

Exhibit No.:

Issues: Cost of Capital

Witness: Samuel C. Hadaway

Sponsoring Party: Aquila Networks-L&P

Case No.: HR-

Before the Public Service Commission  
of the State of Missouri

Direct Testimony

of

Samuel C. Hadaway

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**BEFORE THE PUBLIC SERVICE COMMISSION  
OF THE STATE OF MISSOURI  
DIRECT TESTIMONY OF SAMUEL C. HADAWAY  
ON BEHALF OF AQUILA, INC.  
D/B/A AQUILA NETWORKS-L&P  
CASE NO. HR-\_\_\_\_\_**

1    **I.    INTRODUCTION AND SUMMARY OF RECOMMENDATIONS**

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

3    A.    My name is Samuel C. Hadaway. I am a Principal in FINANCO, Inc., Financial  
4    Analysis Consultants, 3520 Executive Center Drive, Austin, Texas 78731.

5    **Q.    On whose behalf are you testifying?**

6    A.    I am testifying on behalf of Aquila, Inc. (“Aquila” or “Company”) in this  
7    proceeding before the Missouri Public Service Commission (“Commission”).

8    **Q.    Please state your educational background and describe your professional  
9    training and experience.**

10   A.    I have an economics degree from Southern Methodist University and MBA and  
11   Ph.D. degrees in finance from the University of Texas at Austin (“UT Austin”). I  
12   am presently an adjunct professor in the McCombs School of Business at UT  
13   Austin. I have taught economics and finance courses at several universities, and I  
14   have conducted research and directed graduate students writing in these areas. I  
15   was previously Director of the Economic Research Division at the Public Utility  
16   Commission of Texas (“PUC”), where I supervised the PUC finance, economics,  
17   and accounting staff and served as the PUC’s chief financial witness in electric  
18   and telephone utility rate cases. In various utility conferences I have taught  
19   courses on cost of capital, capital structure, utility financial condition, and cost  
20   allocation and rate design methods. I have made presentations before the New

1 York Society of Security Analysts, the National Rate of Return Analysts Forum,  
2 and various other professional and legislative groups. I have served on the board  
3 of directors and as a vice president of the Financial Management Association.

4 A list of my publications and testimony I have given before various  
5 regulatory bodies and in state and federal courts is contained in my resume, which  
6 is included as Appendix A.

7 **Q. What is the purpose of your testimony?**

8 A. The purpose of my testimony is to estimate the market required rate of return on  
9 equity ("ROE") for Aquila's St. Joseph Light & Power Company ("LP") Missouri  
10 steam operations and to present and support the requested capital structure and  
11 overall rates of return for the Company's steam operations.

12 **Q. Please describe the LP steam operations.**

13 A. The steam operations of LP flow steam generated as a by-product from LP's  
14 power production plants to steam customers through a system built specifically to  
15 handle its distribution. Since electric power and steam are produced  
16 simultaneously by LP's power generating facilities, there should be no  
17 differentiation in the cost of capital or capital structure between the two  
18 businesses.

19 **Q. What are you recommending as the cost of capital that should be adopted for**  
20 **LP's steam operations?**

21 A. Because the products of steam and electricity for LP are sourced from the same  
22 investment in generation made by the Company, I am recommending the same  
23 allowed return and capital structure for both. In support of my recommendations

1 for the steam operations, I am adopting the same analysis, conclusions and  
2 testimony as I filed for the LP electric operations. There is no differentiation in  
3 the level of risk between the two businesses and they should be entitled to earn  
4 the same rate of return. As in the LP electric case, I am therefore recommending  
5 that the Commission allow LP's steam operations to earn a return on equity of  
6 11.5%, a cost of debt of 7.96% on a capital structure consisting of 48.2% equity  
7 and 51.2% debt. My Schedule SCH- 6a has been included to illustrate the "stand-  
8 alone" credit metrics for the LP steam operations with the same sensitivities to  
9 assumed rate relief as illustrated in Schedule SCH- 6 of my electric testimony.

