are based on information obtained from Company responses to data requests, the Company's Application and from market-based research that I conducted during my analysis.

Q. Is this your first case involving UNSE?

A. No. In 2003 I was involved with UniSource's acquisition of UniSource Energy Corporation's gas and electric assets from Citizens' Utilities Company. The UNSE entity was the result of that acquisition. I also provided cost of capital testimony in the Company's most recent rate case proceeding which resulted in Decision No. 70360, dated May 27, 2008. UNSE's present rates were established in that Decision.

Q. Were you also responsible for conducting an analysis of the Company's proposed revenue level, rate base and rate design?

A. No. Those aspects of the case were handled by Ben Johnson, Ph.D. of Ben Johnson Associates, Inc. Dr. Johnson will provide testimony on RUCO's recommended level of required revenue (based on his adjustments to Company-proposed levels of rate base and operating expense). Dr. Johnson will also provide testimony on his recommended methodology to develop a fair value rate of return to be applied to UNSE's fair value rate base.

Q. What areas will you address in your testimony?

A. I will address the cost of capital issues associated with the case.

Q. Please identify the exhibits that you are sponsoring.

A. I am sponsoring Schedules WAR-1 through WAR-9.

SUMMARY OF TESTIMONY AND RECOMMENDATIONS

Q. Briefly summarize how your cost of capital testimony is organized.

A. My cost of capital testimony is organized into seven sections. First, the introduction I have just presented and second, the summary of my testimony that I am about to give. Third, I will present the findings of my cost of equity capital analysis, which utilized both the discounted cash flow ("DCF") method, and the capital asset pricing model ("CAPM"). These are the two methods that RUCO and ACC Staff have consistently used for calculating the cost of equity capital in rate case proceedings in the past, and are the methodologies that the ACC has given the most weight to in setting allowed rates of returns for utilities that operate in the Arizona jurisdiction. In this second section I will also provide a brief overview of the economic climate that UNSE is currently operating in. Fourth, I will discuss my recommended cost of debt. Fifth, I will compare my recommended capital structure with the Company-proposed capital structure. Sixth, I will explain my weighted cost of capital recommendation and seventh, I will comment on UNSE's cost of capital testimony. Schedules WAR-1 through WAR-9 will provide support for my cost of capital analysis.

Q. *Please summarize the recommendations and adjustments that you will address in your testimony.*

A. Based on the results of my analysis of UNSE, I am making the following recommendations:

Original Cost of Equity Capital – I am recommending a 9.25 percent original cost of equity capital. This 9.25 percent original cost figure is based on the range of results that I obtained in my cost of equity analysis, which employed both the DCF and CAPM methodologies. My recommended 9.25 percent figure is 215 basis points lower than the Company-proposed cost of equity capital of 11.40 percent.

Cost of Debt – Based on my review of the costs associated with UNSE's various debt instruments, I am recommending that the Company-proposed 7.05 percent cost of debt be adopted by the Commission.

Capital Structure – I am recommending that the Company-proposed capital structure, which is comprised of 54.24 percent long-term debt and 45.76 percent common equity, be adopted by the Commission.

Original Cost Rate of Return – Based on the results of my recommended capital structure, original cost of equity capital, and debt analyses, I am recommending an 8.06 percent original cost rate of return ("OCROR") for UNSE. This figure represents the weighted average cost of my recommended 9.25 percent original cost of equity capital and my 7.05 percent recommended cost of debt. My recommended 8.06 percent OCROR is 98 basis points lower than the Company-proposed unadjusted 9.04 percent weighted average cost of capital.

Fair Value Rate of Return – As explained in the direct testimony of RUCO witness Dr. Johnson, RUCO is recommending a 5.96 percent fair value rate of return ("FVROR") which is 210 basis points lower than my recommended 8.06 percent OCROR. In arriving at this 5.96 percent FVROR figure RUCO considered several different methods to determine an appropriate rate of return to apply to the Company's fair value rate base. The method that RUCO used to arrive at its recommended 5.96 percent FVROR comports with the provisions of Decision No. 70441, dated July 28, 2008, which resulted from a prior remand proceeding which involved Chaparral City Water Company.[1]

Q. Please explain why RUCO is recommending two different rates of return in this case?

A. UNSE has chosen to use an average of the Company's original cost rate base ("OCRB"), which is based on the original book value of plant assets, and a rate base derived from a reconstruction cost new study ("RCND"), which takes general inflation into consideration, to arrive at a fair value rate base ("FVRB") which reflects the current dollar value of UNSE's original cost rate base. Because general inflation is also reflected in my OCROR figure, it is inappropriate to apply it to an OCRB. To do so would result in a double counting of inflation. For this reason Dr. Johnson has derived a FVROR which reduces my recommended OCROR by an inflation factor of 210 basis points.

Q. Can you explain further why it is necessary to determine an inflation factor adjustment to arrive at an OCROR?

A. Yes. Unless a utility elects to forego an RCND study that restates the value of the OCRB in current dollars, and agrees to use its OCRB as its FVRB, the utility's FVRB is calculated by averaging its OCRB and its RCND rate bases. Because an RCND study restates the OCRB in current

[1] Chaparral City Water Company has appealed that Decision. The appeal is currently pending before the Arizona Court of Appeals.

dollars (through the use of engineering indexes that contain certain inflation factors to calculate an RCND rate base), it is inappropriate to apply an OCROR to a FVRB. This is because the OCROR, like the FVRB, contains an inflation component in it. Consequently, the application of the OCRB rate of return to a FVRB (calculated using the average of an OCRB and the RCND rate base) produces an inappropriate level of operating income which reflects an over-counting of the effects of inflation. As a result, a utility's investors would earn additional operating income on the effects of inflation, as opposed to only earning a return on actual investor supplied capital. To remedy this situation, the OCROR is adjusted downward by removing the inflation expectation that is embedded in it.[2] This is the same rationale that the Commission relied on in Decision No. 70441.

Q. Why do you believe that RUCO's recommended 5.96 percent FVROR is an appropriate rate of return for UNSE to earn on its invested capital?

A. The FVROR that RUCO is recommending meets the criteria established in the landmark Supreme Court cases of Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia (262 U.S. 679, 1923) and Federal Power Commission v. Hope Natural Gas Company (320 U.S. 391, 1944). Simply stated, these two cases affirmed that a public utility that is efficiently and economically managed is entitled

[2] In a case where there is deflation, an upward adjustment would be made to account for a level of deflation.

to a return on investment that instills confidence in its financial soundness, allows the utility to attract capital, and also allows the utility to perform its duty to provide service to ratepayers. The rate of return adopted for the utility should also be comparable to a return that investors would expect to receive from investments with similar risk.

The Hope decision allows for the rate of return to cover both the operating expenses and the "capital costs of the business" which includes interest on debt and dividend payment to shareholders. This is predicated on the belief that, in the long run, a company that cannot meet its debt obligations and provide its shareholders with an adequate rate of return will not continue to supply adequate public utility service to ratepayers.

Q. Do the Bluefield and Hope decisions indicate that a rate of return sufficient to cover all operating and capital costs is guaranteed?

A. No. Neither case *guarantees* a rate of return on utility investment. What the Bluefield and Hope decisions *do allow*, is for a utility to be provided with the *opportunity* to earn a reasonable rate of return on its investment. That is to say that a utility, such as UNSE, is provided with the opportunity to earn an appropriate rate of return if the Company's management exercises good judgment and manages its assets and resources in a manner that is both prudent and economically efficient.

COST OF EQUITY CAPITAL

Q. What is your recommended cost of equity capital for UNSE?

A. Based on the results of my DCF and CAPM analyses, which ranged from 6.15 percent to 9.55 percent for a sample of electric utility companies, I am recommending a 9.25 percent original cost of equity capital for UNSE. My recommended original cost of equity capital figure falls on the higher end of an acceptable range of results obtained from my DCF and CAPM analyses, which utilized a sample of publicly traded electric utility companies.

Discounted Cash Flow (DCF) Method

Q. Please explain the DCF method that you used to estimate UNSE's cost of equity capital.

A. The DCF method employs a stock valuation model known as the constant growth valuation model, that bears the name of Dr. Myron J. Gordon (i.e. the Gordon model), the professor of finance who was responsible for its development. Simply stated, the DCF model is based on the premise that the current price of a given share of common stock is determined by the present value of all of the future cash flows that will be generated by that share of common stock. The rate that is used to discount these cash flows back to their present value is often referred to as the investor's cost of capital (i.e. the cost at which an investor is willing to forego other investments in favor of the one that he or she has chosen).

Another way of looking at the investor's cost of capital is to consider it from the standpoint of a company that is offering its shares of stock to the investing public. In order to raise capital, through the sale of common stock, a company must provide a required rate of return on its stock that will attract investors to commit funds to that particular investment. In this respect, the terms "cost of capital" and "investor's required return" are one in the same. For common stock, this required return is a function of the dividend that is paid on the stock. The investor's required rate of return can be expressed as the percentage of the dividend that is paid on the stock (dividend yield) plus an expected rate of future dividend growth. This is illustrated in mathematical terms by the following formula:

$$k = \frac{D_1}{P_0} + g$$

where: k = the required return (cost of equity, equity capitalization rate),

$\frac{D_1}{P_0}$ = the dividend yield of a given share of stock calculated by dividing the expected dividend by the current market price of the given share of stock, and

g = the expected rate of future dividend growth

This formula is the basis for the standard growth valuation model that I used to determine UNSE's cost of equity capital.

Q. In determining the rate of future dividend growth for UNSE, what assumptions did you make?

A. There are two primary assumptions regarding dividend growth that must be made when using the DCF method. First, dividends will grow by a constant rate into perpetuity, and second, the dividend payout ratio will remain at a constant rate. Both of these assumptions are predicated on the traditional DCF model's basic underlying assumption that a company's earnings, dividends, book value and share growth all increase at the same constant rate of growth into infinity. Given these assumptions, if the dividend payout ratio remains constant, so does the earnings retention ratio (the percentage of earnings that are retained by the company as opposed to being paid out in dividends). This being the case, a company's dividend growth can be measured by multiplying its retention ratio (1 - dividend payout ratio) by its book return on equity. This can be stated as $g = b \times r$.

Q. Would you please provide an example that will illustrate the relationship that earnings, the dividend payout ratio and book value have with dividend growth?

A. RUCO consultant Stephen Hill illustrated this relationship in a Citizens Utilities Company 1993 rate case by using a hypothetical utility.[3]

[3] Citizens Utilities Company, Arizona Gas Division, Docket No. E-1032-93-111, Prepared Testimony, dated December 10, 1993, p. 25.

Table I

	Year 1	Year 2	Year 3	Year 4	Year 5	Growth
Book Value	$10.00	$10.40	$10.82	$11.25	$11.70	4.00%
Equity Return	10%	10%	10%	10%	10%	N/A
Earnings/Sh.	$1.00	$1.04	$1.082	$1.125	$1.170	4.00%
Payout Ratio	0.60	0.60	0.60	0.60	0.60	N/A
Dividend/Sh	$0.60	$0.624	$0.649	$0.675	$0.702	4.00%

Table I of Mr. Hill's illustration presents data for a five-year period on his hypothetical utility. In Year 1, the utility had a common equity or book value of $10.00 per share, an investor-expected equity return of ten percent, and a dividend payout ratio of sixty percent. This results in earnings per share of $1.00 ($10.00 book value x 10 percent equity return) and a dividend of $0.60 ($1.00 earnings/sh. x 0.60 payout ratio) during Year 1. Because forty percent (1 - 0.60 payout ratio) of the utility's earnings are retained as opposed to being paid out to investors, book value increases to $10.40 in Year 2 of Mr. Hill's illustration. Table I presents the results of this continuing scenario over the remaining five-year period.

The results displayed in Table I demonstrate that under "steady-state" (i.e. constant) conditions, book value, earnings and dividends all grow at the same constant rate. The table further illustrates that the dividend growth rate, as discussed earlier, is a function of (1) the internally generated funds or earnings that are retained by a company to become new equity, and (2) the return that an investor earns on that new equity. The DCF dividend growth rate, expressed as g = b x r, is also referred to as the internal or sustainable growth rate.

Q. If earnings and dividends both grow at the same rate as book value, shouldn't that rate be the sole factor in determining the DCF growth rate?

A. No. Possible changes in the expected rate of return on either common equity or the dividend payout ratio make earnings and dividend growth by themselves unreliable. This can be seen in the continuation of Mr. Hill's illustration on a hypothetical utility.

Table II

	Year 1	Year 2	Year 3	Year 4	Year 5	Growth
Book Value	$10.00	$10.40	$10.82	$11.47	$12.158	5.00%
Equity Return	10%	10%	15%	15%	15%	10.67%
Earnings/Sh	$1.00	$1.04	$1.623	$1.720	$1.824	16.20%
Payout Ratio	0.60	0.60	0.60	0.60	0.60	N/A
Dividend/Sh	$0.60	$0.624	$0.974	$1.032	$1.094	16.20%

In the example displayed in Table II, a sustainable growth rate of four percent[4] exists in Year 1 and Year 2 (as in the prior example). In Year 3, Year 4 and Year 5, however, the sustainable growth rate increases to six

[4] [(Year 2 Earnings/Sh – Year 1 Earnings/Sh) ÷ Year 1 Earnings/Sh] = [($1.04 - $1.00) ÷ $1.00] = [$0.04 ÷ $1.00] = <u>4.00%</u>

percent.[5] If the hypothetical utility in Mr. Hill's illustration were expected to earn a fifteen-percent return on common equity on a continuing basis, then a six percent long-term rate of growth would be reasonable. However, the compound growth rate for earnings and dividends, displayed in the last column, is 16.20 percent. If this rate was to be used in the DCF model, the utility's return on common equity would be expected to increase by fifty percent every five years, [(15 percent ÷ 10 percent) – 1]. This is clearly an unrealistic expectation.

Although it is not illustrated in Mr. Hill's hypothetical example, a change in only the dividend payout ratio will eventually result in a utility paying out more in dividends than it earns. While it is not uncommon for a utility in the real world to have a dividend payout ratio that exceeds one hundred percent on occasion, it would be unrealistic to expect the practice to continue over a sustained long-term period of time.

Q. Other than the retention of internally generated funds, as illustrated in Mr. Hill's hypothetical example, are there any other sources of new equity capital that can influence an investor's growth expectations for a given company?

A. Yes, a company can raise new equity capital externally. The best example of external funding would be the sale of new shares of common stock. This would create additional equity for the issuer and is often the

[5] [(1 – Payout Ratio) x Rate of Return] = [(1 - 0.60) x 15.00%] = 0.40 x 15.00% = <u>6.00%</u>

case with utilities that are either in the process of acquiring smaller systems or providing service to rapidly growing areas.

Q. How does external equity financing influence the growth expectations held by investors?

A. Rational investors will put their available funds into investments that will either meet or exceed their given cost of capital (i.e. the return earned on their investment). In the case of a utility, the book value of a company's stock usually mirrors the equity portion of its rate base (the utility's earning base). Because regulators allow utilities the opportunity to earn a reasonable rate of return on rate base, an investor would take into consideration the effect that a change in book value would have on the rate of return that he or she would expect the utility to earn. If an investor believes that a utility's book value (i.e. the utility's earning base) will increase, then he or she would expect the return on the utility's common stock to increase. If this positive trend in book value continues over an extended period of time, an investor would have a reasonable expectation for sustained long-term growth.

Q. Please provide an example of how external financing affects a utility's book value of equity.

A. As I explained earlier, one way that a utility can increase its equity is by selling new shares of common stock on the open market. If these new shares are purchased at prices that are higher than those shares sold previously, the utility's book value per share will increase in value. This would increase both the earnings base of the utility and the earnings expectations of investors. However, if new shares sold at a price below the pre-sale book value per share, the after-sale book value per share declines in value. If this downward trend continues over time, investors might view this as a decline in the utility's sustainable growth rate and will have lower expectations regarding growth. Using this same logic, if a new stock issue sells at a price per share that is the same as the pre-sale book value per share, there would be no impact on either the utility's earnings base or investor expectations.

Q. Please explain how the external component of the DCF growth rate is determined.

A. In his book, The Cost of Capital to a Public Utility,[6] Dr. Gordon (the individual responsible for the development of the DCF or constant growth model) identified a growth rate that includes both expected internal and external financing components. The mathematical expression for Dr. Gordon's growth rate is as follows:

[6] Gordon, M.J., The Cost of Capital to a Public Utility, East Lansing, MI: Michigan State University, 1974, pp. 30-33.

$$g = (br) + (sv)$$

where: g = DCF expected growth rate,

b = the earnings retention ratio,

r = the return on common equity,

s = the fraction of new common stock sold that accrues to a current shareholder, and

v = funds raised from the sale of stock as a fraction of existing equity.

and $v = 1 - [(BV) \div (MP)]$

where: BV = book value per share of common stock, and

MP = the market price per share of common stock.

Q. Did you include the effect of external equity financing on long-term growth rate expectations in your analysis of expected dividend growth for the DCF model?

A. Yes. The external growth rate estimate (sv) is displayed on Page 1 of Schedule WAR-4, where it is added to the internal growth rate estimate (br) to arrive at a final sustainable growth rate estimate.

…

Q. Please explain why your calculation of external growth on page 2 of Schedule WAR-4, is the current market-to-book ratio averaged with 1.0 in the equation [(M ÷ B) + 1] ÷ 2.

A. The market price of a utility's common stock will tend to move toward book value, or a market-to-book ratio of 1.0, if regulators allow a rate of return that is equal to the cost of capital (one of the desired effects of regulation). As a result of this situation, I used [(M ÷ B) + 1] ÷ 2 as opposed to the current market-to-book ratio by itself to represent investor's expectations that, in the future, a given utility will achieve a market-to-book ratio of 1.0.

Q. Has the Commission ever adopted a cost of capital estimate that included this assumption?

A. Yes. In a prior Southwest Gas Corporation rate case[7], the Commission adopted the recommendations of ACC Staff's cost of capital witness, Stephen Hill, who I noted earlier in my testimony. In that case, Mr. Hill used the same methods that I have used in arriving at the inputs for the DCF model. His final recommendation for Southwest Gas Corporation was largely based on the results of his DCF analysis, which incorporated the same valid market-to-book ratio assumption that I have used consistently in the DCF model as a cost of capital witness for RUCO.

[7] Decision No. 68487, Dated February 23, 2006 (Docket No. G-01551A-04-0876)

Q. How did you develop your dividend growth rate estimate?

A. I analyzed data on a proxy group consisting of ten electric utility companies that have similar operating characteristics to UNS.

Q. Why did you use a proxy group methodology as opposed to a direct analysis of UNSE?

A. One of the problems in performing this type of analysis is that the utility applying for a rate increase is not always a publicly traded company, as is the case with UNSE itself. Consequently it was necessary to create a proxy by analyzing publicly traded electric utilities with similar risk characteristics.

Q. Are there any other advantages to the use of a proxy?

A. Yes. As I noted earlier, the U.S. Supreme Court ruled in the Hope decision that a utility is entitled to earn a rate of return that is commensurate with the returns on investments of other firms with comparable risk. The proxy technique that I have used derives that rate of return. One other advantage to using a sample of companies is that it reduces the possible impact that any undetected biases, anomalies, or measurement errors may have on the DCF growth estimate.

...

Q. What criteria did you use in selecting the companies that make up your proxy for UNSE?

A. All of the electric utilities in my sample are publicly traded on the NYSE and are followed by The Value Line Investment Survey's ("Value Line") electric utility industry segment. All of the companies in the proxy are engaged in the provision of regulated electric services. Attachment A of my testimony contains Value Line's most recent evaluation of the ten electric utilities that I used for my cost of common equity analysis.

Q. What companies are included your proxy?

A. The ten electric utility companies included in my proxy (and their NYSE ticker symbols) are ALLETE, Inc. ("ALE"), Black Hills Corporation ("BKH"), CH Energy Group,, Inc. ("CHG"), Empire District Electric Company ("EDE"), Hawaiian Electric Industries, Inc. ("HE"), MGE Energy, Inc. ("MGEE"), Northeast Utilities ("NU"), NSTAR ("NST") Otter Tail Corporation ("OTTR"), and UIL Holdings. ("UIL").

Q. Did the Company's witness also perform a similar analysis using electric utilities?

A. Yes, the Company's witness, Martha B. Pritz, performed a similar analysis of publicly traded electric utilities.

Q. Does your sample of electric utilities include all of the same electric utility companies that Ms. Pritz included in her sample?

A. No. My sample includes eight of the sample electric utility companies that Ms. Pritz selected for her sample.

Q. Please explain the difference in your samples.

A. In addition to the eight companies that our samples have in common, Ms. Pritz also included Northwestern Corporation and Portland General Electric Company. I decided not to include those two utilities because of a lack of Value Line information on them. In the case of Northwestern Corporation, the utility is covered in Value Line's Small and Mid-Cap Edition which does not provide projections extending into the 2014 time frame which I rely on in my DCF analysis. While Value Line does provide such projections on Portland General Electric Company, the utility did not have a full five years of historical data that I also rely on in my DCF model. Consequently, I substituted these two utilities with two other electrics: Black Hills Corporation ("BKH") and Otter Tail Corporation ("OTTR").

Q. Please explain your DCF growth rate calculations for the sample companies used in your proxy.

A. Schedule WAR-5 provides retention ratios, returns on book equity, internal growth rates, book values per share, numbers of shares outstanding, and the compounded share growth for each of the utilities included in the sample for the historical observation period 2004 to 2008. Schedule WAR-5 also includes Value Line's projected 2009, 2010 and 2012-14 values for the retention ratio, equity return, book value per share growth rate, and number of shares outstanding for the electric utilities in my sample.

Q. Please describe how you used the information displayed in Schedule WAR-5 to estimate each comparable utility's dividend growth rate.

A. In explaining my analysis, I will use ALLETE, Inc., (NYSE symbol ALE) as an example. The first dividend growth component that I evaluated was the internal growth rate. I used the "b x r" formula (described on page 18) to multiply ALE's earned return on common equity by its earnings retention ratio for each year during the 2004 to 2008 observation period to derive the utility's annual internal growth rates. I used the mean average of this five-year period as a benchmark against which I compared the projected growth rate trends provided by Value Line. Because an investor is more likely to be influenced by recent growth trends, as opposed to historical averages, the five-year mean noted earlier was used only as a benchmark figure. As shown on Schedule WAR-5, Page 1, ALE's sustainable internal growth rate increased from 4.74 percent in 2004 to 5.60 percent in 2005. The company's growth rates experienced a pattern of decline during the remainder of the observation period, which resulted in a 5.06 percent average over the 2004 to 2008 time frame. Value Line's analysts are forecasting this trend to continue through 2009 before growth climbs steadily to 2.72 percent through the 2012-14 period. Based on these estimates I believe a 2.75 percent rate of internal growth is possible for AGL (Schedule WAR-4, Page 1, Column A, Line 1).

Q. Please continue with the external growth rate "s x v" component portion of your analysis.

A. Schedule WAR-5 demonstrates that ALE's share growth averaged just 2.36 percent over the observation period. Value Line expects future outstanding shares to increase from 32.60 million in 2008 to 41.00 million by the end of 2014. Taking this data into consideration, I am estimating a 5.00 percent rate of share growth for ALE's (Schedule WAR-4, Page 2, Column A, Line 1). I used this estimate to calculate the s x v component of the DCF dividend growth rate (which is 0.77 percent for ALE). My final dividend growth rate estimate for ALE is 3.52 percent (2.75 percent internal growth + 0.77 percent external growth) and is shown on Page 1 of Schedule WAR-4.

Q. What is your average dividend growth rate estimate using the DCF model for the electric utilities?

A. Based on the DCF model, my average dividend growth rate estimate is 4.15 percent, which is also displayed on page 1 of Schedule WAR-4.

Q. How do your average dividend growth rate estimates compare with the growth rate data published by Value Line and other analysts?

A. The average dividend growth rate estimate that I've calculated falls between the projections of the securities analysts I've relied on. My 4.15 percent estimate is 229 basis points lower than the 6.44 percent consensus EPS projections published by Zacks Investment Research ("Zacks"), exhibited in my Attachment B, and 42 basis points higher than Value Line's 3.73 percent projected estimates. As can also be seen on Schedule WAR-6, the 4.15 percent estimate that I have calculated is 166 basis points higher than the 2.49 percent five-year historical average of Value Line data (on EPS, DPS and BVPS) and is 78 basis point higher than the 3.37 percent average of the 5-year EPS means provided by Zacks, and the aforementioned percent five-year historical average of Value Line data. In fact, my 4.15 percent estimate is 56 basis points higher than the 3.59 percent Value Line 5-year compound history that is also displayed on Schedule WAR-6. Based on the information presented in Schedule WAR-6, I would say that my 4.15 percent estimate, which falls between Zack's and Value Line's projections, is a fair representation of the growth estimates presented by securities analysts at this point in time.

Q. How did you calculate the dividend yields displayed in Schedule WAR-3?

A. I used the estimated annual dividends, for the next twelve-month period, that appeared in Value Line's August 7, August 28 and September 25, 2009 Ratings and Reports Electric Utility Industry updates for electric utilities located in the western, eastern and central regions of the U.S. I then divided those figures by the eight-week average price per share of the appropriate utility's common stock. The eight-week average price is based on the daily closing stock prices for each of the companies in my proxies for the period August 17, 2009 to October 10, 2009.

Q. Based on the results of your DCF analysis, what is your cost of equity capital estimate for the electric utilities included in your sample?

A. As shown in Schedule WAR-2, the cost of equity capital derived from my DCF analysis is 9.55 percent.

Capital Asset Pricing Model (CAPM) Method

Q. Please explain the theory behind CAPM and why you decided to use it as an equity capital valuation method in this proceeding.

A. CAPM is a mathematical tool that was developed during the early 1960's by William F. Sharpe[8], the Timken Professor Emeritus of Finance at Stanford University, who shared the 1990 Nobel Prize in Economics for research that eventually resulted in the CAPM model. CAPM is used to analyze the relationships between rates of return on various assets and

[8] William F. Sharpe, "A Simplified Model of Portfolio Analysis," Management Science, Vol. 9, No. 2 (January 1963), pp. 277-93.

risk as measured by beta.[9] In this regard, CAPM can help an investor to determine how much risk is associated with a given investment so that he or she can decide if that investment meets their individual preferences. Finance theory has always held that as the risk associated with a given investment increases, so should the expected rate of return on that investment and vice versa. According to CAPM theory, risk can be classified into two specific forms: nonsystematic or diversifiable risk, and systematic or non-diversifiable risk. While nonsystematic risk can be virtually eliminated through diversification (i.e. by including stocks of various companies in various industries in a portfolio of securities), systematic risk, on the other hand, cannot be eliminated by diversification. Thus, systematic risk is the only risk of importance to investors. Simply stated, the underlying theory behind CAPM states that the expected return on a given investment is the sum of a risk-free rate of return plus a market risk premium that is proportional to the systematic (non-diversifiable risk) associated with that investment. In mathematical terms, the formula is as follows:

[9] Beta is defined as an index of volatility, or risk, in the return of an asset relative to the return of a market portfolio of assets. It is a measure of systematic or non-diversifiable risk. The returns on a stock with a beta of 1.0 will mirror the returns of the overall stock market. The returns on stocks with betas greater than 1.0 are more volatile or riskier than those of the overall stock market; and if a stock's beta is less than 1.0, its returns are less volatile or riskier than the overall stock market.

$$k = r_f + [\, ß\,(r_m - r_f)\,]$$

where:

k	=	the expected return of a given security,
r_f	=	risk-free rate of return,
$ß$	=	beta coefficient, a statistical measurement of a security's systematic risk,
r_m	=	average market return (e.g. S&P 500), and
$r_m - r_f$	=	market risk premium.

Q. What types of financial instruments are generally used as a proxy for the risk-free rate of return in the CAPM model?

A. Generally speaking, the yields of U.S. Treasury instruments are used by analysts as a proxy for the risk-free rate of return component.

Q. Please explain why U.S. Treasury instruments are regarded as a suitable proxy for the risk-free rate of return?

A. As citizens and investors, we would like to believe that U.S. Treasury securities (which are backed by the full faith and credit of the United States Government) pose no threat of default no matter what their maturity dates are. However, a comparison of various Treasury instruments will reveal that those with longer maturity dates do have slightly higher yields. Treasury yields are comprised of two separate components,[10] a real rate

[10] As a general rule of thumb, there are three components that make up a given interest rate or rate of return on a security: the real rate of interest, an inflationary expectation, and a risk

of interest (believed to be approximately 2.00 percent) and an inflationary expectation. When the real rate of interest is subtracted from the total treasury yield, all that remains is the inflationary expectation. Because increased inflation represents a potential capital loss, or risk, to investors, a higher inflationary expectation by itself represents a degree of risk to an investor. Another way of looking at this is from an opportunity cost standpoint. When an investor locks up funds in long-term T-Bonds, compensation must be provided for future investment opportunities foregone. This is often described as maturity or interest rate risk and it can affect an investor adversely if market rates increase before the instrument matures (a rise in interest rates would decrease the value of the debt instrument). As discussed earlier in the DCF portion of my testimony, this compensation translates into higher rates of returns to the investor.

Q. What security did you use for a risk-free rate of return in your CAPM analysis?

A. I used an eight-week average of the yields on a 5-year U.S. Treasury instrument. The yields were published in Value Line's Selection and Opinion publication dated August 21, 2009 through October 9, 2009 (Attachment C). This resulted in a risk-free (r_f) rate of return of 2.41 percent.

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premium. The approximate risk premium of a given security can be determined by simply subtracting a 91-day T-Bill rate from the yield on the security.

Q. Why did you use the yield on a 5-year year U.S. Treasury instrument as opposed to a short-term T-Bill?

A. While a shorter term instrument, such as a 91-day T-Bill, presents the lowest possible total risk to an investor, a good argument can be made that the yield on an instrument that matches the investment period of the asset being analyzed in the CAPM model should be used as the risk-free rate of return. Since utilities in Arizona generally file for rates every three to five years, the yield on a 5-year U.S. Treasury Instrument closely matches the investment period or, in the case of regulated utilities, the period that new rates will be in effect.

Q. How did you calculate the market risk premium used in your CAPM analysis?

A. I used both the 9.60 percent geometric mean and the 11.70 percent arithmetic mean of the historical total returns on the S&P 500 index from 1926 to 2008 as the proxy for the market rate of return (r_m). For the risk-free portion of the risk premium component (r_f), I used the geometric mean of the total returns of intermediate-term government bonds for the same eighty-two year period. The market risk premium (r_m - r_f) that results by using these inputs is 4.20 percent (9.60% - 5.40% = 4.20%). The market risk premium that results by using the arithmetic mean calculation is 6.10 percent (11.70% - 5.60% = 6.10%).

Q. How did you select the beta coefficients that were used in your CAPM analysis?

A. The beta coefficients (ß), for the individual utilities used in both my proxies, were calculated by Value Line and were current as of October 9, 2009. Value Line calculates its betas by using a regression analysis between weekly percentage changes in the market price of the security being analyzed and weekly percentage changes in the NYSE Composite Index over a five-year period. The betas are then adjusted by Value Line for their long-term tendency to converge toward 1.00. The beta coefficients for the electric utilities included in my sample ranged from 0.65 to 0.90 with an average beta of 0.73.

Q. What are the results of your CAPM analysis?

A. As shown on pages 1 and 2 of Schedule WAR-7, my CAPM calculation using a geometric mean to calculate the risk premium results in an average expected return of 5.46 percent. My calculation using an arithmetic mean results in an average expected return of 6.83 percent.

Q. Please summarize the results derived under each of the methodologies presented in your testimony.

A. The following is a summary of the cost of equity capital derived under each methodology used:

METHOD	RESULTS
DCF	9.55%
CAPM	5.46% – 6.83%

Based on these results, my best estimate of an appropriate range for an original cost of equity capital for UNSE is 5.46 percent to 9.55 percent. My final recommended original cost of equity capital figure is 9.25 percent.

Q How did you arrive at your recommended original cost of equity capital figure of 9.25 percent?

A. My recommended original cost of equity capital figure of 9.25 percent falls on the high end of the range of estimates produced by my DCF and CAPM results and is based on my analysis of projected returns of the electric utilities included in my sample.

Q. How does your recommended original cost of equity capital compare with the cost of equity capital proposed by the Company?

A. The 11.40 percent cost of equity capital proposed by the Company is 215 basis points higher than the 9.25 percent original cost of equity capital that I am recommending.

Current Economic Environment

Q. Please explain why it is necessary to consider the current economic environment when performing a cost of equity capital analysis for a regulated utility.

A. Consideration of the economic environment is necessary because trends in interest rates, present and projected levels of inflation, and the overall state of the U.S. economy determine the rates of return that investors earn on their invested funds. Each of these factors represent potential risks that must be weighed when estimating the cost of equity capital for a regulated utility and are, most often, the same factors considered by individuals who are also investing in non-regulated entities.

Q. Please discuss your analysis of the current economic environment.

A. My analysis includes a brief review of the economic events that have occurred since 1990. Schedule WAR-8 displays various economic indicators and other data that I will refer to during this portion of my testimony.

In 1991, as measured by the most recently revised annual change in gross domestic product ("GDP"), the U.S. economy experienced a rate of growth of negative 0.20 percent. This decline in GDP marked the beginning of a mild recession that ended sometime before the end of the first half of 1992. Reacting to this situation, the Federal Reserve Board

("Federal Reserve" or "Fed"), then chaired by noted economist Alan Greenspan, lowered its benchmark federal funds rate[11] in an effort to further loosen monetary constraints - an action that resulted in lower interest rates.

During this same period, the nation's major money center banks followed the Federal Reserve's lead and began lowering their interest rates as well. By the end of the fourth quarter of 1993, the prime rate (the rate charged by banks to their best customers) had dropped to 6.00 percent from a 1990 level of 10.01 percent. In addition, the Federal Reserve's discount rate on loans to its member banks had fallen to 3.00 percent and short-term interest rates had declined to levels that had not been seen since 1972.

Although GDP increased in 1992 and 1993, the Federal Reserve took steps to increase interest rates beginning in February of 1994, in order to keep inflation under control. By the end of 1995, the Federal discount rate had risen to 5.21 percent. Once again, the banking community followed the Federal Reserve's moves. The Fed's strategy, during this period, was to engineer a "soft landing." That is to say that the Federal Reserve wanted to foster a situation in which economic growth would be stabilized without incurring either a prolonged recession or runaway inflation.

[11] This is the interest rate charged by banks with excess reserves at a Federal Reserve district bank to banks needing overnight loans to meet reserve requirements. The federal funds rate is the most sensitive indicator of the direction of interest rates, since it is set daily by the market, unlike the prime rate and the discount rate, which are periodically changed by banks and by the Federal Reserve Board, respectively.

Q. Did the Federal Reserve achieve its goals during this period?

A. Yes. The Fed's strategy of decreasing interest rates to stimulate the economy worked. The annual change in GDP began an upward trend in 1992. A change of 4.50 percent and 4.20 percent were recorded at the end of 1997 and 1998 respectively. Based on daily reports that were presented in the mainstream print and broadcast media during most of 1999, there appeared to be little doubt among both economists and the public at large that the U.S. was experiencing a period of robust economic growth highlighted by low rates of unemployment and inflation. Investors, who believed that technology stocks and Internet company start-ups (with little or no history of earnings) had high growth potential, purchased these types of issues with enthusiasm. These types of investors, who exhibited what former Chairman Greenspan described as "irrational exuberance," pushed stock prices and market indexes to all time highs from 1997 to 2000.

Q. What has been the state of the economy since 2001?

A. The U.S. economy entered into a recession near the end of the first quarter of 2001. The bullish trend, which had characterized the last half of the 1990's, had already run its course sometime during the third quarter of 2000. Economic data released since the beginning of 2001 had already been disappointing during the months preceding the September 11, 2001 terrorist attacks on the World Trade Center and the Pentagon. Slower growth figures, rising layoffs in the high technology manufacturing sector, and falling equity prices (due to lower earnings expectations) prompted the Fed to begin cutting interest rates as it had done in the early 1990's. The now infamous terrorist attacks on New York City and Washington D.C. marked a defining point in this economic slump and prompted the Federal Reserve to continue its rate cutting actions through December 2001. Prior to the 9/11 attacks, commentators, reporting in both the mainstream financial press and various economic publications including Value Line, believed that the Federal Reserve was cutting rates in the hope of avoiding a recession.

Despite several intervals during 2002 and 2003 in which the Federal Open Market Committee ("FOMC") decided not to change interest rates – moves which indicated that the worst may be over and that the recession might have bottomed out during the last quarter of 2001 – a lackluster economy persisted. The continuing economic malaise and even fears of possible deflation prompted the FOMC to make a thirteenth rate cut on June 25, 2003. The quarter point cut reduced the federal funds rate to 1.00 percent, the lowest level in forty-five years.

Even though some signs of economic strength, mainly attributed to consumer spending, began to crop up during the latter part of 2002 and into 2003, Chairman Greenspan appeared to be concerned with sharp declines in capital spending in the business sector.

During the latter part of 2003, the FOMC went on record as saying that it intended to leave interest rates low "for a considerable period." After its two-day meeting that ended on January 28, 2004, the FOMC announced "that with inflation 'quite low' and plenty of excess capacity in the economy, policy-makers 'can be patient in removing its policy accommodation.'[12]

Q. What actions has the Federal Reserve taken in terms of interest rates since the beginning of 2001?

A. As noted earlier, from January 2001 to June 2003 the Federal Reserve cut interest rates a total of thirteen times. During this period, the federal funds rate fell from 6.50 percent to 1.00 percent. The FOMC reversed this trend on June 29, 2004 and raised the federal funds rate 25 basis points to 1.25 percent. From June 29, 2004 to January 31, 2006, the FOMC raised the federal funds rate thirteen more times to a level of 4.50 percent.

The FOMC's January 31, 2006 meeting marked the final appearance of Alan Greenspan, who had presided over the rate setting body for a total of eighteen years. On that same day, Greenspan's successor, Ben Bernanke, the former chairman of the President's Council of Economic Advisers and a former Fed governor under Greenspan from 2002 to 2005, was confirmed by the U.S. Senate to be the new Federal Reserve chief.

[12] Wolk, Martin, "Fed holds interest rates steady," MSNBC, January 28, 2004.

As expected by Fed watchers, Chairman Bernanke picked up where his predecessor left off and increased the federal funds rate by 25 basis points during each of the next three FOMC meetings for a total of seventeen consecutive rate increases since June 2004, and raising the federal funds rate to a level of 5.25 percent. The Fed's rate increase campaign finally came to a halt at the FOMC meeting held on August 8, 2006, when the FOMC decided not to raise rates.

Q. What was the reaction in the financial community to the Fed's decision not to raise interest rates?

A. As in the past, banks followed the Fed's lead once again and held the prime rate to a level of 8.25 percent, or 300 basis points higher than the federal funds rate of 5.25 percent established on June 29, 2006.

Q. How did analysts view the Fed's actions between January 2001 and August 2006?

A. According to an article that appeared in the December 2, 2004 edition of The Wall Street Journal, the FOMC's decision to begin raising rates two years ago was viewed as a move to increase rates from emergency lows in order to avoid creating an inflation problem in the future as opposed to slowing down the strengthening economy.[13] In other words, the Fed was

[13] McKinnon, John D. and Greg IP, "Fed Raises Rates by a Quarter Point," The Wall Street Journal, September 22, 2004.

trying to head off inflation *before* it became a problem. During the period following the August 8, 2006 FOMC meeting, the Fed's decisions not to raise rates were viewed as a gamble that a slower U.S. economy would help to cap growing inflationary pressures.[14]

Q. Was the Fed attempting to engineer another "soft landing", as it did in the mid-nineties, by holding interest rates steady?

A. Yes, however, as pointed out in an August 2006 article in The Wall Street Journal by E.S. Browning, soft landings – like the one that the Fed managed to pull off during the 1994-95 time frame, in which a recession or a bear market were avoided – rarely happen[15]. Since it began increasing the federal funds rate in June 2004, the Fed had assured investors that it would increase rates at a "measured" pace. Many analysts and economists interpreted this language to mean that former Chairman Greenspan would be cautious in increasing interest rates too quickly in order to avoid what is considered to be one of the Fed's few blunders during Greenspan's tenure – a series of increases in 1994 that caught the financial markets by surprise after a long period of low rates. The rapid rise in rates contributed to the bankruptcy of Orange County, California

[14] Ip, Greg, "Fed Holds Interest Rates Steady As Slowdown Outweighs Inflation," The Wall Street Journal Online Edition, August 8, 2006.