10 **Q. Please outline and describe the testimony you will present.**

11 A. My testimony is divided into six sections. Following this introduction, in Section  
12 II, I present and explain the requested capital structure and overall rates of return  
13 for MPS/LP. In Section III, I discuss the concept of financial integrity and  
14 explain why it is a key element in the regulatory process. In Section IV, I review  
15 various methods for estimating the cost of equity capital. In this section, I discuss  
16 the discounted cash flow ("DCF") model as well as risk premium methods and  
17 other approaches often used to estimate the cost of capital. In Section V, I review  
18 general capital market costs and conditions and discuss recent developments in  
19 the electric utility industry that affect the cost of capital. In Section VI, I present  
20 the details of my cost of equity studies and provide a summary table of my ROE  
21 results.

22 **Q. Please summarize your cost of equity studies and state your overall rate of**  
23 **return recommendation.**

1 A. First, my recommendation is premised upon the fair rate of return principles  
2 established by the U.S. Supreme Court in *Federal Power Commission v. Hope*  
3 *Natural Gas Company*, 320 US 591, 603 (1944) and *Blue field Waterworks v.*  
4 *Public Service Commission*, 262 US 679, 693 (1923). That is to say, the return  
5 authorized a utility by a regulatory body, such as the Commission, should be  
6 commensurate with returns on investments in other enterprises having  
7 corresponding risks. The return should also be sufficient to assure confidence in  
8 the financial integrity of the utility so as to maintain its credit and to attract capital  
9 so that it is able to properly discharge its public duties. Given these legal  
10 principles, I have used several methods to determine an appropriate ROE and  
11 overall rates of return for Aquila's Missouri operating divisions. These methods  
12 and the underlying economic models are applied to an investment grade company  
13 reference group of other similarly situated electric utilities.

14 **Q. Please explain.**

15 A. My ROE estimate is based on alternative versions of the DCF model and is  
16 confirmed by my risk premium analysis and my review of projected interest rates  
17 and economic conditions. The DCF model cannot be applied directly to Aquila  
18 because the Company does not presently pay dividends to its shareholders and, in  
19 any case, diverse "parent" Company financial data are not the appropriate basis  
20 for setting the required rates of return for the MPS/LP operating divisions. For  
21 this reason I apply the DCF model to a large sample reference group of  
22 investment grade electric utilities selected from the *Value Line Investment Survey*.  
23 To be included in my group, reference companies must have at least a BBB-/Baa3

1 bond rating; they must derive at least 70 percent of revenues from regulated utility  
2 sales; and they must have consistent financial records not affected by recent  
3 mergers or restructuring, and a consistent dividend record with no recent dividend  
4 cuts.

5 To test my DCF results, I also conduct a risk-premium analysis based on  
6 ROEs allowed by state regulators relative to Moody's utility debt costs. In this  
7 analysis, I also include S&P's forecasted higher interest rates for the coming year.  
8 S&P forecasts that long-term Government and corporate interest rates will  
9 increase by 80 to 100 basis points (0.80%-1.00%) by the 2<sup>nd</sup> Quarter of 2006.  
10 Under current economic, market, and electric utility industry conditions, the  
11 combination of the DCF and risk premium models tempered by consensus  
12 forecasts about future interest rates provides an appropriate approach for  
13 estimating MPS/LP's fair cost of equity capital.

14 **Q. Should the reference group ROE be applied directly to MPS/LP?**

15 A. No. The reference group is the appropriate starting for point for estimating ROE,  
16 but the reference group ROE is lower than the fair cost of equity for MPS/LP.  
17 This is so because MPS/LP faces considerably higher construction and operating  
18 risks than the average company in the reference group. Under these  
19 circumstances the Commission should add an ROE increment or adjustment to the  
20 reference group ROE to account for MPS/LP's higher risks.

21 **Q. Why do you use this approach?**

22 A. Again, as I have indicated and as I will discuss in more detail below, this  
23 approach of using a comparable reference group of investment grade utilities and

1 adjusting for risk is consistent with the legal requirements of *Hope* and *Bluefield*  
2 and it is the appropriate method for determining a fair rate of return on MPS/LP  
3 equity capital. It is important to note that the risk adjustment is not related to  
4 Aquila's relatively weak financial condition that has resulted from the Company's  
5 financial losses. MPS/LP's specific risks and the need for the risk adjustment  
6 stem from the higher construction and operating requirements they face.

7 **Q. Please explain.**

8 A. In the assessment of a fair rate of return for MPS/LP, I have evaluated the specific  
9 circumstances of these operating divisions relative to my reference group of  
10 investment grade utilities. The two key additional risk factors for MPS/LP are the  
11 magnitude of their expected capital expenditure programs in Missouri and the  
12 additional operating risks they face. As shown in my Schedule SCH-1, page 1 of  
13 3, MPS/LP capital expenditures over the next five years are expected to equal  
14 about 81 percent of their current net plant. For the average reference company,  
15 capital spending for the next five years is expected to be only 49 percent of net  
16 plant. MPS/LP's larger construction program increases their financing and  
17 regulatory risks and therefore should be reflected in a higher allowed rate of  
18 return. The Missouri expenditure program is discussed more fully in Company  
19 witness Jon Empson's testimony.

20 **Q. Are there other risk factors for MPS/LP?**

21 A. Yes. Other less easily quantified risk factors also include MPS/LP's smaller size  
22 and the heretofore existing prohibition against fuel and purchased power  
23 adjustment clauses in Missouri. This latter risk factor may have been mitigated



1 by legislation recently enacted by the Missouri legislature. I say “may” because  
2 at the time of this testimony it is uncertain whether this legislation will become  
3 law and, if it becomes law, how it will be applied to MPS/LP in this case. In  
4 Schedule SCH-1, pages 2 and 3, I have listed the status of fuel and purchased  
5 power adjustment clauses for each reference company. That analysis shows that  
6 about two-thirds of the companies have adjustment clauses. Additionally, there is  
7 sound academic evidence to support a small company risk premium. Considering  
8 all of this, to reflect the higher risk factors for MPS/LP’s operations, I have  
9 adjusted the ROE estimate from the reference group upward by 50 basis points.

10 **Q. What DCF ROE range is indicated by your analysis?**

11 A. My reference group analysis indicates a DCF ROE range of 10.6 percent to 11.1  
12 percent. As I will explain in more detail later, results from the traditional constant  
13 growth DCF model fail to meet basic checks of reasonableness and, therefore, are  
14 not included in my recommended DCF range.

15 **Q. Please explain.**

16 A. Currently, the traditional constant growth DCF model does not reasonably reflect  
17 the market cost of equity because that model, as typically applied, depends on  
18 historically low dividend yields and pessimistic analysts’ growth forecasts. These  
19 near-term circumstances do not reasonably reflect longer-term expectations for  
20 higher capital costs. My risk premium analysis, which serves as a check of  
21 reasonableness for the DCF results, demonstrates this fact. My basic risk  
22 premium analysis, based on allowed returns from other state regulators, indicates

1       that an ROE of 11.0 percent is appropriate, with other risk premium approaches  
2       indicating ROEs as high as 11.8 percent.

3               Because recent historical data have a significant effect in the traditional  
4       constant growth DCF model and because recent data appear to represent historic  
5       lows in the economic cycle, those data should not be the primary basis for setting  
6       MPS/LP's allowed rate of return.

7       **Q.    What do you conclude from your analysis?**

8       A.    Based on the combination of quantitative model results and my review of current  
9       economic, market, and electric utility industry conditions, I estimate the reference  
10      group companies' fair cost of equity at 11.0 percent. This estimate is consistent  
11      with capital market trends and projections and is a reasonable estimate of capital  
12      costs that will prevail during the period that the rates from this case are in effect.  
13      To reflect the higher utility risk profile of MPS/LP as discussed previously, the  
14      ROE for the operating divisions should be increased by 50 basis points relative to  
15      the cost of equity for the reference group, which results in a requested ROE of  
16      11.5 percent.