[15] Browning, E.S, "Not Too Fast, Not Too Slow…," The Wall Street Journal Online Edition, August 21, 2006.

and the Mexican peso crisis[16]. According to Mr. Browning, at the time that his article was published, the hope was that Chairman Bernanke would succeed in slowing the economy "just enough to prevent serious inflation, but not enough to choke off growth." In other words, "a 'Goldilocks economy,' in which growth is not too hot and not too cold."

Q. Was the Fed's attempt to engineer a soft landing successful during the period that followed the August 8, 2006 FOMC meeting?

A. It would appear so. Articles published in the mainstream financial press were generally upbeat on the economy during that period. An example of this is an article written by Nell Henderson that appeared in the January 30, 2007 edition of The Washington Post. According to Ms. Henderson, "a year into [Fed Chairman] Bernanke's tenure, the [economic] picture has turned considerably brighter. Inflation is falling; unemployment is low; wages are rising; and the economy, despite continued problems in housing, is growing at a brisk clip."[17]

Q. What has been the state of the economy over the past two years?

A. Reports in the mainstream financial press during the majority of 2007 reflected the view that the U.S. economy was slowing as a result of a worsening situation in the housing market and higher oil prices. The

[16] Associated Press (AP), "Fed begins debating interest rates" USA Today, June 29, 2004.

[17] Henderson, Nell, "Bullish on Bernanke" The Washington Post, January 30, 2007.

overall outlook for the economy was one of only moderate growth at best. Also during this period the Fed's key measure of inflation began to exceed the rate setting body's comfort level.

On August 7, 2007, the FOMC decided not to increase or decrease the federal funds rate for the ninth straight time and left its target rate unchanged at 5.25 percent.[18] At the time of the Fed's decision, analysts speculated that a rate cut over the next several months was unlikely given the Fed's concern that inflation would fail to moderate. However, during this same period, evidence of an even slower economy and a possible recession was beginning to surface. Within days of the Fed's decision to stand pat on rates, a borrowing crisis rooted in a deterioration of the market for subprime mortgages and securities linked to them, forced the Fed to inject $24 billion in funds (raised through open market operations) into the credit markets.[19] By Friday, August 17, 2007, after a turbulent week on Wall Street, the Fed made the decision to lower its discount rate (i.e. the rate charged on direct loans to banks) by 50 basis points, from 6.25 percent to 5.75 percent, and took steps to encourage banks to borrow from the Fed's discount window in order to provide liquidity to lenders. According to an article that appeared in the August 18, 2007 edition of The Wall Street Journal, [20] the Fed had used all of its tools to

[18] Ip, Greg, "Markets Gyrate As Fed Straddles Inflation, Growth" The Wall Street Journal, August 8, 2007

[19] Ip, Greg, "Fed Enters Market To Tamp Down Rate" The Wall Street Journal, August 9, 2007

[20] Ip, Greg, Robin Sidel and Randall Smith, "Fed Offers Banks Loans Amid Crises" The Wall

restore normalcy to the financial markets. If the markets failed to settle down, the Fed's only weapon left was to cut the Federal Funds rate – possibly before the next FOMC meeting scheduled on September 18, 2007.

Q. Did the Fed cut rates as a result of the subprime mortgage borrowing crises?

A. Yes. At its regularly scheduled meeting on September 18, 2007, the FOMC surprised the investment community and cut both the federal funds rate and the discount rate by 50 basis points (25 basis points more than what was anticipated). This brought the federal funds rate down to a level of 4.75 percent. The Fed's action was seen as an effort to curb the aforementioned slowdown in the economy. Over the course of the next four months, the FOMC reduced the Federal funds rate by a total 175 basis points to a level of 3.00 percent – mainly as a result of concerns that the economy was slipping into a recession. This included a 75 basis point reduction that occurred one week prior to the FOMC's meeting on January 29, 2008.

...

Street Journal, August 9, 2007

Q. What actions has the Fed taken in regard to interest rates since the beginning of 2008?

A. The Fed made two more rate cuts which included a 75 basis point reduction in the federal funds rate on March 18, 2008 and an additional 25 basis point reduction on April 30, 2008. The Fed's decision to cut rates was based on its belief that the slowing economy was a greater concern than the current rate of inflation (which the majority of FOMC members believed would moderate during the economic slowdown).[21] As a result of the Fed's actions, the federal funds rate was reduced to a level of 2.00 percent. From April 30, 2008 through September 16, 2008, the Fed took no further action on its key interest rate. However, the days before and after the Fed's September 16, 2008 meeting saw longstanding Wall Street firms such as Lehman Brothers, Merrill Lynch and AIG failing as a result of their subprime holdings. By the end of the week, the Bush administration had announced plans to deal with the deteriorating financial condition which had now become a worldwide crisis. The administrations actions included former Treasury Secretary Henry Paulson's request to Congress for $700 billion to buy distressed assets as part of a plan to halt what has been described as the worst financial crisis since the 1930's[22]. Amidst this turmoil, the Fed made the decision to cut the federal funds rate by another

[21] Ip, Greg, "Credit Worries Ease as Fed Cuts, Hints at More Relief" The Wall Street Journal, March 19, 2008

[22] Soloman, Deborah, Michael R. Crittenden and Damian Paletta, "U.S. Bailout Plan Calms Markets, But Struggle Looms Over Details" The Wall Street Journal, September 20, 2008

50 basis points in a coordinated move with foreign central banks on October 8, 2008. This was followed by another 50 basis point cut during the regular FOMC meeting on October 29, 2008. At the time of this writing, the federal funds target rate now stands at 0.25 percent, the result of a 75 basis point cut announced on December 16, 2008. After FOMC meetings in January, March April, June, August and September of 2009, the Fed elected not to make any changes in the federal funds rate, stating in January that the rate would remain low "for some time."[23] Presently, the Fed's discount rate is at 0.50 percent, a level not seen since the 1940s.[24] Based on data released during the early part of December 2008, the U.S. has officially been in a recession since December of 2007.

Q. Putting this all into perspective, how have the Fed's actions since 2000 affected benchmark rates?

A. U.S. Treasury instruments are for the most part still at historically low levels. As can be seen on the first page of Attachment C, the previously mentioned federal discount rate (the rate charged to the Fed's member banks), has fallen to 0.50 percent from 1.75 percent in 2008.

[23] Hilsenrath, Jon and Liz Rappaport, "Fed Weighs Idea of Buying Treasurys as Focus Shifts" The Wall Street Journal, January 29, 2009

[24] Hilsenrath, Jon, "Fed Cuts Rates Near Zero to Battle Slump" The Wall Street Journal, December 17, 2008

Q. What has been the trend in other leading interest rates over the last year?

A. All of the leading interest rates have dropped from levels that existed a year ago (Attachment C, Value Line Selection & Opinion page 3277, dated October 9, 2009). The prime rate has fallen from 5.00 percent a year ago to 3.25 percent. The benchmark federal funds rate, just discussed, has decreased from 2.00 percent, in October 2008, to a level of 0.00 - 0.25 percent (as a result of the December 16, 2008 rate cut discussed above). The yields on all of the non-inflation protected maturities of U.S. Treasury instruments (exhibited in Attachment C) have also decreased over the past year. A previous trend, described by former Chairman Greenspan as a "conundrum"[25], in which long-term rates fell as short-term rates increased, thus creating a somewhat inverted yield curve that existed as late as June 2007, is completely reversed and a more traditional yield curve (one where yields increase as maturity dates lengthen) presently exists (Attachment C). The 5-year Treasury yield, used in my CAPM analysis, has fallen from 2.86 percent, in October 2008, to 2.31 percent. The 30-Year Treasury constant maturity rate also decreased from 4.22 percent over the past year to 4.05 percent as has the 30-year zero rate which has dropped from 4.22 percent to 4.13 percent. These current yields are considerably lower than corresponding yields that existed during the early nineties and at the beginning of the current decade (as can be seen on Schedule WAR-8).

[25] Wolk, Martin, "Greenspan wrestling with rate 'conundrum'," MSNBC, June 8, 2005

Q. What is the current outlook for the economy?

A. Value Line's analysts have become increasingly optimistic in their outlook on the economy as of late and had this to say on the housing situation in the October 9, 2009 edition of Value Line's <u>Selection and Opinion</u> publication:

> **The unfolding housing recovery is likely to be a drawn out affair**, as the nation strives to rebound from the worst slump in this sector in decades. For the most part, housing has shown steady improvement, since seemingly bottoming out earlier in 2009, as data on housing starts and sales of new homes and existing residences have mostly trended higher. However, the latest figures point up the fragility of this recovery, as sales of existing homes fell 2.7% in August—after four straight monthly increases—while new home sales were basically flat with a month earlier. Home prices continue to be soft, meantime, with prices near their lows for the past few years, as the massive inventories of unsold houses are depressing home values across much of the country.

Value Line's analysts went on to state

> **Elsewhere, the picture is mixed as well.** For example, weekly jobless claims have been trending lower for the most part in recent weeks, but key industrial sectors (notably the capital goods arena) are exhibiting some lingering weakness. We think the economy will continue to press forward in uneven increments for the balance of this year and into 2010.

Q. How are Value Lines analysts viewing electric utilities as an investment opportunity?

A. Value Line's analysts are recommending electric utilities as a relatively safe investment. In the August 28, 2009 Value Line Electric Utility (East) Industry update, analyst Michael Ratty had this to say:

> During these challenging economic times, utility stocks are still sought after due to their relative stability and attractive dividend yields. With several stocks yielding over 7%, income-oriented investors should have little trouble finding appeal in this industry. All told, we believe this might be a good time to increase your portfolio's electric-utility exposure.

In the September 25, 2009 Value Line Electric Utility (Central) Industry update, analyst Paul E. Debbas, CFA stated the following:

> Electric utility stocks have not participated in the partial recovery that the market has made so far this year after the horrible showing in 2008. To date, the Value Line Composite Average is up over 25%, but the Value Line Utility Average has hardly budged. Thus, this group's valuation has become relatively more attractive. The industry's average yield of 5% is more than twice the market mean. Many of these equities offer attractive yields that are above the industry average, plus some dividend-growth potential. Investors should be cautious about most stocks with a well above-average yield, however, due to the possibility of a dividend cut. We show a split dividend at the top of the page if we believe that there is a chance of a reduction.

Q. After weighing the economic information that you've just discussed, do you believe that the cost of equity that you have estimated is reasonable for UNSE?

A. I believe that my recommended cost of equity will provide UNSE with a reasonable rate of return on the Company's invested capital when economic data on interest rates (that are still low by historical standards) and a low and stable outlook for inflation are all taken into consideration. As I noted earlier, the Hope decision determined that a utility is entitled to earn a rate of return that is commensurate with the returns it would make on other investments with comparable risk. I believe that my cost of capital analysis has produced such a return.

COST OF DEBT

Q. Have you reviewed UNSE's testimony on the Company-proposed cost of long-term debt?

A. Yes, I have reviewed the testimony prepared by Ms. Pritz.

Q. Do you agree with Ms. Pritz's inclusion of the amortized debt discount and expenses and losses attributed to reacquired debt and the credit facility fees to arrive at her cost of debt figure of 7.05 percent?

A. Yes.

Q. What cost of long-term debt are you recommending for UNSE?

A. I am recommending that the Commission adopt the Company proposed cost of debt of 7.05 percent.

CAPITAL STRUCTURE

Q. Have you reviewed UNSE's testimony regarding the Company's proposed capital structure?

A. Yes.

Q. Please describe the Company's proposed capital structure.

A. The Company is proposing a capital structure comprised of 54.24 percent long-term debt and 45.76 percent common equity.

Q. What capital structure are you proposing for UNSE?

A. I am recommending that the Commission adopt the Company-proposed capital structure.

Q. Is UNSE's actual capital structure in line with industry averages?

A. No. UNSE's capital structure is higher in debt than the average capital structure of the electric utilities. As can be seen in Schedule WAR-9, the capital structures for those utilities averaged approximately 48 percent for debt and 52 percent for equity (51.6 percent common equity + 0.4 percent preferred equity). UNSE would be viewed by investors as having more financial risk (i.e. the risk of not being able to service debt instruments) and would expect a slightly higher return on equity.

Q. Have you made an upward adjustment to your cost of common equity that was derived from the sample electric utilities that exhibited lower financial risk?

A. No. As explained in the testimony of RUCO witness Dr. Johnson, RUCO's recommended FVROR will provide UNSE with adequate operating income to mitigate concerns regarding the level of debt in the Company's capital structure.

WEIGHTED COST OF CAPITAL

Q. How does the Company's proposed weighted average cost of capital compare with your recommendation?

A. The Company has proposed an unadjusted weighted average cost of capital of 9.04 percent. This composite figure is the result of a weighted average of UNSE's proposed 7.05 percent cost of long-term debt and 11.40 percent cost of common equity. The Company-proposed 9.04 percent OCRB weighted cost of capital is 98 basis points higher than the 8.06 percent OCRB weighted cost that I am recommending, which is the weighted cost of my recommended 7.05 percent cost of long-term debt and my recommended 9.25 percent cost of common equity. In its Application, the Company makes a 134 basis point upward adjustment to the aforementioned 9.04 percent weighted average cost of capital in order to arrive at a 10.38 percent OCROR that produces the same level of operating income as the Company-proposed 6.88 percent FVROR does.

Q. How does the Company's proposed FVROR of 6.88 percent compare with RUCO's recommendation?

A. The Company-proposed FVROR of 6.88 percent is 92 basis points higher than the 5.96 percent FVROR that RUCO witness Dr. Johnson is recommending.

Q. Why is RUCO recommending a FVROR that is lower than the OCROR that was derived from the results of your DCF and CAPM analyses?

A. As I explained earlier in my testimony, the lower FVROR removes an inflation expectation that is embedded in the OCROR. The method that RUCO has relied on to arrive at its recommended 596 percent FVROR is consistent with the provisions contained in Decision No. 70441 which established a FVROR for Chaparral City Water Company ("Remand Proceeding"). During the Remand Proceeding, the Commission was required to develop an appropriate rate of return on Chaparral's FVRB under a remand order from the Arizona Court of Appeals. In doing so, the Commission adopted, in part, a methodology that was proposed by Dr. Johnson who testified on behalf of RUCO on the FVRB rate of return issue that was central to that proceeding.[26]

Q. What did Dr. Johnson recommend in the Remand Proceeding?

A. Dr. Johnson recommended that a 200 basis point adjustment be made to the original weighted average cost of capital in order to remove the effects of general inflation from Chaparrals FVRRB. His recommendation was based on the low end of a range of figures that represented the difference

[26] On September 30, 2005, the Commission issued Decision No. 68176 which granted a permanent rate increase to Chaparral. Following the Commission's decision on the matter, the Company filed an application for rehearing on which the Commission took no action. Chaparral subsequently filed an appeal with the Arizona Court of Appeals, Division One ("Court of Appeals"). The Company's appeal claimed that Chaparral was denied a fair rate of return on its invested capital as a result of the Commission's established method of calculating a level of operating income based on the Company's fair value rate base ("FVRB"). On February 13, 2007, the Court of Appeals issued a Memorandum Decision which affirmed in part, vacated, and remanded Decision No. 68176 to the Commission for further determination.

between Treasury Inflation-Protected Securities ("TIPS") and U.S. Treasury bonds with similar liquidity and maturity characteristics.

Q. Did the Commission adopt Dr. Johnson's recommendation?

A. In part, yes. The Commission adopted a FVROR that was derived from a an inflation adjustment that reduced the cost of common equity by 200 basis points as opposed to Dr. Johnson's recommendation to reduce the original weighted average cost of capital by 200 basis points.

COMMENTS ON UNSE'S COST OF EQUITY CAPITAL TESTIMONY

Q. What methods did Ms. Pritz use to arrive at her cost of common equity for UNSE?

A. Ms. Pritz used a DCF methodology and a CAPM methodology to estimate UNSE's cost of common equity. She also relied on a bond yield plus risk premium approach to estimating the cost of common equity which is somewhat similar to the CAPM methodology.

Q. Did you conduct a bond yield plus risk premium approach to estimating your recommended cost of common equity?

A. No. I believe that the CAPM is a better model for the risk positioning type of methodology that the risk premium approach employs.

Q. Can you provide a comparison of the results derived from your respective DCF and CAPM models?

A. Yes.

DCF Comparison

Q. Were there any differences in the way that you conducted your DCF analysis and the way that Ms. Pritz conducted hers?

A. Yes, Ms. Pritz relied on the results of a multi-stage DCF model, using her proxy of ten electric utilities that I described earlier in my testimony, as opposed to the single-stage constant growth model that I relied on.

Q. Do you agree with Ms. Pritz's reliance on the multi-stage DCF model?

A. No. The 6.50 percent long-term growth rate that Ms. Pritz uses in the second stage of her multi-stage DCF model is the median value of her growth rate estimate that relied on five year-growth rate estimates from analysts from Value Line, Zacks, and SNL. The multi-stage model calculates this additional 6.50 percent rate of growth into perpetuity. Her multi-stage DCF model produces an average estimated cost of equity of 12.10 percent for her sample group of electric utilities.

…

Q. Does Ms. Pritz give equal weight to the near-term and long-term growth estimates in her multi-stage model?

A. Yes Ms. Pritz gives equal weight to both her near-term and long-term multi-stage inputs. A good argument can be made that more emphasis should be placed on the near-term component of Ms. Pritz's 's multi-stage DCF model as opposed to the long-term growth rate that is carried out into perpetuity.

Q. Why didn't you conduct a multi-stage DCF analysis like the one conducted by Ms. Pritz?

A. Given the fact that the single-stage model is a constant growth model, I saw no need to rely on a model which calculates a second growth rate estimate into perpetuity. The five-year growth rate projections that I rely on in for the single-stage DCF model is also consistent with the use of a 5-year treasury instrument as the risk free rate of return in my CAPM model. This 5-year investment horizon is very close to the 3 to 5-year periods that utilities in Arizona apply for rate relief.

Q. What is the difference between Ms. Pritz's DCF estimate and your DCF estimate?

A. As I noted earlier, Ms. Pritz's multi-stage DCF produced an estimate of 12.10 percent which is 255 basis points higher than the 9.55 percent cost of common equity derived from my DCF analysis which is a mean average of the DCF estimates of the ten electric utilities in my proxy.

Q. Does Ms. Pritz provide an estimate that is based on the single-stage model that you employed?

A. Not directly, however the exhibits in her testimony contain inputs and estimates used in her multi-stage model that can also be used in the single-stage model. Using the inputs and estimates that appear in Ms. Pritz's exhibits, a single-stage model would produce a mean average estimate of 11.40 percent or 185 basis points higher than my 9.55 percent DCF estimate.

Q. What is the main reason for the difference between your single-stage DCF results and the single stage results obtained from Ms. Pritz's data?

A. The main difference is her higher growth rate estimate of 5.62 percent, which was based on EPS estimates only, as opposed to my 4.15 percent estimate. There is not much difference in our average dividend yields.

CAPM Comparison

Q. Please describe the differences in the way that you conducted your CAPM analysis and the way that Ms. Pritz conducted hers?

A. The main differences between Ms. Pritz's CAPM analysis and mine are her use of a 20-year Treasury instrument for the risk free rate of return (as opposed to my use of a 5-year instrument) and her upwardly adjusted market risk premium. In regard to her market risk premium, Ms. Pritz relied solely on an arithmetic mean average of the difference between 20-year Treasury returns and the historical returns of large company stocks from 1926 to 2008 to derive a market risk premium of 6.50 percent. She then added an additional 2.29 percent to arrive at her market risk premium of 8.79 percent.

Q. What does the 2.29 percent adjustment to Ms. Pritz's market risk premium represent?

A. On page 14 of her direct testimony, Ms. Pritz states that the 2.29 percent upward adjustment is the observed increase between yields on Baa/BBB-rated bonds and the yields on 30-year U.S. Treasury bonds since August 2008 when the credit markets began to deteriorate.

Q. Do you agree with the upward adjustment Ms. Pritz has made to the historical average return on the market obtained from Morningstar's 2009 SBBI Yearbook?

A. No I do not agree with her upward adjustment. On the one hand she has chosen a twenty-year treasury instrument to derive the historical market risk premium but then wants to adjust an 82 year average of market results upward based on the spread between a 30-year treasury instrument and Baa/BBB-rated debt that only occurred over a brief period of time.

Q. Why has Ms. Pritz made her adjustment to the historical market risk premium obtained from Morningstar?

A. Ms. Pritz stated that the reason for it is because the CAPM is producing "illogical results" given the current economic environment.

Q. Do you agree with Ms. Pritz's rationale?

A. No. I believe that the CAPM is producing expected returns that are reflective of the current economic environment. I am unaware of any time during the late nineties or prior to the current recession that analysts, testifying before the Commission, made downward adjustments to the market risk premium in the CAPM because it was producing "illogical results" during a robust period of economic growth.

Q. What is the difference between Ms. Pritz's adjusted market risk premium and your recommended market risk premiums that relied on arithmetic and geometric means?

A. There is a 40 basis point difference between her higher unadjusted market risk premium of 6.50 percent (which is the arithmetic mean of historical returns on the market minus the historical yields on a 20-year Treasury instrument) and my arithmetic mean market risk premium of 6.10 percent.

The difference between her higher unadjusted market risk premium of 6.50 percent and my geometric mean market risk premium of 4.20 percent is 230 basis points.

Q. What financial instrument did Ms. Pritz use as a proxy for the risk free (i.e. r_f) rate in her CAPM model?

A. Ms. Pritz used the average yield on a 20-year U.S. Treasury instrument during February 2009, which was 3.83 percent over that period, as opposed to my 5-year treasury instrument yield of 2.41 percent.

Q. What is the difference in the average beta that you used in your CAPM models?

A. Ms. Pritz's sample of electric utilities had an average beta of 0.71 as opposed to my average beta of 0.73.

Q. Has there been a change in the betas since Ms. Pritz filed her direct testimony?

A. Yes. The current average beta for her sample is 0.70. However, I need to point out that this includes only nine of the electric utilities included in her sample since Value Line is currently unable to calculate a meaningful beta for Northwestern Corporation. This was one of the two utilities that I excluded from my sample.

Q. What is the difference between Ms. Pritz's CAPM estimate and your CAPM estimate?

A. Ms. Pritz's CAPM estimate, derived from her arithmetic mean model, of 10.10 percent is 327 basis points higher than the 6.83 percent cost of common equity derived from my arithmetic mean CAPM analysis and 464 basis points higher than my 5.46 percent cost of common equity derived from my geometric mean CAPM analysis.

Q. What expected return would Ms. Pritz's CAPM produce if her inputs were updated with her unadjusted market risk premium of 6.5 percent?

A. Updating Ms. Pritz's risk free rate of return to a more recent yield of 4.14 percent (the average for the month of September 2009) and a beta of 0.70 would produce an expected return of 8.69 percent, which is 131 basis points lower than the 10.10 percent figure presented in her testimony, and is 56 basis points lower than my recommended cost of common equity of 9.25 percent.

Final Cost of Equity Estimate

Q. How did Ms. Pritz arrive at her proposed 11.40 percent cost of common equity for UNSE?

A. Ms. Pritz averaged the results of her DCF, CAPM and risk premium analyses to arrive at her proposed 11.40 percent cost of common equity.

Q. Does your silence on any of the issues, matters or findings addressed in the testimony of Ms. Pritz, Mr. Grant or any other witness for UNSE constitute your acceptance of their positions on such issues, matters or findings?

A. No, it does not.

Q. Does this conclude your testimony on UNSE?

A. Yes, it does.

Qualifications of William A. Rigsby, CRRA

EDUCATION:

University of Phoenix
Master of Business Administration, Emphasis in Accounting, 1993

Arizona State University
College of Business
Bachelor of Science, Finance, 1990

Mesa Community College
Associate of Applied Science, Banking and Finance, 1986

Society of Utility and Regulatory Financial Analysts
38th Annual Financial Forum and CRRA Examination
Georgetown University Conference Center, Washington D.C.
Awarded the Certified Rate of Return Analyst designation
after successfully completing SURFA's CRRA examination.

Michigan State University
Institute of Public Utilities
N.A.R.U.C. Annual Regulatory Studies Program, 1997 &1999

Florida State University
Center for Professional Development & Public Service
N.A.R.U.C. Annual Western Utility Rate School, 1996

EXPERIENCE:

Public Utilities Analyst V
Residential Utility Consumer Office
Phoenix, Arizona
April 2001 – Present

Senior Rate Analyst
Accounting & Rates - Financial Analysis Unit
Arizona Corporation Commission, Utilities Division
Phoenix, Arizona
July 1999 – April 2001

Senior Rate Analyst
Residential Utility Consumer Office
Phoenix, Arizona
December 1997 – July 1999

Utilities Auditor II and III
Accounting & Rates – Revenue Requirements Analysis Unit
Arizona Corporation Commission, Utilities Division
Phoenix, Arizona
October 1994 – November 1997

Tax Examiner Technician I / Revenue Auditor II
Arizona Department of Revenue
Transaction Privilege / Corporate Income Tax Audit Units
Phoenix, Arizona
July 1991 – October 1994

RESUME OF RATE CASE AND REGULATORY PARTICIPATION

Utility Company	Docket No.	Type of Proceeding
ICR Water Users Association	U-2824-94-389	Original CC&N
Rincon Water Company	U-1723-95-122	Rate Increase
Ash Fork Development Association, Inc.	E-1004-95-124	Rate Increase
Parker Lakeview Estates Homeowners Association, Inc.	U-1853-95-328	Rate Increase
Mirabell Water Company, Inc.	U-2368-95-449	Rate Increase
Bonita Creek Land and Homeowner's Association	U-2195-95-494	Rate Increase
Pineview Land & Water Company	U-1676-96-161	Rate Increase
Pineview Land & Water Company	U-1676-96-352	Financing
Montezuma Estates Property Owners Association	U-2064-96-465	Rate Increase
Houghland Water Company	U-2338-96-603 et al	Rate Increase
Sunrise Vistas Utilities Company – Water Division	U-2625-97-074	Rate Increase
Sunrise Vistas Utilities Company – Sewer Division	U-2625-97-075	Rate Increase
Holiday Enterprises, Inc. dba Holiday Water Company	U-1896-97-302	Rate Increase
Gardener Water Company	U-2373-97-499	Rate Increase
Cienega Water Company	W-2034-97-473	Rate Increase
Rincon Water Company	W-1723-97-414	Financing/Auth. To Issue Stock
Vail Water Company	W-01651A-97-0539 et al	Rate Increase
Bermuda Water Company, Inc.	W-01812A-98-0390	Rate Increase
Bella Vista Water Company	W-02465A-98-0458	Rate Increase
Pima Utility Company	SW-02199A-98-0578	Rate Increase

RESUME OF RATE CASE AND REGULATORY PARTICIPATION (Cont.)

Utility Company	Docket No.	Type of Proceeding
Pineview Water Company	W-01676A-99-0261	WIFA Financing
I.M. Water Company, Inc.	W-02191A-99-0415	Financing
Marana Water Service, Inc.	W-01493A-99-0398	WIFA Financing
Tonto Hills Utility Company	W-02483A-99-0558	WIFA Financing
New Life Trust, Inc. dba Dateland Utilities	W-03537A-99-0530	Financing
GTE California, Inc.	T-01954B-99-0511	Sale of Assets
Citizens Utilities Rural Company, Inc.	T-01846B-99-0511	Sale of Assets
MCO Properties, Inc.	W-02113A-00-0233	Reorganization
American States Water Company	W-02113A-00-0233	Reorganization
Arizona-American Water Company	W-01303A-00-0327	Financing
Arizona Electric Power Cooperative	E-01773A-00-0227	Financing
360networks (USA) Inc.	T-03777A-00-0575	Financing
Beardsley Water Company, Inc.	W-02074A-00-0482	WIFA Financing
Mirabell Water Company	W-02368A-00-0461	WIFA Financing
Rio Verde Utilities, Inc.	WS-02156A-00-0321 et al	Rate Increase/ Financing
Arizona Water Company	W-01445A-00-0749	Financing
Loma Linda Estates, Inc.	W-02211A-00-0975	Rate Increase
Arizona Water Company	W-01445A-00-0962	Rate Increase
Mountain Pass Utility Company	SW-03841A-01-0166	Financing
Picacho Sewer Company	SW-03709A-01-0165	Financing
Picacho Water Company	W-03528A-01-0169	Financing
Ridgeview Utility Company	W-03861A-01-0167	Financing
Green Valley Water Company	W-02025A-01-0559	Rate Increase
Bella Vista Water Company	W-02465A-01-0776	Rate Increase
Arizona Water Company	W-01445A-02-0619	Rate Increase

RESUME OF RATE CASE AND REGULATORY PARTICIPATION (Cont.)

Utility Company	Docket No.	Type of Proceeding
Arizona-American Water Company	W-01303A-02-0867 et al.	Rate Increase
Arizona Public Service Company	E-01345A-03-0437	Rate Increase
Rio Rico Utilities, Inc.	WS-02676A-03-0434	Rate Increase
Qwest Corporation	T-01051B-03-0454	Renewed Price Cap
Chaparral City Water Company	W-02113A-04-0616	Rate Increase
Arizona Water Company	W-01445A-04-0650	Rate Increase
Tucson Electric Power	E-01933A-04-0408	Rate Review
Southwest Gas Corporation	G-01551A-04-0876	Rate Increase
Arizona-American Water Company	W-01303A-05-0405	Rate Increase
Black Mountain Sewer Corporation	SW-02361A-05-0657	Rate Increase
Far West Water & Sewer Company	WS-03478A-05-0801	Rate Increase
Gold Canyon Sewer Company	SW-02519A-06-0015	Rate Increase
Arizona Public Service Company	E-01345A-05-0816	Rate Increase
Arizona-American Water Company	W-01303A-06-0014	Rate Increase
Arizona-American Water Company	W-01303A-05-0718	Transaction Approval
Arizona-American Water Company	W-01303A-05-0405	ACRM Filing
UNS Gas, Inc.	G-04204A-06-0463	Rate Increase
Arizona-American Water Company	W-01303A-07-0209	Rate Increase
Tucson Electric Power	E-01933A-07-0402	Rate Increase
Southwest Gas Corporation	G-01551A-07-0504	Rate Increase
Chaparral City Water Company	W-02113A-07-0551	Rate Increase
Arizona-American Water Company	W-01303A-08-0227 et al.	Rate Increase
Far West Water & Sewer Company	WS-03478A-08-0608	Interim Rate Increase
Johnson Utilities, LLC	WS-02987A-08-0180	Rate Increase
UNS Gas, Inc.	G-04204A-08-0571	Rate Increase
Arizona Water Company	W-01445A-08-0440	Rate Increase

RESUME OF RATE CASE AND REGULATORY PARTICIPATION (Cont.)

Utility Company	Docket No.	Type of Proceeding
Black Mountain Sewer Corporation	SW-02361A-08-0609	Rate Increase
Global Utilities	SW-02445A-09-0077 et al.	Rate Increase
Litchfield Park Service Company	SW-01428A-09-0104 et al.	Rate Increase

ATTACHMENT A

All the major utilities in the eastern region of the United States are reviewed in this Issue. Those serving the central region will be found in Issue 5. All of the western providers are covered in Issue 11.

During the second quarter, utility stocks significantly underperformed the major market averages. As other, more sensitive economic sectors rebounded strongly off bear-market lows, the utility group lagged a bit. The group's 9.1% quarterly return ranked toward the bottom of all industries, topping only the Telecommunications group. This came as little surprise however, as utility companies suffered considerably less during last year's broad market selloff, attributable to their more conservative, stable business models. Utilities historically rebound at a much slower pace.

Lower Demand for Electricity

During the first half of 2009, the demand for electricity declined roughly 4%, marking a rare occurrence for the generally stable industry. As a result, several utilities have scaled back their 2009 earnings outlooks to reflect lower usage.

Coal vs. Alternative Fuel Sources

Coal remains the most popular fuel source in the United States (responsible for roughly 50% of domestic power) due to its abundance and low cost. However, its share of total output has been on a downward trend. In fact, on a year-over-year basis, coal generation has declined over 10% in the United States. This can be attributed to stricter curbs on CO2 emissions, but more notably, the increased popularity in alternative energy sources, such as wind (up 29%) and solar power (up 3%). Government incentive programs coupled with public concern over environmental issues are the main drivers of this development. Long-term, we look for this trend to continue based primarily on a recently passed congressional bill. The bill requires 20% of electricity sales in 2021 to come from renewable resources. This in turn would create a cap and trade program to reduce greenhouse gas emissions by 17% below 2005 levels by 2020, and 83% by 2050.

INDUSTRY TIMELINESS: 66 (of 98)

Dividends

Utility dividends have continued to increase during the first half of 2009 supported by reduced dividend tax rates. Currently, the average yield among the utilities group is about 5%, more than double the median of all dividend-paying stocks under our coverage. Leaders in issue 1 include, *Pepco Holdings* (7.7%), *UIL Holdings* (6.8%), *Duke Energy* (6.4%), *Progress Energy* (6.4%), *TECO Energy* (6.2%) and *Con Edison* (6.0%).

The American Recovery and Reinvestment Act

In February 2009, Congress passed this act in an attempt to provide a stimulus to the struggling U.S. economy. Of the $787 billion included in the package, the Department of Energy (DOE) is responsible for implementing roughly $40 billion. Of the DOE total, $4.5 billion is alotted to the Office of Electricity Delivery and Energy Reliability (OE). These funds will be geared towards the modernization of the nation's energy and communication infrastructure. The OE is awarding 50% matching grants to utilities and other organizations that promote investments associated with this cause. We believe the majority of these grants will likely support the advancement of *Smart Grid* programs. This technology enables real time monitoring of energy usage and automated adaption of energy flow. Customers will be able to better monitor consumption, which will ultimately lead to reduced costs for utility companies. Over the past three months, several utilities in this issue have submitted applications to invest in *Smart Grid* technology, including Washington DC.-based *Pepco Holdings* ($142 million), North Carolina-based *Progress Energy* ($200 million), New York-based *Con Edison* ($172 million), and Connecticut-based *UIL Holdings* ($38 million).

Conclusion

During these challenging economic times, utility stocks are still sought after due to their relative stability and attractive dividend yields. With several stocks yielding over 7%, income-oriented investors should have little trouble finding appeal in this industry. All told, we believe this might be a good time to increase your portfolio's electric-utility exposure.

Michael Ratty

Composite Statistics: Electric Utility Industry

2005	2006	2007	2008	2009	2010		12-14
304.7	325.7	343.2	365.3	**355**	**375**	Revenues ($bill)	**440**
21.4	25.3	27.7	28.1	**27.5**	**30.5**	Net Profit ($bill)	**38.0**
29.1%	31.4%	33.2%	33.5%	**34.0%**	**34.0%**	Income Tax Rate	**34.0%**
4.6%	4.8%	6.1%	7.7%	**10.0%**	**7.0%**	AFUDC % to Net Profit	**6.0%**
54.8%	51.8%	51.0%	53.7%	**52.5%**	**51.5%**	Long-Term Debt Ratio	**50.0%**
44.0%	47.1%	47.9%	45.3%	**47.0%**	**47.5%**	Common Equity Ratio	**49.5%**
405.6	468.3	471.7	518.4	**505**	**535**	Total Capital ($bill)	**635**
426.0	491.9	509.6	559.1	**555**	**595**	Net Plant ($bill)	**710**
7.1%	7.0%	7.5%	7.0%	**6.5%**	**7.0%**	Return on Total Cap'l	**7.0%**
11.7%	11.2%	12.0%	11.7%	**10.5%**	**11.0%**	Return on Shr. Equity	**11.0%**
11.9%	11.4%	12.1%	11.8%	**10.5%**	**11.0%**	Return on Com Equity	**11.5%**
5.1%	5.6%	5.6%	5.0%	**4.5%**	**5.0%**	Retained to Com Eq	**5.5%**
57%	52%	54%	58%	**63%**	**59%**	All Div'ds to Net Prof	**66%**
16.1	14.8	17.0	15.4	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	**13.5**
.86	.80	.90	.93			Relative P/E Ratio	**.90**
3.5%	3.5%	3.2%	3.7%			Avg Ann'l Div'd Yield	**4.3%**

COMPOSITE OPERATING STATISTICS: ELECTRIC UTILITY INDUSTRY

	2005	2006	2007
% Change Retail Sales (kwh)	+5.4	+1.3	+2.2
Average Indust. Use (mwh)	1568	1578	1571
Avg. Indust. Revs. per kwh (¢)	5.73	6.10	6.35
Regulated Cap. at Peak (mw)	NA	NA	NA
Peak Load, Summer (mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr.-end)	+1.2	+1.7	+.7
Fixed Charge Coverage (%)	253	265	289

Sources: Annual Reports; Estimates, Value Line; Edison Electric Institute

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INDUSTRY TIMELINESS: 64 (of 98)

All of the major electric utilities located in the western region of the United States are reviewed in this Issue; eastern electrics, in Issue 1; and the remaining utilities, in Issue 5.

We present our rankings of states' regulatory climates. There have been some changes since our last report on regulatory climates.

Electric utility stocks have not participated in the stock market's partial recovery in 2009. Even so, many issues are appealing for income-oriented investors.

Ranking The Regulators

From time to time, we run a list showing each state's regulatory climate, along with that of the District of Columbia and the Federal Energy Regulatory Commission (FERC). This is important because, even in states that have had partial deregulation of the electric utility industry, the power distribution function is still regulated by a state commission. Regulation is becoming more significant because many utilities have large capital projects under way or on the drawing board. Moreover, kilowatt-hour sales are declining in many regions due to the recession, and this lessens a utility's ability to earn its allowed return on equity. Most of the companies in this Issue have rate cases pending or have just concluded them. Finally, regulation can come into play even for utilities that don't have distribution operations in a particular state. For example, *Entergy* wants to spin off its nonregulated nuclear assets into a separate company but cannot do so until the commissions in New York and Vermont grant their permission.

In some states, the governor appoints the commissioners; in others, this is an elected office. But a state's regulatory climate entails more than just the commission. The executive, legislative, and judicial branches of the state government play a part and are considered in our rankings.

Note that seven states are excluded from the list below, either because of an absence of investor-owned electric utilities or because we do not cover any companies that have a significant presence in the state. The states are Alaska, Kentucky, Maine, Nebraska, Rhode Island, Tennessee, and Utah.

• *Above Average:* Alabama, California, Colorado, Florida, Idaho, Indiana, Massachusetts, Ohio, South Dakota, Wisconsin, FERC.

• *Average:* Arizona, Delaware, District of Columbia, Georgia, Hawaii, Iowa, Kansas, Louisiana, Michigan, Minnesota, Mississippi, Missouri, Montana, Nevada, New Hampshire, New Jersey, New Mexico, North Carolina, North Dakota, Oklahoma, Pennsylvania, South Carolina, Texas, Virginia, Washington, Wyoming.

• *Below Average:* Arkansas, Connecticut, Illinois, Maryland, New York, Oregon, Vermont, West Virginia.

Since we ran this list in May of this year, we have made four changes. We raised Michigan and New Hampshire from Below Average to Average; lowered Hawaii from Above Average to Average; and lowered Maryland from Average to Below Average. Michigan passed a law last year that will result in more timely rate relief for utilities. New Hampshire (served by a subsidiary of Northeast Utilities) has generally been providing reasonable regulatory treatment in recent years—a far cry from the time when Public Service of New Hampshire filed for bankruptcy protection. The utilities of Hawaiian Electric Industries are underearning their allowed ROEs due, in part, to regulatory lag. Maryland forced Constellation Energy to give back some money it would have kept as a result of a shift to market-based pricing, and has ruled that it had the grounds to review an asset sale, contrary to what Constellation contends.

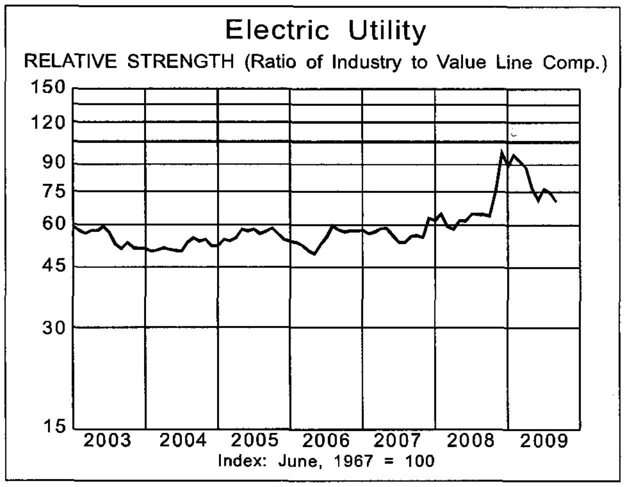
Conclusion

Electric utility stocks have not participated in the partial recovery that the market has made so far this year after the horrible showing in 2008. To date, the Value Line Composite Average is up over 25%, but the Value Line Utility Average has hardly budged. Thus, this group's valuation has become relatively more attractive. The industry's average yield of 5% is more than twice the market mean. Many of these equities offer attractive yields that are above the industry average, plus some dividend-growth potential. Investors should be cautious about most stocks with a well above-average yield, however, due to the possibility of a dividend cut. We show a split dividend at the top of the page if we believe that there is a chance of a reduction.

Paul E. Debbas, CFA

Composite Statistics: Electric Utility Industry

2005	2006	2007	2008	2009	2010		12-14
304.7	325.7	343.2	365.3	335	355	Revenues ($bill)	420
21.4	25.3	27.7	28.1	27.0	30.0	Net Profit ($bill)	38.0
29.1%	31.4%	33.2%	33.5%	34.5%	34.0%	Income Tax Rate	34.5%
4.6%	4.8%	6.1%	7.7%	10.0%	7.0%	AFUDC % to Net Profit	6.0%
54.8%	51.8%	51.0%	53.7%	52.5%	52.0%	Long-Term Debt Ratio	50.0%
44.0%	47.1%	47.9%	45.3%	46.5%	47.5%	Common Equity Ratio	49.0%
405.6	468.3	471.7	518.4	510	535	Total Capital ($bill)	635
426.0	491.9	509.6	559.1	560	595	Net Plant ($bill)	700
7.1%	7.0%	7.5%	7.0%	6.5%	7.0%	Return on Total Cap'l	7.0%
11.7%	11.2%	12.0%	11.7%	10.5%	11.0%	Return on Shr. Equity	11.0%
11.9%	11.4%	12.1%	11.8%	10.5%	11.0%	Return on Com Equity	11.0%
5.1%	5.6%	5.6%	5.0%	4.5%	5.0%	Retained to Com Eq	5.0%
57%	52%	54%	58%	65%	60%	All Div'ds to Net Prof	56%
16.1	14.8	17.0	15.4	Bold figures are Value Line estimates		Avg Ann'l P/E Ratio	13.5
.86	.80	.90	.92			Relative P/E Ratio	.90
3.5%	3.5%	3.2%	3.7%			Avg Ann'l Div'd Yield	4.3%



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All of the major electric utilities located in the western region of the United States are reviewed in this Issue; eastern electrics, in Issue 1; and the remaining utilities, in Issue 5.

Oil prices have been extremely volatile for well over a year. We examine the effect that oil prices have on electric utilities.

Electric utilities are continuing to feel the effects of the recession.

Currently, there is no merger and acquisition activity in this industry.

The underperformance of this sector has made electric utility stocks relatively more attractive.

How Oil Prices Affect Utilities

Contrary to what some people believe, oil is not widely used to generate electricity in the United States. According to the federal government's Energy Information Association, in the past three years only 1% of the nation's electricity was generated from oil. In fact, the only investor-owned utilities that use oil to produce a significant proportion of their power are the three utilities that are part of *Hawaiian Electric Industries*, which used oil to generate 60% of its electricity in 2008. The most important fuel source is coal, at slightly under 50%. Natural gas and nuclear fuel each have around a 20% share.

Utilities that have gas and oil exploration and production subsidiaries stand to benefit from higher oil prices. *Black Hills Corporation* is one such company. However, the gas portion of its E&P business is far greater than the oil portion, so the effects of weak gas prices are outweighing the benefits of high (compared with the level in early 2009) oil prices.

The Recession Is Affecting Electric Sales

Although electric utilities are somewhat resistant to the state of the economy—sales to residential customers are influenced more by the weather than the economy—there is no doubt that the recession is hurting these companies. Some companies have seen their customer growth rates drop significantly from the levels experienced just a few years ago. This is especially true for *Pinnacle West*, *NV Energy*, and *UniSource Energy*, which operate in states hit hard by the housing slump.

INDUSTRY TIMELINESS: 57 (of 98)

Others are experiencing worse-than-expected sales. This was one reason why *Portland General Electric* sharply reduced its earnings expectation for 2009. *El Paso Electric* is another utility that has reduced its guidance as sales have fallen short of expectations.

Utilities were already facing a tough comparison for kilowatt-hour sales simply because 2008 was a leap year and thus had one extra day. Although this might seem trivial, it really does affect the year-to-year sales comparisons for utilities.

A Lack Of Merger And Acquisition Activity

Last month, Exelon terminated its hostile takeover bid for NRG Energy (an independent power producer that is covered in Issue 6) after its slate of nominees to NRG's board failed to win enough support. Accordingly, there is no current merger and acquisition activity in this industry that involves entire companies (as opposed to asset sales).

The credit crisis that began last September lessened many companies' ability to obtain capital at attractive terms. Although the crisis has become less severe since then, many utilities are still taking a cautious stance. Another factor is that obtaining regulatory approval for utility mergers and acquisitions is frequently lengthy and difficult. (The CEO of a utility that was involved in a proposed merger that fell through lamented that the time to close utility deals is measured in years, not months.) And this industry's track record in mergers and acquisitions is mixed. This is not to say that there won't be any merger announcements anytime soon, but we do not advise investors to purchase utility stocks based on the possibility of a deal. Some investors have held shares of *El Paso Electric* and CH Energy Group for many years, waiting for a takeover bid that has yet to occur.

Conclusion

The Value Line Composite Average is up 18% so far this year, but the Value Line Utility Average is down 1%. This divergent performance has made electric utility equities relatively more attractive. This group's average dividend yield, at about 5%, is more than twice the median of all dividend-paying stocks under our coverage. There are numerous stocks in this industry that offer a high, secure yield and good 3- to 5-year dividend-growth potential.

Paul E. Debbas, CFA

Composite Statistics: ELECTRIC UTILITY INDUSTRY

2005	2006	2007	2008	2009	2010		12-14
304.7	325.7	343.2	365.3	***355***	***375***	Revenues ($bill)	***440***
21.4	25.3	27.7	28.1	***27.5***	***30.5***	Net Profit ($bill)	***38.0***
29.1%	31.4%	33.2%	33.5%	***34.0%***	***34.0%***	Income Tax Rate	***34.0%***
4.6%	4.8%	6.1%	7.7%	***10.0%***	***7.0%***	AFUDC % to Net Profit	***6.0%***
54.8%	51.8%	51.0%	53.7%	***52.5%***	***51.5%***	Long-Term Debt Ratio	***50.0%***
44.0%	47.1%	47.9%	45.3%	***47.0%***	***47.5%***	Common Equity Ratio	***49.5%***
405.6	468.3	471.7	518.4	***505***	***535***	Total Capital ($bill)	***635***
426.0	491.9	509.6	559.1	***555***	***595***	Net Plant ($bill)	***710***
7.1%	7.0%	7.5%	7.0%	***6.5%***	***7.0%***	Return on Total Cap'l	***7.0%***
11.7%	11.2%	12.0%	11.7%	***10.5%***	***11.0%***	Return on Shr. Equity	***11.0%***
11.9%	11.4%	12.1%	11.8%	***10.5%***	***11.0%***	Return on Com Equity	***11.5%***
5.1%	5.6%	5.6%	5.0%	***4.5%***	***5.0%***	Retained to Com Eq	***5.5%***
57%	52%	54%	58%	***63%***	***59%***	All Div'ds to Net Prof	***66%***
16.1	14.8	17.0	15.4	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	***13.5***
.86	.80	.90	.93			Relative P/E Ratio	***.90***
3.5%	3.5%	3.2%	3.7%			Avg Ann'l Div'd Yield	***4.3%***

COMPOSITE OPERATING STATISTICS: ELECTRIC UTILITY INDUSTRY

	2005	2006	2007
% Change Retail Sales (kwh)	+5.4	+1.3	+2.2
Average Indust. Use (mwh)	1568	1578	1571
Avg. Indust. Revs. per kwh (¢)	5.73	6.10	6.35
Capacity at Peak (mw)	NA	NA	NA
Peak Load, Summer (mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr.-end)	+1.2	+1.7	+.3
Fixed Charge Coverage (%)	254	270	291

Sources: Annual Reports; Estimates, Value Line; Edison Electric Institute

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ALLETE NYSE-ALE

RECENT PRICE 33.10 | P/E RATIO 15.8 (Trailing: 13.4 / Median: NMF) | RELATIVE P/E RATIO 0.92 | DIV'D YLD 5.4% | VALUE LINE

TIMELINESS **4** Lowered 5/29/09
SAFETY **2** New 10/1/04
TECHNICAL **4** Lowered 9/11/09
BETA .70 (1.00 = Market)

2012-14 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	45	(+35%)	12%
Low	35	(+5%)	7%

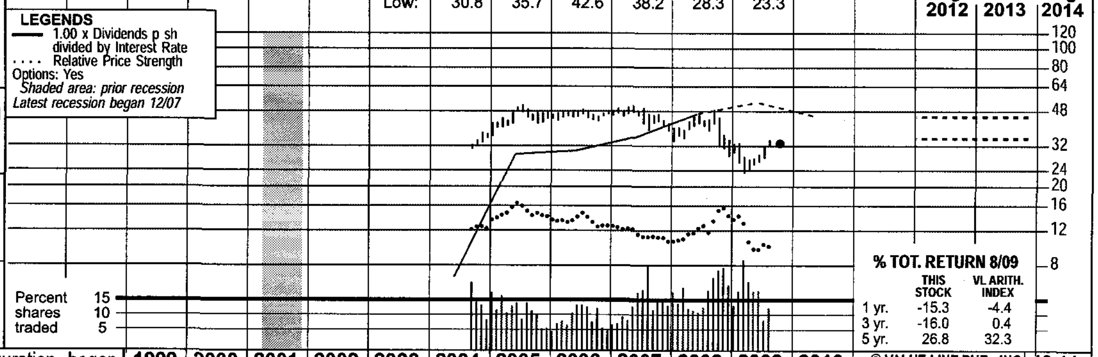
Insider Decisions

	O	N	D	J	F	M	A	M	J
to Buy	0	0	0	0	1	0	0	0	1
Options	0	1	0	0	0	0	0	0	0
to Sell	0	0	0	0	0	0	0	0	0

Institutional Decisions

	4Q2008	1Q2009	2Q2009
to Buy	74	82	80
to Sell	77	61	60
Hld's(000)	17191	17770	19395

	2004	2005	2006	2007	2008	2009
High:	37.5	51.7	49.3	51.3	49.0	34.5
Low:	30.8	35.7	42.6	38.2	28.3	23.3



% TOT. RETURN 8/09

	THIS STOCK	VL ARITH. INDEX
1 yr.	-15.3	-4.4
3 yr.	-16.0	0.4
5 yr.	26.8	32.3

ALLETE, in its current configuration, began trading on September 21, 2004, the day after it spun off its automotive services business, ADESA (NYSE: KAR), to shareholders and effected a 1-for-3 reverse stock split. ALLETE shareholders received one share of ADESA for each ALLETE share held. Data for the "old" ALLETE are not shown because they are not comparable.

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	© VALUE LINE PUB., INC.	12-14
--	--	--	--	--	25.30	24.50	25.23	27.33	24.57	*21.30*	*21.25*	Revenues per sh	*20.50*
--	--	--	--	--	2.97	3.85	4.14	4.42	4.23	*3.55*	*4.00*	"Cash Flow" per sh	*4.50*
--	--	--	--	--	1.35	2.48	2.77	3.08	2.82	*1.95*	*2.30*	Earnings per sh A	*2.75*
--	--	--	--	--	.30	1.25	1.45	1.64	1.72	*1.76*	*1.80*	Div'd Decl'd per sh B ■ †	*1.92*
--	--	--	--	--	2.12	1.95	3.37	6.82	9.24	*8.70*	*8.70*	Cap'l Spending per sh	*6.75*
--	--	--	--	--	21.23	20.03	21.90	24.11	25.37	*25.65*	*26.30*	Book Value per sh C	*28.75*
--	--	--	--	--	29.70	30.10	30.40	30.80	32.60	*34.50*	*36.00*	Common Shs Outst'g D	*41.00*
--	--	--	--	--	25.2	17.9	16.5	14.8	13.9	*Bold figures are*		Avg Ann'l P/E Ratio	*14.0*
--	--	--	--	--	1.33	.95	.89	.79	.86	*Value Line*		Relative P/E Ratio	*.95*
--	--	--	--	--	.9%	2.8%	3.2%	3.6%	4.4%	*estimates*		Avg Ann'l Div'd Yield	*4.9%*
--	--	--	--	--	751.4	737.4	767.1	841.7	801.0	*735*	*765*	Revenues ($mill)	*855*
--	--	--	--	--	38.5	68.0	77.3	87.6	82.5	*60.0*	*75.0*	Net Profit ($mill)	*105*
--	--	--	--	--	38.8%	28.4%	37.5%	34.8%	34.3%	*35.0%*	*36.0%*	Income Tax Rate	*35.0%*
--	--	--	--	--	1.8%	.4%	1.4%	6.6%	5.8%	*8.0%*	*7.0%*	AFUDC % to Net Profit	*4.0%*
--	--	--	--	--	38.2%	39.1%	35.1%	35.6%	41.6%	*44.5%*	*46.5%*	Long-Term Debt Ratio	*48.5%*
--	--	--	--	--	61.8%	60.9%	64.9%	64.4%	58.4%	*55.5%*	*53.5%*	Common Equity Ratio	*51.5%*
--	--	--	--	--	1020.7	990.6	1025.6	1153.5	1415.4	*1595*	*1765*	Total Capital ($mill)	*2325*
--	--	--	--	--	883.1	860.4	921.6	1104.5	1387.3	*1625*	*1875*	Net Plant ($mill)	*2325*
--	--	--	--	--	5.1%	8.0%	8.6%	8.6%	6.7%	*5.0%*	*5.5%*	Return on Total Cap'l	*5.5%*
--	--	--	--	--	6.1%	11.3%	11.6%	11.8%	10.0%	*7.0%*	*8.0%*	Return on Shr. Equity	*9.0%*
--	--	--	--	--	6.1%	11.3%	11.6%	11.8%	10.0%	*7.0%*	*8.0%*	Return on Com Equity E	*9.0%*
--	--	--	--	--	4.7%	5.2%	5.0%	5.8%	3.9%	*.5%*	*1.5%*	Retained to Com Eq	*2.5%*
--	--	--	--	--	23%	54%	57%	51%	61%	*96%*	*83%*	All Div'ds to Net Prof	*74%*

CAPITAL STRUCTURE as of 6/30/09
Total Debt $646.2 mill. **Due in 5 Yrs** $109.1 mill.
LT Debt $627.2 mill. **LT Interest** $30.7 mill.
(LT interest earned: 5.1x)
Leases, Uncapitalized Annual rentals $8.3 mill.

Pension Assets-12/08 $273.7 mill. **Oblig.** $440.4 mill.

Pfd Stock None

Common Stock 34,100,096 shs.

MARKET CAP: $1.1 billion (Mid Cap)

ELECTRIC OPERATING STATISTICS

	2006	2007	2008
% Change Retail Sales (KWH)	+1.1	+.3	+1.5
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	4.15	4.82	4.73
Capacity at Peak (Mw)	1761	1701	1757
Peak Load, Winter (Mw)	1586	1614	1582
Annual Load Factor (%)	*80.0*	*80.0*	*80.0*
% Change Customers (avg.)	+1.3	+1.3	.7
Fixed Charge Cov. (%)	503	503	438

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '06-'08 to '12-'14
Revenues	--	--	*-3.5%*
"Cash Flow"	--	--	*1.0%*
Earnings	--	--	*-1.0%*
Dividends	--	--	*3.0%*
Book Value	--	--	*3.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2006	192.5	178.3	199.1	197.2	767.1
2007	205.3	223.3	200.8	212.3	841.7
2008	213.4	189.8	201.7	196.1	801.0
2009	199.6	164.7	*185*	*185.7*	*735*
2010	*205*	*175*	*195*	*190*	*765*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2006	.68	.49	.78	.82	2.77
2007	.93	.80	.58	.77	3.08
2008	.82	.37	.85	.78	2.82
2009	.55	.29	*.51*	*.60*	*1.95*
2010	*.70*	*.35*	*.60*	*.65*	*2.30*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2005	.30	.315	.315	.315	1.25
2006	.3625	.3625	.3625	.3625	1.45
2007	.41	.41	.41	.41	1.64
2008	.43	.43	.43	.43	1.72
2009	.44	.44	.44		

BUSINESS: ALLETE, Inc. is the parent company of Minnesota Power, which supplies electricity to 142,000 customers in northeastern Minn., and Superior Water, Light & Power in northwestern Wisc. Electric revenue mix, '08: taconite mining/processing, 31%; paper/wood products, 11%; other industrial, 2%; residential, 12%; commercial, 12%; wholesale, 23% other, 9%. Has real estate operation in Florida. Discontinued water-utility ops. in '01. Spun off automotive remarketing ops. in '04. Generating sources, '08: coal & lignite, 65%; hydro, 4%; purchased, 31%. '08 depr. rate: 2.5%. Has 1,500 employees. Chairman & CEO: Donald J. Shippar. President: Alan R. Hodnik. Inc.: MN. Address: 30 West Superior St., Duluth, MN 55802-2093. Tel.: 218-279-5000. Internet: www.allete.com.

ALLETE's utility subsidiary had a disappointing regulatory outcome this year . . . Although the final order of the Minnesota Public Utilities Commission (MPUC) won't come until the fourth quarter, indications are that it will be far less than the interim rate increase of $41 million that Minnesota Power was granted last year. Accordingly, the utility is taking reserves for the refunding of previously collected revenues to customers. This amounted to $0.34 a share in the first half of 2009 and might total as much as $0.10 a share in the second half of the year. What's more, after the company and some intervenors filed for reconsideration, the MPUC actually trimmed the expected rate increase (originally $21.1 million) to $20.4 million.

. . . so Minnesota Power will file a rate case in late 2009. An interim tariff hike will occur in early 2010, with the final order due in the fourth quarter. The utility has not stated how much it plans to request.

Earnings are headed sharply lower this year. The revenue refunds are the main reason. ALLETE's real estate operation is likely to contribute nothing to the bottom line in 2009, compared with a modest profit a year ago. Finally, interest expense and average shares outstanding are up because the company needs to finance part of its large capital budget. We have lowered our earnings estimate from $2.10 a share to $1.95.

We look for a partial bottom-line recovery in 2010. We assume that Minnesota Power gets some interim rate relief early in the year. Our earnings estimate is $2.30 a share, which we consider on the conservative side. ALLETE has not yet given earnings guidance for 2010, but expects to do so when it reports third-quarter results this fall. If the company's profit expectation for next year is at least as high as our estimate, then we believe that the board of directors will boost the dividend in 2010.

This stock's yield is slightly above the utility average. On the other hand, total return potential to 2012-2014 is somewhat below average, even with our projection of continued dividend growth over that time. Meanwhile, the stock is untimely.

Paul E. Debbas, CFA *September 25, 2009*

(A) Diluted EPS. Excl. nonrec. gain (loss): '04, 2¢ net; '05, ($1.84); gain (losses) on discontinued operations: '04, $2.57, '05, (16¢); '06, (2¢); loss from accounting change: '04, 27¢. Next earnings report due late Oct. (B) Div'ds historically paid in early Mar., June, Sept., and Dec. ■ Div'd reinvestment plan avail. † Shareholder investment plan avail. (C) Incl. deferred charges. In '08: $7.65/sh. (D) In mill. (E) Rate base: Original cost deprec. Rate allowed on com. eq. in '09: 10.74%; earned on avg. com. eq., '08: 10.7%. Regulatory Climate: Average.

Company's Financial Strength	A
Stock's Price Stability	95
Price Growth Persistence	55
Earnings Predictability	65

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BLACK HILLS CORP. NYSE-BKH

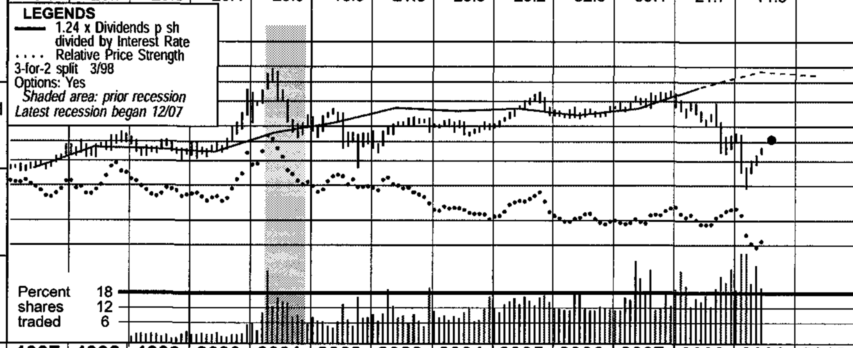
RECENT PRICE	25.79	P/E RATIO	10.7 (Trailing: 31.8 / Median: 15.0)	RELATIVE P/E RATIO	0.66	DIV'D YLD	5.6%	VALUE LINE

TIMELINESS 3 Raised 11/21/08
SAFETY 3 Lowered 8/15/03
TECHNICAL 4 Lowered 7/24/09
BETA .85 (1.00 = Market)

	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
High:	27.9	26.5	46.1	58.5	36.9	33.5	32.5	44.6	37.9	45.4	44.0	27.8
Low:	20.7	20.3	20.4	26.0	18.3	21.8	26.5	29.2	32.5	35.4	21.7	14.5

Target Price Range 2012 | 2013 | 2014

LEGENDS
— 1.24 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
3-for-2 split 3/98
Options: Yes
Shaded area: prior recession
Latest recession began 12/07



2012-14 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	40	(+55%)	15%
Low	25	(-5%)	5%

Insider Decisions

	S	O	N	D	J	F	M	A	M
to Buy	0	0	1	0	0	0	0	0	1
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	0	0	0	0	0	0	0

Institutional Decisions

	3Q2008	4Q2008	1Q2009
to Buy	66	73	70
to Sell	83	80	74
Hld's(000)	26962	27542	26204

Percent shares traded 18 / 12 / 6

% TOT. RETURN 6/09

	THIS STOCK	VL ARITH. INDEX
1 yr.	-24.0	-14.0
3 yr.	-23.7	-14.4
5 yr.	-10.3	5.1

1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	© VALUE LINE PUB., INC.	12-14
6.51	6.74	6.92	7.50	14.45	31.48	37.05	69.69	57.96	15.74	35.17	34.54	41.97	19.69	18.41	26.03	*40.50*	*42.40*	Revenues per sh	*48.25*
1.82	1.92	2.09	2.45	2.52	2.72	2.88	3.68	5.27	4.93	4.26	4.46	4.81	5.04	5.29	2.95	*5.90*	*5.95*	"Cash Flow" per sh	*7.50*
1.11	1.11	1.19	1.40	1.49	1.60	1.70	2.37	3.42	2.33	1.84	1.74	2.11	2.21	2.68	.18	*2.40*	*2.20*	Earnings per sh A	*3.00*
.85	.88	.89	.92	.95	1.00	1.04	1.08	1.12	1.16	1.20	1.24	1.28	1.32	1.37	1.40	*1.42*	*1.44*	Div'd Decl'd per sh B ■ †	*1.56*
1.88	4.78	2.40	1.13	.98	1.18	4.89	5.79	14.07	8.65	2.80	2.80	4.18	9.24	6.92	8.51	*7.35*	*5.50*	Cap'l Spending per sh	*5.75*
7.85	8.13	8.43	8.91	9.46	9.58	10.14	11.95	18.95	19.66	21.72	22.43	22.29	23.68	25.66	27.19	*27.80*	*28.55*	Book Value per sh C	*32.00*
21.40	21.58	21.64	21.68	21.70	21.58	21.37	23.30	26.89	26.93	32.30	32.48	33.16	33.37	37.80	38.64	*39.00*	*39.25*	Common Shs Outst'g D	*40.00*
15.3	12.4	13.1	11.9	13.0	14.9	13.6	10.9	11.4	12.5	15.9	17.1	17.3	15.8	15.0	NMF	*Bold figures are*		Avg Ann'l P/E Ratio	*11.5*
.90	.81	.88	.75	.75	.77	.78	.71	.58	.68	.91	.90	.92	.85	.80	NMF	*Value Line*		Relative P/E Ratio	*.75*
5.0%	6.4%	5.8%	5.5%	4.9%	4.2%	4.5%	4.2%	2.9%	4.0%	4.1%	4.2%	3.5%	3.8%	3.4%	4.2%	*estimates*		Avg Ann'l Div'd Yield	*4.6%*

CAPITAL STRUCTURE as of 3/31/09
Total Debt $983.1 mill. **Due in 5 Yrs** $745.1 mill.
LT Debt $471.2 mill. **LT Interest** $31.6 mill.
(Interest not earned.)
Leases, Uncapitalized Annual rentals $3.7 mill.

Pension Assets-12/08 $136.9 mill. **Oblig.** $242.6 mill.
Pfd Stock None

Common Stock 38,798,483 shs. as of 4/30/09

MARKET CAP: $1.0 billion (Mid Cap)

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010		12-14
791.9	1623.8	1558.6	423.9	1136.1	1121.7	1391.6	656.9	695.9	1005.8	*1580*	*1665*	Revenues ($mill)	*1925*
36.5	52.8	88.1	63.2	57.1	57.2	70.3	74.0	100.1	6.8	*95.0*	*90.0*	Net Profit ($mill)	*125*
29.8%	36.5%	36.5%	31.9%	34.4%	31.8%	33.8%	31.3%	31.3%	33.1%	*30.0%*	*33.0%*	Income Tax Rate	*33.0%*
3.3%	3.8%	8.5%	18.2%	.7%	.3%	1.0%	9.7%	14.8%	NMF	*13.0%*	*9.0%*	AFUDC % to Net Profit	*3.0%*
42.6%	52.1%	44.7%	53.6%	55.0%	49.9%	47.6%	44.3%	36.8%	32.3%	*44.5%*	*46.5%*	Long-Term Debt Ratio	*41.0%*
57.4%	47.2%	54.7%	45.9%	44.5%	49.6%	52.4%	55.7%	63.2%	67.7%	*55.5%*	*53.5%*	Common Equity Ratio	*59.0%*
377.3	589.4	931.0	1154.0	1578.2	1469.3	1409.1	1418.4	1534.2	1551.8	*1955*	*2085*	Total Capital ($mill)	*2150*
464.2	794.3	1238.2	1476.3	1442.4	1445.7	1435.4	1646.4	1823.5	2022.2	*2175*	*2245*	Net Plant ($mill)	*2400*
11.4%	10.6%	10.6%	6.6%	4.8%	5.3%	6.6%	6.8%	7.9%	1.6%	*6.0%*	*6.0%*	Return on Total Cap'l	*7.5%*
16.8%	18.7%	17.1%	11.8%	8.0%	7.8%	9.5%	9.4%	10.3%	.7%	*8.5%*	*8.0%*	Return on Shr. Equity	*9.5%*
16.8%	19.0%	17.2%	11.9%	8.1%	7.8%	9.5%	9.4%	10.3%	.7%	*8.5%*	*8.0%*	Return on Com Equity E	*9.5%*
6.4%	10.5%	11.6%	6.0%	2.8%	2.3%	3.8%	3.8%	5.1%	NMF	*3.5%*	*3.0%*	Retained to Com Eq	*5.0%*
62%	45%	33%	50%	65%	71%	60%	59%	50%	NMF	*58%*	*64%*	All Div'ds to Net Prof	*50%*

ELECTRIC OPERATING STATISTICS

	2006	2007	2008
% Change Retail Sales (KWH)	+3.1	+2.8	+34.0
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	4.78	5.06	5.97
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	570	593	881
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+1.1	+1.7	+87.6
Fixed Charge Cov. (%)	275	352	238

ANNUAL RATES

of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '06-'08 to '12-'14
Revenues	2.0%	-10.0%	*14.5%*
"Cash Flow"	5.5%	-1.5%	*9.0%*
Earnings	1.0%	-8.0%	*10.0%*
Dividends	3.5%	3.5%	*2.5%*
Book Value	10.5%	5.0%	*4.0%*

QUARTERLY REVENUES ($ mill.)

Cal-endar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2006	171.9	153.8	157.6	173.6	656.9
2007	186.5	163.9	162.4	183.1	695.9
2008	152.8	153.3	291.9	407.8	1005.8
2009	437.9	*350*	*360*	*432.1*	*1580*
2010	*460*	*370*	*380*	*455*	*1665*

EARNINGS PER SHARE A

Cal-endar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2006	.55	.37	.66	.62	2.21
2007	.91	.66	.46	.65	2.68
2008	.31	.34	.51	d.98	.18
2009	.94	*.46*	*.50*	*.50*	*2.40*
2010	*.60*	*.50*	*.55*	*.55*	*2.20*

QUARTERLY DIVIDENDS PAID B ■ †

Cal-endar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2005	.32	.32	.32	.32	1.28
2006	.33	.33	.33	.33	1.32
2007	.34	.34	.34	.35	1.37
2008	.35	.35	.35	.35	1.40
2009	.355	.355			

BUSINESS: Black Hills Corporation is a holding company for utilities that serve 202,000 electric customers in CO, SD, WY, and MT, and 557,000 gas customers in NE, IA, KS, CO, and WY. Electric rev. breakdown, '08: res'l, 26%; comm'l, 33%; ind'l, 11%; wholesale, 25%; other, 5%. Generating sources, '08: coal, 44%; oil & gas, 1%; purchased, 55%. Mines coal & has an oil & gas E&P business. Acq'd Wickford Energy Mktg. 7/97; Mallon Resources 3/03; Cheyenne Light 1/05; utility ops. from Aquila 7/08. Discont. telecom in '05; oil mktg. in '06. Fuel costs: 45% of revs. '08 depr. rate: 4.0%. Has about 2,200 empls. Chairman, Pres. & CEO: David R. Emery. Inc.: SD. Address: P.O. Box 1400, 625 Ninth St., Rapid City, SD 57709. Tel.: 605-721-1700. Internet: www.blackhillscorp.com.

We have raised our 2009 earnings estimate for Black Hills by $0.75 a share, to $2.40. In the March quarter, earnings benefited from $0.25 a share of income from mark-to-market accounting gains associated with an interest rate swap. Also, the company recorded a $3.8 million tax benefit in the period. Finally, the nonutility operations fared better than we expected. We'll continue to include any mark-to-market gains or losses in our presentation, but given their unpredictability, we have not factored any of these in our estimates.

Due to the unusually tough comparison, we now believe that share earnings will decline in 2010, despite the fact that we boosted our estimate from $1.95 to $2.20.

The company is building a coal-fired plant. Black Hills Power will own 75% of the Wygen Unit III, a 110-megawatt facility. The company's share of the cost is an estimated $191 million. The plant should come on line in June of 2010. The utility intends to file rate cases this fall, so that new tariffs can take effect when Wygen III begins commercial operation.

The utility was granted a gas rate increase in Iowa. The rate hike was $10.4 million (5.8%), based on a return of 10.1% on a common-equity ratio of 51.4%. New tariffs went into effect at the end of July.

Black Hills has repaid a bridge loan that it took on in 2008 to buy some utility properties. But this entailed the issuance of $250 million of five-year notes at a lofty interest rate of 9%. Additional debt financing is likely by yearend to help fund the company's capital budget. Even with these additional borrowings, the common-equity ratio will remain healthy.

Black Hills needs more generating capacity in Colorado. The utility was granted permission to build two 100-mw gas-fired units. It will get additional capacity through a competitive bidding process.

This stock has risen more than 30% in price since our May report due likely in part to increased interest by value investors. Even after this advance, the stock offers a yield that is somewhat above the utility mean. Total return potential to 2012-2014 is below average for a utility, however.

Paul E. Debbas, CFA *August 7, 2009*

(A) Dil. EPS. Excl. nonrec. losses: '05, 99¢; '08, $1.55; '09, 28¢; gains (losses) on disc. ops.: '03, 30¢; '04, 2¢; '05, (7¢); '06, 21¢; '07, (4¢); '08, $4.12. '06 EPS don't add due to rounding. Next egs. report due early Nov. (B) Div'ds histor. paid in early Mar., Jun., Sept., & Dec. ■ Div'd reinv. plan avail. † Shareholder invest. plan avail. (C) Incl. def'd chgs. In '08: $13.16/sh. (D) In mill., adj. for split. (E) Rate base: Net orig. cost. Rate all'd on com. eq. in SD in '99: none specified; earned on avg. com. eq., '08: .7%. Regul. Climate: Above Avg.

Company's Financial Strength	B+
Stock's Price Stability	95
Price Growth Persistence	40
Earnings Predictability	45

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CH ENERGY GROUP NYSE-CHG

RECENT PRICE	P/E RATIO	(Trailing / Median)	RELATIVE P/E RATIO	DIV'D YLD	
47.55	22.2	(Trailing: 21.0; Median: 17.0)	1.40	4.5%	VALUE LINE

TIMELINESS 3 Lowered 7/10/09
SAFETY 1 Raised 12/7/01
TECHNICAL 4 Raised 8/28/09
BETA .65 (1.00 = Market)

High:	47.1	45.0	46.3	45.9	52.4	49.7	49.6	50.2	54.9	53.8	52.4	52.7
Low:	38.9	30.6	26.1	38.3	39.9	40.2	43.1	42.1	44.6	41.4	33.4	37.7

2012-14 PROJECTIONS

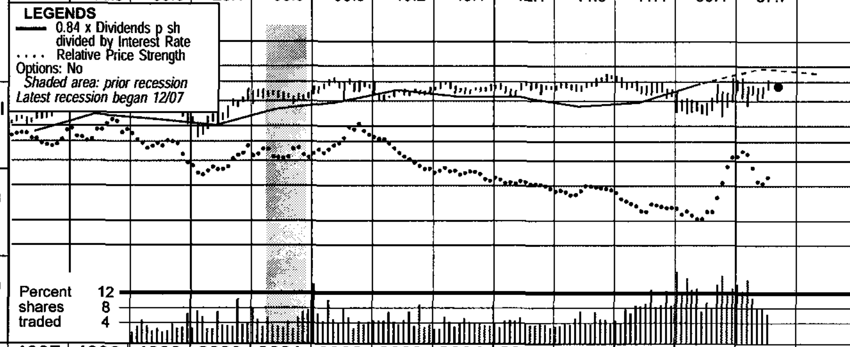
	Price	Gain	Ann'l Total Return
High	45	(-5%)	3%
Low	35	(-25%)	-2%

Insider Decisions

	O	N	D	J	F	M	A	M	J
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	0	0	0	0	0	0	0

Institutional Decisions

	3Q2008	4Q2008	1Q2009
to Buy	40	69	75
to Sell	47	50	46
Hld's(000)	8521	8358	8543



Target Price Range 2012 | 2013 | 2014
80
60
50
40
30
25
20
15
10
7.5

% TOT. RETURN 7/09

	THIS STOCK	VL ARITH. INDEX
1 yr.	43.2	-6.0
3 yr.	15.3	-2.1
5 yr.	42.5	24.2

1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	© VALUE LINE PUB., INC.	12-14
30.52	29.91	29.28	29.28	30.11	29.86	30.95	45.83	44.52	43.29	51.18	50.22	61.70	63.03	75.93	84.45	*79.10*	*87.00*	Revenues per sh	*100.00*
5.23	5.25	5.33	5.69	5.80	5.83	5.92	6.49	5.50	4.18	5.02	4.89	5.11	4.83	4.98	4.65	*4.80*	*5.20*	"Cash Flow" per sh	*6.15*
2.68	2.68	2.74	2.99	2.97	2.90	2.88	3.05	3.11	2.12	2.78	2.69	2.81	2.56	2.70	2.22	*2.25*	*2.50*	Earnings per sh A	*3.00*
2.05	2.08	2.10	2.12	2.14	2.16	2.16	2.16	2.16	2.16	2.16	2.16	2.16	2.16	2.16	2.16	*2.16*	*2.16*	Div'd Decl'd per sh B ■ †	*2.16*
3.13	3.37	2.87	2.84	2.54	2.71	2.76	3.58	4.14	4.50	3.79	3.98	4.05	4.76	5.37	5.33	*6.30*	*5.70*	Cap'l Spending per sh	*5.65*
24.65	25.33	25.96	26.87	27.61	28.00	28.73	29.38	30.33	30.31	30.80	31.31	31.97	32.54	33.19	33.17	*34.55*	*34.95*	Book Value per sh C	*36.45*
16.95	17.24	17.50	17.56	17.28	16.86	16.86	16.36	16.36	16.06	15.76	15.76	15.76	15.76	15.76	15.78	*15.80*	*15.80*	Common Shs Outst'g D	*16.00*
12.2	10.0	10.2	10.1	11.5	14.6	13.5	11.4	13.6	22.6	15.7	17.2	16.5	19.1	17.5	17.9	*Bold figures are*		Avg Ann'l P/E Ratio	*13.5*
.72	.66	.68	.63	.66	.76	.77	.74	.70	1.23	.90	.91	.88	1.03	.93	1.09	*Value Line*		Relative P/E Ratio	*.90*
6.3%	7.8%	7.5%	7.0%	6.3%	5.1%	5.6%	6.2%	5.1%	4.5%	4.9%	4.7%	4.7%	4.4%	4.6%	5.4%	*estimates*		Avg Ann'l Div'd Yield	*5.3%*

CAPITAL STRUCTURE as of 6/30/09
Total Debt $463.8 mill. **Due in 5 Yrs** $110.0 mill.
LT Debt $463.8 mill. **LT Interest** $20.0 mill.
(LT interest earned: 3.8x)
Leases, Uncapitalized Annual rentals $3.2 mill.
Pension Assets-12/08 $261.3 mill. **Oblig.** $423.5 mill.
Pfd Stock $21.0 mill. **Pfd Div'd** $1.0 mill.
210,300 shs. 4½%-4.96% cum., $100 par, redeemable at $101-$107/sh.

Common Stock 15,790,053 shs.
as of 7/31/09
MARKET CAP: $750 million (Small Cap)

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010		12-14
521.9	749.9	728.4	695.5	806.7	791.5	972.5	993.4	1196.8	1332.9	*1250*	*1375*	Revenues ($mill)	*1600*
51.8	54.2	54.1	36.6	45.4	43.4	45.3	41.4	43.6	36.1	*35.5*	*39.5*	Net Profit ($mill)	*48.0*
35.8%	41.4%	--	36.6%	40.1%	41.9%	36.3%	36.3%	33.5%	37.6%	*37.0%*	*37.0%*	Income Tax Rate	*37.0%*
.8%	1.4%	1.4%	2.3%	1.6%	.9%	.9%	1.5%	2.5%	2.0%	*2.0%*	*2.0%*	AFUDC % to Net Profit	*2.0%*
38.3%	37.4%	28.1%	34.1%	35.5%	38.3%	39.6%	38.8%	42.6%	43.2%	*47.0%*	*47.0%*	Long-Term Debt Ratio	*49.5%*
55.3%	56.1%	64.6%	61.6%	61.8%	59.1%	58.0%	58.8%	55.2%	54.6%	*51.0%*	*51.0%*	Common Equity Ratio	*48.5%*
875.9	857.1	768.5	790.3	785.3	834.4	868.7	871.8	948.1	958.5	*990*	*970*	Total Capital ($mill)	*1050*
921.4	930.9	561.8	601.7	707.5	745.1	779.5	827.1	891.3	945.9	*950*	*1000*	Net Plant ($mill)	*1100*
7.3%	7.7%	8.1%	5.4%	6.5%	5.9%	6.0%	5.7%	5.6%	4.8%	*4.5%*	*5.0%*	Return on Total Cap'l	*5.5%*
9.6%	10.1%	9.8%	7.0%	9.0%	8.4%	8.6%	7.7%	8.0%	6.6%	*6.5%*	*7.0%*	Return on Shr. Equity	*8.0%*
10.0%	10.6%	10.2%	7.1%	9.1%	8.6%	8.8%	7.9%	8.1%	6.7%	*6.5%*	*7.0%*	Return on Com Equity E	*8.0%*
2.5%	3.1%	3.1%	NMF	2.0%	1.7%	2.0%	1.2%	1.6%	.4%	*.5%*	*1.0%*	Retained to Com Eq	*2.0%*
77%	73%	71%	102%	78%	81%	77%	85%	80%	95%	*96%*	*86%*	All Div'ds to Net Prof	*73%*

ELECTRIC OPERATING STATISTICS

	2006	2007	2008
% Change Retail Sales (KWH)	-4.2	+2.4	+2.5
Avg. Indust. Use (MWH)	1377	1108	1090
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	1295	1185	1187
Peak Load, Summer (Mw)	1295	1185	1187
Annual Load Factor (%)	50.0	56.0	55.0
% Change Customers (avg.)	+.9	+1.0	+1.0
Fixed Charge Cov. (%)	328	306	282

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '06-'08 to '12-'14
Revenues	9.5%	10.0%	*5.0%*
"Cash Flow"	-2.0%	-0.5%	*4.0%*
Earnings	-1.5%	-1.5%	*3.0%*
Dividends	--	--	*Nil*
Book Value	2.0%	1.5%	*1.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2006	317.2	213.9	239.8	222.5	993.4
2007	343.4	271.0	260.1	322.3	1196.8
2008	409.8	313.6	300.8	308.7	1332.9
2009	378.4	200.2	*320*	*351.4*	*1250*
2010	*380*	*315*	*325*	*355*	*1375*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2006	1.16	.26	.55	.60	2.56
2007	1.37	.33	.27	.73	2.70
2008	1.22	.11	.18	.71	2.22
2009	1.46	d.09	*.35*	*.53*	*2.25*
2010	*1.35*	*.25*	*.36*	*.54*	*2.50*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2005	.54	.54	.54	.54	2.16
2006	.54	.54	.54	.54	2.16
2007	.54	.54	.54	.54	2.16
2008	.54	.54	.54	.54	2.16
2009	.54	.54	.54		

BUSINESS: CH Energy Group, Inc. is a holding company for Central Hudson Gas & Electric, which provides electricity and gas in the Mid-Hudson Valley region of New York State (75% of '08 income). Customers: 300,000 electric, 74,000 gas. Griffith Energy provides gas, oil, electricity, & propane to over 111,000 customers in Northeast (12% of '08 income). Investments were 13% of '08 income. Electric revenue breakdown, '08: residential, 48%; commercial, 28%; industrial, 7%; other, 17%. Generating sources, '08: hydro, 2%; purchased, 98%. Fuel costs: 70% of revenues. '08 reported depreciation rate (utility): 2.8%. Chairman, President & CEO: Steven V. Lant. Inc.: NY. Address: 284 South Ave., Poughkeepsie, NY 12601-4879. Tel.: 845-452-2000. Internet: www.chenergy.com.

CH Energy Group's share earnings performance slipped into the red in the June interim. A revenue gap was to blame for most of the lackluster showing as the rate plan that recently expired did not counter economic headwinds. Consumer conservation and rising uncollectible accounts owing to the recession continue to weigh on the bottom line. Thus, we have trimmed our 2009 share earnings estimate by $0.30, to $2.25.

A new rate agreement went into effect on July 1st. The plans grants a 47% common equity ratio, increased from 45%, and moves up the allowed return on equity from 9.6% to 10%. This may prove to be a challenge to this regional electricity and gas provider as the public service commission (PSC) rejected several large expenses. First, liability insurance for directors and officers and, secondly, variable pay for management were not recognized. On top of that, the PSC implied a $3 million reduction for austerity measures. CHG may be hard-pressed to wring out further cost savings as it has trimmed expense levels in order to help offset slow and nonpaying accounts.

CH Energy has filed a new rate case for the period beginning July 1, 2010. The utility is seeking to increase revenues for delivered electricity by $15.2 million and gas by $3.9 million. Upgrades to its energy grid system, compliance costs, and rising property taxes have necessitated the modest request. CH has built expectations with its request to attempt cost containment, especially of its pension obligations and post-retirement benefits, that should garner close to $15 million in annual savings. But the outcome of the proposed rate increase will not be determined until next June, and the uncertainty of unemployment levels and general economic health may still cause some unpredictability.

Investors ought to stay on the sidelines for now. Most accounts are drawn to the utility sector thanks to above-average dividends. CHG's payout, however, has been stagnant for years and offers an on-par yield. Relative stock price performance in the year ahead is average, and the 3- to 5-year outlook appears negligible since CHG currently trades above our Target Price Range.

Mary Beth Wiedenkeller August 28, 2009

(A) Diluted earnings. Excl. nonrecurring gains: '02, 12¢; '06, 17¢; gain from discontinued operation: '02, 29¢. '05 & '06 earnings don't total due to rounding. Next earnings report due late October. (B) Div'ds historically paid in early Feb., May, Aug., and Nov. ■ Div'd reinvestment plan available. † Shareholder investment plan available. (C) Incl. intangibles. In '08: $420.5 mill., $26.65/sh. (D) In mill. (E) Rate base: Net orig. cost. Rate allowed on com. eq. in '06: 9.6%; earned on avg. com. eq., '07: 8.2%. Regulatory Climate: Below Average.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	30
Earnings Predictability	90

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EMPIRE DISTRICT NYSE-EDE

RECENT PRICE 18.09 | P/E RATIO 12.2 (Trailing: 13.3 Median: 20.0) | RELATIVE P/E RATIO 0.71 | DIV'D YLD 7.1% | VALUE LINE

TIMELINESS 3 Lowered 8/10/07
SAFETY 3 Lowered 10/4/02
TECHNICAL 3 Raised 9/18/09
BETA .75 (1.00 = Market)

High:	26.1	26.8	30.8	26.6	22.0	22.5	23.5	25.0	25.1	26.1	23.5	19.0
Low:	18.4	20.7	18.9	17.5	15.1	17.0	19.5	19.3	20.3	21.1	14.9	11.9

2012-14 PROJECTIONS

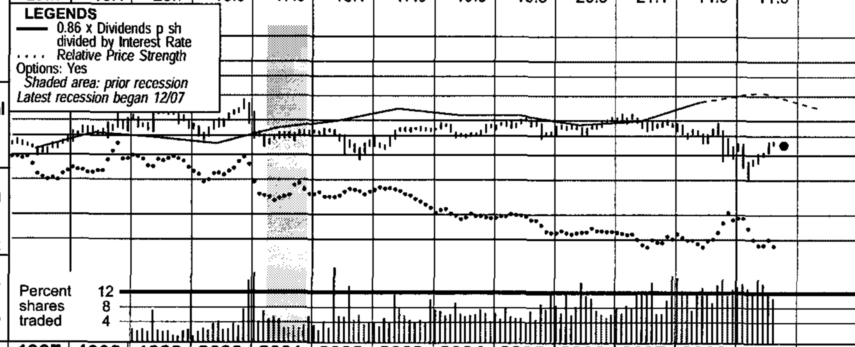
	Price	Gain	Ann'l Total Return
High	30	(+65%)	18%
Low	20	(+10%)	9%

Insider Decisions

	O	N	D	J	F	M	A	M	J
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	2	0	0
to Sell	0	0	0	0	0	0	0	0	2

Institutional Decisions

	4Q2008	1Q2009	2Q2009
to Buy	49	67	56
to Sell	55	43	48
Hld's(000)	14026	13650	13254



Target Price Range 2012 | 2013 | 2014
64 48 40 32 24 20 16 12 8 6

% TOT. RETURN 8/09

	THIS STOCK	VL ARITH. INDEX
1 yr.	-7.0	-4.4
3 yr.	-2.8	0.4
5 yr.	20.6	32.3

1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	© VALUE LINE PUB., INC.	12-14
12.41	12.75	12.67	12.53	12.83	14.02	13.94	14.78	13.37	13.56	13.03	12.67	14.80	13.67	14.59	15.25	*14.20*	*14.15*	Revenues per sh	*15.75*
2.49	2.62	2.52	2.67	2.67	2.97	2.89	3.12	2.19	2.43	2.48	2.22	2.45	2.75	2.69	2.91	*2.95*	*3.05*	"Cash Flow" per sh	*3.50*
1.16	1.32	1.18	1.23	1.29	1.53	1.13	1.35	.59	1.19	1.29	.86	.92	1.41	1.09	1.17	*1.50*	*1.55*	Earnings per sh A	*1.75*
1.28	1.28	1.28	1.28	1.28	1.28	1.28	1.28	1.28	1.28	1.28	1.28	1.28	1.28	1.28	1.28	*1.28*	*1.28*	Div'd Decl'd per sh B ■ †	*1.35*
3.27	5.14	3.34	3.79	3.38	3.03	4.14	7.61	4.02	3.43	2.65	1.64	2.83	3.97	5.46	6.28	*4.70*	*3.00*	Cap'l Spending per sh	*2.50*
12.37	12.47	12.69	12.96	13.06	13.43	13.48	13.65	13.58	14.59	15.17	14.76	15.08	15.49	16.04	15.56	*15.80*	*16.30*	Book Value per sh C	*17.50*
13.57	13.94	15.22	16.44	16.78	17.11	17.37	17.60	19.76	22.57	24.98	25.70	26.08	30.25	33.61	33.98	*38.00*	*40.25*	Common Shs Outst'g D	*41.00*
19.6	13.3	14.9	14.8	13.9	14.0	21.7	17.7	33.9	16.2	15.8	24.8	24.5	15.9	21.7	17.3	*Bold figures are*		Avg Ann'l P/E Ratio	*14.0*
1.16	.87	1.00	.93	.80	.73	1.24	1.15	1.74	.88	.90	1.31	1.30	.86	1.15	1.06	*Value Line*		Relative P/E Ratio	*.95*
5.6%	7.3%	7.3%	7.0%	7.1%	6.0%	5.2%	5.4%	6.4%	6.6%	6.3%	6.0%	5.7%	5.7%	5.4%	6.3%	*estimates*		Avg Ann'l Div'd Yield	*5.5%*

CAPITAL STRUCTURE as of 6/30/09
Total Debt $780.1 mill. **Due in 5 Yrs** $253.6 mill.
LT Debt $637.5 mill. **LT Interest** $44.5 mill.
Incl. $50 mill. 8.5% trust preferred securities.
(LT interest earned: 2.3x)
Leases, Uncapitalized Annual rentals $1.1 mill.
Pension Assets-12/08 $92.7 mill. **Oblig.** $154.3 mill.
Pfd Stock None

Common Stock 34,492,377 shs.
as of 8/1/09

MARKET CAP: $625 million (Small Cap)

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010		12-14
242.2	260.0	264.3	305.9	325.5	325.5	386.2	413.5	490.2	518.2	*540*	*570*	Revenues ($mill)	*650*
22.2	23.6	10.4	25.5	29.5	21.8	23.8	39.9	33.2	39.7	*52.0*	*61.0*	Net Profit ($mill)	*75.0*
41.9%	32.7%	--	34.3%	34.5%	34.1%	33.4%	35.4%	30.3%	32.5%	*34.0%*	*35.5%*	Income Tax Rate	*35.5%*
5.4%	24.5%	34.7%	2.2%	1.0%	1.0%	2.4%	10.7%	23.1%	31.5%	*28.0%*	*12.0%*	AFUDC % to Net Profit	*3.0%*
59.6%	57.6%	57.2%	55.5%	52.0%	51.3%	51.0%	49.7%	50.1%	53.6%	*54.0%*	*53.5%*	Long-Term Debt Ratio	*51.0%*
40.4%	42.4%	42.8%	44.5%	48.0%	48.7%	49.0%	50.3%	49.9%	46.4%	*46.0%*	*46.5%*	Common Equity Ratio	*49.0%*
580.0	565.8	626.9	740.3	789.2	779.1	803.3	931.0	1081.1	1140.4	*1305*	*1410*	Total Capital ($mill)	*1475*
616.0	720.3	750.5	794.1	833.9	857.0	896.0	1031.0	1178.9	1342.8	*1460*	*1520*	Net Plant ($mill)	*1600*
5.5%	6.5%	4.0%	5.4%	5.7%	4.7%	4.7%	5.9%	4.7%	5.2%	*5.5%*	*6.0%*	Return on Total Cap'l	*7.0%*
9.5%	9.8%	3.9%	7.8%	7.8%	5.8%	6.0%	8.5%	6.2%	7.5%	*8.5%*	*9.5%*	Return on Shr. Equity	*10.5%*
8.8%	9.8%	3.9%	7.8%	7.8%	5.8%	6.0%	8.5%	6.2%	7.5%	*8.5%*	*9.5%*	Return on Com Equity E	*10.5%*
NMF	.5%	NMF	NMF	.1%	NMF	NMF	.8%	NMF	NMF	*1.0%*	*1.5%*	Retained to Com Eq	*3.0%*
107%	95%	NMF	109%	99%	NMF	NMF	90%	117%	109%	*88%*	*83%*	All Div'ds to Net Prof	*73%*

ELECTRIC OPERATING STATISTICS

	2006	2007	2008
% Change Retail Sales (KWH)	+2.6	+1.4	+2.8
Avg. Industrial Use (MWH)	3096	3067	2973
Avg. Industrial Rev/KWH (¢)	5.66	6.10	6.28
Capacity at Peak (Mw)	1262	1255	1255
Peak Load, Summer (Mw)	1159	1173	1152
Annual Load Factor (%)	52.5	53.4	54.3
% Change Customers (avg.)	+2.1	+1.5	+.7
Fixed Charge Cov. (%)	273	203	208

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '06-'08 to '12-'14
Revenues	1.0%	1.5%	1.5%
"Cash Flow"	--	3.5%	4.0%
Earnings	-1.0%	3.5%	6.0%
Dividends	--	--	1.5%
Book Value	2.0%	1.5%	2.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2006	84.0	91.7	131.2	106.6	413.5
2007	125.7	107.2	142.5	114.8	490.2
2008	136.9	111.3	138.7	131.3	518.2
2009	136.0	112.2	*156.8*	*135*	*540*
2010	*145*	*120*	*165*	*140*	*570*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2006	.08	.28	.74	.26	1.41
2007	.15	.19	.76	d.01	1.09
2008	.21	.14	.59	.23	1.17
2009	.32	.22	*.71*	*.25*	*1.50*
2010	*.30*	*.20*	*.75*	*.30*	*1.55*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2005	.32	.32	.32	.32	1.28
2006	.32	.32	.32	.32	1.28
2007	.32	.32	.32	.32	1.28
2008	.32	.32	.32	.32	1.28
2009	.32	.32	.32		

BUSINESS: The Empire District Electric Company supplies electricity to 167,000 customers in a 10,000 sq. mi. area in Missouri (89% of '08 retail elec. revs.), Kansas (5%), Oklahoma (3%), & Arkansas (3%). Acq'd Missouri Gas (45,000 customers) 6/06. Supplies water service and has a small fiber-optic operation. Electric revenue breakdown, '08: residential, 40%; commercial, 30%; industrial, 15%; other, 15%. Generating sources, '08: coal, 36%; gas, 24%; hydro, 1%; purchased, 39%. Fuel costs: 48% of revenues. '08 reported deprec. rate: 3.0%. Has 733 employees. Chairman: Myron W. McKinney. President & CEO: William L. Gipson. Inc.: KS. Address: 602 S. Joplin Ave., P.O. Box 127, Joplin, MO 64802-0127. Tel.: 417-625-5100. Internet: www.empiredistrict.com.

We estimate that Empire District Electric's earnings will rise significantly in 2009. The main reason is a full year's benefit of the $22.0 million electric rate increase that took effect last September. If the company attains our $1.50 estimate, this would be its highest share profit since 1998.

Now that the stock price has rebounded, the company is issuing shares under a $60 million "dribble" program. The stock price fell below $12 earlier this year but has recovered to above $18. We believe that Empire District will need additional equity beyond this $60 million, due to its high capital budget (see below). Because average shares outstanding will probably be higher than we thought three months ago, we have lowered our 2010 earnings estimate by $0.15 a share, to $1.55.

Some significant capital projects are under construction. Empire District will own 50 megawatts of a 665-mw coal-fired plant at a cost of $88.0 million and 102 mw of an 850-mw coal-fired facility at a cost of $218 million-$230 million. These plants will probably go into service in the summer of 2010. The utility will file a rate case in Missouri next year in order to place these projects into the rate base.

We believe that the dividend will hold at the current level. Earlier this year, we were concerned that a dividend cut was possible due to the low stock price, which made an equity offering unappealing. Cutting the dividend might have been a necessary but unpleasant alternative to issuing stock at a depressed price. The stock price recovery precludes a dividend cut, in our view. The payout ratio is high, but the board of directors didn't cut the dividend even when the company didn't cover it.

The utility is seeking a gas rate increase. Empire District filed for a boost of $2.9 million (4.9%) based on a return on equity of 11.3%. A rate order is due by early May, but this will come too late for the primary heating season in the first quarter of 2010.

This stock's main attraction is its high yield. It is two percentage points above the utility average. Due to the high payout ratio, however, 3- to 5-year dividend growth potential is now unspectacular.

Paul E. Debbas, CFA *September 25, 2009*

(A) Excl. loss from discontinued operations: '06, 2¢. '06 EPS don't add to full-year total due to change in shares. Next earnings report due late Oct. (B) Dividends historically paid in mid-March, June, September, and December. ■ Dividend reinvestment plan available (3% discount). † Shareholder investment plan available. (C) Incl. intangibles. In '08: $210.7 mill., $6.20/sh. (D) In mill. (E) Rate base: Deprec. original cost. Rate allowed on common equity in MO in '08: 10.8%; earned on avg. com. eq., '08: 7.4%. Regulatory Climate: Average.

Company's Financial Strength	B+
Stock's Price Stability	100
Price Growth Persistence	25
Earnings Predictability	65

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HAWAIIAN ELECTRIC NYSE-HE

RECENT PRICE 17.63 | P/E RATIO 15.3 (Trailing: 20.0; Median: 16.0) | RELATIVE P/E RATIO 0.94 | DIV'D YLD 7.0-4.5% | VALUE LINE

TIMELINESS 4 Lowered 4/17/09

SAFETY 3 Lowered 5/8/09

TECHNICAL 4 Lowered 7/31/09

BETA .70 (1.00 = Market)

	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
High:	21.3	20.3	19.0	20.6	24.5	24.0	29.5	29.8	28.9	27.5	29.8	22.7	
Low:	18.2	14.0	13.8	16.8	17.3	19.1	23.0	24.6	25.7	20.3	21.0	12.1	

Target Price Range 2012 | 2013 | 2014

2012-14 PROJECTIONS

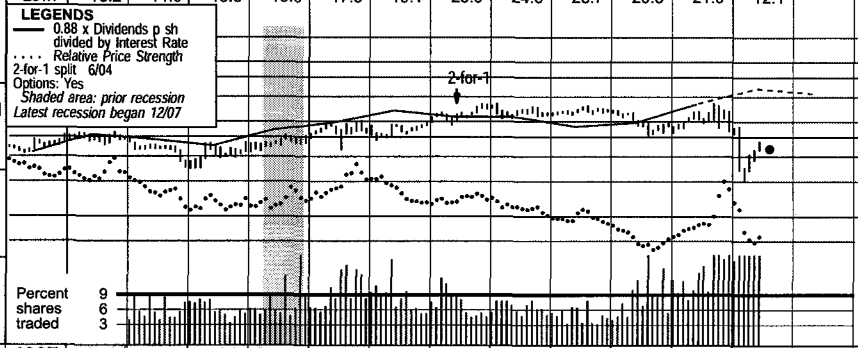
	Price	Gain	Ann'l Total Return
High	25	(+40%)	14%
Low	18	(Nil)	7%

Insider Decisions

	S	O	N	D	J	F	M	A	M
to Buy	1	0	0	2	0	1	4	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	0	0	0	0	1	0	0

Institutional Decisions

	3Q2008	4Q2008	1Q2009
to Buy	100	108	91
to Sell	84	95	101
Hld's(000)	36080	36535	38420



% TOT. RETURN 6/09

	THIS STOCK	VL ARITH. INDEX
1 yr.	-17.9	-14.0
3 yr.	-19.6	-14.4
5 yr.	-5.6	5.1

1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	© VALUE LINE PUB., INC.	12-14
20.64	20.74	21.76	22.86	22.95	23.12	23.64	26.05	24.26	22.46	23.49	23.85	27.36	30.21	30.40	35.56	**27.25**	**29.35**	Revenues per sh	**32.00**
2.23	2.52	2.73	2.81	3.01	3.23	3.35	3.08	3.33	3.52	3.54	3.09	3.22	3.19	3.01	2.72	**2.90**	**3.35**	"Cash Flow" per sh	**3.75**
1.19	1.30	1.33	1.30	1.38	1.48	1.45	1.27	1.60	1.62	1.58	1.36	1.46	1.33	1.11	1.07	**1.15**	**1.50**	Earnings per sh A	**1.75**
1.15	1.17	1.19	1.21	1.22	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	**1.24**	**1.24**	Div'd Decl'd per sh B ■ †	**1.24**
4.06	3.50	3.27	3.33	2.31	2.60	2.09	2.04	1.77	1.74	2.15	2.66	2.76	2.58	2.62	3.12	**3.80**	**2.95**	Cap'l Spending per sh	**3.75**
11.62	11.90	12.25	12.52	12.77	12.87	13.16	12.72	13.06	14.21	14.36	15.01	15.02	13.44	15.29	15.35	**15.25**	**15.45**	Book Value per sh C	**16.75**
55.35	57.31	59.55	61.71	63.79	64.23	64.43	65.98	71.20	73.62	75.84	80.69	80.98	81.46	83.43	90.52	**91.75**	**92.00**	Common Shs Outst'g D	**93.50**
15.5	12.5	13.5	13.7	13.2	13.4	12.1	12.9	11.8	13.5	13.8	19.2	18.3	20.3	21.6	23.2	*Bold figures are*		Avg Ann'l P/E Ratio	**13.0**
.92	.82	.90	.86	.76	.70	.69	.84	.60	.74	.79	1.01	.97	1.10	1.15	1.41	*Value Line*		Relative P/E Ratio	**.85**
6.2%	7.2%	6.6%	6.8%	6.7%	6.2%	7.1%	7.5%	6.6%	5.7%	5.7%	4.8%	4.6%	4.6%	5.2%	5.0%	*estimates*		Avg Ann'l Div'd Yield	**5.5%**

CAPITAL STRUCTURE as of 3/31/09
Total Debt $1214.7 mill. **Due in 5 Yrs** $265.0 mill.
LT Debt $1214.7 mill. **LT Interest** $66.8 mill.
Incl. $50 mill. 6.5% oblig. pfd. sec. of trust subsid.
(LT interest earned: 2.7x)
Pension Assets-12/08 $619.1 mill. **Oblig.** $964.3 mill.
Pfd Stock $34.3 mill. **Pfd Div'd** $2.0 mill.
1,114,657 shs. 4¼% to 5¼%, $20 par. call. $20 to $21; 120,000 shs. 7⅝%, $100 par. call. $100.
Sinking fund ends 2018.
Common Stock 91,533,957 shs.
as of 4/30/09
MARKET CAP: $1.6 billion (Mid Cap)

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010		12-14
1523.3	1719.0	1727.3	1653.7	1781.3	1924.1	2215.6	2460.9	2536.4	3218.9	**2500**	**2700**	Revenues ($mill)	**3000**
111.1	84.6	109.8	120.2	120.1	109.6	120.3	109.9	93.6	92.2	**110**	**140**	Net Profit ($mill)	**160**
33.9%	41.6%	34.6%	34.6%	34.9%	45.8%	36.4%	36.5%	35.4%	34.7%	**39.0%**	**40.0%**	Income Tax Rate	**40.0%**
6.1%	9.8%	5.9%	4.8%	5.1%	7.6%	5.9%	8.4%	8.3%	14.2%	**17.0%**	**7.0%**	AFUDC % to Net Profit	**10.0%**
47.2%	58.4%	56.9%	52.0%	48.6%	47.6%	45.2%	49.9%	47.6%	46.0%	**49.0%**	**44.0%**	Long-Term Debt Ratio	**41.0%**
41.4%	39.9%	41.6%	46.5%	49.8%	51.0%	53.3%	48.6%	51.0%	52.7%	**50.0%**	**52.0%**	Common Equity Ratio	**55.0%**
2049.5	2101.2	2235.8	2251.0	2186.9	2375.1	2283.9	2252.7	2501.8	2635.2	**2795**	**2750**	Total Capital ($mill)	**2825**
2066.2	2091.3	2067.5	2079.3	2311.9	2422.3	2542.8	2647.5	2743.4	2907.4	**3095**	**3190**	Net Plant ($mill)	**3650**
6.8%	5.9%	6.7%	7.3%	7.3%	6.0%	6.8%	6.4%	5.2%	4.7%	**5.0%**	**6.5%**	Return on Total Cap'l	**7.0%**
10.3%	9.7%	11.4%	11.1%	10.7%	8.8%	9.6%	9.7%	7.1%	6.5%	**7.5%**	**9.0%**	Return on Shr. Equity	**10.0%**
11.0%	9.8%	11.6%	11.3%	10.8%	8.9%	9.7%	9.9%	7.2%	6.5%	**7.5%**	**9.5%**	Return on Com Equity E	**10.0%**
1.5%	1.7%	4.4%	4.3%	3.9%	1.1%	1.5%	.7%	.8%	.5%	**NMF**	**1.5%**	Retained to Com Eq	**2.5%**
88%	84%	63%	63%	64%	87%	85%	93%	89%	93%	**106%**	**84%**	All Div'ds to Net Prof	**75%**

ELECTRIC OPERATING STATISTICS

	2006	2007	2008
% Change Retail Sales (KWH)	+.3	- -	-1.8
Avg. Indust. Use (MWH)	6623	6584	6623
Avg. Indust. Revs. per KWH (¢)	17.38	17.68	25.36
Capacity at Yearend (Mw)	2204	2223	2227
Peak Load, Winter (Mw)	1685	1635	1590
Annual Load Factor (%)	72.5	74.7	75.3
% Change Customers (yr-end)	+1.2	+1.3	+.1
Fixed Charge Cov. (%)	301	262	255

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '06-'08 to '12-'14
Revenues	3.5%	6.5%	*Nil*
"Cash Flow"	- -	-3.0%	*4.0%*
Earnings	-1.5%	-6.0%	*7.0%*
Dividends	- -	- -	*Nil*
Book Value	1.5%	1.0%	*2.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2006	574.9	605.0	673.9	607.1	2460.9
2007	554.0	600.8	673.4	708.2	2536.4
2008	729.6	774.1	915.4	799.8	3218.9
2009	543.8	***650***	***650***	***656.2***	***2500***
2010	***650***	***675***	***700***	***675***	***2700***

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2006	.40	.33	.40	.20	1.33
2007	.17	.21	.24	.49	1.11
2008	.41	.06	.44	.16	1.07
2009	.22	***.22***	***.35***	***.36***	***1.15***
2010	***.37***	***.37***	***.38***	***.38***	***1.50***

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2005	.31	.31	.31	.31	1.24
2006	.31	.31	.31	.31	1.24
2007	.31	.31	.31	.31	1.24
2008	.31	.31	.31	.31	1.24
2009	.31	.31			

BUSINESS: Hawaiian Electric Industries, Inc. is the parent company of *Hawaiian Electric Company* (HECO) & *American Savings* Bank (ASB). HECO & its subs., Maui Electric Co. (MECO) & Hawaii Electric Light Co. (HELCO), supply electricity to 440,000 customers on Oahu, Maui, Molokai, Lanai, & Hawaii. Operating companies' systems are not interconnected. Discontinued int'l power sub. in '01. Elec. rev. breakdown, '08: res'l, 33%; comm'l, 34%; large light & power, 32%; other, 1%. Generating sources, '08: oil, 60%; purchased, 40%. Fuel costs: 60% of revs. '08 reported depr. rate (utility): 3.8%. Has 3,600 employees. Chairman: Jeffrey N. Watanabe. Pres. & CEO: Constance H. Lau. Inc.: HI. Address: P.O. Box 730, Honolulu, HI 96808-0730. Tel.: 808-543-5662. Web: www.hei.com.

Hawaiian Electric Industries' largest utility subsidiary has received an interim rate increase. The Public Utilities Commission of Hawaii (PUC) granted Hawaiian Electric Company (HECO) an interim tariff hike that was less than the $79.8 million (6.2%) boost, based on a 10.5% return on equity, agreed upon by the utility and various intervenor groups. HECO believes that the interim order amounts to a $61.1 million (4.7%) increase, but the PUC will have to rule on this, and on the timing of the rate hike. Hearings aren't going to occur until the last week of October. As for the final tariff increase, HECO is requesting $86.8 million (6.7%), based on an 11% return on equity.

The interim rate hike will help HEI's earnings once it is implemented. The company expects a 13% increase in utility operating and maintenance costs this year. Higher utility expenses hurt earnings considerably in the first quarter of 2009, and we expect a similar result in the second period. (Earnings were released shortly after this report went to press.) Another challenge is a decline in kilowatt-hour sales, stemming from the weak economy.

We would not be surprised if HEI's two other utilities file rate cases in the coming months. Like HECO, Hawaii Electric Light Company (HELCO) and Maui Electric Company have been earning ROEs of less than 8%. All three utilities (including HECO) are seeking regulatory mechanisms that will decouple electric volume and electric sales. And HELCO will need to file an application in order to place an 18-megawatt facility (at a cost of $92 million) in the rate base.

American Savings Bank is facing some challenges. The effects of the weak economy have hurt credit quality. Also, the bank is undertaking a cost-cutting program, but expenses aren't likely to reach desired levels until 2010.

We advise investors to look elsewhere. Although the board of directors has held the dividend steady so far, we still do not rule out a cut. That's why we are showing a split dividend at the top of the page. Even if HEI avoids a dividend reduction, a dividend increase is unlikely anytime soon, and total return potential to 2012-2014 is unimpressive.

Paul E. Debbas, CFA *August 7, 2009*

(A) Diluted EPS. Excl. gains (losses) from disc. ops.: '98, (16¢); '99, 6¢; '00, (56¢); '01, (36¢); '03, (5¢); '04, 2¢; '05, (1¢); nonrec. gain (loss): '05, 11¢; '07, (9¢). Next egs. due early Nov.
(B) Div'ds historically paid in early Mar., June, Sept., and Dec. ■ Div'd reinv. plan avail. † Sharehldr. invest. plan avail. (C) Incl. intang. In '08: $6.77/sh. (D) In mill., adj. for split. (E) Rate base: Orig. cost. Rate all'd on com. eq. in '07: HECO, 10.7% (interim); in '07: HELCO, 10.7%; in '07: MECO, 10.7%; earned on avg. com. eq., '08: 6.8%. Regulatory Climate: Above Average.

Company's Financial Strength	B+
Stock's Price Stability	95
Price Growth Persistence	45
Earnings Predictability	65

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MGE ENERGY INC. NDQ-MGEE

RECENT PRICE	37.12	P/E RATIO	15.6 (Trailing: 15.8; Median: 15.0)	RELATIVE P/E RATIO	0.91	DIV'D YLD	4.0%	VALUE LINE

TIMELINESS 3 Lowered 6/26/09
SAFETY 1 New 1/3/03
TECHNICAL 4 Lowered 8/14/09
BETA .65 (1.00 = Market)

	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
High:	23.8	23.9	23.7	27.8	30.1	35.8	36.4	38.8	37.0	37.2	36.5	37.2
Low:	20.6	16.4	16.8	20.9	24.6	25.0	27.6	30.5	29.2	29.4	27.9	27.3

Target Price Range 2012 | 2013 | 2014

2012-14 PROJECTIONS

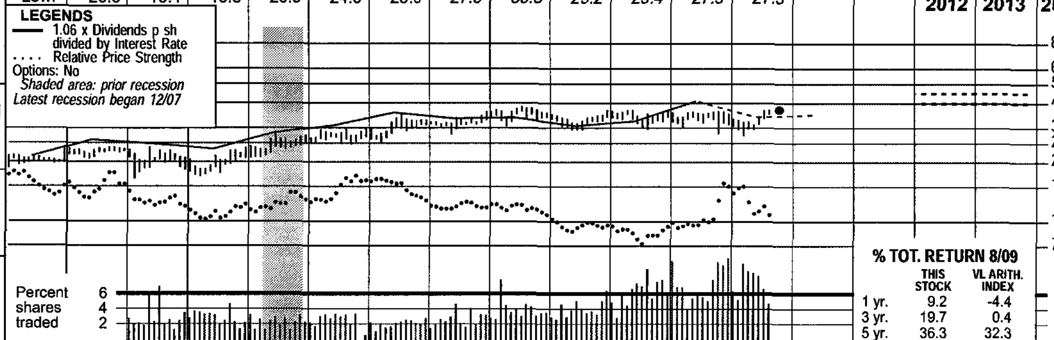
	Price	Gain	Ann'l Total Return
High	45	(+20%)	9%
Low	40	(+10%)	6%

Insider Decisions

	O	N	D	J	F	M	A	M	J
to Buy	0	1	0	0	0	3	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	0	0	0	0	0	0	0

Institutional Decisions

	4Q2008	1Q2009	2Q2009
to Buy	55	47	52
to Sell	38	42	44
Hld's(000)	7627	7435	7661



% TOT. RETURN 8/09

	THIS STOCK	VL ARITH. INDEX
1 yr.	9.2	-4.4
3 yr.	19.7	0.4
5 yr.	36.3	32.3

1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	© VALUE LINE PUB., INC.	12-14
15.18	15.23	15.46	15.75	16.46	15.53	16.96	19.50	19.55	19.75	21.89	20.84	25.10	24.20	24.49	26.02	**24.80**	**25.45**	Revenues per sh	**25.80**
2.86	2.92	3.03	2.41	3.26	3.59	3.81	3.89	3.78	3.33	2.94	2.88	3.00	3.52	3.69	4.02	**3.85**	**3.95**	"Cash Flow" per sh	**4.20**
1.51	1.53	1.49	.82	1.40	1.38	1.48	1.67	1.62	1.69	1.71	1.77	1.57	2.06	2.27	2.38	**2.40**	**2.50**	Earnings per sh A	**2.80**
1.19	1.25	1.26	1.28	1.29	1.30	1.31	1.32	1.33	1.34	1.35	1.36	1.37	1.39	1.41	1.43	**1.45**	**1.47**	Div'd Decl'd per sh B ■	**1.54**
1.47	1.64	1.19	1.36	1.35	1.92	3.16	4.44	2.47	4.45	4.52	4.70	4.19	4.41	6.21	4.62	**2.30**	**2.30**	Cap'l Spending per sh	**2.50**
11.51	11.78	12.01	11.14	11.25	11.34	11.49	12.05	12.67	12.94	14.34	16.59	16.81	17.89	19.49	20.88	**21.85**	**22.85**	Book Value per sh	**21.05**
16.08	16.08	16.08	16.08	16.08	16.08	16.16	16.62	17.07	17.57	18.34	20.39	20.45	20.98	21.95	22.90	**23.20**	**23.20**	Common Shs Outst'g C	**25.00**
15.2	14.3	14.5	28.1	14.5	16.2	14.0	11.7	14.8	16.0	17.5	18.0	22.4	15.9	15.0	14.2	*Bold figures are*		Avg Ann'l P/E Ratio	**15.0**
.90	.94	.97	1.76	.84	.84	.80	.76	.76	.87	1.00	.95	1.19	.86	.80	.87	*Value Line*		Relative P/E Ratio	**1.00**
5.2%	5.7%	5.8%	5.5%	6.3%	5.8%	6.3%	6.7%	5.5%	5.0%	4.5%	4.3%	3.9%	4.3%	4.1%	4.2%	*estimates*		Avg Ann'l Div'd Yield	**4.6%**

CAPITAL STRUCTURE as of 6/30/09
Total Debt $366.4 mill. **Due in 5 Yrs** $34.6 mill.
LT Debt $272.4 mill. **LT Interest** $12.0 mill.
(LT interest earned: 4.3x)

Leases, Uncapitalized *Annual rentals $2.4 mill.*
Pension Assets-12/08 $103.1 mill.
Obligation $191.8 mill.
Pfd Stock None

Common Stock 23,113,638 shs.
as of 7/31/09
MARKET CAP: $850 million (Small Cap)

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010		12-14
274.0	324.1	333.7	347.1	401.5	424.9	513.4	507.5	537.6	596.0	**575**	**590**	Revenues ($mill)	**645**
23.8	27.4	27.2	29.2	30.6	33.8	32.1	42.4	48.8	52.8	**56.0**	**58.0**	Net Profit ($mill)	**70.0**
36.9%	36.5%	36.9%	39.1%	39.4%	37.9%	38.2%	37.9%	36.3%	35.5%	**36.5%**	**36.5%**	Income Tax Rate	**36.5%**
1.9%	1.9%	2.2%	--	--	--	--	--	2.2%	2.0%	**2.0%**	**2.0%**	AFUDC % to Net Profit	**2.0%**
44.5%	47.8%	42.2%	45.8%	43.5%	37.4%	39.3%	38.7%	35.2%	36.3%	**36.0%**	**35.5%**	Long-Term Debt Ratio	**35.0%**
55.5%	52.2%	57.8%	54.2%	56.5%	62.6%	60.7%	61.3%	64.8%	63.7%	**64.0%**	**64.5%**	Common Equity Ratio	**65.0%**
334.3	383.7	373.9	419.5	465.3	540.5	566.2	612.6	660.1	750.6	**785**	**815**	Total Capital ($mill)	**940**
260.1	342.8	401.2	451.5	537.5	607.4	667.7	728.4	844.0	901.2	**910**	**965**	Net Plant ($mill)	**1000**
8.8%	8.8%	9.0%	8.1%	7.8%	7.1%	6.6%	7.8%	8.1%	7.7%	**8.5%**	**8.5%**	Return on Total Cap'l	**9.0%**
12.8%	13.7%	12.6%	12.8%	11.6%	10.0%	9.3%	11.3%	11.4%	11.0%	**11.5%**	**11.0%**	Return on Shr. Equity	**12.0%**
12.8%	13.7%	12.6%	12.8%	11.6%	10.0%	9.3%	11.3%	11.4%	11.0%	**11.5%**	**11.0%**	Return on Com Equity D	**12.0%**
1.5%	2.9%	2.3%	2.6%	2.5%	2.3%	1.2%	3.7%	4.3%	4.4%	**5.0%**	**4.5%**	Retained to Com Eq	**5.5%**
89%	79%	82%	79%	79%	77%	87%	67%	62%	60%	**59%**	**58%**	All Div'ds to Net Prof	**55%**

ELECTRIC OPERATING STATISTICS

	2006	2007	2008
% Change Retail Sales (KWH)	-0.7	+2.8	-2.8
Avg. Indust. Use (MWH)	2865	2846	2737
Avg. Indust. Revs. per KWH (¢)	6.20	6.20	7.11
Capacity at Peak (Mw)	780	780	NA
Peak Load, Summer (Mw)	NA	NA	772
Annual Load Factor (%)	NA	NA	NA
% Change Customers (avg.)	NA	NA	NA
Fixed Charge Cov. (%)	340	350	350

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '06-'08 to '12-'14
Revenues	4.5%	4.0%	*.5%*
"Cash Flow"	2.0%	2.0%	*.5%*
Earnings	6.5%	6.0%	*6.0%*
Dividends	1.0%	1.0%	*.5%*
Book Value	5.5%	8.0%	*7.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2006	158.6	99.7	110.6	138.6	507.5
2007	167.9	110.6	116.3	142.8	537.6
2008	190.0	124.7	125.8	155.5	596.0
2009	181.1	107.6	***125***	***161.3***	***575***
2010	***183***	***114***	***128***	***165***	***590***

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2006	.56	.34	.62	.54	2.06
2007	.59	.47	.71	.50	2.27
2008	.63	.48	.78	.49	2.38
2009	.65	.43	***.79***	***.51***	***2.40***
2010	***.65***	***.52***	***.80***	***.53***	***2.50***

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2005	.342	.342	.345	.345	1.37
2006	.345	.345	.348	.348	1.39
2007	.348	.348	.355	.355	1.41
2008	.355	.355	.3617	.3617	1.43
2009	.3617	.3617	.3684		

BUSINESS: MGE Energy Inc. is a holding company for Madison Gas and Electric, which provides electric service to approximately 137,000 customers in a 316-square-mile area of Dane County and gas service to 141,000 customers in 1,630 square miles in seven counties in Wisconsin. Electric revenue breakdown, '08: residential, 34%; commercial, 54%; industrial, 6%; public authorities and other, 6%. Generating sources, '08: coal, 52%; purchased power, 39%; natural gas and other, 9%. Fuel costs: 51% of revenues. '07 reported depreciation rate: electric, 3.4%; gas, 3.3%. Has 750 employees. Chairman, President & CEO: Gary J. Wolter. Inc.: Wisconsin. Address: 133 South Blair St., P.O. Box 1231, Madison, WI 53701-1231. Telephone: 608-252-7000. Internet: www.mge.com.

We've shaved a nickel off our 2009 share-net estimate for MGE Energy. Our revised assessment represents a modest increase over the $2.38 per share that the Wisconsin electric and gas utility earned in 2008. A more conservative stance seems prudent, given generally weak power demand, coinciding with lower overall economic activity in the upper Midwest. The company experienced a 3.4% year-over-year decline in electric utility revenue during the second quarter, reflecting both lower direct sales and fewer resale opportunities. Comparatively, electric revenue increased nearly 4% during last year's June period.

MGE is still well positioned for the long haul, thanks to an attractive service area that includes Dane County and the city of Madison. The population of Dane County is expected to grow faster than any other region in Wisconsin over the next two decades or so. Madison, meanwhile, gets high marks for job and GDP growth. The city is home to a major campus in the state university system, which remains a magnet for residential and commercial activity.

MGE remains a good clean-energy investment play. The company is installing a public network of six electric vehicle-charging stations in its service area. The interconnected system is the first of its kind in the United States. MGE also recently agreed to purchase land development rights for two wind generation sites in northeast Iowa. The sites, located near Wellsburg and Hawkeye, could produce up to 175 megawatts of renewable energy. MGE currently boasts 137 mw of wind capacity through wholly owned and partnership facilities.

MGE recently raised its quarterly common stock dividend by 2%, to 36.84 cents, marking the 33rd straight year that the company has raised its payout. We expect MGE to pay out $34 million in dividends this year, more than seven times 1976's $4.7 million total.

MGE shares are ranked 3 (Average) for year-ahead relative price performance. At the current quotation, long-term appreciation potential doesn't stand out, either. However, the stock may appeal to conservative, income-oriented investors.

Nils C. Van Liew *September 25, 2009*

(A) Excl. nonrecurring loss: '96, 42¢. Next earnings report due late Oct. (B) Dividends historically paid in mid-March, June, September, December. ■ Dvd. reinvestment plan available. (C) In millions. (D) Rate allowed on common equity in '08: 12.9%; earned on average common equity, '08: 13.0%. Regulatory Climate: Above Average.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	55
Earnings Predictability	85

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NORTHEAST UTILITIES NYSE-NU

RECENT PRICE **23.55** | P/E RATIO **12.7** (Trailing: 11.8 / Median: 19.0) | RELATIVE P/E RATIO **0.80** | DIV'D YLD **4.2%** | VALUE LINE

TIMELINESS 3 Lowered 5/29/09

SAFETY 3 Raised 9/6/02

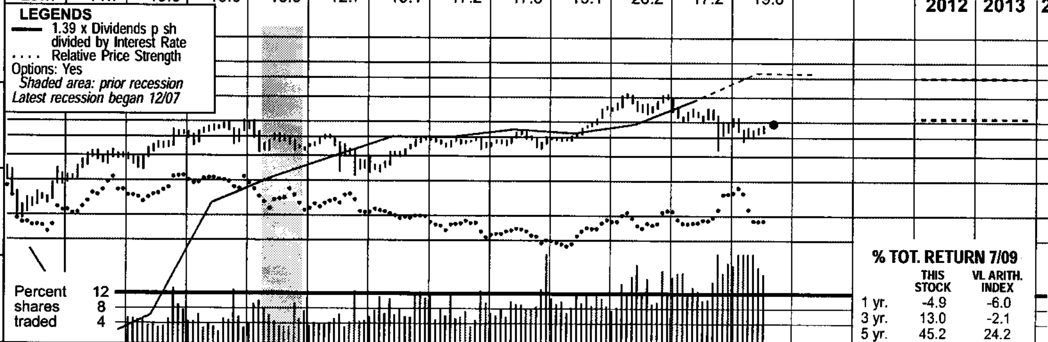
TECHNICAL 3 Raised 7/17/09

BETA .70 (1.00 = Market)

	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
High:	17.3	22.0	24.6	24.3	20.7	20.3	20.3	22.0	28.9	33.6	31.6
Low:	11.7	13.6	18.0	16.6	12.7	13.1	17.2	17.3	19.1	26.2	17.2

High:	25.3
Low:	19.0

Target Price Range 2012 | 2013 | 2014



2012-14 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	40	(+70%)	17%
Low	25	(+5%)	5%

Insider Decisions

	O	N	D	J	F	M	A	M	J
to Buy	0	0	0	0	0	0	0	0	0
Options	0	3	0	0	0	0	0	0	0
to Sell	0	3	0	0	0	0	0	0	0

Institutional Decisions

	3Q2008	4Q2008	1Q2009
to Buy	109	124	178
to Sell	112	97	91
Hld's(000)	114850	113282	135401

% TOT. RETURN 7/09

	THIS STOCK	VL ARITH. INDEX
1 yr.	-4.9	-6.0
3 yr.	13.0	-2.1
5 yr.	45.2	24.2

1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	© VALUE LINE PUB., INC.	12-14
29.19	29.15	29.51	29.52	29.46	28.77	33.91	40.86	52.82	40.89	47.53	51.82	41.85	44.64	37.27	37.22	*32.40*	*34.65*	Revenues per sh	*33.25*
5.86	6.26	6.02	3.77	2.68	3.73	5.68	3.39	10.48	6.32	5.80	5.00	5.46	3.69	4.82	6.16	*5.15*	*5.50*	"Cash Flow" per sh	*5.75*
1.60	2.30	2.24	.01	d1.05	d.36	d1.14	d.20	1.37	1.08	1.24	.91	.98	.82	1.59	1.86	*1.85*	*1.95*	Earnings per sh A	*2.25*
1.76	1.76	1.76	1.38	.25	--	.10	.40	.45	.53	.58	.63	.68	.73	.78	.83	*.95*	*1.00*	Div'd Decl'd per sh B ■	*1.15*
2.49	2.31	1.97	1.85	1.85	1.79	2.50	2.88	3.40	3.86	4.31	4.85	5.89	5.49	7.14	8.06	*5.35*	*7.25*	Cap'l Spending per sh	*5.75*
17.89	18.48	19.08	17.73	16.34	15.63	15.80	15.43	16.27	17.33	17.73	17.80	18.46	18.14	18.65	19.38	*20.25*	*21.25*	Book Value per sh C	*25.00*
124.33	124.96	127.05	128.44	130.18	130.95	131.87	143.82	130.13	127.56	127.70	129.03	131.59	154.23	156.22	155.83	*176.00*	*176.00*	Common Shs Outst'g D	*210.00*
16.6	10.0	10.3	NMF	--	--	--	--	14.1	16.1	13.4	20.8	19.8	27.1	18.7	13.7	*Bold figures are*		Avg Ann'l P/E Ratio	*14.5*
.98	.66	.69	NMF	--	--	--	--	.72	.88	.76	1.10	1.05	1.46	.99	.82	*Value Line*		Relative P/E Ratio	*.95*
6.6%	7.7%	7.6%	8.9%	2.4%	--	.6%	1.9%	2.3%	3.0%	3.5%	3.3%	3.5%	3.3%	2.6%	3.2%	*estimates*		Avg Ann'l Div'd Yield	*3.5%*

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010		12-14
4471.3	5876.6	6873.8	5216.3	6069.2	6686.7	5507.3	6884.4	5822.2	5800.1	*5700*	*6100*	Revenues ($mill)	*7000*
d127.0	d14.4	186.4	144.2	162.7	122.1	128.5	126.2	251.5	296.2	*320*	*350*	Net Profit ($mill)	*455*
--	--	--	--	32.1%	29.8%	30.8%	--	30.3%	29.7%	*34.0%*	*30.0%*	Income Tax Rate	*30.0%*
--	--	--	9.2%	7.1%	6.8%	17.4%	21.5%	13.9%	15.8%	*9.0%*	*14.0%*	AFUDC % to Net Profit	*14.0%*
49.9%	45.7%	65.9%	64.3%	63.9%	64.2%	63.2%	58.7%	59.2%	60.4%	*59.0%*	*59.0%*	Long-Term Debt Ratio	*55.0%*
42.7%	48.8%	32.4%	33.9%	34.3%	34.0%	35.1%	39.7%	39.2%	38.1%	*40.0%*	*39.5%*	Common Equity Ratio	*44.0%*
4876.0	4546.6	6544.7	6513.2	6591.6	6749.4	6923.2	7052.0	7431.1	7926.2	*8930*	*9445*	Total Capital ($mill)	*11925*
3947.4	3547.2	3822.1	4728.4	5429.9	5864.2	6417.2	6242.2	7229.9	8207.9	*8710*	*9510*	Net Plant ($mill)	*12575*
--	1.9%	4.6%	4.1%	4.2%	2.8%	3.5%	2.9%	5.0%	5.4%	*5.0%*	*5.5%*	Return on Total Cap'l	*5.5%*
NMF	NMF	8.3%	6.2%	6.8%	5.1%	5.0%	4.3%	8.3%	9.4%	*8.5%*	*9.0%*	Return on Shr. Equity	*8.5%*
NMF	NMF	8.5%	6.3%	6.9%	5.1%	5.1%	4.3%	8.4%	9.6%	*9.0%*	*9.5%*	Return on Com Equity E	*8.5%*
NMF	NMF	5.6%	3.2%	3.7%	1.6%	1.5%	.3%	4.3%	5.3%	*4.5%*	*4.5%*	Retained to Com Eq	*4.0%*
NMF	NMF	37%	51%	48%	70%	72%	94%	50%	45%	*51%*	*52%*	All Div'ds to Net Prof	*53%*

CAPITAL STRUCTURE as of 6/30/09
Total Debt $5536.0 mill. **Due in 5 Yrs** $1129.2 mill.
LT Debt $4909.4 mill. **LT Interest** $294.6 mill.
Incl. $566.2 mill. of rate reduction bonds.
(LT interest earned: 2.3x)
Leases, Uncapitalized Annual rentals $24.6 mill.

Pension Assets-12/08 $1.56 bill. **Oblig.** $2.30 bill.
Pfd Stock $116.2 mill. **Pfd Div'd** $5.6 mill.
Incl. 2,324,000 shs $1.90-$3.28 rates ($50 par) not subject to mandatory redemption.
Common Stock 175,281,532 shs.
as of 7/31/09
MARKET CAP: $4.1 billion (Mid Cap)

ELECTRIC OPERATING STATISTICS

	2006	2007	2008
% Change Retail Sales (KWH)	-4.1	+1.5	-3.5
Avg. Indust. Use (MWH)	776	772	NA
Avg. Indust. Revs. per KWH (¢)	7.76	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Winter (Mw)	NA	NA	NA
Capacity Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.2	+.5	NA
Fixed Charge Cov. (%)	NMF	201	215

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '06-'08 to '12-'14
Revenues	3.0%	-3.5%	*-3.0%*
"Cash Flow"	3.5%	-8.5%	*2.5%*
Earnings	--	3.0%	*8.0%*
Dividends	3.5%	8.5%	*6.5%*
Book Value	1.0%	2.0%	*5.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2006	2147	1661	1593	1483	6884.4
2007	1703	1391	1451	1276	5822.2
2008	1520	1325	1506	1447	5800.1
2009	1593	1224	*1433*	*1450*	*5700*
2010	*1600*	*1400*	*1600*	*1500*	*6100*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2006	d.13	.09	.67	.19	.82
2007	.49	.30	.32	.47	1.59
2008	.57	.37	.47	.46	1.86
2009	.60	.47	*.38*	*.40*	*1.85*
2010	*.60*	*.40*	*.48*	*.47*	*1.95*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2005	.1625	.1625	.175	.175	.68
2006	.175	.175	.1875	.1875	.73
2007	.1875	.1875	.20	.20	.78
2008	.20	.20	.2125	.2125	.83
2009	.2375	.2375			

BUSINESS: Northeast Utilities is the parent of the NU system, which is the largest utility in New England and serves 1.9 million electric and 200,000 gas customers. Connecticut Light & Power (CL&P) provides service to most of CT; Public Service Co. of New Hampshire (PSNH) supplies power to three quarters of NH's population; Western Massachusetts Electric Co. (WMECO) serves the western half of MA. Acq'd Yankee Energy 3/00. Electric rev. breakdown, '08: res'l, 55%; comm'l, 35%; ind'l, 9%; other, 1%. Generating sources not available. Fuel costs: 52% of revs. '08 reported depr. rate: 3.0%. Has 6,200 employees. Chairman, President & CEO: Charles W. Shivery. Inc.: CT. Address: P.O. Box 270, Hartford, CT 06141-0270. Tel.: 800-999-7269. Internet: www.nu.com.

Northeast Utilities' distribution operations are underearning their allowed returns on equity. This situation has persisted for several quarters, but has worsened of late due to declining electric sales, rising operating and maintenance expense, and higher bad-debt expense. For the 12-month period that ended June 30th, the earned ROEs for Connecticut Light & Power, Public Service of New Hampshire, Western Massachusetts Electric, and Yankee Gas were 7.7%, 5%, 7.7%, and 8.1%, respectively. Except for PSNH, these figures are likely to decline by yearend.

Rate cases at each electric utility are pending or upcoming. PSNH filed a request for permanent rate increases of $51 million, based on a 10.5% ROE, effective August 1, 2009 and an additional $17 million effective July 1, 2010. The commission granted the utility a temporary rate hike of $25.6 million that took effect on August 1st. (The final rate order will be retroactive to this date.) CL&P expects to file a rate application in late 2009 or early 2010, and WMECO plans to file one in mid-2010.

The second half of 2009 isn't likely to be as good as the first half. Thus, we expect earnings for the full year to be flattish, despite favorable first-half comparisons. Our estimate of $1.85 a share is at the midpoint of NU's targeted range of $1.80-$1.90. We expect profit growth, to $1.95 a share, in 2010, based on the benefits of rate relief at PSNH and the effects of a better economy on electric sales.

NU's transmission business is faring well. The company is earning an ROE of around 13% on its transmission rate base. NU is requesting siting approval to build three projects in New England at a cost of $1.46 billion from 2009 through 2013. It also has a 75% stake in a joint venture to build a transmission line to Quebec. The federal regulators have approved this project, but other approvals are needed before NU and its partner can begin building the $700 million-$800 million line.

By utility standards, this stock's yield is somewhat below average. Over the 3- to 5-year period, transmission investments should enhance NU's earning power, and dividend growth should be good. The subpar regulatory climate in Connecticut is worrisome, however.

Paul E. Debbas, CFA *August 28, 2009*

(A) Diluted EPS. Excl. nonrec. gains (losses): '99, $1.40; '01, 42¢; '02, 10¢; '03, (32¢); '04, (7¢); '05, ($1.36); '08, (19¢). '07, '08 EPS don't add due to rounding. Next egs. report due early Nov. (B) Div'd susp. 2Q '97; reinstated 4Q '99. Div'ds historically paid late Mar., June, Sept. & Dec. ■ Div'd reinv. plan avail. (C) Incl. def'd chgs. In '08: $24.32/sh. (D) In mill. (E) Rate all'd on com. eq. in MA: '99, 11%; in CT: (elec.) '08, 9.40% (gas) '07, 10.1%; in NH: '97, 11%; earned on avg. com. eq., '08: 9.7%. Regulatory Climate: CT, NH, Below Avg.; MA, Above Avg.

Company's Financial Strength	B+
Stock's Price Stability	100
Price Growth Persistence	45
Earnings Predictability	50

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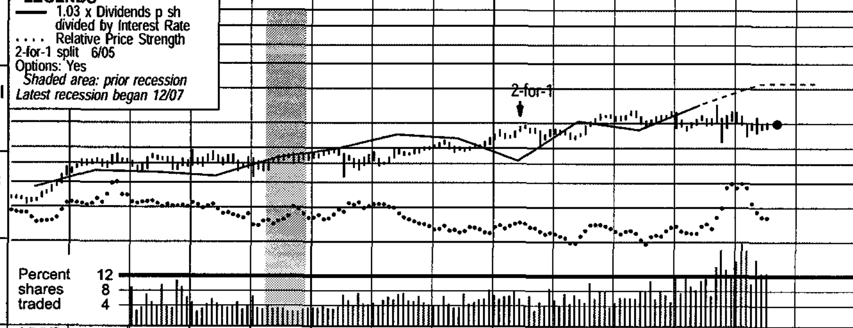
NSTAR NYSE-NST

RECENT PRICE	31.97	P/E RATIO	13.4 (Trailing: 14.0 / Median: 14.0)	RELATIVE P/E RATIO	0.84	DIV'D YLD	4.9%	VALUE LINE

TIMELINESS 3 Lowered 6/19/09
SAFETY 1 Raised 6/11/99
TECHNICAL 4 Lowered 8/14/09
BETA .65 (1.00 = Market)

	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
High:	22.5	22.3	23.5	22.6	24.1	24.5	27.2	31.5	35.9	37.4	40.0	36.8
Low:	17.5	18.2	18.2	17.0	17.0	19.3	22.7	24.9	26.5	30.8	25.7	27.5

LEGENDS
— 1.03 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
2-for-1 split 6/05
Options: Yes
Shaded area: prior recession
Latest recession began 12/07



Target Price Range

2012	2013	2014

2012-14 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	50	(+55%)	*16%*
Low	40	(+25%)	*10%*

Insider Decisions

	O	N	D	J	F	M	A	M	J
to Buy	0	0	0	0	0	0	0	0	0
Options	0	1	3	1	1	0	0	0	0
to Sell	0	3	3	3	2	0	0	1	0

Institutional Decisions

	3Q2008	4Q2008	1Q2009
to Buy	91	117	133
to Sell	100	101	96
Hld's(000)	48045	50208	52014

% TOT. RETURN 7/09

	THIS STOCK	VL ARITH. INDEX
1 yr.	5.5	-6.0
3 yr.	16.7	-2.1
5 yr.	69.1	24.2

1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	© VALUE LINE PUB., INC.	12-14
16.42	17.00	16.96	17.17	18.31	17.19	15.94	25.45	30.09	25.64	27.48	27.73	30.36	33.50	30.54	31.32	*30.90*	*33.00*	Revenues per sh	*40.00*
2.98	3.35	3.11	3.65	3.66	3.84	3.04	3.78	3.81	3.95	3.98	4.09	5.00	5.34	5.55	5.84	*6.00*	*6.30*	"Cash Flow" per sh	*7.25*
1.14	1.21	1.04	1.31	1.36	1.38	1.39	1.60	1.64	1.69	1.74	1.76	1.83	1.93	2.07	2.22	*2.35*	*2.55*	Earnings per sh A	*3.25*
.86	.89	.92	.94	.94	.95	.98	1.01	1.04	1.07	1.09	1.13	.87	1.54	1.33	1.43	*1.53*	*1.63*	Div'd Decl'd per sh B ■	*1.95*
2.81	2.42	2.08	2.13	1.23	1.57	1.53	1.78	2.22	3.50	2.94	2.95	3.63	3.99	3.37	3.95	*3.40*	*3.30*	Cap'l Spending per sh	*2.75*
9.71	10.06	10.31	10.54	10.98	11.14	13.29	12.65	11.90	12.25	12.84	13.52	14.37	14.82	15.95	16.74	*17.60*	*18.55*	Book Value per sh C	*22.00*
90.26	91.07	96.01	97.02	97.03	94.37	116.12	106.07	106.07	106.07	106.07	106.55	106.81	106.81	106.81	106.81	*106.81*	*106.81*	Common Shs Outst'g D	*106.81*
13.1	10.7	12.3	9.7	10.6	14.6	14.6	12.9	12.7	12.7	12.8	14.0	15.5	15.9	16.6	14.8	*Bold figures are*		Avg Ann'l P/E Ratio	*14.0*
.77	.70	.82	.61	.61	.76	.83	.84	.65	.69	.73	.74	.83	.86	.88	.89	*Value Line*		Relative P/E Ratio	*.95*
5.8%	6.9%	7.2%	7.4%	6.5%	4.7%	4.8%	4.9%	5.0%	4.9%	4.9%	4.6%	3.1%	5.0%	3.9%	4.3%	*estimates*		Avg Ann'l Div'd Yield	*4.3%*

CAPITAL STRUCTURE as of 6/30/09
Total Debt $2964.5 mill. **Due in 5 Yrs** $1977.5 mill.
LT Debt $1741.3 mill. **LT Interest** $104.5 mill.
Incl. $252.9 mill. securitized bonds.
(LT interest earned: 3.5x)
Leases, Uncapitalized Annual rentals $17.1 mill.
Pension Assets-12/08 $716.7 mill. **Oblig.** $1.07 bill.
Pfd Stock $43.0 mill. **Pfd Div'd** $2.0 mill.
430,000 shs. 4.25%-4.78%, cumulative, redeemable at $102.80-$103.625.
Common Stock 106,808,376 shs. **as of 7/31/09**
MARKET CAP: $3.4 billion (Mid Cap)

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010		12-14
1851.4	2699.5	3191.8	2719.1	2914.1	2954.3	3243.1	3577.7	3261.8	3345.4	*3300*	*3525*	Revenues ($mill)	*4275*
146.5	181.0	179.1	181.3	188.0	190.4	198.1	208.7	223.5	239.5	*255*	*275*	Net Profit ($mill)	*345*
29.1%	41.6%	41.4%	35.8%	37.5%	38.5%	35.6%	37.8%	37.4%	38.1%	*38.0%*	*38.0%*	Income Tax Rate	*38.0%*
1.5%	2.5%	2.8%	1.6%	2.4%	.5%	1.9%	3.3%	1.7%	.8%	*Nil*	*Nil*	AFUDC % to Net Profit	*1.0%*
50.0%	59.4%	59.2%	60.9%	58.5%	58.6%	60.4%	59.2%	58.9%	56.1%	*46.5%*	*50.0%*	Long-Term Debt Ratio	*45.0%*
47.2%	39.4%	39.5%	37.8%	40.2%	40.2%	38.6%	39.7%	40.1%	42.8%	*52.5%*	*49.0%*	Common Equity Ratio	*54.0%*
3269.3	3409.8	3197.4	3433.7	3387.1	3585.3	3980.4	3986.3	4248.2	4174.8	*3585*	*4045*	Total Capital ($mill)	*4375*
2550.6	2523.6	2625.4	2847.6	3216.1	3425.0	3701.8	3945.3	4142.3	4398.4	*4525*	*4625*	Net Plant ($mill)	*4725*
6.1%	7.6%	8.1%	7.5%	7.8%	7.4%	7.1%	7.3%	7.1%	7.7%	*9.0%*	*8.0%*	Return on Total Cap'l	*9.5%*
9.0%	13.1%	13.7%	13.5%	13.4%	12.8%	12.6%	12.8%	12.8%	13.1%	*13.0%*	*13.5%*	Return on Shr. Equity	*14.5%*
9.1%	13.0%	13.7%	13.8%	13.7%	13.1%	12.8%	13.1%	13.0%	13.3%	*13.5%*	*14.0%*	Return on Com Equity E	*14.5%*
2.4%	4.8%	5.0%	5.2%	5.1%	4.8%	4.6%	4.9%	4.9%	4.9%	*5.0%*	*5.0%*	Retained to Com Eq	*6.0%*
74%	64%	65%	63%	63%	64%	64%	63%	63%	63%	*65%*	*63%*	All Div'ds to Net Prof	*61%*

ELECTRIC OPERATING STATISTICS

	2006	2007	2008
% Change Retail Sales (KWH)	-1.9	+1.8	- -
Avg. Indust. Use (MWH)	1001	983	982
Avg. Indust. Revs. per KWH (¢)	8.40	6.80	7.40
Capacity at Peak (Mw)	NMF	NMF	NA
Peak Load, Summer (Mw)	4959	4555	4562
Annual Load Factor (%)	NMF	NMF	NA
% Change Customers (avg.)	+1.5	+.7	+.4
Fixed Charge Cov. (%)	262	294	296

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '06-'08 to '12-'14
Revenues	6.0%	3.0%	*4.0%*
"Cash Flow"	4.0%	7.5%	*4.5%*
Earnings	4.5%	4.0%	*8.0%*
Dividends	4.0%	6.0%	*5.5%*
Book Value	4.0%	5.0%	*5.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2006	1034.8	784.6	956.3	802.0	3577.7
2007	984.4	725.1	804.9	747.4	3261.8
2008	895.6	743.7	892.2	813.9	3345.4
2009	947.8	707.5	*850*	*794.7*	*3300*
2010	*975*	*775*	*925*	*850*	*3525*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2006	.41	.43	.72	.38	1.93
2007	.45	.47	.79	.37	2.07
2008	.55	.47	.80	.39	2.22
2009	.57	.53	*.82*	*.43*	*2.35*
2010	*.60*	*.60*	*.90*	*.45*	*2.55*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2005	.29	.29	.29	.29	1.16
2006	.3025	.3025	.3025	.3025	1.21
2007	.325	.325	.325	.325	1.30
2008	.35	.35	.35	.35	1.40
2009	.375	.375	.375		

BUSINESS: NSTAR is a holding company for NSTAR Electric, *which distributes electricity to an area of 1,702 sq. mi. in eastern* Massachusetts, incl. Boston and 80 surrounding towns and cities, and NSTAR Gas, which distributes gas to an area of 1,067 sq. mi. in 51 communities in central and eastern Massachusetts. Acq'd Commonwealth Energy 8/99. Serves 1.1 mill. electric, 300,000 gas customers. Electric rev. breakdown, '08: residential, 42%; commercial, 53%; industrial, 5%; other, less than 1%. Sold fossil plants in '98, nuclear plant in '99. Fuel costs: 54% of revs. '08 reported deprec. rate: 3.0%. Has 3,250 employees. Chairman, Pres. & CEO: Thomas J. May. Inc.: MA. Address: 800 Boylston St., Boston, MA 02199-8003. Tel.: 617-424-2000. Internet: www.nstar.com.

We have trimmed our 2009 earnings estimate for NSTAR by a nickel a share, to $2.35. Second-quarter profits fell slightly short of our $0.55-a-share estimate due to milder-than-usual weather conditions. The utility's service territory experienced one of the coolest Junes on record. With the mild summer weather continuing as the third quarter began, we decided to lower our third-quarter estimate as well. Our full-year forecast of $2.35 a share is still within NSTAR's targeted range of $2.33-$2.43 and would produce a healthy 6% earnings increase from the 2008 tally.

Earnings should advance steadily through 2012, thanks to a regulatory agreement that provides for annual base rate increases. (Another good feature of the regulatory plan is an allowed return on equity of 12.5%.) Investment in NSTAR's transmission system is also increasing the company's earning power. And the utility is controlling its operating and maintenance costs effectively. We're sticking with our 2010 share-net estimate of $2.55, which is based on a return to normal weather patterns. This would produce earnings growth at the high end of NSTAR's targeted annual range of 6%-8%. The company has an identical goal for annual dividend growth. It has achieved this objective in recent years — the decline shown in the statistical array for 2005 was merely due to the shift of a dividend declaration from the fourth quarter of 2005 to the first period of 2006.

NSTAR and its partner, Northeast Utilities, received a favorable ruling from the Federal Energy Regulatory Commission on the companies' plan to build a transmission line to Quebec. Other approvals will be needed before the companies can break ground, probably in 2011. NSTAR's 25% stake in the project would amount to as much as $200 million. Each of these companies has fared well in recent years when developing transmission projects in New England.

This high-quality stock is an average utility selection. NSTAR is a financially sound company with a good track record of earnings and dividend growth, but these strong points are already reflected in the share price.

Paul E. Debbas, CFA *August 28, 2009*

(A) Diluted EPS. Excl. nonrecurring losses: '01, $1.66 net; '02, 17¢; '03, 4¢. '06, '07 & '08 EPS don't add to full-year total due to rounding. Next earnings report due late Oct. (B) Div'ds historically paid in early Feb., May, Aug., and Nov. There were only 3 div'd declarations in '05, 5 in '06. ■ Div'd reinvestment plan available. (C) Incl. intangibles. In '08: $2.5 bill., $23.69/sh. (D) In mill., adj. for split. (E) Rate base: Net original cost. Rate allowed on com. eq. in '06: 12.5%; earned on avg. com. eq., '08: 13.5%. Regulatory Climate: Above Average.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	75
Earnings Predictability	100

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OTTER TAIL CORP. NDQ-OTTR

RECENT PRICE 24.54 | P/E RATIO 25.0 (Trailing: 27.6 / Median: 17.0) | RELATIVE P/E RATIO 1.45 | DIV'D YLD 4.9% | VALUE LINE

TIMELINESS 4 Lowered 11/14/08
SAFETY 2 New 7/27/90
TECHNICAL 3 Lowered 9/25/09
BETA .90 (1.00 = Market)

	High:	Low:
1998	21.4	15.1
1999	22.8	17.0
2000	29.0	17.8
2001	31.0	23.0
2002	34.9	22.8
2003	28.9	23.8
2004	27.5	23.8
2005	32.0	24.0
2006	31.9	25.8
2007	39.4	29.0
2008	46.2	15.0
2009	25.2	15.5

2012-14 PROJECTIONS

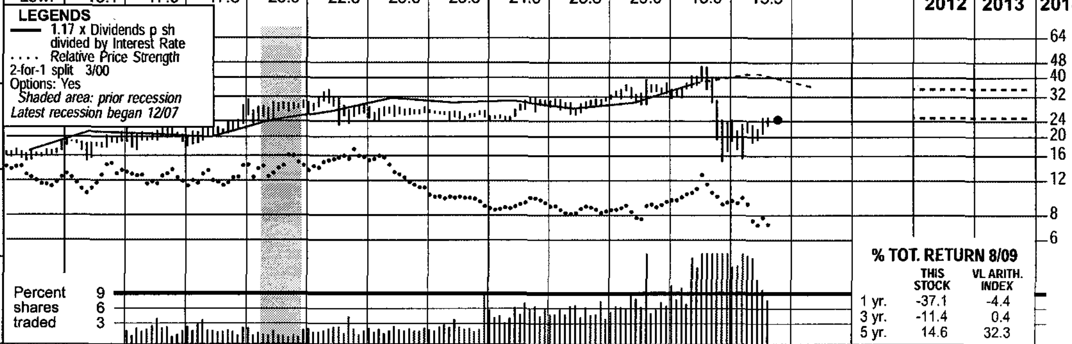
	Price	Gain	Ann'l Total Return
High	35	(+45%)	12%
Low	25	(Nil)	5%

Insider Decisions

	O	N	D	J	F	M	A	M	J
to Buy	0	0	0	0	0	2	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	1	0	0	1	0	0	0

Institutional Decisions

	4Q2008	1Q2009	2Q2009
to Buy	70	61	54
to Sell	48	43	41
Hld's(000)	16809	16765	16375



% TOT. RETURN 8/09

	THIS STOCK	VL ARITH. INDEX
1 yr.	-37.1	-4.4
3 yr.	-11.4	0.4
5 yr.	14.6	32.3

1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	© VALUE LINE PUB., INC.	12-14
11.86	12.86	14.70	16.13	16.80	18.14	19.48	23.45	26.53	27.75	29.28	30.45	35.59	37.43	41.50	37.06	32.20	35.15	Revenues per sh	40.00
2.25	2.33	2.47	2.78	2.95	2.75	2.91	3.21	3.40	3.44	3.30	2.88	3.35	3.39	3.55	2.81	2.85	3.25	"Cash Flow" per sh	4.40
1.12	1.17	1.19	1.24	1.29	1.29	1.45	1.60	1.68	1.79	1.51	1.50	1.78	1.69	1.78	1.09	.90	1.20	Earnings per sh A	1.90
.84	.86	.88	.90	.93	.96	.99	1.02	1.04	1.06	1.08	1.10	1.12	1.15	1.17	1.19	1.19	1.22	Div'd Decl'd per sh B ■	1.30
1.38	1.36	1.66	2.85	1.79	1.23	1.37	1.85	2.17	2.95	1.97	1.72	2.04	2.35	5.43	7.51	3.35	4.05	Cap'l Spending per sh	5.75
7.62	7.90	8.24	8.61	8.96	9.47	10.30	10.87	11.33	12.25	12.98	14.81	15.80	16.67	17.55	19.14	19.45	20.25	Book Value per sh C	22.50
22.36	22.36	22.36	22.43	23.46	23.76	23.85	23.85	24.65	25.59	25.72	28.98	29.40	29.52	29.85	35.38	36.00	37.00	Common Shs Outst'g D	40.00
15.6	13.8	14.2	14.0	12.8	14.4	13.9	13.5	16.4	16.0	17.8	17.3	15.4	17.3	19.0	30.1	Bold figures are		Avg Ann'l P/E Ratio	15.0
.92	.91	.95	.88	.74	.75	.79	.88	.84	.87	1.01	.91	.82	.93	1.01	1.84	Value Line		Relative P/E Ratio	1.00
4.8%	5.3%	5.2%	5.2%	5.6%	5.2%	4.9%	4.7%	3.8%	3.7%	4.0%	4.2%	4.1%	3.9%	3.5%	3.6%	estimates		Avg Ann'l Div'd Yield	4.6%

CAPITAL STRUCTURE as of 6/30/09
Total Debt $533.0 mill. **Due in 5 Yrs** $246.0 mill.
LT Debt $411.8 mill. **LT Interest** $20.0 mill.
(LT interest earned: 2.9x)

Leases, Uncapitalized Annual rentals $46 mill.
Pension Assets-12/08 $127.5 mill. **Oblig.** $182.6 mill.
Pfd Stock $15.5 mill. **Pfd Div'd** $.7 mill.
155,000 shs. $3.60-$6.75, cum., no par ($100 liquidating value).
Common Stock 35,611,789 shs.
as of 7/31/09
MARKET CAP: $875 million (Small Cap)

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010		12-14
464.6	559.4	654.1	710.1	753.2	882.3	1046.4	1105.0	1238.9	1311.2	1160	1300	Revenues ($mill)	1600
36.9	40.2	43.6	46.1	39.7	40.0	52.9	50.8	54.0	35.1	32.0	45.0	Net Profit ($mill)	75.0
32.2%	30.3%	31.5%	30.3%	27.4%	29.8%	34.6%	34.8%	34.1%	30.0%	30.0%	30.0%	Income Tax Rate	30.0%
.7%	.8%	3.1%	5.7%	5.0%	2.4%	1.7%	1.9%	4.2%	6.1%	6.0%	8.0%	AFUDC % to Net Profit	8.0%
38.7%	39.5%	43.5%	44.0%	43.2%	37.1%	35.0%	33.5%	38.9%	32.9%	36.0%	32.0%	Long-Term Debt Ratio	31.0%
53.9%	53.5%	53.5%	53.4%	54.3%	60.7%	62.9%	64.5%	59.4%	65.6%	63.0%	67.0%	Common Equity Ratio	68.0%
455.6	484.4	522.2	587.2	614.6	706.5	738.2	763.0	882.1	1032.5	1110	1125	Total Capital ($mill)	1310
503.0	515.9	543.0	587.9	633.3	682.1	697.1	718.6	854.0	1037.6	1100	1200	Net Plant ($mill)	1500
9.7%	9.6%	9.3%	9.0%	7.8%	6.8%	8.3%	7.7%	7.2%	4.3%	3.5%	5.0%	Return on Total Cap'l	6.5%
13.2%	13.7%	14.8%	14.0%	11.4%	9.0%	11.0%	10.0%	10.0%	5.1%	4.5%	6.0%	Return on Shr. Equity	8.5%
14.1%	14.8%	14.9%	14.5%	11.7%	9.1%	11.2%	10.2%	10.2%	5.1%	4.5%	6.0%	Return on Com Equity E	8.5%
4.5%	5.4%	5.8%	6.0%	3.2%	2.5%	4.2%	3.3%	3.5%	NMF	NMF	NMF	Retained to Com Eq	2.5%
70%	65%	63%	60%	73%	73%	63%	68%	66%	108%	136%	102%	All Div'ds to Net Prof	70%

ELECTRIC OPERATING STATISTICS

	2006	2007	2008
% Change Retail Sales (KWH)	+2.5	+3.3	+3.0
Avg. Indust. Use (MWH)	30169	31458	32402
Avg. Indust. Revs. per KWH (¢)	5.04	5.20	5.15
Capacity at Peak (Mw)	711	NA	NA
Peak Load, Winter (Mw)	690	705	773
Annual Load Factor (%)	66.2	NA	NA
% Change Customers (yr-end)	+.5	+.2	NA
Fixed Charge Cov. (%)	446	410	257

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '06-'08 to '12-'14
Revenues	8.5%	7.0%	.5%
"Cash Flow"	1.5%	-1.0%	5.0%
Earnings	2.0%	-1.5%	4.0%
Dividends	2.5%	2.0%	2.0%
Book Value	7.0%	8.0%	4.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2006	257.8	279.9	280.6	286.7	1105.0
2007	301.1	305.9	302.2	329.7	1238.9
2008	300.2	323.6	352.9	334.5	1311.2
2009	277.2	246.9	325	310.9	1160
2010	300	310	340	350	1300

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2006	.50	.37	.45	.37	1.69
2007	.34	.53	.44	.47	1.78
2008	.27	.12	.31	.39	1.09
2009	.12	.07	.30	.41	.90
2010	.20	.20	.35	.45	1.20

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2005	.28	.28	.28	.28	1.12
2006	.288	.288	.288	.288	1.15
2007	.293	.293	.293	.293	1.17
2008	.298	.298	.298	.298	1.19
2009	.298	.298	.298		

BUSINESS: Otter Tail Corporation is the parent of Otter Tail Power Company, which supplies electricity to over 129,000 customers in a mainly rural area in Minnesota (50% of retail elec. revs.), North Dakota (41%), and South Dakota (9%). Electric revenue breakdown, '08: residential, 31%; commercial & farms, 36%; industrial, 23%; other, 10%. Fuel costs: 10% of revenues. Has operations in manufacturing, plastics, health services, food ingredients, & others. 2008 reported depreciation rate: 4.3%. Has 4,166 employees. Chairman: John MacFarlane. President & Chief Executive Officer: John D. Erickson. Incorporated: Minnesota. Address: 215 South Cascade St., P.O. Box 496, Fergus Falls, Minnesota 56538-0496. Telephone: 800-664-1259. Internet: www.ottertail.com.

Otter Tail Corporation reported unfavorable results for the second quarter. The company has been operating in a challenging environment in recent periods. Although the retail business benefited from some improvement on the residential front, OTTR continued to experience weakness in the wholesale power market. Meanwhile, the nonelectric businesses have experienced lower orders from major customers, owing to weakness in the broader economy. Looking forward, higher rates and efforts to control expenses should benefit the company. Still, challenges might well persist in the near term. For full-year 2009, the company has lowered its share earnings guidance to $0.70-$1.10. We concur, and have adjusted our estimate at the midpoint. Performance might improve in 2010, assuming a more-favorable operating climate.

The South Dakota Public Utilities Commission granted the company a rate increase of $2.9 million (roughly 11.7%). The approved rates were implemented in July of 2009. Elsewhere, Otter Tail has requested a revenue increase of $6.1 million (5.1%) in North Dakota. It has been granted an interim annual increase of $4.8 million (4.1%) from January onward. A tentative settlement was filed in June. Regulatory authorities have scheduled a hearing for September 28th to consider the settlement. The company's focus on procuring rate relief is important, as it depends upon such approved revenue increases to help it cope with greater costs.

Otter Tail has completed the transition to a holding company structure, effective July 1, 2009. As part of the arrangement, Otter Tail Corporation now functions as a holding company with two main subsidiaries, Otter Tail Power Company and Varistar Corporation, which operates the nonelectric businesses. This new legal structure should be well-received by the regulatory community, and allow for better execution of debt transactions at Otter Tail Power Company.

This stock is unfavorably ranked for year-ahead performance. Looking further out, we expect increased share net by 2012-2014. From the present quotation, this issue offers decent long-term total return potential, on a risk-adjusted basis.

Michael Napoli, CPA *September 25, 2009*

(A) Diluted earnings. Excl. nonrecurring gains: '98, 7¢; '99, 34¢; gains from discont. operations: '04, 8¢; '05, 33¢; '06, 1¢. Next earnings report due early November. (B) Div'ds historically paid in early March, June, Sept., and Dec. ■ Div'd reinvestment plan avail. (C) Incl. intangibles. In '08: $4.02/sh. (D) In mill., adj. for split. (E) Regulatory Climate: MN, ND, Average; SD, Above Average.

Company's Financial Strength	A
Stock's Price Stability	75
Price Growth Persistence	40
Earnings Predictability	70

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UIL HOLDINGS NYSE-UIL

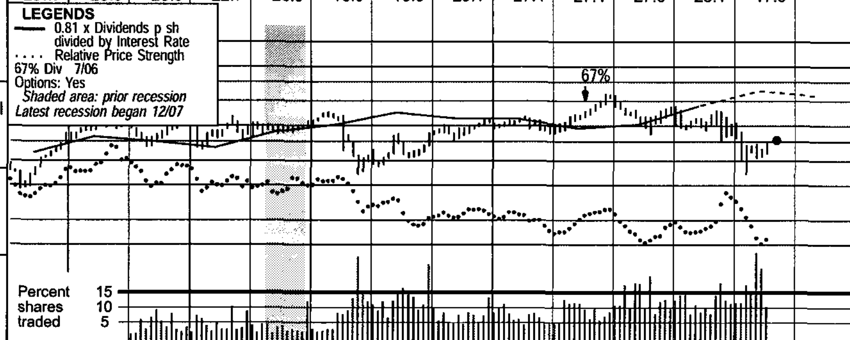
RECENT PRICE	25.52	P/E RATIO	13.6 (Trailing: 11.8; Median: 17.0)	RELATIVE P/E RATIO	0.86	DIV'D YLD	6.8%	VALUE LINE

TIMELINESS 3 Raised 11/16/07
SAFETY 2 Raised 2/29/08
TECHNICAL 5 Lowered 8/7/09
BETA .70 (1.00 = Market)

High:	32.5	32.2	33.6	31.8	35.3	27.6	32.8	33.7	43.8	43.0	37.8	31.2
Low:	25.0	23.3	22.7	26.3	16.9	18.5	25.1	27.4	27.4	27.0	25.1	17.0

Target Price Range 2012 | 2013 | 2014

LEGENDS
— 0.81 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
67% Div 7/06
Options: Yes
Shaded area: prior recession
Latest recession began 12/07



2012-14 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	35	(+35%)	13%
Low	25	(Nil)	6%

Insider Decisions

	O	N	D	J	F	M	A	M	J
to Buy	0	1	0	0	2	1	0	0	0
Options	0	1	0	0	0	0	0	0	0
to Sell	0	1	0	0	1	0	0	0	0

Institutional Decisions

	3Q2008	4Q2008	1Q2009
to Buy	60	68	55
to Sell	41	43	53
Hld's(000)	12931	11775	11952

% TOT. RETURN 7/09

	THIS STOCK	VL ARITH. INDEX
1 yr.	-16.3	-6.0
3 yr.	-16.9	-2.1
5 yr.	14.4	24.2

1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	© VALUE LINE PUB., INC.	12-14
27.82	27.97	29.38	30.89	30.64	29.34	29.01	37.54	46.15	47.55	40.39	45.87	49.88	34.03	39.23	37.69	*32.00*	*33.10*	Revenues per sh	*42.20*
4.90	4.77	4.91	4.81	5.40	5.34	4.67	5.53	6.61	5.89	4.69	4.37	4.13	4.65	5.48	5.93	*5.40*	*5.80*	"Cash Flow" per sh	*6.80*
1.88	1.91	2.18	1.90	1.96	1.80	2.23	2.56	2.53	1.85	1.24	1.54	1.30	1.86	1.87	1.89	*1.90*	*2.00*	Earnings per sh A	*2.25*
1.60	1.66	1.69	1.73	1.73	1.73	1.73	1.73	1.73	1.73	1.73	1.73	1.73	1.73	1.73	1.73	*1.73*	*1.73*	Div'd Decl'd per sh B ■	*1.73*
4.04	2.69	2.53	2.01	1.44	1.63	1.48	2.31	2.01	2.41	2.19	2.04	2.25	3.09	9.92	8.57	*7.50*	*7.80*	Cap'l Spending per sh	*8.10*
18.03	18.23	18.72	18.72	18.94	19.05	19.55	20.42	21.25	20.28	20.65	22.84	22.39	18.53	18.55	18.85	*19.35*	*19.85*	Book Value per sh C	*21.75*
23.47	23.48	23.50	23.50	23.18	23.39	23.44	23.46	23.53	23.79	23.86	24.01	24.32	24.86	25.03	25.17	*30.00*	*30.20*	Common Shs Outst'g E	*30.80*
13.6	10.5	9.3	11.4	10.1	16.3	12.6	10.8	11.5	15.0	18.0	18.7	23.5	18.7	18.4	16.7	*Bold figures are*		Avg Ann'l P/E Ratio	*14.0*
.80	.69	.62	.71	.58	.85	.72	.70	.59	.82	1.03	.99	1.25	1.01	.98	1.00	*Value Line*		Relative P/E Ratio	*.95*
6.2%	8.2%	8.3%	8.0%	8.8%	5.9%	6.2%	6.2%	5.9%	6.2%	7.7%	6.0%	5.7%	5.0%	5.0%	5.5%	*estimates*		Avg Ann'l Div'd Yield	*5.5%*

CAPITAL STRUCTURE as of 6/30/09
Total Debt $694.3 mill. **Due in 5 Yrs.** $255.0 mill.
LT Debt $594.4 mill. **LT Interest** $30.0 mill.
(LT interest earned: 3.9x)
Leases, Uncapitalized: Ann. rentals $13.1 mill.

Pension Assets-12/08 $212 mill. **Oblig.** $348 mill.

Pfd Stock None

Common Stock 29,929,591 shs.
as of 8/3/09
MARKET CAP: $775 million (Small Cap)

1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010		12-14
680.0	880.9	1085.8	1131.0	963.7	1101.3	1213.1	846.0	982.0	948.7	*960*	*1000*	Revenues ($mill)	*1300*
52.2	59.9	59.4	44.0	29.5	36.9	31.4	45.4	46.7	48.1	*57.0*	*60.5*	Net Profit ($mill)	*69.0*
56.0%	44.5%	44.8%	45.2%	53.1%	45.4%	44.1%	31.2%	39.5%	42.2%	*40.0%*	*40.0%*	Income Tax Rate	*40.0%*
4.3%	4.4%	3.2%	5.1%	8.5%	1.1%	9.0%	8.0%	8.3%	8.2%	*8.0%*	*8.0%*	AFUDC % to Net Profit	*8.0%*
50.5%	52.2%	49.9%	45.0%	50.1%	47.2%	47.2%	47.0%	50.8%	53.6%	*52.0%*	*52.0%*	Long-Term Debt Ratio	*52.0%*
44.6%	47.8%	50.1%	55.0%	49.9%	52.8%	52.8%	53.0%	49.2%	46.4%	*48.0%*	*48.0%*	Common Equity Ratio	*48.0%*
1026.5	1001.3	998.6	877.8	988.2	1039.6	1031.5	869.2	943.6	1023.6	*1205*	*1250*	Total Capital ($mill)	*1400*
521.5	550.7	546.4	517.1	548.8	563.9	592.1	647.0	878.4	1073.6	*1150*	*1180*	Net Plant ($mill)	*1250*
7.1%	7.9%	8.1%	7.3%	4.3%	4.5%	4.1%	6.5%	6.2%	6.1%	*6.0%*	*6.0%*	Return on Total Cap'l	*6.5%*
10.3%	12.5%	11.9%	9.1%	6.0%	6.7%	5.8%	9.9%	10.1%	10.1%	*10.0%*	*10.0%*	Return on Shr. Equity	*10.5%*
11.4%	12.5%	11.9%	9.1%	6.0%	6.7%	5.8%	9.9%	10.1%	10.1%	*10.0%*	*10.0%*	Return on Com Equity D	*10.5%*
2.5%	4.0%	3.8%	.6%	NMF	NMF	NMF	NMF	3.1%	1.0%	*1.0%*	*1.5%*	Retained to Com Eq	*2.5%*
78%	68%	68%	93%	NMF	NMF	NMF	NMF	70%	90%	*91%*	*87%*	All Div'ds to Net Prof	*76%*

ELECTRIC OPERATING STATISTICS

	2006	2007	2008
% Change Retail Sales (KWH)	-3.1	Nil	-3.2
Avg. Indust. Use (MWH)	657	665	650
Avg. Indust. Revs. per KWH (¢)	10.2	9.9	8.4
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	Nil	+.5	Nil
Fixed Charge Cov. (%)	323	343	322

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '06-'08 to '12-'14
Revenues	2.0%	-3.5%	*2.0%*
"Cash Flow"	.5%	-1.5%	*4.0%*
Earnings	--	--	*3.0%*
Dividends	--	--	*Nil*
Book Value	--	-2.0%	*2.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2006	200.3	199.8	261.1	184.8	846.0
2007	274.6	216.7	267.9	222.8	982.0
2008	234.6	216.1	278.7	219.3	948.7
2009	235.5	200.4	*284.1*	*240*	*960*
2010	*240*	*230*	*290*	*240*	*1000*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2006	.15	.42	1.21	.08	1.86
2007	.22	.38	.92	.35	1.87
2008	.23	.45	.86	.35	1.89
2009	.48	.51	*.65*	*.26*	*1.90*
2010	*.45*	*.47*	*.75*	*.33*	*2.00*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2005	.432	.432	.432	.432	1.73
2006	.432	.432	.432	.432	1.73
2007	.432	.432	.432	.432	1.73
2008	.432	.432	.432	.432	1.73
2009	.432	.432	.432		

BUSINESS: UIL Holdings, parent of The United Illuminating Company, provides electricity to 324,000 customers in largely urban and suburban southern Connecticut. Revenue distribution: resid, 40%; commer, 47%; indust, 12%; other, 1%. Largest industrial customers: primary metals, fabricated metal products, transportation equipment. Sold American Payment Systems in 2004. Sold Xcelecom in 2006. Fuel costs: 54% of revenues; labor costs, 14%. 2008 depreciation rate: 4.0%. Has 981 employees. Non-Executive Chairman: F. Patrick McFadden. Chief Executive Officer & President: James P. Torgerson. Incorporated: Connecticut. Address: 157 Church Street, P.O. Box 1564, New Haven, Connecticut 06506-0901. Telephone: 203-499-2394. Internet: www.uil.com.

UIL Holdings posted strong second-quarter results. The Connecticut-based energy provider reported share earnings of $0.51 for the period, up 13% from last year's figure. Performance was primarily driven by increased distribution profits (up 30% year over year), reflecting the recent rate relief in the company's Connecticut service area. Decreased uncollectible expense and lower operating and maintenance costs further aided the bottom-line advance. Meanwhile, transmission operations declined slightly on a year-over-year basis, despite the completion of the Middletown-Norwalk 345-kilovolt project, which came on line in December of last year.

Expansion projects and infrastructure upgrades ought to boost earnings in the years ahead. Last year, the United Illuminating Company (UIL's power distributor) entered into a 50-50 joint venture with NRG Energy to construct the GenConn project. The project consists of two, 200 megawatt peaking generation units, one located in Devon and the other in Middletown. Management indicated that construction of the Devon site is already under way and is scheduled to be in service by June, 2010, while Middletown is scheduled for June, 2011. Upon their completion, we believe these additions will largely improve United Illuminating's generation capabilities, and act as key catalysts down the road.

The company has revised its capital expenditure program. Management indicated it now intends to spend about $125 million in 2009, up from previous the range of $75 million to $90 million. Over the next 10 years, UIL forecasts it will spend $1.7 billion on capital projects, with approximately 70% geared toward distribution, 25% toward transmission, and the remaining 5% for United Illuminating's 50-50 joint venture with NRG Energy (GenConn project).

These neutrally ranked shares may appeal to income-oriented investors. The stock currently offers a yield (6.8%) that is almost two full percentage points above the utility average. However, the high payout ratio indicates that an increase in the dividend is unlikely over the 3- to 5-year pull.

Michael Ratty *August 28, 2009*

(A) EPS basic. Excl. nonrecur. gains (losses): '92, 35¢; '93, (34¢); '94, (6¢); '96, 17¢; '00, 4¢; '03, (26¢); '04, $2.14; '06, ($5.07). Next egs. report due early Nov. (B) Div'ds historically paid in early Jan., early April, early July, and early Oct. ■ Div'd reinvest. plan avail. (C) Incl. deferred chgs. & regul. assets. In '08: $30.77/sh. (D) Rate base: orig. cost. Rate allowed on common equity in '08: 8.75%. Earned on average common equity in '08: 10.0%. Regul. Clim.: Below Average. (E) In millions. Adjust for stock dividends.

Company's Financial Strength	B++
Stock's Price Stability	95
Price Growth Persistence	45
Earnings Predictability	70

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ATTACHMENT B

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ALLETE INC (NYSE)					Scottrade
ALE	33.72	0.14	(0.42%)	Vol. 81,018	14:52 ET

ALLETE is a multi-services company. ALLETE's holdings include the one of the largest wholesale automobile auction networks in North America; a provider of independent auto dealer inventory financing; one of the largest investor-owned water utilities in Florida and North Carolina; significant real estate holdings in Florida and a low-cost electric utility that serves some of the largest industrial customers in the United States. (Company Press Release)

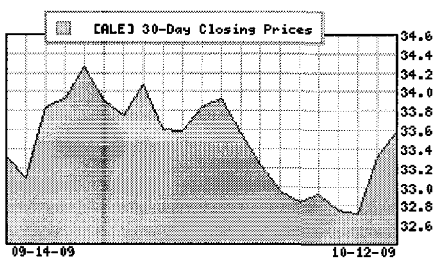
General Information

ALLETE INC
30 West Superior Street
Duluth, MN 55802-2093
Phone: 218-279-5000
Fax: 218-723-3944
Web: www.allete.com
Email: tthorp@allete.com

Industry	UTIL-ELEC PWR
Sector:	Utilities
Fiscal Year End	December
Last Reported Quarter	09/30/09
Next EPS Date	10/23/2009

Price and Volume Information

Zacks Rank	
Yesterday's Close	33.58
52 Week High	41.61
52 Week Low	23.35
Beta	0.70
20 Day Moving Average	188,136.66
Target Price Consensus	36.5



% Price Change		**% Price Change Relative to S&P 500**	
4 Week	0.78	4 Week	-1.73
12 Week	13.10	12 Week	-0.04
YTD	4.06	YTD	-12.96

Share Information		**Dividend Information**	
Shares Outstanding (millions)	34.10	Dividend Yield	5.24%
		Annual Dividend	$1.76
Market Capitalization (millions)	1,145.08	Payout Ratio	0.00
Short Ratio	12.77	Change in Payout Ratio	0.00
Last Split Date	09/21/2004	Last Dividend Payout / Amount	08/12/2009 / $0.44

EPS Information		**Consensus Recommendations**	
Current Quarter EPS Consensus Estimate	0.52	Current (1=Strong Buy, 5=Strong Sell)	2.00
Current Year EPS Consensus Estimate	2.13	30 Days Ago	2.00
Estimated Long-Term EPS Growth Rate	4.00	60 Days Ago	2.25
Next EPS Report Date	10/23/2009	90 Days Ago	2.60

Fundamental Ratios

P/E		**EPS Growth**		**Sales Growth**	
Current FY Estimate:	15.79	vs. Previous Year	-21.62%	vs. Previous Year	-13.22%
Trailing 12 Months:	13.02	vs. Previous Quarter	-56.06%	vs. Previous Quarter:	-17.48%
PEG Ratio	3.95				
Price Ratios		**ROE**		**ROA**	
Price/Book	1.17	09/30/09	-	09/30/09	-

Price/Cash Flow	7.70	06/30/09	9.25	06/30/09	3.72
Price / Sales	-	03/31/09	9.76	03/31/09	3.99
Current Ratio		**Quick Ratio**		**Operating Margin**	
09/30/09	-	09/30/09	-	09/30/09	-
06/30/09	1.59	06/30/09	1.23	06/30/09	10.22
03/31/09	1.78	03/31/09	1.41	03/31/09	10.06
Net Margin		**Pre-Tax Margin**		**Book Value**	
09/30/09	-	09/30/09	-	09/30/09	-
06/30/09	14.87	06/30/09	14.87	06/30/09	28.70
03/31/09	14.84	03/31/09	14.84	03/31/09	26.25
Inventory Turnover		**Debt-to-Equity**		**Debt to Capital**	
09/30/09	-	09/30/09	-	09/30/09	-
06/30/09	5.14	06/30/09	0.71	06/30/09	41.48
03/31/09	5.48	03/31/09	0.73	03/31/09	42.22

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BLACK HILLS CORP (NYSE)

Scottrade

BKH	25.27	▲0.09	(0.36%)	Vol. 195,649	14:57 ET

Black Hills Corp. is an energy company primarily consisting of four principal businesses: electric, coal mining, oil and gas production, and energy marketing. The Company's mission statement is to position the Company nationally to build value for shareholders, offer competitive prices for customers and create opportunities for employees through quality energy products and services.

General Information

BLACK HILLS COR
625 Ninth Street
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Phone: 605 721-1700
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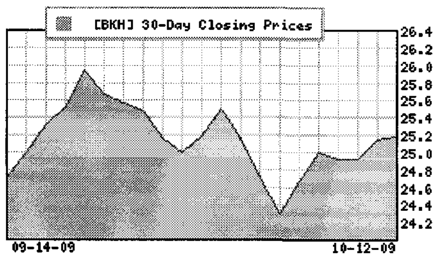
Web: www.blackhillscorp.com
Email: djahr@bh-corp.com

Industry	UTIL-ELEC PWR
Sector:	Utilities
Fiscal Year End	December
Last Reported Quarter	09/30/09
Next EPS Date	11/04/2009

Price and Volume Information

Zacks Rank	
Yesterday's Close	25.18
52 Week High	28.93
52 Week Low	14.54
Beta	1.12
20 Day Moving Average	252,932.75
Target Price Consensus	22.5



% Price Change		% Price Change Relative to S&P 500	
4 Week	1.90	4 Week	-0.64
12 Week	4.70	12 Week	-7.47
YTD	-6.60	YTD	-21.39

Share Information		Dividend Information	
Shares Outstanding (millions)	38.84	Dividend Yield	5.64%
		Annual Dividend	$1.42
Market Capitalization (millions)	978.04	Payout Ratio	0.00
Short Ratio	14.55	Change in Payout Ratio	0.00
Last Split Date	03/11/1998	Last Dividend Payout / Amount	08/14/2009 / $0.35

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	0.19	Current (1=Strong Buy, 5=Strong Sell)	3.00
Current Year EPS Consensus Estimate	1.55	30 Days Ago	3.00
Estimated Long-Term EPS Growth Rate	-	60 Days Ago	3.00
Next EPS Report Date	11/04/2009	90 Days Ago	3.00

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	16.28	vs. Previous Year	-55.88%	vs. Previous Year	67.90%
Trailing 12 Months:	13.47	vs. Previous Quarter	-74.58%	vs. Previous Quarter:	-41.24%
PEG Ratio	2.71				
Price Ratios		**ROE**		**ROA**	
Price/Book	0.90	09/30/09	-	09/30/09	-

Price/Cash Flow	5.53	06/30/09	6.63	06/30/09	2.25
Price / Sales	-	03/31/09	7.49	03/31/09	2.57
Current Ratio		**Quick Ratio**		**Operating Margin**	
09/30/09	-	09/30/09	-	09/30/09	-
06/30/09	0.71	06/30/09	0.59	06/30/09	5.17
03/31/09	0.55	03/31/09	0.49	03/31/09	6.15
Net Margin		**Pre-Tax Margin**		**Book Value**	
09/30/09	-	09/30/09	-	09/30/09	-
06/30/09	-4.26	06/30/09	-4.26	06/30/09	27.84
03/31/09	-6.13	03/31/09	-6.13	03/31/09	27.69
Inventory Turnover		**Debt-to-Equity**		**Debt to Capital**	
09/30/09	-	09/30/09	-	09/30/09	-
06/30/09	8.39	06/30/09	0.67	06/30/09	39.97
03/31/09	6.56	03/31/09	0.44	03/31/09	30.54

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CH ENERGY GROUP INC (NYSE)

Scottrade

CHG	43.33	-0.34	(-0.78%)	Vol. 19,690	14:47 ET

CENTRAL HUDSON GAS & ELECTRIC generates, purchases and distributes electricity and purchases and distributes gas. The Company, in the opinion of its general counsel, has, with minor exceptions, valid franchises, unlimited in duration, to serve a territory extending about 85 miles along the Hudson River and about 25 to 40 miles east and west from such River. The southern end of the territory is about 25 miles north of New York City, and the northern end is about 10 miles south of the City of Albany.

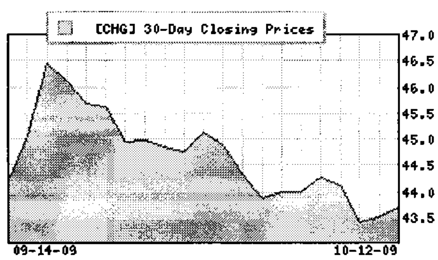
General Information

CH ENERGY GRP
284 South Avenue
Poughkeepsie, NY 12601-4879
Phone: 845 452-2000
Fax: 914 486-5415
Web: www.chenergygroup.com
Email: customerservices@cenhud.com

Industry	UTIL-ELEC PWR
Sector:	Utilities
Fiscal Year End	December
Last Reported Quarter	09/30/09
Next EPS Date	10/26/2009

Price and Volume Information

Zacks Rank	
Yesterday's Close	43.67
52 Week High	52.66
52 Week Low	36.63
Beta	0.38
20 Day Moving Average	41,586.85
Target Price Consensus	N/A



% Price Change		% Price Change Relative to S&P 500	
4 Week	-1.22	4 Week	-3.69
12 Week	-9.17	12 Week	-19.73
YTD	-15.02	YTD	-28.64

Share Information		Dividend Information	
Shares Outstanding (millions)	15.79	Dividend Yield	4.95%
		Annual Dividend	$2.16
Market Capitalization (millions)	689.55	Payout Ratio	0.00
Short Ratio	15.84	Change in Payout Ratio	0.00
Last Split Date	N/A	Last Dividend Payout / Amount	10/08/2009 / $0.54

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	0.33	Current (1=Strong Buy, 5=Strong Sell)	3.00
Current Year EPS Consensus Estimate	2.45	30 Days Ago	3.00
Estimated Long-Term EPS Growth Rate	-	60 Days Ago	3.00
Next EPS Report Date	10/26/2009	90 Days Ago	3.00

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	17.82	vs. Previous Year	-181.82%	vs. Previous Year	-36.16%
Trailing 12 Months:	19.32	vs. Previous Quarter	-106.16%	vs. Previous Quarter:	-47.10%
PEG Ratio	-				

Price Ratios	ROE	ROA

Price/Book	1.30	09/30/09	-	09/30/09	-
Price/Cash Flow	8.87	06/30/09	6.70	06/30/09	2.13
Price / Sales	-	03/31/09	7.30	03/31/09	2.38
Current Ratio		**Quick Ratio**		**Operating Margin**	
09/30/09	-	09/30/09	-	09/30/09	-
06/30/09	1.42	06/30/09	1.27	06/30/09	3.01
03/31/09	1.33	03/31/09	1.22	03/31/09	2.99
Net Margin		**Pre-Tax Margin**		**Book Value**	
09/30/09	-	09/30/09	-	09/30/09	-
06/30/09	4.99	06/30/09	4.99	06/30/09	33.56
03/31/09	4.94	03/31/09	4.94	03/31/09	35.51
Inventory Turnover		**Debt-to-Equity**		**Debt to Capital**	
09/30/09	-	09/30/09	-	09/30/09	-
06/30/09	22.02	06/30/09	0.88	06/30/09	47.79
03/31/09	24.61	03/31/09	0.74	03/31/09	42.47

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EMPIRE DIST ELEC CO (NYSE)

Scottrade

EDE	18.37	-0.20	(-1.08%)	Vol. 64,109	14:52 ET

The Empire District Electric Company is an operating public utility engagedin the generation, purchase, transmission, distribution and sale ofelectricity in parts of Missouri, Kansas, Oklahoma and Arkansas. TheCompany also provides water service to several towns in Missouri.

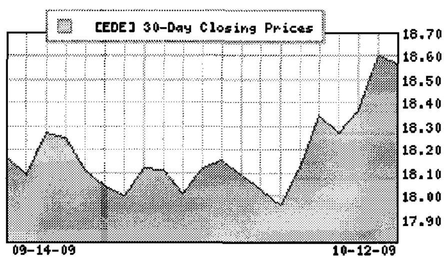
General Information

EMPIRE DISTRICT
602 Joplin Street
Joplin, MO 64801
Phone: 417 625-5100
Fax: 417 625-5173
Web: www.empiredistrict.com
Email: jwatson@empiredistrict.com

Industry	UTIL-ELEC PWR
Sector:	Utilities
Fiscal Year End	December
Last Reported Quarter	09/30/09
Next EPS Date	10/15/2009

Price and Volume Information

Zacks Rank	
Yesterday's Close	18.57
52 Week High	19.68
52 Week Low	11.92
Beta	0.76
20 Day Moving Average	151,225.45
Target Price Consensus	18.5



% Price Change		% Price Change Relative to S&P 500	
4 Week	2.20	4 Week	-0.35
12 Week	6.72	12 Week	-5.68
YTD	5.51	YTD	-10.91

Share Information		Dividend Information	
Shares Outstanding (millions)	34.49	Dividend Yield	6.89%
		Annual Dividend	$1.28
Market Capitalization (millions)	640.52	Payout Ratio	0.00
Short Ratio	7.02	Change in Payout Ratio	0.00
Last Split Date	01/30/1992	Last Dividend Payout / Amount	08/28/2009 / $0.32

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	0.69	Current (1=Strong Buy, 5=Strong Sell)	3.00
Current Year EPS Consensus Estimate	1.50	30 Days Ago	3.00
Estimated Long-Term EPS Growth Rate	-	60 Days Ago	3.00
Next EPS Report Date	10/15/2009	90 Days Ago	3.00

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	12.41	vs. Previous Year	57.14%	vs. Previous Year	0.85%
Trailing 12 Months:	13.56	vs. Previous Quarter	-31.25%	vs. Previous Quarter:	-17.49%
PEG Ratio	-				

Price Ratios		ROE		ROA	
Price/Book	1.20	09/30/09	-	09/30/09	-
Price/Cash Flow		06/30/09		06/30/09	

	6.38		8.73		2.73
Price / Sales	-	03/31/09	8.11	03/31/09	2.63
Current Ratio		**Quick Ratio**		**Operating Margin**	
09/30/09	-	09/30/09	-	09/30/09	-
06/30/09	0.59	06/30/09	0.38	06/30/09	-
03/31/09	0.88	03/31/09	0.59	03/31/09	-
Net Margin		**Pre-Tax Margin**		**Book Value**	
09/30/09	-	09/30/09	-	09/30/09	-
06/30/09	-	06/30/09	-	06/30/09	15.48
03/31/09	-	03/31/09	-	03/31/09	15.58
Inventory Turnover		**Debt-to-Equity**		**Debt to Capital**	
09/30/09	-	09/30/09	-	09/30/09	-
06/30/09	-	06/30/09	1.21	06/30/09	54.66
03/31/09	-	03/31/09	1.30	03/31/09	56.50

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HAWAIIAN ELEC INDUSTRIES (NYSE)

Scottrade

HE	18.70	-0.23	(-1.22%)	Vol. 252,604	14:54 ET

Hawaiian Electric Industries, Inc. is a holding company with subsidiaries engaged in the electric utility, savings bank, freight transportation, real estate development and other businesses, primarily in the State of Hawaii, and in the pursuit of independent power projects in Asia and the Pacific.

General Information

HAWAIIAN ELEC
900 Richards Street
Honolulu, HI 96813
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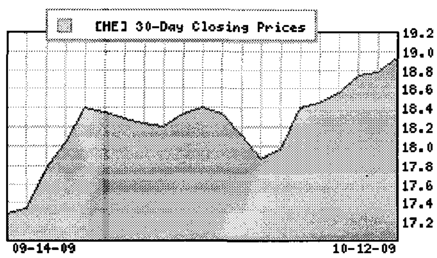
Fax: 808 543-7966
Web: www.hei.com
Email: shollinger@hei.com

Industry	UTIL-ELEC PWR
Sector:	Utilities
Fiscal Year End	December
Last Reported Quarter	09/30/09
Next EPS Date	11/10/2009

Price and Volume Information

Zacks Rank	
Yesterday's Close	18.93
52 Week High	27.55
52 Week Low	12.09
Beta	0.56
20 Day Moving Average	606,279.38
Target Price Consensus	17.65



% Price Change		% Price Change Relative to S&P 500	
4 Week	9.55	4 Week	6.82
12 Week	10.38	12 Week	-2.45
YTD	-14.50	YTD	-28.53

Share Information		Dividend Information	
Shares Outstanding (millions)	91.56	Dividend Yield	6.55%
		Annual Dividend	$1.24
Market Capitalization (millions)	1,733.19	Payout Ratio	0.00
Short Ratio	14.96	Change in Payout Ratio	0.00
Last Split Date	06/14/2004	Last Dividend Payout / Amount	08/20/2009 / $0.31

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	0.28	Current (1=Strong Buy, 5=Strong Sell)	2.75
Current Year EPS Consensus Estimate	0.94	30 Days Ago	2.75
Estimated Long-Term EPS Growth Rate	6.00	60 Days Ago	3.00
Next EPS Report Date	11/10/2009	90 Days Ago	3.00

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	20.21	vs. Previous Year	-64.58%	vs. Previous Year	-32.06%
Trailing 12 Months:	19.12	vs. Previous Quarter	-22.73%	vs. Previous Quarter:	-3.29%
PEG Ratio	3.37				

Price Ratios		ROE		ROA	
Price/Book	1.21	09/30/09	-	09/30/09	-
Price/Cash Flow		06/30/09		06/30/09	

	13.47		6.24		1.20
Price / Sales	-	03/31/09	8.25	03/31/09	1.54
Current Ratio		**Quick Ratio**		**Operating Margin**	
09/30/09	-	09/30/09	-	09/30/09	-
06/30/09	0.91	06/30/09	0.91	06/30/09	3.13
03/31/09	0.92	03/31/09	0.92	03/31/09	3.70
Net Margin		**Pre-Tax Margin**		**Book Value**	
09/30/09	-	09/30/09	-	09/30/09	-
06/30/09	2.54	06/30/09	2.54	06/30/09	15.69
03/31/09	1.77	03/31/09	1.77	03/31/09	15.87
Inventory Turnover		**Debt-to-Equity**		**Debt to Capital**	
09/30/09	-	09/30/09	-	09/30/09	-
06/30/09	-	06/30/09	0.85	06/30/09	45.83
03/31/09	-	03/31/09	0.84	03/31/09	45.78

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MGE ENERGY INC (NASD)

Scottrade

MGEE	36.20	-0.33	(-0.90%)	Vol. 38,753	14:55 ET

MGE Energy is a public utility holding company. Its principal subsidiary, MGE, generates and distributes electricity to more than 128,000 customers in Dane County, Wisconsin (250 square miles) and purchases, transports and distributes natural gas to nearly 123,000 customers in seven south-central and western Wisconsin counties (1,375 square miles). (Press Release)

General Information

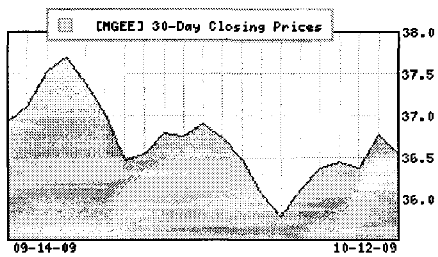
MGE ENERGY INC
133 South Blair Street
Madison, WI 53703
Phone: 608 252-7000
Fax: 608 252-7098
Web: www.mgeenergy.com
Email: investor@mgeenergy.com

Industry	UTIL-ELEC PWR
Sector:	Utilities

Fiscal Year End	December
Last Reported Quarter	09/30/09
Next EPS Date	11/04/2009

Price and Volume Information

Zacks Rank	
Yesterday's Close	36.53
52 Week High	38.23
52 Week Low	27.27
Beta	0.29
20 Day Moving Average	53,735.85
Target Price Consensus	37



% Price Change		% Price Change Relative to S&P 500	
4 Week	-1.06	4 Week	-3.52
12 Week	4.94	12 Week	-7.25
YTD	10.70	YTD	-6.10

Share Information		Dividend Information	
Shares Outstanding (millions)	23.11	Dividend Yield	4.03%
		Annual Dividend	$1.47
Market Capitalization (millions)	844.35	Payout Ratio	0.00
Short Ratio	7.54	Change in Payout Ratio	0.00
Last Split Date	02/21/1996	Last Dividend Payout / Amount	08/28/2009 / $0.37

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	0.65	Current (1=Strong Buy, 5=Strong Sell)	3.00
Current Year EPS Consensus Estimate	2.25	30 Days Ago	3.00
Estimated Long-Term EPS Growth Rate	5.00	60 Days Ago	3.00
Next EPS Report Date	11/04/2009	90 Days Ago	0.00

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	16.24	vs. Previous Year	-10.42%	vs. Previous Year	-13.77%
Trailing 12 Months:	15.55	vs. Previous Quarter	-33.85%	vs. Previous Quarter:	-40.62%
PEG Ratio	3.25				

Price Ratios		ROE		ROA	
Price/Book	1.71	09/30/09	-	09/30/09	-

Price/Cash Flow	8.85	06/30/09	11.11	06/30/09	4.34
Price / Sales	-	03/31/09	11.54	03/31/09	4.49
Current Ratio		**Quick Ratio**		**Operating Margin**	
09/30/09	-	09/30/09	-	09/30/09	-
06/30/09	0.93	06/30/09	0.63	06/30/09	9.34
03/31/09	0.96	03/31/09	0.69	03/31/09	9.18
Net Margin		**Pre-Tax Margin**		**Book Value**	
09/30/09	-	09/30/09	-	09/30/09	-
06/30/09	14.41	06/30/09	14.41	06/30/09	21.34
03/31/09	14.19	03/31/09	14.19	03/31/09	21.33
Inventory Turnover		**Debt-to-Equity**		**Debt to Capital**	
09/30/09	-	09/30/09	-	09/30/09	-
06/30/09	9.33	06/30/09	0.55	06/30/09	35.61
03/31/09	8.96	03/31/09	0.56	03/31/09	35.77

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NORTHEAST UTILS (NYSE)

Scottrade

NU	23.29	-0.23	(-0.98%)	Vol. 837,579	14:56 ET

Northeast Utilities is the parent company of the Northeast Utilitiessystem. The Northeast Utilities system furnishes franchised retail electric service in Connecticut, New Hampshire and western Massachusetts through three of the company's wholly owned subsidiaries: The Connecticut Light and Power Company; Public Service Company of New Hampshire; and Western Massachusetts Electric Company. It also provides service to a limited number of customers through another wholly owned subsidiary, Holyoke Water Power Company.

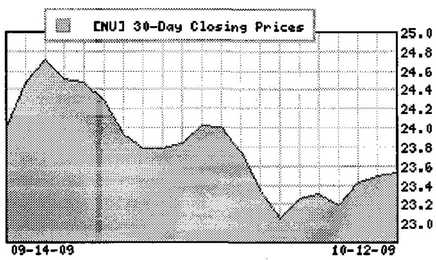
General Information

NORTHEAST UTIL
One Federal Street
Building 111-4
Springfield, MA 01105
Phone: 860-665-5000
Fax: 413-665-3652
Web: www.nu.com
Email: psnhreq@psnh.com

Industry	UTIL-ELEC PWR
Sector:	Utilities
Fiscal Year End	December
Last Reported Quarter	09/30/09
Next EPS Date	11/09/2009

Price and Volume Information

Zacks Rank	
Yesterday's Close	23.52
52 Week High	25.31
52 Week Low	18.82
Beta	0.49
20 Day Moving Average	1,491,480.75
Target Price Consensus	25.94



% Price Change		% Price Change Relative to S&P 500	
4 Week	-2.04	4 Week	-4.48
12 Week	6.57	12 Week	-5.81
YTD	-2.24	YTD	-17.66

Share Information		Dividend Information	
Shares Outstanding (millions)	175.28	Dividend Yield	4.04%
		Annual Dividend	$0.95
Market Capitalization (millions)	4,122.63	Payout Ratio	0.00
Short Ratio	4.32	Change in Payout Ratio	0.00
Last Split Date	N/A	Last Dividend Payout / Amount	08/28/2009 / $0.24

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	0.39	Current (1=Strong Buy, 5=Strong Sell)	1.50
Current Year EPS Consensus Estimate	1.84	30 Days Ago	1.50
Estimated Long-Term EPS Growth Rate	8.50	60 Days Ago	1.44
Next EPS Report Date	11/09/2009	90 Days Ago	1.50

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	12.81	vs. Previous Year	27.03%	vs. Previous Year	-7.61%
Trailing 12 Months:	11.76	vs. Previous Quarter	-21.67%	vs. Previous Quarter:	-23.16%
PEG Ratio	1.51				

Price Ratios		**ROE**		**ROA**	
Price/Book	1.18	09/30/09	-	09/30/09	-
Price/Cash Flow	3.87	06/30/09	10.01	06/30/09	2.36
Price / Sales	-	03/31/09	9.66	03/31/09	2.24
Current Ratio		**Quick Ratio**		**Operating Margin**	
09/30/09	-	09/30/09	-	09/30/09	-
06/30/09	1.23	06/30/09	1.04	06/30/09	5.63
03/31/09	1.26	03/31/09	1.09	03/31/09	5.11
Net Margin		**Pre-Tax Margin**		**Book Value**	
09/30/09	-	09/30/09	-	09/30/09	-
06/30/09	8.38	06/30/09	8.38	06/30/09	20.00
03/31/09	7.48	03/31/09	7.48	03/31/09	19.68
Inventory Turnover		**Debt-to-Equity**		**Debt to Capital**	
09/30/09	-	09/30/09	-	09/30/09	-
06/30/09	13.70	06/30/09	1.24	06/30/09	56.01
03/31/09	13.55	03/31/09	1.26	03/31/09	56.39

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NSTAR (NYSE) Scottrade

NST	31.57	-0.19	(-0.60%)	Vol. 341,473	14:57 ET

NSTAR was formed through a merger of BEC Energy and Commonwealth Energy System. The company, headquartered in Boston, Massachusetts provides regulated electric and gas utility services and is also engaged intelecommunications and other non-regulated activities. NSTAR, through its subsidiaries, Boston Edison Company, Cambridge Electric Light Company, Commonwealth Electric Company and Commonwealth Gas Company, serves approximately 1.3 million customers throughout Massachusetts. (Press Release)

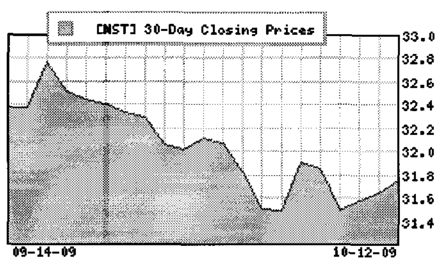
General Information

NSTAR
800 Boylston Street
Boston, MA 02199
Phone: 617 424-2000
Fax: 617 424-4032
Web: www.nstaronline.com
Email: ir@nstar.com

Industry	UTIL-ELEC PWR
Sector:	Utilities
Fiscal Year End	December
Last Reported Quarter	09/30/09
Next EPS Date	11/05/2009

Price and Volume Information

Zacks Rank	
Yesterday's Close	31.76
52 Week High	36.94
52 Week Low	27.17
Beta	0.24
20 Day Moving Average	541,710.31
Target Price Consensus	33.17



% Price Change		% Price Change Relative to S&P 500	
4 Week	-1.91	4 Week	-4.36
12 Week	3.45	12 Week	-8.57
YTD	-12.96	YTD	-26.88

Share Information		Dividend Information	
Shares Outstanding (millions)	106.81	Dividend Yield	4.72%
		Annual Dividend	$1.50
Market Capitalization (millions)	3,392.22	Payout Ratio	0.00
Short Ratio	10.73	Change in Payout Ratio	0.00
Last Split Date	06/06/2005	Last Dividend Payout / Amount	10/07/2009 / $0.38

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	0.83	Current (1=Strong Buy, 5=Strong Sell)	2.33
Current Year EPS Consensus Estimate	2.37	30 Days Ago	1.86
Estimated Long-Term EPS Growth Rate	5.70	60 Days Ago	2.13
Next EPS Report Date	11/05/2009	90 Days Ago	2.00

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	13.41	vs. Previous Year	12.77%	vs. Previous Year	-4.87%
Trailing 12 Months:	13.87	vs. Previous Quarter	-7.02%	vs. Previous Quarter:	-25.35%
PEG Ratio	2.37				

Price Ratios	ROE	ROA

Price/Book	1.82	09/30/09	-	09/30/09	-
Price/Cash Flow	5.44	06/30/09	13.49	06/30/09	3.05
Price / Sales	-	03/31/09	13.36	03/31/09	3.01
Current Ratio		**Quick Ratio**		**Operating Margin**	
09/30/09	-	09/30/09	-	09/30/09	-
06/30/09	0.52	06/30/09	0.49	06/30/09	7.32
03/31/09	0.60	03/31/09	0.57	03/31/09	7.04
Net Margin		**Pre-Tax Margin**		**Book Value**	
09/30/09	-	09/30/09	-	09/30/09	-
06/30/09	11.79	06/30/09	11.79	06/30/09	17.45
03/31/09	11.40	03/31/09	11.40	03/31/09	17.35
Inventory Turnover		**Debt-to-Equity**		**Debt to Capital**	
09/30/09	-	09/30/09	-	09/30/09	-
06/30/09	28.12	06/30/09	0.93	06/30/09	48.29
03/31/09	24.77	03/31/09	1.01	03/31/09	50.21

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OTTER TAIL CP (NASD)					Scottrade
OTTR	24.25	▼-0.03	(-0.12%)	Vol. 53,901	15:02 ET

OTTER TAIL's primary business is the production, transmission, distribution and sale of electric energy. The Company, through its subsidiaries, is also engaged in other businesses which are referred to as Health Services Operations and Diversified Operations.

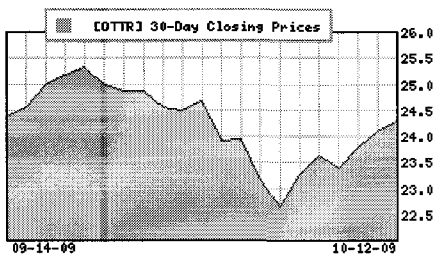
General Information

OTTER TAIL CORP
215 South Cascade Street
Box 496
Fergus Falls, MN 56538-0496
Phone: 218-739-8479
Fax: 218-998-3165
Web: www.ottertail.com
Email: sharesvc@ottertail.com

Industry	UTIL-ELEC PWR
Sector:	Utilities
Fiscal Year End	December
Last Reported Quarter	09/30/09
Next EPS Date	11/09/2009

Price and Volume Information

Zacks Rank	
Yesterday's Close	24.28
52 Week High	25.40
52 Week Low	14.99
Beta	1.13
20 Day Moving Average	137,201.30
Target Price Consensus	22.33



% Price Change		% Price Change Relative to S&P 500	
4 Week	-0.33	4 Week	-2.82
12 Week	3.32	12 Week	-8.69
YTD	4.07	YTD	-12.92

Share Information		Dividend Information	
Shares Outstanding (millions)	35.61	Dividend Yield	4.90%
		Annual Dividend	$1.19
Market Capitalization (millions)	864.66	Payout Ratio	0.00
Short Ratio	27.23	Change in Payout Ratio	0.00
Last Split Date	03/16/2000	Last Dividend Payout / Amount	08/12/2009 / $0.30

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	0.29	Current (1=Strong Buy, 5=Strong Sell)	4.00
Current Year EPS Consensus Estimate	0.88	30 Days Ago	4.00
Estimated Long-Term EPS Growth Rate	11.70	60 Days Ago	4.00
Next EPS Report Date	11/09/2009	90 Days Ago	4.00

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	27.59	vs. Previous Year	-36.36%	vs. Previous Year	-23.80%
Trailing 12 Months:	26.11	vs. Previous Quarter	-58.82%	vs. Previous Quarter:	-11.06%
PEG Ratio	2.36				

Price Ratios		ROE		ROA	
Price/Book	1.29	09/30/09	-	09/30/09	-

Price/Cash Flow	8.58	06/30/09	4.80	06/30/09	1.93
Price / Sales	-	03/31/09	5.20	03/31/09	2.02
Current Ratio		**Quick Ratio**		**Operating Margin**	
09/30/09	-	09/30/09	-	09/30/09	-
06/30/09	1.30	06/30/09	0.92	06/30/09	2.66
03/31/09	1.29	03/31/09	0.94	03/31/09	2.56
Net Margin		**Pre-Tax Margin**		**Book Value**	
09/30/09	-	09/30/09	-	09/30/09	-
06/30/09	3.20	06/30/09	3.20	06/30/09	18.76
03/31/09	3.24	03/31/09	3.24	03/31/09	18.91
Inventory Turnover		**Debt-to-Equity**		**Debt to Capital**	
09/30/09	-	09/30/09	-	09/30/09	-
06/30/09	8.88	06/30/09	0.62	06/30/09	37.76
03/31/09	9.17	03/31/09	0.51	03/31/09	34.68

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UIL HLDG CORP (NYSE)

UIL	26.80	-0.16	(-0.59%)	Vol. 32,781	15:02 ET

Scottrade

UIL Holdings Corporation is the holding company for The United Illuminating Company and United Resources. United Illuminating Company is aNew Haven-based regional distribution utility that provides electricity and energy-related services to customers in municipalities in the Greater New Haven and Greater Bridgeport areas.(PR)

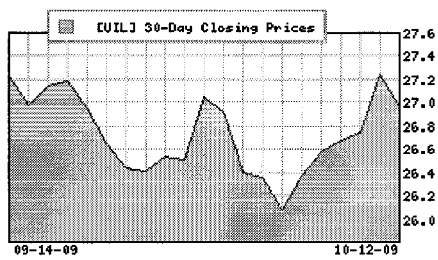
General Information

UIL HOLDINGS CP
157 Church Street
New Haven, CT 06506
Phone: 203-499-2000
Fax: 203-499-3626
Web: www.uil.com
Email: Susan.Allen@uinet.com

Industry	UTIL-ELEC PWR
Sector:	Utilities
Fiscal Year End	December
Last Reported Quarter	09/30/09
Next EPS Date	11/10/2009

Price and Volume Information

Zacks Rank	
Yesterday's Close	26.96
52 Week High	34.67
52 Week Low	17.00
Beta	0.73
20 Day Moving Average	96,142.35
Target Price Consensus	26.75



% Price Change		% Price Change Relative to S&P 500	
4 Week	-0.96	4 Week	-3.43
12 Week	15.71	12 Week	2.26
YTD	-10.22	YTD	-23.53

Share Information		Dividend Information	
Shares Outstanding (millions)	29.93	Dividend Yield	6.41%
		Annual Dividend	$1.73
Market Capitalization (millions)	806.91	Payout Ratio	0.00
Short Ratio	6.61	Change in Payout Ratio	0.00
Last Split Date	07/05/2006	Last Dividend Payout / Amount	09/15/2009 / $0.43

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	0.69	Current (1=Strong Buy, 5=Strong Sell)	2.00
Current Year EPS Consensus Estimate	1.93	30 Days Ago	2.00
Estimated Long-Term EPS Growth Rate	4.20	60 Days Ago	2.00
Next EPS Report Date	11/10/2009	90 Days Ago	1.33

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	14.01	vs. Previous Year	13.33%	vs. Previous Year	-7.29%
Trailing 12 Months:	12.37	vs. Previous Quarter	8.51%	vs. Previous Quarter:	-14.92%
PEG Ratio	3.33				

Price Ratios		ROE		ROA	
Price/Book	1.39	09/30/09	-	09/30/09	-
Price/Cash Flow		06/30/09		06/30/09	

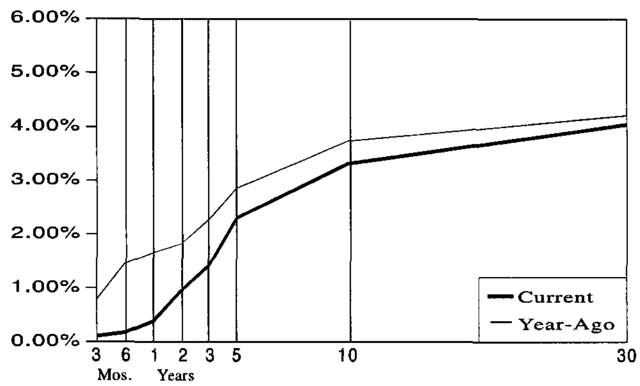
	5.22		11.29		2.73
Price / Sales	-	03/31/09	11.39	03/31/09	2.69
Current Ratio		**Quick Ratio**		**Operating Margin**	
09/30/09	-	09/30/09	-	09/30/09	-
06/30/09	1.05	06/30/09	1.03	06/30/09	6.03
03/31/09	0.76	03/31/09	0.75	03/31/09	5.67
Net Margin		**Pre-Tax Margin**		**Book Value**	
09/30/09	-	09/30/09	-	09/30/09	-
06/30/09	10.13	06/30/09	10.13	06/30/09	19.44
03/31/09	9.62	03/31/09	9.62	03/31/09	18.87
Inventory Turnover		**Debt-to-Equity**		**Debt to Capital**	
09/30/09	-	09/30/09	-	09/30/09	-
06/30/09	160.84	06/30/09	1.04	06/30/09	51.04
03/31/09	156.24	03/31/09	1.19	03/31/09	54.43

ATTACHMENT C

Selected Yields

	Recent (9/30/09)	3 Months Ago (6/30/09)	Year Ago (10/01/08)
TAXABLE			
Market Rates			
Discount Rate	0.50	0.50	2.25
Federal Funds	0.00-0.25	0.00-0.25	2.00
Prime Rate	3.25	3.25	5.00
30-day CP (A1/P1)	0.18	0.41	3.05
3-month LIBOR	0.29	0.60	4.15
Bank CDs			
6-month	0.40	0.65	1.61
1-year	0.64	0.86	2.14
5-year	2.27	1.92	3.77
U.S. Treasury Securities			
3-month	0.11	0.18	0.80
6-month	0.17	0.34	1.45
1-year	0.38	0.48	1.66
5-year	2.31	2.56	2.86
10-year	3.31	3.53	3.74
10-year (inflation-protected)	1.53	1.80	2.25
30-year	4.05	4.33	4.22
30-year Zero	4.13	4.41	4.22

Treasury Security Yield Curve



	Recent (9/30/09)	3 Months Ago (6/30/09)	Year Ago (10/01/08)
Mortgage-Backed Securities			
GNMA 6.5%	3.63	3.77	5.64
FHLMC 6.5% (Gold)	2.82	3.23	5.63
FNMA 6.5%	2.60	3.07	5.54
FNMA ARM	2.62	2.53	3.88
Corporate Bonds			
Financial (10-year) A	5.61	6.87	7.25
Industrial (25/30-year) A	5.31	5.96	6.52
Utility (25/30-year) A	5.40	5.79	6.46
Utility (25/30-year) Baa/BBB	5.73	6.88	6.61
Foreign Bonds (10-Year)			
Canada	3.31	3.36	3.71
Germany	3.22	3.39	4.00
Japan	1.30	1.36	1.51
United Kingdom	3.59	3.69	4.43
Preferred Stocks			
Utility A	5.77	6.10	6.53
Financial A	6.61	7.75	7.78
Financial Adjustable A	5.48	5.48	5.48
TAX-EXEMPT			
Bond Buyer Indexes			
20-Bond Index (GOs)	4.04	4.79	5.23
25-Bond Index (Revs)	4.86	5.77	5.56
General Obligation Bonds (GOs)			
1-year Aaa	0.37	0.40	2.10
1-year A	0.80	1.10	2.20
5-year Aaa	1.57	2.07	3.32
5-year A	2.00	3.47	3.37
10-year Aaa	2.57	3.23	4.23
10-year A	2.95	4.75	4.43
25/30-year Aaa	3.92	4.66	5.29
25/30-year A	4.45	6.18	5.67
Revenue Bonds (Revs) (25/30-Year)			
Education AA	4.70	6.05	5.45
Electric AA	4.75	6.10	5.40
Housing AA	5.10	6.50	5.90
Hospital AA	5.25	6.45	5.95
Toll Road Aaa	4.75	6.05	5.40

Federal Reserve Data

BANK RESERVES

(Two-Week Period; in Millions, Not Seasonally Adjusted)

	Recent Levels			Average Levels Over the Last...		
	9/23/09	**9/9/09**	**Change**	**12 Wks.**	**26 Wks.**	**52 Wks.**
Excess Reserves	854633	823202	31431	763053	790331	675003
Borrowed Reserves	307300	320295	-12995	347846	444263	518826
Net Free/Borrowed Reserves	547333	502907	44426	415208	346068	156178

MONEY SUPPLY

(One-Week Period; in Billions, Seasonally Adjusted)

	Recent Levels			Growth Rates Over the Last...		
	9/14/09	**9/7/09**	**Change**	**3 Mos.**	**6 Mos.**	**12 Mos.**
M1 (Currency+demand deposits)	1668.5	1666.8	1.7	3.0%	13.4%	16.7%
M2 (M1+savings+small time deposits)	8303.3	8307.2	-3.9	-3.9%	-1.4%	7.6%

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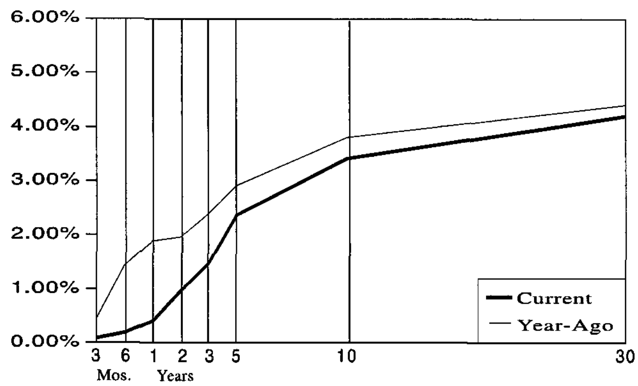
Selected Yields

	Recent (9/23/09)	3 Months Ago (6/24/09)	Year Ago (9/24/08)
TAXABLE			
Market Rates			
Discount Rate	0.50	0.50	2.25
Federal Funds	0.00-0.25	0.00-0.25	2.00
Prime Rate	3.25	3.25	5.00
30-day CP (A1/P1)	0.21	0.44	2.85
3-month LIBOR	0.29	0.60	3.48
Bank CDs			
6-month	0.40	0.65	1.61
1-year	0.64	0.87	2.14
5-year	2.27	1.92	3.77
U.S. Treasury Securities			
3-month	0.09	0.18	0.46
6-month	0.19	0.31	1.43
1-year	0.40	0.46	1.89
5-year	2.37	2.71	2.91
10-year	3.42	3.69	3.81
10-year (inflation-protected)	1.60	1.88	1.99
30-year	4.20	4.43	4.41
30-year Zero	4.30	4.50	4.39

	Recent (9/23/09)	3 Months Ago (6/24/09)	Year Ago (9/24/08)
Mortgage-Backed Securities			
GNMA 6.5%	3.77	3.79	5.56
FHLMC 6.5% (Gold)	2.57	3.28	5.43
FNMA 6.5%	2.36	3.06	5.34
FNMA ARM	2.62	2.53	3.86
Corporate Bonds			
Financial (10-year) A	5.68	6.75	7.14
Industrial (25/30-year) A	5.47	6.07	6.53
Utility (25/30-year) A	5.58	5.89	6.50
Utility (25/30-year) Baa/BBB	6.14	7.30	6.74
Foreign Bonds (10-Year)			
Canada	3.42	3.45	3.66
Germany	3.37	3.42	4.16
Japan	1.35	1.39	1.49
United Kingdom	3.75	3.70	4.57
Preferred Stocks			
Utility A	6.08	6.05	6.85
Financial A	6.55	8.21	8.04
Financial Adjustable A	5.47	5.47	5.47
TAX-EXEMPT			
Bond Buyer Indexes			
20-Bond Index (GOs)	4.20	4.86	5.03
25-Bond Index (Revs)	4.98	5.78	5.44
General Obligation Bonds (GOs)			
1-year Aaa	0.40	0.40	2.15
1-year A	0.90	0.90	2.25
5-year Aaa	1.61	2.17	3.10
5-year A	3.01	2.60	3.20
10-year Aaa	2.65	3.27	4.02
10-year A	4.15	3.63	4.22
25/30-year Aaa	4.03	4.70	5.13
25/30-year A	5.60	5.15	5.45
Revenue Bonds (Revs) (25/30-Year)			
Education AA	5.35	5.80	5.55
Electric AA	5.40	5.90	5.60
Housing AA	5.80	6.10	5.90
Hospital AA	5.80	6.05	5.95
Toll Road Aaa	5.35	5.85	5.65

Treasury Security Yield Curve



Federal Reserve Data

BANK RESERVES
(Two-Week Period; in Millions, Not Seasonally Adjusted)

	Recent Levels			Average Levels Over the Last...		
	9/9/09	**8/26/09**	**Change**	**12 Wks.**	**26 Wks.**	**52 Wks.**
Excess Reserves	823201	794546	28655	754077	773683	643434
Borrowed Reserves	320295	327647	-7352	369408	467326	513721
Net Free/Borrowed Reserves	502906	466899	36007	384669	306357	129712

MONEY SUPPLY
(One-Week Period; in Billions, Seasonally Adjusted)

	Recent Levels			Growth Rates Over the Last...		
	9/7/09	**8/31/09**	**Change**	**3 Mos.**	**6 Mos.**	**12 Mos.**
M1 (Currency+demand deposits)	1667.2	1635.6	31.6	9.2%	11.6%	18.0%
M2 (M1+savings+small time deposits)	8306.2	8293.6	12.6	-3.0%	-0.5%	8.0%

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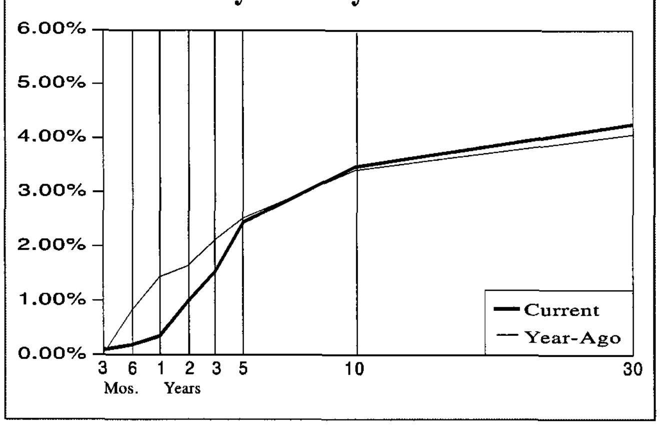
Selected Yields

TAXABLE

	Recent (9/16/09)	3 Months Ago (6/17/09)	Year Ago (9/17/08)
Market Rates			
Discount Rate	0.50	0.50	2.25
Federal Funds	0.00-0.25	0.00-0.25	2.00
Prime Rate	3.25	3.25	5.00
30-day CP (A1/P1)	0.21	0.42	2.50
3-month LIBOR	0.29	0.61	3.06
Bank CDs			
6-month	0.40	0.66	1.61
1-year	0.65	0.87	2.26
5-year	2.30	1.92	4.10
U.S. Treasury Securities			
3-month	0.10	0.16	0.04
6-month	0.19	0.31	0.81
1-year	0.35	0.47	1.44
5-year	2.44	2.68	2.52
10-year	3.47	3.69	3.41
10-year (inflation-protected)	1.60	1.92	1.74
30-year	4.26	4.51	4.07
30-year Zero	4.37	4.60	4.11

	Recent (9/16/09)	3 Months Ago (6/17/09)	Year Ago (9/17/08)
Mortgage-Backed Securities			
GNMA 6.5%	3.57	4.00	5.43
FHLMC 6.5% (Gold)	2.71	3.13	5.33
FNMA 6.5%	2.47	2.96	5.24
FNMA ARM	2.62	2.53	3.86
Corporate Bonds			
Financial (10-year) A	5.74	6.70	6.79
Industrial (25/30-year) A	5.55	6.13	6.08
Utility (25/30-year) A	5.59	5.95	5.94
Utility (25/30-year) Baa/BBB	6.21	7.54	6.51
Foreign Bonds (10-Year)			
Canada	3.38	3.44	3.44
Germany	3.34	3.48	4.02
Japan	1.33	1.47	1.50
United Kingdom	3.69	3.79	4.41
Preferred Stocks			
Utility A	6.29	5.47	6.56
Financial A	6.73	8.72	8.77
Financial Adjustable A	5.47	5.47	5.47

Treasury Security Yield Curve



TAX-EXEMPT

	Recent (9/16/09)	3 Months Ago (6/17/09)	Year Ago (9/17/08)
Bond Buyer Indexes			
20-Bond Index (GOs)	4.33	4.86	4.54
25-Bond Index (Revs)	5.33	5.76	5.09
General Obligation Bonds (GOs)			
1-year Aaa	0.40	0.40	1.73
1-year A	0.90	1.10	1.83
5-year Aaa	1.71	2.25	2.79
5-year A	2.15	3.65	2.84
10-year Aaa	2.78	3.33	3.59
10-year A	3.15	4.85	3.79
25/30-year Aaa	4.10	4.72	4.94
25/30-year A	4.56	6.24	5.32
Revenue Bonds (Revs) (25/30-Year)			
Education AA	4.85	6.30	5.05
Electric AA	4.90	6.35	5.00
Housing AA	5.30	6.65	5.40
Hospital AA	5.35	6.60	5.45
Toll Road Aaa	4.90	6.30	5.00

Federal Reserve Data

BANK RESERVES

(Two-Week Period; in Millions, Not Seasonally Adjusted)

	Recent Levels			Average Levels Over the Last...		
	9/9/09	8/26/09	Change	12 Wks.	26 Wks.	52 Wks.
Excess Reserves	823201	794546	28655	754077	773683	643434
Borrowed Reserves	320295	327647	-7352	369408	467326	513721
Net Free/Borrowed Reserves	502906	466899	36007	384669	306357	129712

MONEY SUPPLY

(One-Week Period; in Billions, Seasonally Adjusted)

	Recent Levels			Growth Rates Over the Last...		
	8/31/09	8/24/09	Change	3 Mos.	6 Mos.	12 Mos.
M1 (Currency+demand deposits)	1635.7	1639.0	-3.3	9.9%	9.6%	17.6%
M2 (M1+savings+small time deposits)	8293.7	8282.4	11.3	-3.4%	0.1%	7.6%

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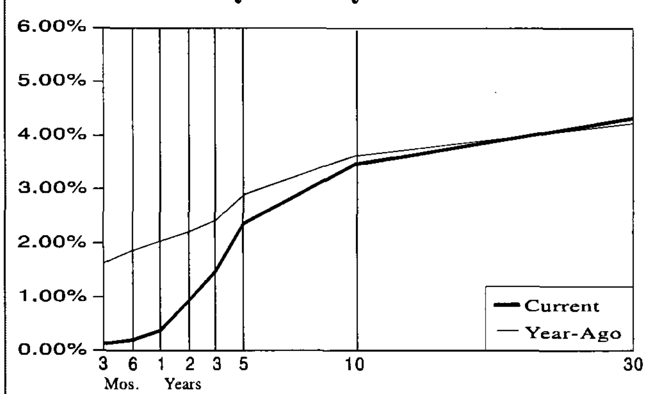
Selected Yields

	Recent (9/02/09)	3 Months Ago (6/10/09)	Year Ago (9/10/08)
TAXABLE			
Market Rates			
Discount Rate	0.50	0.50	2.25
Federal Funds	0.00-0.25	0.00-0.25	2.00
Prime Rate	3.25	3.25	5.00
30-day CP (A1/P1)	0.21	0.34	3.00
3-month LIBOR	0.30	0.64	2.82
Bank CDs			
6-month	0.42	0.66	1.60
1-year	0.72	0.87	2.26
5-year	2.30	1.92	4.15
U.S. Treasury Securities			
3-month	0.14	0.17	1.64
6-month	0.20	0.31	1.86
1-year	0.38	0.53	2.04
5-year	2.37	2.92	2.90
10-year	3.47	3.95	3.63
10-year (inflation-protected)	1.63	1.86	1.61
30-year	4.33	4.76	4.23
30-year Zero	4.46	4.84	4.27

Treasury Security Yield Curve



	Recent (9/02/09)	3 Months Ago (6/10/09)	Year Ago (9/10/08)
Mortgage-Backed Securities			
GNMA 6.5%	3.77	4.26	5.31
FHLMC 6.5% (Gold)	2.90	3.07	5.36
FNMA 6.5%	2.72	2.91	5.20
FNMA ARM	2.62	2.53	3.86
Corporate Bonds			
Financial (10-year) A	6.04	6.82	6.51
Industrial (25/30-year) A	5.63	6.50	6.08
Utility (25/30-year) A	5.65	6.28	6.04
Utility (25/30-year) Baa/BBB	6.40	7.76	6.49
Foreign Bonds (10-Year)			
Canada	3.42	3.64	3.46
Germany	3.42	3.69	4.07
Japan	1.33	1.55	1.52
United Kingdom	3.76	3.92	4.46
Preferred Stocks			
Utility A	5.84	7.62	6.12
Financial A	6.62	8.63	7.33
Financial Adjustable A	5.54	5.46	5.46
TAX-EXEMPT			
Bond Buyer Indexes			
20-Bond Index (GOs)	4.37	4.71	4.62
25-Bond Index (Revs)	5.43	5.63	5.15
General Obligation Bonds (GOs)			
1-year Aaa	0.40	0.40	1.58
1-year A	1.10	0.90	1.68
5-year Aaa	1.76	2.14	2.69
5-year A	3.16	2.57	2.79
10-year Aaa	2.88	3.21	3.48
10-year A	4.40	3.57	3.68
25/30-year Aaa	4.21	4.72	4.53
25/30-year A	5.75	5.16	4.77
Revenue Bonds (Revs) (25/30-Year)			
Education AA	5.50	5.85	4.87
Electric AA	5.55	5.95	4.92
Housing AA	6.05	6.25	5.13
Hospital AA	6.05	6.20	5.15
Toll Road Aaa	5.50	6.00	4.95

Federal Reserve Data

BANK RESERVES

(Two-Week Period; in Millions, Not Seasonally Adjusted)

	Recent Levels			Average Levels Over the Last...		
	8/26/09	**8/12/09**	**Change**	**12 Wks.**	**26 Wks.**	**52 Wks.**
Excess Reserves	794546	708501	86045	756262	762985	613021
Borrowed Reserves	327647	340534	-12887	394750	486512	508084
Net Free/Borrowed Reserves	466899	367967	98932	361513	276473	104936

MONEY SUPPLY

(One-Week Period; in Billions, Seasonally Adjusted)

	Recent Levels			Growth Rates Over the Last...		
	8/24/09	**8/17/09**	**Change**	**3 Mos.**	**6 Mos.**	**12 Mos.**
M1 (Currency+demand deposits)	1639.0	1656.3	-17.3	9.4%	12.4%	18.0%
M2 (M1+savings+small time deposits)	8282.4	8310.5	-28.1	-4.3%	0.5%	7.6%

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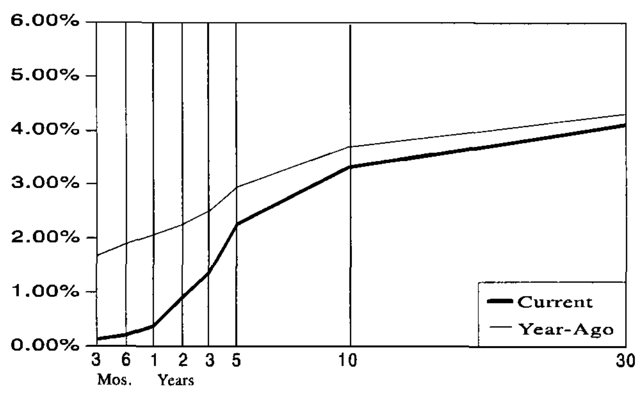
Selected Yields

	Recent (9/02/09)	3 Months Ago (6/3/09)	Year Ago (9/03/08)
TAXABLE			
Market Rates			
Discount Rate	0.50	0.50	2.25
Federal Funds	0.00-0.25	0.00-0.25	2.00
Prime Rate	3.25	3.25	5.00
30-day CP (A1/P1)	0.23	0.28	2.88
3-month LIBOR	0.33	0.64	2.81
Bank CDs			
6-month	0.42	0.70	1.60
1-year	0.72	0.92	2.26
5-year	2.25	1.92	4.15
U.S. Treasury Securities			
3-month	0.13	0.12	1.68
6-month	0.21	0.25	1.90
1-year	0.38	0.44	2.07
5-year	2.27	2.42	2.95
10-year	3.31	3.54	3.70
10-year (inflation-protected)	1.74	1.63	1.64
30-year	4.12	4.45	4.32
30-year Zero	4.22	4.53	4.37

	Recent (9/02/09)	3 Months Ago (6/3/09)	Year Ago (9/03/08)
Mortgage-Backed Securities			
GNMA 6.5%	3.92	3.37	5.60
FHLMC 6.5% (Gold)	3.07	2.89	5.67
FNMA 6.5%	2.85	2.78	5.48
FNMA ARM	2.62	2.53	3.89
Corporate Bonds			
Financial (10-year) A	5.79	6.82	6.69
Industrial (25/30-year) A	5.43	6.35	6.11
Utility (25/30-year) A	5.45	6.17	6.13
Utility (25/30-year) Baa/BBB	6.14	7.83	6.54
Foreign Bonds (10-Year)			
Canada	3.33	3.36	3.48
Germany	3.23	3.57	4.14
Japan	1.32	1.55	1.47
United Kingdom	3.55	3.79	4.50
Preferred Stocks			
Utility A	6.37	6.10	6.16
Financial A	5.94	8.35	6.97
Financial Adjustable A	5.53	5.53	5.53

Treasury Security Yield Curve



	Recent (9/02/09)	3 Months Ago (6/3/09)	Year Ago (9/03/08)
TAX-EXEMPT			
Bond Buyer Indexes			
20-Bond Index (GOs)	4.53	4.61	4.68
25-Bond Index (Revs)	5.99	5.53	5.17
General Obligation Bonds (GOs)			
1-year Aaa	0.40	0.40	1.58
1-year A	0.90	1.13	1.68
5-year Aaa	1.80	2.02	2.74
5-year A	2.24	3.45	2.84
10-year Aaa	2.93	3.01	3.55
10-year A	3.30	4.55	3.75
25/30-year Aaa	4.36	4.64	4.69
25/30-year A	4.82	6.16	5.07
Revenue Bonds (Revs) (25/30-Year)			
Education AA	5.30	6.20	4.85
Electric AA	5.40	6.25	4.80
Housing AA	5.55	6.55	5.15
Hospital AA	5.60	6.50	5.25
Toll Road Aaa	5.35	6.30	4.80

Federal Reserve Data

BANK RESERVES

(Two-Week Period; in Millions, Not Seasonally Adjusted)

	Recent Levels			Average Levels Over the Last...		
	8/26/09	8/12/09	Change	12 Wks.	26 Wks.	52 Wks.
Excess Reserves	794546	708501	86045	756262	762985	613020
Borrowed Reserves	327647	340534	-12887	394750	486512	508084
Net Free/Borrowed Reserves	466899	367967	98932	361512	276473	104936

MONEY SUPPLY

(One-Week Period; in Billions, Seasonally Adjusted)

	Recent Levels			Growth Rates Over the Last...		
	8/17/09	8/10/09	Change	3 Mos.	6 Mos.	12 Mos.
M1 (Currency+demand deposits)	1658.2	1663.6	-5.4	17.9%	13.1%	19.9%
M2 (M1+savings+small time deposits)	8312.4	8318.3	-5.9	-1.5%	1.1%	8.1%

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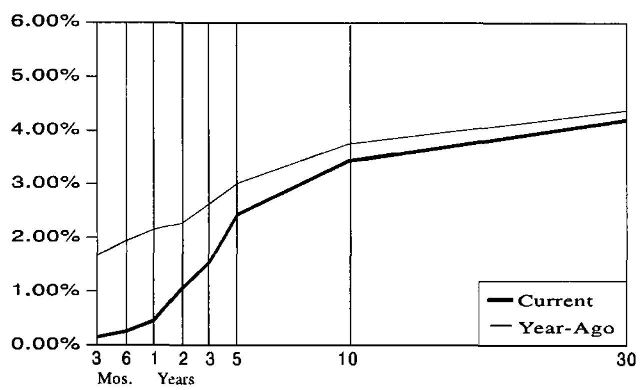
Selected Yields

	Recent (8/26/09)	3 Months Ago (5/27/09)	Year Ago (8/27/08)
TAXABLE			
Market Rates			
Discount Rate	0.50	0.50	2.25
Federal Funds	0.00-0.25	0.00-0.25	2.00
Prime Rate	3.25	3.25	5.00
30-day CP (A1/P1)	0.24	0.31	2.84
3-month LIBOR	0.37	0.67	2.81
Bank CDs			
6-month	0.48	0.69	1.60
1-year	0.72	0.92	2.26
5-year	2.25	1.92	4.15
U.S. Treasury Securities			
3-month	0.15	0.16	1.67
6-month	0.25	0.29	1.94
1-year	0.45	0.47	2.15
5-year	2.44	2.44	3.01
10-year	3.43	3.74	3.76
10-year (inflation-protected)	1.70	1.81	1.51
30-year	4.20	4.63	4.38
30-year Zero	4.29	4.74	4.44

	Recent (8/26/09)	3 Months Ago (5/27/09)	Year Ago (8/27/08)
Mortgage-Backed Securities			
GNMA 6.5%	3.95	3.34	5.62
FHLMC 6.5% (Gold)	2.95	2.61	5.66
FNMA 6.5%	2.73	2.28	5.56
FNMA ARM	2.75	2.78	4.02
Corporate Bonds			
Financial (10-year) A	6.13	7.00	6.60
Industrial (25/30-year) A	5.52	6.61	6.18
Utility (25/30-year) A	5.53	6.44	6.15
Utility (25/30-year) Baa/BBB	6.17	8.01	6.57
Foreign Bonds (10-Year)			
Canada	3.40	3.57	3.53
Germany	3.24	3.63	4.17
Japan	1.32	1.48	1.45
United Kingdom	3.55	3.75	4.51
Preferred Stocks			
Utility A	6.34	6.08	6.16
Financial A	5.99	8.28	7.08
Financial Adjustable A	5.52	5.53	5.53
TAX-EXEMPT			
Bond Buyer Indexes			
20-Bond Index (GOs)	4.58	4.44	4.64
25-Bond Index (Revs)	5.62	5.42	5.15
General Obligation Bonds (GOs)			
1-year Aaa	0.40	0.42	1.56
1-year A	1.10	1.15	1.66
5-year Aaa	1.81	1.87	2.79
5-year A	3.21	3.29	2.89
10-year Aaa	2.96	2.84	3.60
10-year A	4.48	4.40	3.80
25/30-year Aaa	4.54	4.41	4.71
25/30-year A	6.05	5.89	4.95
Revenue Bonds (Revs) (25/30-Year)			
Education AA	5.80	5.94	5.05
Electric AA	5.85	6.04	5.10
Housing AA	6.35	6.34	5.25
Hospital AA	6.35	6.29	5.30
Toll Road Aaa	5.80	6.09	5.10

Treasury Security Yield Curve



Federal Reserve Data

BANK RESERVES
(Two-Week Period; in Millions, Not Seasonally Adjusted)

	Recent Levels			Average Levels Over the Last...		
	8/12/09	7/29/09	Change	12 Wks.	26 Wks.	52 Wks.
Excess Reserves	708499	728888	-20389	768051	749904	583661
Borrowed Reserves	340534	347217	-6683	427197	503204	502158
Net Free/Borrowed Reserves	367965	381671	-13706	340854	246700	81504

MONEY SUPPLY
(One-Week Period; in Billions, Seasonally Adjusted)

	Recent Levels			Growth Rates Over the Last...		
	8/10/09	8/3/09	Change	3 Mos.	6 Mos.	12 Mos.
M1 (Currency+demand deposits)	1663.8	1677.2	-13.4	17.9%	12.1%	18.7%
M2 (M1+savings+small time deposits)	8318.3	8323.9	-5.6	-0.7%	1.6%	7.9%

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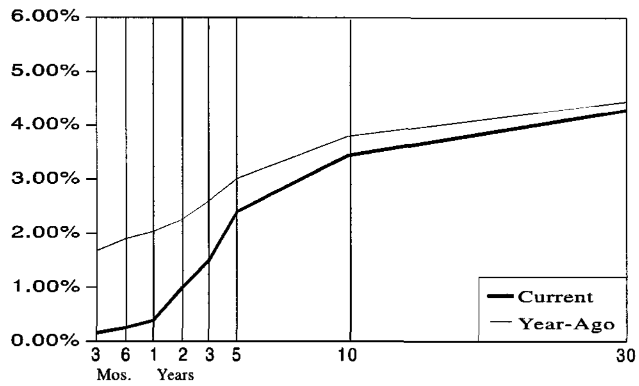
Selected Yields

	Recent (8/19/09)	3 Months Ago (5/20/09)	Year Ago (8/20/08)
TAXABLE			
Market Rates			
Discount Rate	0.50	0.50	2.25
Federal Funds	0.00-0.25	0.00-0.25	2.00
Prime Rate	3.25	3.25	5.00
30-day CP (A1/P1)	0.23	0.26	2.77
3-month LIBOR	0.42	0.72	2.81
Bank CDs			
6-month	0.48	0.72	1.63
1-year	0.72	0.97	2.26
5-year	1.90	1.92	4.16
U.S. Treasury Securities			
3-month	0.16	0.17	1.68
6-month	0.25	0.27	1.90
1-year	0.39	0.42	2.04
5-year	2.41	2.03	3.01
10-year	3.45	3.19	3.80
10-year (inflation-protected)	1.69	1.51	1.54
30-year	4.29	4.14	4.45
30-year Zero	4.42	4.26	4.51

Treasury Security Yield Curve



	Recent (8/19/09)	3 Months Ago (5/20/09)	Year Ago (8/20/08)
Mortgage-Backed Securities			
GNMA 6.5%	3.85	3.02	5.63
FHLMC 6.5% (Gold)	2.95	2.27	5.69
FNMA 6.5%	2.73	2.03	5.58
FNMA ARM	2.75	2.78	4.02
Corporate Bonds			
Financial (10-year) A	6.23	6.66	6.46
Industrial (25/30-year) A	5.60	6.21	6.22
Utility (25/30-year) A	5.64	6.01	6.17
Utility (25/30-year) Baa/BBB	6.23	7.59	6.65
Foreign Bonds (10-Year)			
Canada	3.40	3.14	3.58
Germany	3.25	3.43	4.12
Japan	1.35	1.43	1.45
United Kingdom	3.59	3.58	4.56
Preferred Stocks			
Utility A	6.02	6.09	6.18
Financial A	7.10	8.37	7.26
Financial Adjustable A	5.52	5.52	5.52
TAX-EXEMPT			
Bond Buyer Indexes			
20-Bond Index (GOs)	4.65	4.61	4.67
25-Bond Index (Revs)	5.66	5.53	5.17
General Obligation Bonds (GOs)			
1-year Aaa	0.40	0.43	1.56
1-year A	0.90	1.16	1.66
5-year Aaa	1.73	1.82	2.80
5-year A	2.17	3.25	2.90
10-year Aaa	2.94	2.81	3.58
10-year A	3.30	4.35	3.78
25/30-year Aaa	4.54	4.40	4.66
25/30-year A	5.00	5.92	5.04
Revenue Bonds (Revs) (25/30-Year)			
Education AA	5.50	5.97	4.80
Electric AA	5.60	6.02	4.75
Housing AA	5.75	6.32	5.10
Hospital AA	5.85	6.27	5.20
Toll Road Aaa	5.55	6.07	4.75

Federal Reserve Data

BANK RESERVES
(Two-Week Period; in Millions, Seasonally Adjusted)

	Recent Levels			Average Levels Over the Last...		
	8/12/09	**7/29/09**	**Change**	**12 Wks.**	**26 Wks.**	**52 Wks.**
Excess Reserves	708500	728855	-20355	768047	749902	583660
Borrowed Reserves	340534	347217	-6683	427197	503204	502158
Net Free/Borrowed Reserves	367966	381638	-13672	340849	246697	81502

MONEY SUPPLY
(One-Week Period; in Billions, Seasonally Adjusted)

	Recent Levels			Growth Rates Over the Last...		
	8/3/09	**7/27/09**	**Change**	**3 Mos.**	**6 Mos.**	**12 Mos.**
M1 (Currency+demand deposits)	1677.5	1647.6	29.9	17.9%	14.1%	18.8%
M2 (M1+savings+small time deposits)	8323.6	8365.6	-42.0	0.1%	2.0%	7.9%

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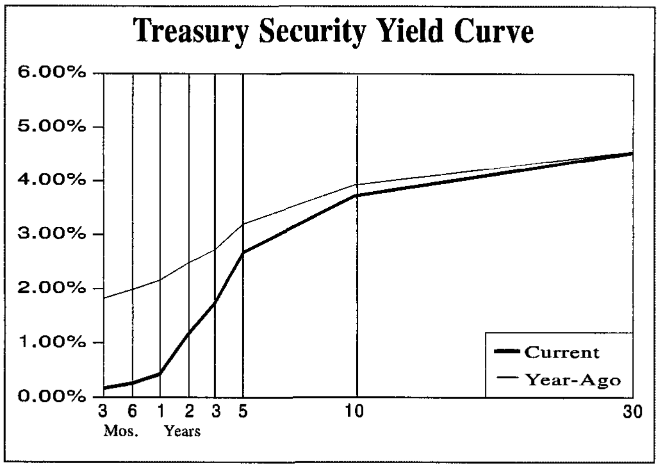
Selected Yields

	Recent (8/12/09)	3 Months Ago (5/13/09)	Year Ago (8/13/08)
TAXABLE			
Market Rates			
Discount Rate	0.50	0.50	2.25
Federal Funds	0.00-0.25	0.00-0.25	2.00
Prime Rate	3.25	3.25	5.00
30-day CP (A1/P1)	0.25	0.32	2.74
3-month LIBOR	0.45	0.88	2.80
Bank CDs			
6-month	0.50	0.73	1.60
1-year	0.73	0.98	2.26
5-year	1.90	1.93	4.16
U.S. Treasury Securities			
3-month	0.17	0.17	1.83
6-month	0.26	0.28	1.99
1-year	0.43	0.50	2.16
5-year	2.68	1.98	3.20
10-year	3.72	3.12	3.93
10-year (inflation-protected)	1.83	1.64	1.68
30-year	4.54	4.10	4.56
30-year Zero	4.65	4.18	4.61



	Recent (8/12/09)	3 Months Ago (5/13/09)	Year Ago (8/13/08)
Mortgage-Backed Securities			
GNMA 6.5%	3.83	3.09	5.84
FHLMC 6.5% (Gold)	3.19	2.38	5.87
FNMA 6.5%	2.91	2.20	5.79
FNMA ARM	2.75	2.78	4.02
Corporate Bonds			
Financial (10-year) A	6.45	6.94	6.20
Industrial (25/30-year) A	5.85	6.19	6.29
Utility (25/30-year) A	5.79	6.01	6.27
Utility (25/30-year) Baa/BBB	6.62	7.57	6.75
Foreign Bonds (10-Year)			
Canada	3.52	3.10	3.61
Germany	3.46	3.34	4.21
Japan	1.43	1.46	1.46
United Kingdom	3.79	3.52	4.60
Preferred Stocks			
Utility A	5.66	6.35	6.27
Financial A	6.06	8.65	7.37
Financial Adjustable A	5.51	5.51	5.51
TAX-EXEMPT			
Bond Buyer Indexes			
20-Bond Index (GOs)	4.65	4.63	4.75
25-Bond Index (Revs)	5.68	5.57	5.23
General Obligation Bonds (GOs)			
1-year Aaa	0.40	0.43	1.56
1-year A	1.10	1.16	1.66
5-year Aaa	1.69	1.82	2.90
5-year A	3.09	3.24	3.00
10-year Aaa	2.98	2.86	3.68
10-year A	4.50	4.41	3.88
25/30-year Aaa	4.66	4.43	4.75
25/30-year A	6.17	5.91	5.10
Revenue Bonds (Revs) (25/30-Year)			
Education AA	5.90	5.96	5.00
Electric AA	5.95	6.06	5.05
Housing AA	6.45	6.36	5.20
Hospital AA	6.45	6.31	5.20
Toll Road Aaa	5.90	6.11	5.10

Federal Reserve Data

BANK RESERVES

(Two-Week Period; in Millions, Not Seasonally Adjusted)

	Recent Levels			Average Levels Over the Last...		
	7/29/09	7/15/09	Change	12 Wks.	26 Wks.	52 Wks.
Excess Reserves	728856	743860	-15004	777896	755940	557494
Borrowed Reserves	347217	387829	-40612	451108	519244	495733
Net Free/Borrowed Reserves	381639	356031	25608	326788	236696	61761

MONEY SUPPLY

(One-Week Period; in Billions, Seasonally Adjusted)

	Recent Levels			Growth Rates Over the Last...		
	7/27/09	7/20/09	Change	3 Mos.	6 Mos.	12 Mos.
M1 (Currency+demand deposits)	1647.6	1644.8	2.8	19.0%	13.0%	16.9%
M2 (M1+savings+small time deposits)	8365.7	8341.1	24.6	3.1%	2.3%	8.1%

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UNS ELECTRIC, INC.
DOCKET NO. E-04204A-09-0206
TABLE OF CONTENTS TO SCHEDULES WAR

UNS ELECTRIC, INC.
TEST YEAR ENDED DECEMBER 31, 2008
COST OF CAPITAL SUMMARY

DOCKET NO. E-04204A-09-0206
SCHEDULE WAR - 1

ORIGINAL COST WEIGHTED AVERAGE COST OF CAPITAL

LINE NO.	DESCRIPTION	(A) CAPITALIZATION PER COMPANY	(B) RUCO ADJUSTED	(C) RUCO ADJUSTED CAPITALIZATION	(D) CAPITAL RATIO	(E) COST	(F) WEIGHTED COST
2	LONG-TERM DEBT	$ 99,272	$ -	$ 99,272	54.24%	7.05%	3.82%
3	COMMON EQUITY	83,755	-	83,755	45.76%	9.25%	4.23%
4	TOTAL CAPITALIZATION	$ 183,027	$ -	$ 183,027	100.00%		
5	**ORIGINAL COST WEIGHTED AVERAGE COST OF CAPITAL**						**8.06%**

REFERENCES:
COLUMN (A): COMPANY SCHEDULE D-1
COLUMN (B): TESTIMONY, WAR
COLUMN (C): COLUMN (A) + COLUMN (B)
COLUMN (D): COLUMN (C) ÷ COLUMN (C), LINE 4
COLUMN (E): LINE 1 - COMPANY SCHEDULE D-1
COLUMN (E): LINE 2 - TESTIMONY WAR
COLUMN (E): LINE 3 - SCHEDULE WAR-1, PAGE 2 LINE 9
COLUMN (F): COLUMN (D) x COLUMN (E)

UNS ELECTRIC, INC.
TEST YEAR ENDED DECEMBER 31, 2008
DCF COST OF EQUITY CAPITAL

DOCKET NO. E-04204A-09-0206
SCHEDULE WAR - 2

LINE NO.	STOCK SYMBOL	COMPANY	(A) DIVIDEND YIELD	+	(B) GROWTH RATE (g)	=	(C) DCF COST OF EQUITY CAPITAL
1	ALE	ALLETE, INC.	5.25%	+	3.52%	=	8.77%
2	BKH	BLACK HILLS CORPORATION	5.60%	+	6.06%	=	11.66%
3	CHG	CH ENERGY GROUP, INC.	4.79%	+	2.29%	=	7.08%
4	EDE	EMPIRE DISTRICT ELECTRIC COMPANY	7.04%	+	3.00%	=	10.04%
5	HE	HAWAIIAN ELECTRIC INDUSTRIES, INC.	6.97%	+	2.98%	=	9.95%
6	MGEE	MGE ENERGY, INC.	4.06%	+	5.76%	=	9.82%
7	NU	NORTHEAST UTILITIES	3.99%	+	5.04%	=	9.03%
8	NST	NSTAR	4.74%	+	5.75%	=	10.49%
9	OTTR	OTTER TAIL CORPORATION	4.95%	+	2.97%	=	7.92%
10	UIL	UIL HOLDINGS	6.60%	+	4.16%	=	10.77%
11	**AVERAGE**						**9.55%**

REFERENCES:
COLUMN (A): SCHEDULE WAR - 3, COLUMN C
COLUMN (B): SCHEDULE WAR - 4, PAGE 1, COLUMN C
COLUMN (C): COLUMN (A) + COLUMN (B)

DIVIDEND YIELD CALCULATION

LINE NO.	STOCK SYMBOL	COMPANY	(A) ESTIMATED DIVIDEND (PER SHARE)	÷	(B) AVERAGE STOCK PRICE (PER SHARE)	=	(C) DIVIDEND YIELD
1	ALE	ALLETE, INC.	$1.76	÷	$33.51	=	5.25%
2	BKH	BLACK HILLS CORPORATION	1.42	÷	25.36	=	5.60%
3	CHG	CH ENERGY GROUP, INC.	2.16	÷	45.12	=	4.79%
4	EDE	EMPIRE DISTRICT ELECTRIC COMPANY	1.28	÷	18.18	=	7.04%
5	HE	HAWAIIAN ELECTRIC INDUSTRIES, INC.	1.24	÷	17.80	=	6.97%
6	MGEE	MGE ENERGY, INC.	1.47	÷	36.34	=	4.06%
7	NU	NORTHEAST UTILITIES	0.95	÷	23.80	=	3.99%
8	NST	NSTAR	1.50	÷	31.64	=	4.74%
9	OTTR	OTTER TAIL CORPORATION	1.19	÷	24.06	=	4.95%
10	UIL	UIL HOLDINGS	1.73	÷	26.17	=	6.60%
11	**AVERAGE**						**5.40%**

REFERENCES:
COLUMN (A): ESTIMATED 12 MONTH DIVIDEND REPORTED IN VALUE LINE INVESTMENT SURVEY - RATINGS & REPORTS DATED 08/07/2009, 08/28/2009 & 09/25/2009.
COLUMN (B): EIGHT WEEK AVERAGE OF CLOSING PRICES FROM 08/17/2009 TO 10/09/2009 STOCK QUOTES OBTAINED THROUGH BIG CHARTS WEB SITE - HISTORICAL QUOTES (www.bigcharts.com).
COLUMN (C): COLUMN (A) ÷ COLUMN (B)

LINE NO.	STOCK SYMBOL	COMPANY	(A) INTERNAL GROWTH (br)	+	(B) EXTERNAL GROWTH (sv)	=	(C) DIVIDEND GROWTH (g)
1	ALE	ALLETE, INC.	2.75%	+	0.77%	=	3.52%
2	BKH	BLACK HILLS CORPORATION	4.50%	+	1.56%	=	6.06%
3	CHG	CH ENERGY GROUP, INC.	2.25%	+	0.04%	=	2.29%
4	EDE	EMPIRE DISTRICT ELECTRIC COMPANY	2.40%	+	0.60%	=	3.00%
5	HE	HAWAIIAN ELECTRIC INDUSTRIES, INC.	2.90%	+	0.08%	=	2.98%
6	MGEE	MGE ENERGY, INC.	5.35%	+	0.41%	=	5.76%
7	NU	NORTHEAST UTILITIES	4.25%	+	0.79%	=	5.04%
8	NST	NSTAR	5.75%	+	0.00%	=	5.75%
9	OTTR	OTTER TAIL CORPORATION	2.70%	+	0.27%	=	2.97%
10	UIL	UIL HOLDINGS	2.40%	+	1.76%	=	4.16%
11	**AVERAGE**						**4.15%**

REFERENCES:
COLUMN (A): TESTIMONY, WAR
COLUMN (B): SCHEDULE WAR - 4, PAGE 2, COLUMN C
COLUMN (C): COLUMN (A) + COLUMN (B)

UNS ELECTRIC, INC.
TEST YEAR ENDED DECEMBER 31, 2008
DIVIDEND GROWTH RATE CALCULATION

LINE NO.	STOCK SYMBOL	COMPANY	(A) SHARE GROWTH	x	(B) { [((M ÷ B) + 1) ÷ 2] - 1 }	=	(C) EXTERNAL GROWTH (sv)
1	ALE	ALLETE, INC.	5.00%	x	{ [((1.31) + 1) ÷ 2] - 1 }	=	0.77%
2	BKH	BLACK HILLS CORPORATION	0.80%	x	{ [((0.91) + 1) ÷ 2] + 1 }	=	1.56%
3	CHG	CH ENERGY GROUP, INC.	0.25%	x	{ [((1.31) + 1) ÷ 2] - 1 }	=	0.04%
4	EDE	EMPIRE DISTRICT ELECTRIC COMPANY	8.00%	x	{ [((1.15) + 1) ÷ 2] - 1 }	=	0.60%
5	HE	HAWAIIAN ELECTRIC INDUSTRIES, INC.	1.00%	x	{ [((1.17) + 1) ÷ 2] - 1 }	=	0.08%
6	MGEE	MGE ENERGY, INC.	1.25%	x	{ [((1.66) + 1) ÷ 2] - 1 }	=	0.41%
7	NU	NORTHEAST UTILITIES	9.00%	x	{ [((1.18) + 1) ÷ 2] - 1 }	=	0.79%
8	NST	NSTAR	0.01%	x	{ [((1.80) + 1) ÷ 2] - 1 }	=	0.00%
9	OTTR	OTTER TAIL CORPORATION	2.25%	x	{ [((1.24) + 1) ÷ 2] - 1 }	=	0.27%
10	UIL	UIL HOLDINGS	10.00%	x	{ [((1.35) + 1) ÷ 2] - 1 }	=	1.76%
11	**AVERAGE**						**0.63%**

REFERENCES:
COLUMN (A): TESTIMONY, WAR
COLUMN (B): VALUE LINE INVESTMENT SURVEY RATINGS & REPORTS DATED 08/07/2009, 08/28/2009 & 09/25/2009
COLUMN (C): COLUMN (A) x COLUMN (B)

UNS ELECTRIC, INC.
TEST YEAR ENDED DECEMBER 31, 2008
DIVIDEND GROWTH COMPONENTS

DOCKET NO. E-04204A-09-0206
SCHEDULE WAR - 5

LINE NO.	STOCK SYMBOL	LOCAL DISTRIBUTION COMPANY NAME	OPERATING PERIOD	(A) RETENTION RATIO (b)	x	(B) RETURN ON BOOK EQUITY (r)	=	(C) DIVIDEND GROWTH (g)	(D) BOOK VALUE ($/SHARE)	(E) SHARES OUTST. (MILLIONS)	(F) SHARE GROWTH
1	ALE	ALLETE, INC.	2004	0.7778		6.10%		4.74%	21.23	29.70	
2			2005	0.4960		11.30%		5.60%	20.03	30.10	
3			2006	0.4765		11.60%		5.53%	21.90	30.40	
4			2007	0.4675		11.80%		5.52%	24.11	30.80	
5			2008	0.3901		10.00%		3.90%	25.37	32.60	
6			GROWTH 2004 - 2008					5.06%	-		2.36%
7			2009	0.0974		7.00%		0.68%		34.50	5.83%
8			2010	0.2174		8.00%		1.74%		36.00	5.09%
9			2012-14	0.3018		9.00%		2.72%	3.00%	41.00	4.69%
10											
11	BKH	BLACK HILLS CORPORATION	2004	0.2874		7.80%		2.24%	22.43	32.48	
12			2005	0.3934		9.50%		3.74%	22.29	33.16	
13			2006	0.4027		9.40%		3.79%	23.68	33.37	
14			2007	0.4888		10.30%		5.03%	25.66	37.80	
15			2008	-6.7778		0.70%		NMF	27.19	38.64	
16			GROWTH 2004 - 2008					3.70%	5.00%		4.44%
17			2005	0.4083		8.50%		3.47%		39.00	0.93%
18			2006	0.3455		8.00%		2.76%		39.25	0.79%
19			2007	0.4800		9.50%		4.56%	4.00%	40.00	0.69%
20											
21	CHG	CH ENERGY GROUP, INC.	2004	0.1970		8.60%		1.69%	31.31	15.76	
22			2005	0.2313		8.80%		2.04%	31.97	15.76	
23			2006	0.1563		7.90%		1.23%	32.54	15.76	
24			2007	0.2000		8.10%		1.62%	33.19	15.76	
25			2008	0.0270		6.70%		0.18%	33.17	15.78	
26			GROWTH 2004 - 2008					1.35%	1.50%		0.03%
27			2009	0.0400		6.50%		0.26%		15.80	0.13%
28			2010	0.1360		7.00%		0.95%		15.80	0.06%
29			2012-14	0.2800		8.00%		2.24%	1.50%	16.00	0.28%
30											
31	EDE	EMPIRE DISTRICT ELECTRIC COMPANY	2004	-0.4884		5.80%		NMF	14.76	25.70	
32			2005	-0.3913		6.00%		NMF	15.08	26.08	
33			2006	0.0922		8.50%		0.78%	15.49	30.25	
34			2007	-0.1743		6.20%		NMF	16.04	33.61	
35			2008	-0.0940		7.50%		NMF	15.56	33.98	
36			GROWTH 2004 - 2008					0.78%	1.50%		7.23%
37			2009	0.1467		8.50%		1.25%		38.00	11.83%
38			2010	0.1742		9.50%		1.65%		40.25	8.84%
39			2012-14	0.2286		10.50%		2.40%	2.00%	41.00	3.83%

REFERENCES:
COLUMNS (A) & (B): VALUE LINE INVESTMENT SURVEY - RATINGS & REPORTS
DATED 08/07/2009, 08/28/2009 AND 09/25/2009
COLUMN (C): COLUMN (A) x COLUMN (B)
COLUMN (C): LINES 6, 16, 26 & 36, SIMPLE AVERAGE GROWTH, 2004 - 2008
COLUMN (D): VALUE LINE INVESTMENT SURVEY
COLUMN (D): LINES 6, 16, 26 & 36, COMPOUND GROWTH RATE
COLUMN (E): VALUE LINE INVESTMENT SURVEY
COLUMN (F): COMPOUND GROWTH RATES OF DATES SHOWN

UNS ELECTRIC, INC.
TEST YEAR ENDED DECEMBER 31, 2008
DIVIDEND GROWTH COMPONENTS

LINE NO.	STOCK SYMBOL	LOCAL DISTRIBUTION COMPANY NAME	OPERATING PERIOD	(A) RETENTION RATIO (b)	x	(B) RETURN ON BOOK EQUITY (r)	=	(C) DIVIDEND GROWTH (g)	(D) BOOK VALUE ($/SHARE)	(E) SHARES OUTST. (MILLIONS)	(F) SHARE GROWTH
1	HE	HAWAIIAN ELECTRIC INDUSTRIES, INC.	2004	0.0882		8.90%		0.79%	15.01	80.69	
2			2005	0.1507		9.70%		1.46%	15.02	80.98	
3			2006	0.0677		9.90%		0.67%	13.44	81.46	
4			2007	-0.1171		7.20%		NMF	15.29	83.43	
5			2008	-0.1589		6.50%		NMF	15.35	90.52	
6			GROWTH 2004 - 2008					0.97%	1.00%		2.92%
7			2009	-0.0783		7.50%		NMF		91.75	1.36%
8			2010	0.1733		9.50%		1.65%		92.00	0.81%
9			2012-14	0.2914		10.00%		2.91%	2.00%	93.50	0.65%
10											
11	MGEE	MGE ENERGY, INC.	2004	0.2316		10.00%		2.32%	16.59	20.39	
12			2005	0.1274		9.30%		1.18%	16.81	20.45	
13			2006	0.3252		11.30%		3.68%	17.89	20.98	
14			2007	0.3789		11.40%		4.32%	19.49	21.95	
15			2008	0.3992		11.00%		4.39%	20.88	22.90	
16			GROWTH 2004 - 2008					3.18%	8.00%		2.94%
17			2009	0.3958		11.50%		4.55%		23.20	1.31%
18			2010	0.4120		11.00%		4.53%		23.20	0.65%
19			2012-14	0.4500		12.00%		5.40%	7.00%	25.00	1.77%
20											
21	NU	NORTHEAST UTILITIES	2004	0.3077		5.10%		1.57%	17.80	129.03	
22			2005	0.3061		5.10%		1.56%	18.46	131.59	
23			2006	0.1098		4.30%		0.47%	18.14	154.23	
24			2007	0.5094		8.40%		4.28%	18.65	156.22	
25			2008	0.5538		9.60%		5.32%	19.38	155.83	
26			GROWTH 2004 - 2008					2.64%	2.00%		4.83%
27			2009	0.4865		9.00%		4.38%		176.00	12.94%
28			2010	0.4872		9.50%		4.63%		176.00	6.27%
29			2012-14	0.4889		8.50%		4.16%	5.00%	210.00	6.15%
30											
31	NST	NSTAR	2004	0.3580		13.10%		4.69%	13.52	106.55	
32			2005	0.5246		12.80%		6.71%	14.37	106.81	
33			2006	0.2021		13.10%		2.65%	14.82	106.81	
34			2007	0.3575		13.00%		4.65%	15.95	106.81	
35			2008	0.3559		13.30%		4.73%	16.74	106.81	
36			GROWTH 2004 - 2008					4.69%	5.00%		0.06%
37			2009	0.3489		13.50%		4.71%		106.81	0.00%
38			2010	0.3608		14.00%		5.05%		106.81	0.00%
39			2012-14	0.4000		14.50%		5.80%	5.50%	106.81	0.00%

REFERENCES:
COLUMNS (A) & (B): VALUE LINE INVESTMENT SURVEY - RATINGS & REPORTS
DATED 08/07/2009, 08/28/2009 AND 09/25/2009
COLUMN (C): COLUMN (A) x COLUMN (B)
COLUMN (C): LINES 6, 16, 26 & 36, SIMPLE AVERAGE GROWTH, 2004 - 2008

COLUMN (D): VALUE LINE INVESTMENT SURVEY
COLUMN (D): LINES 6, 16, 26 & 36, COMPOUND GROWTH RATE
COLUMN (E): VALUE LINE INVESTMENT SURVEY
COLUMN (F): COMPOUND GROWTH RATES OF DATES SHOWN

LINE NO.	STOCK SYMBOL	LOCAL DISTRIBUTION COMPANY NAME	OPERATING PERIOD	(A) RETENTION RATIO (b)	x	(B) RETURN ON BOOK EQUITY (r)	=	(C) DIVIDEND GROWTH (g)	(D) BOOK VALUE ($/SHARE)	(E) SHARES OUTST. (MILLIONS)	(F) SHARE GROWTH
1	OTTR	OTTER TAIL CORPORATION	2004	0.2667		9.10%		2.43%	14.81	28.98	
2			2005	0.3708		11.20%		4.15%	15.80	29.40	
3			2006	0.3195		10.20%		3.26%	16.67	29.52	
4			2007	0.3427		10.20%		3.50%	17.55	29.85	
5			2008	-0.0917		5.10%		NMF	19.14	35.38	
6			GROWTH 2004 - 2008					3.33%	8.00%		5.12%
7			2009	-0.3222		4.50%		NMF		36.00	1.75%
8			2010	-0.0167		6.00%		NMF		37.00	2.26%
9			2012-14	0.3158		8.50%		2.68%	4.00%	40.00	2.49%
10											
11	UIL	UIL HOLDINGS	2004	-0.1234		6.70%		NMF	22.84	24.01	
12			2005	-0.3308		6.70%		NMF	22.39	24.32	
13			2006	0.0699		9.90%		0.69%	18.53	24.86	
14			2007	0.0749		10.10%		0.76%	18.55	25.03	
15			2008	0.0847		10.10%		0.86%	18.85	25.17	
16			GROWTH 2004 - 2008					0.77%	-2.00%		1.19%
17			2009	0.0895		10.00%		0.89%		30.00	19.19%
18			2010	0.1350		10.00%		1.35%		30.20	9.54%
19			2012-14	0.2311		10.50%		2.43%	2.50%	30.80	4.12%

REFERENCES:

COLUMNS (A) & (B): VALUE LINE INVESTMENT SURVEY - RATINGS & REPORTS
DATED 08/07/2009, 08/28/2009 AND 09/25/2009

COLUMN (C): COLUMN (A) x COLUMN (B)

COLUMN (C): LINES 6 & 16, SIMPLE AVERAGE GROWTH, 2004 - 2008

COLUMN (D): VALUE LINE INVESTMENT SURVEY

COLUMN (D): LINES 6, 16, 26 & 36, COMPOUND GROWTH RATE

COLUMN (E): VALUE LINE INVESTMENT SURVEY

COLUMN (F): COMPOUND GROWTH RATES OF DATES SHOWN

UNS ELECTRIC, INC.
TEST YEAR ENDED DECEMBER 31, 2008
GROWTH RATE COMPARISON

DOCKET NO. E-04204A-09-0206
SCHEDULE WAR - 6

LINE	STOCK	(A)	(B) ZACKS	(C) VALUE LINE PROJECTED			(D) VALUE LINE HISTORIC			(E) VALUE LINE &	(F) 5 - YEAR COMPOUND HISTORY		
NO.	SYMBOL	(br) + (sv)	EPS	EPS	DPS	BVPS	EPS	DPS	BVPS	ZACKS AVGS.	EPS	DPS	BVPS
1	ALE	3.52%	4.00%	-1.00%	3.00%	3.00%	-	-	-	2.25%	20.22%	54.74%	4.55%
2	BKH	6.06%	-	10.00%	2.50%	4.00%	-8.00%	3.50%	5.00%	2.83%	-43.29%	3.08%	4.93%
3	CHG	2.29%	-	3.00%	NMF	1.50%	-1.50%	-	1.50%	1.13%	-4.69%	0.00%	1.45%
4	EDE	3.00%	-	6.00%	1.50%	2.00%	3.50%	-	1.50%	2.90%	8.00%	0.00%	1.33%
5	HE	2.98%	6.00%	7.00%	NMF	2.00%	-6.00%	-	1.00%	2.00%	-5.82%	0.00%	0.56%
6	MGEE	5.76%	5.00%	6.00%	0.50%	7.00%	6.00%	1.00%	8.00%	4.79%	7.68%	1.26%	5.92%
7	NU	5.04%	8.50%	8.00%	0.00%	5.00%	3.00%	8.50%	2.00%	5.93%	19.57%	7.14%	2.15%
8	NST	5.75%	5.70%	8.00%	5.50%	5.50%	4.00%	6.00%	5.00%	5.67%	5.98%	6.06%	5.49%
9	OTTR	2.97%	11.70%	4.00%	2.00%	4.00%	-1.50%	2.00%	8.00%	4.31%	-7.67%	1.99%	6.62%
10	UIL	4.16%	4.20%	3.00%	NMF	2.50%	-	-	-2.00%	1.93%	5.25%	0.00%	-4.69%
11				5.40%	2.14%	3.65%	-0.06%	4.20%	3.33%		0.52%	7.43%	2.83%
12	AVERAGES	4.15%	6.44%		3.73%			2.49%		3.37%		3.59%	

REFERENCES:
COLUMN (A): SCHEDULE WAR - 4, PAGE 1, COLUMN C
COLUMN (B): ZACKS INVESTMENT RESEARCH (www.zacks.com)
COLUMN (C): VALUE LINE INVESTMENT SURVEY - RATINGS & REPORTS DATED 08/07/2009, 08/28/2009 AND 09/25/2009
COLUMN (D): VALUE LINE INVESTMENT SURVEY - RATINGS & REPORTS DATED 08/07/2009, 08/28/2009 AND 09/25/2009
COLUMN (E): SIMPLE AVERAGE OF COLUMNS (B) THRU (D) LINES 1 THROUGH 17
COLUMN (F): 5-YEAR ANNUAL GROWTH RATE CALCULATED WITH DATA COMPILED FROM VALUE LINE INVESTMENT SURVEY - RATINGS & REPORTS DATED 08/07/2009, 08/28/2009 AND 09/25/2009

BASED ON A GEOMETRIC MEAN:

LINE NO.	STOCK SYMBOL	k	=	r_f	+ [	(A) ß	x (	r_m	-	r_f	)]	=	(B) EXPECTED RETURN
1	ALE	k	=	2.41%	+ [	0.70	x (	9.60%	-	5.40%	)]	=	5.35%
2	BKH	k	=	2.41%	+ [	0.85	x (	9.60%	-	5.40%	)]	=	5.98%
3	CHG	k	=	2.41%	+ [	0.65	x (	9.60%	-	5.40%	)]	=	5.14%
4	EDE	k	=	2.41%	+ [	0.75	x (	9.60%	-	5.40%	)]	=	5.56%
5	HE	k	=	2.41%	+ [	0.70	x (	9.60%	-	5.40%	)]	=	5.35%
6	MGEE	k	=	2.41%	+ [	0.65	x (	9.60%	-	5.40%	)]	=	5.14%
7	NU	k	=	2.41%	+ [	0.70	x (	9.60%	-	5.40%	)]	=	5.35%
8	NST	k	=	2.41%	+ [	0.65	x (	9.60%	-	5.40%	)]	=	5.14%
9	OTTR	k	=	2.41%	+ [	0.90	x (	9.60%	-	5.40%	)]	=	6.19%
10	UIL	k	=	2.41%	+ [	0.70	x (	9.60%	-	5.40%	)]	=	5.35%
11	**AVERAGE**					0.73							5.46%

REFERENCES:
COLUMN (A): SHARPE LITNER CAPITAL ASSET PRICING MODEL ("CAPM") FORMULA

$$k = r_f + [\,ß\,(r_m - r_f)\,]$$

WHERE:
k = THE EXPECTED RETURN ON A GIVEN SECURITY
r_f = RATE OF RETURN ON A RISK FREE ASSET PROXY (a)
ß = THE BETA COEFFICIENT OF A GIVEN SECURITY
r_m = PROXY FOR THE MARKET RATE OF RETURN (b)
r_f = PROXY FOR THE RISK FREE RATE ON INTERMEDIATE TREASURIES (b)

COLUMN (B): EXPECTED RATE OF RETURN USING THE CAPM FORMULA

NOTES

(a) AN 8-WEEK AVERAGE OF THE YIELD ON A 5-YEAR U.S. TREASURY INSTRUMENT THAT APPEARED IN *VALUE LINE INVESTMENT SURVEY*'S "SELECTION & OPINIONS" PUBLICATION FROM 08/21/2009 THROUGH 10/09/2009 WAS USED AS A RISK FREE RATE OF RETURN.

(b) THE RISK PREMIUM (RM - RF) USED THE GEOMETRIC MEAN FOR S&P 500 TOTAL RETURNS OVER THE 1926 - 2008 PERIOD MINUS TOTAL RETURNS ON INTERMEDIATE TREASURIES OVER THE SAME PERIOD. THE DATA WAS OBTAINED FROM MORNINGSTAR'S STOCKS, BONDS, BILLS AND INFLATION: 2009 YEARBOOK.

BASED ON AN ARITHMETIC MEAN:

LINE NO.	STOCK SYMBOL	k	=	r_f	+ [	(A) ß	x (	r_m	-	r_f	)]	=	(B) EXPECTED RETURN
1	ALE	k	=	2.41%	+ [	0.70	x (	11.70%	-	5.60%	)]	=	6.68%
2	BKH	k	=	2.41%	+ [	0.85	x (	11.70%	-	5.60%	)]	=	7.60%
3	CHG	k	=	2.41%	+ [	0.65	x (	11.70%	-	5.60%	)]	=	6.38%
4	EDE	k	=	2.41%	+ [	0.75	x (	11.70%	-	5.60%	)]	=	6.99%
5	HE	k	=	2.41%	+ [	0.70	x (	11.70%	-	5.60%	)]	=	6.68%
6	MGEE	k	=	2.41%	+ [	0.65	x (	11.70%	-	5.60%	)]	=	6.38%
7	NU	k	=	2.41%	+ [	0.70	x (	11.70%	-	5.60%	)]	=	6.68%
8	NST	k	=	2.41%	+ [	0.65	x (	11.70%	-	5.60%	)]	=	6.38%
9	OTTR	k	=	2.41%	+ [	0.90	x (	11.70%	-	5.60%	)]	=	7.90%
10	UIL	k	=	2.41%	+ [	0.70	x (	11.70%	-	5.60%	)]	=	6.68%
11	**AVERAGE**					0.73							6.83%

REFERENCES:
COLUMN (A): SHARPE LITNER CAPITAL ASSET PRICING MODEL ("CAPM") FORMULA

$k = r_f + [ß (r_m - r_f)]$

WHERE: k = THE EXPECTED RETURN ON A GIVEN SECURITY
r_f = RATE OF RETURN ON A RISK FREE ASSET PROXY (a)
ß = THE BETA COEFFICIENT OF A GIVEN SECURITY
r_m = PROXY FOR THE MARKET RATE OF RETURN (b)
r_f = PROXY FOR THE RISK FREE RATE ON INTERMEDIATE TREASURIES (b)

COLUMN (B): EXPECTED RATE OF RETURN USING THE CAPM FORMULA

NOTES

(a) AN 8-WEEK AVERAGE OF THE YIELD ON A 5-YEAR U.S. TREASURY INSTRUMENT THAT APPEARED IN VALUE LINE INVESTMENT SURVEY'S "SELECTION & OPINIONS" PUBLICATION FROM 08/21/2009 THROUGH 10/09/2009 WAS USED AS A RISK FREE RATE OF RETURN.

(b) THE RISK PREMIUM (RM - RF) USED THE ARITHMETIC MEAN FOR S&P 500 TOTAL RETURNS OVER THE 1926 - 2008 PERIOD MINUS TOTAL RETURNS ON INTERMEDIATE TREASURIES OVER THE SAME PERIOD. THE DATA WAS OBTAINED FROM MORNINGSTAR'S STOCKS, BONDS, BILLS AND INFLATION: 2009 YEARBOOK

UNS ELECTRIC, INC.
TEST YEAR ENDED DECEMBER 31, 2008
ECONOMIC INDICATORS - 1990 TO PRESENT

DOCKET NO. E-04204A-09-0206
SCHEDULE WAR - 8

LINE NO.	YEAR	(A) CHANGE IN CPI	(B) CHANGE IN GDP (1996 $)	(C) PRIME RATE	(D) FED. DISC. RATE	(E) FED. FUNDS RATE	(F) 91-DAY T-BILLS	(G) 30-YR T-BONDS	(H) A-RATED UTIL. BOND YIELD	(I) Baa-RATED UTIL. BOND YIELD
1	1990	5.39%	1.90%	10.01%	6.98%	8.10%	7.50%	7.49%	9.86%	10.06%
2	1991	4.25%	-0.20%	8.46%	5.45%	5.69%	5.38%	5.38%	9.36%	9.55%
3	1992	3.03%	3.30%	6.25%	3.25%	3.52%	3.43%	3.43%	8.69%	8.86%
4	1993	2.96%	2.70%	6.00%	3.00%	3.02%	3.00%	3.00%	7.59%	7.91%
5	1994	2.61%	4.00%	7.14%	3.60%	4.21%	4.25%	4.25%	8.31%	8.63%
6	1995	2.81%	2.50%	8.83%	5.21%	5.83%	5.49%	5.49%	7.89%	8.29%
7	1996	2.93%	3.70%	8.27%	5.02%	5.30%	5.01%	5.01%	7.75%	8.17%
8	1997	2.34%	4.50%	8.44%	5.00%	5.46%	5.06%	5.06%	7.60%	8.12%
9	1998	1.55%	4.20%	8.35%	4.92%	5.35%	4.78%	4.78%	7.04%	7.27%
10	1999	2.19%	4.50%	7.99%	4.62%	4.97%	4.64%	4.64%	7.62%	7.88%
11	2000	3.38%	3.70%	9.23%	5.73%	6.24%	5.82%	5.82%	8.24%	8.36%
12	2001	2.83%	0.80%	6.92%	3.41%	3.88%	3.40%	5.95%	7.59%	8.02%
13	2002	1.59%	1.60%	4.67%	1.17%	1.67%	1.61%	5.38%	7.41%	7.98%
14	2003	2.27%	2.50%	4.12%	2.03%	1.13%	1.01%	4.92%	6.18%	6.64%
15	2004	2.68%	3.60%	4.34%	2.34%	1.35%	1.37%	5.03%	5.77%	6.20%
16	2005	3.39%	2.90%	6.16%	4.19%	3.22%	3.15%	4.57%	5.38%	5.78%
17	2006	3.24%	2.80%	7.97%	5.96%	4.97%	4.73%	4.91%	5.94%	6.30%
18	2007	2.85%	2.00%	8.05%	5.86%	5.02%	4.36%	4.84%	6.07%	6.24%
19	2008	3.58%	1.30%	5.09%	2.39%	1.92%	1.37%	4.28%	6.34%	6.64%
20	CURRENT	-1.40%	-1.00%	3.25%	0.50%	0.00% - 0.25%	0.11%	4.05%	5.40%	5.73%

REFERENCES:
COLUMN (A): 1990 - CURRENT, U.S. DEPARTMENT OF LABOR, BUREAU OF LABOR STATISTICS WEB SITE
COLUMN (B): 1990 - CURRENT, U.S. DEPARTMENT OF COMMERCE, BUREAU OF ECONOMIC ANALYSIS WEB SITE
COLUMN (C) THROUGH (G): 1990 - 2003, FEDERAL RESERVE BANK OF ST. LOUIS WEB SITE
COLUMN (C) THROUGH (D): CURRENT, THE VALUE LINE INVESTMENT SURVEY, DATED 10/09/2009
COLUMN (F) THROUGH (I): CURRENT, THE VALUE LINE INVESTMENT SURVEY, DATED 10/09/2009
COLUMN (H) THROUGH (I): 1990 - 2000, MOODY'S PUBLIC UTILITY REPORTS
COLUMN (H) THROUGH (I): 2001, MERGENT 2002 PUBLIC UTILITY MANUAL
COLUMN (H) THROUGH (I): 2003 MERGENT NEWS REPORTS

UNS ELECTRIC, INC.
TEST YEAR ENDED DECEMBER 31, 2008
CAPITAL STRUCTURES OF SAMPLE COMPANIES

DOCKET NO. E-04204A-09-0206
SCHEDULE WAR - 9

LINE NO.		ALE	PCT.	BKH	PCT.	CHG	PCT.	EDE	PCT.	HE	PCT.
1	DEBT	$ 588.3	41.6%	$ 501.3	32.3%	$ 413.9	43.2%	$ 611.6	53.6%	$ 307.0	18.1%
3	PREFERRED STOCK	0.0	0.0%	0.0	0.0%	21.0	2.2%	0.0	0.0%	0.0	0.0%
5	COMMON EQUITY	827.1	58.4%	1,050.5	67.7%	523.5	54.6%	528.9	46.4%	1,389.5	81.9%
7	TOTALS	$ 1,415.4	100%	$ 1,551.8	100%	$ 958.5	100%	$ 1,140.4	100%	$ 1,696.5	100%
10		MGEE	PCT.	NU	PCT.	NST	PCT.	OTTR	PCT.	UIL	PCT.
12	DEBT	$ 272.4	36.3%	$ 4,103.2	57.6%	$ 2,343.7	56.1%	$ 339.7	32.9%	$ 549.0	53.6%
14	PREFERRED STOCK	0.0	0.0%	0.0	0.0%	43.0	1.0%	15.5	1.5%	0.0	0.0%
16	COMMON EQUITY	478.2	63.7%	3,020.3	42.4%	1,788.2	42.8%	677.2	65.6%	474.6	46.4%
18	TOTALS	$ 750.6	100%	$ 7,123.5	100%	$ 4,174.8	100%	$ 1,032.5	100%	$1,023.6	100%

LINE NO.		ELECTRIC PROXY AVERAGE	PCT.
24	DEBT	$ 1,003.0	48.1%
26	PREFERRED STOCK	8.0	0.4%
28	COMMON EQUITY	1,075.8	51.6%
30	TOTALS	$ 2,086.8	100%

<u>REFERENCE:</u>
MOST RECENT SEC 10-K FILINGS OR ANNUAL REPORTS