17      **Q.    What is the cost of debt that you have used for MPS/LP?**

18      A.    As shown on Schedule SCH-2, the cost of debt for the MPS and LP divisions are  
19      6.7 percent and 7.96 percent, respectively. These figures result from the  
20      Company's internal capital assignment process whereby it assigns capital to its  
21      operating divisions on an "as needed basis." The cost of debt for each operating  
22      division reflects the average cost rates for issues assigned to each division as of  
23      December 31, 2004. All of the debt issues assigned to either division have been

1 assigned at “investment grade” rates per the Company’s ongoing policy to protect  
2 its ratepayers from the activities of its non-regulated businesses through its capital  
3 assignment process.

4 **II. MPS/LP’s CAPITAL STRUCTURE AND OVERALL RATE OF RETURN**

5 **Q. Please summarize the Company’s requested capital structure and overall**  
6 **rate of return.**

7 A. The following tables identify the requested capital structure components and the  
8 resulting overall rates of return:

9 **Missouri Public Service**

<u>Capital Components</u>	<u>Ratio</u>	<u>Cost</u>	<u>Weighted Cost</u>
Debt	51.8%	6.70%	3.47%
Common Equity	<u>48.2%</u>	11.50%	<u>5.54%</u>
TOTAL	100.00%		9.01%

14 **St. Joseph Light & Power**

<u>Capital Components</u>	<u>Ratio</u>	<u>Cost</u>	<u>Weighted Cost</u>
Debt	51.8%	7.96%	4.12%
Common Equity	<u>48.2%</u>	11.50%	<u>5.54%</u>
TOTAL	100.00%		9.67%

19 **Q. What is the basis for the Company’s requested capital structure and overall**  
20 **rate of return?**

21 A. The Company is requesting a hypothetical capital structure based on the 2004  
22 capital structure percentages of the investment grade 29-company reference group  
23 used to estimate ROE. This approach is appropriate because it comports with the  
24 *Hope* and *Bluefield* principles. That is to say, it matches the financial risk of the  
25 reference group to the estimated ROE and resulting overall rates of return for  
26 MPS/LP. It is also consistent with the Company’s internal capital assignment  
27 process, which it has used to assign the appropriate levels and amounts of equity

1 and debt to its utility operating divisions since 1987. Using this process, the  
2 Company has consistently assigned 47.5 percent equity and 52.5 percent debt to  
3 its electric utility operating divisions. As shown on my Schedule SCH-3, the  
4 reference group capital structure percentages support this level of capital  
5 assignment for the MPS/LP operations. As I will demonstrate below, this  
6 approach also produces an overall rate of return that is consistent with the lower  
7 end of the “optimal” utility capital structure range, with electric utility industry  
8 norms, and with minimum Standard & Poor’s (“S&P”) bond rating criteria for an  
9 investment grade bond rating.

10 **Q. What are the key financial ratios that determine whether a company has an**  
11 **investment grade bond rating?**

12 A. The most important ratios are a utility’s capitalization percentages and its cash  
13 flow coverage of interest and debt requirements. Schedule SCH-4 contains S&P’s  
14 bond rating criteria ratio guidelines for its three key financial ratios. To have a  
15 BBB bond rating, a utility with an operating risk profile of “6” is expected to have  
16 a funds from operations (“FFO”) interest coverage ratio of 3.0 times. This means  
17 that net income plus non-cash expenses (such as depreciation) needs to be at least  
18 three times interest requirements.<sup>1</sup> Similarly, the FFO/Total Debt ratio is  
19 expected to be at least 18 percent for a BBB rating. This means that net income  
20 plus non-cash expenses must equal 18 percent of outstanding debt, or conversely  
21 that debt should not be larger than about five times FFO. The third key ratio is

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<sup>1</sup>The “6” business position for MPS/LP is estimated from the assigned business position rankings of the other investor owned utilities in Missouri.

1 Total Debt/Total Capital. For a BBB bond rating, total debt should not exceed 58  
2 percent.

3 **Q. Are these financial ratios the only factors that may affect bond ratings?**

4 A. No. While absolute levels of financial ratios are extremely important, the rating  
5 agencies also look at trends and target ratios as well as other more qualitative  
6 factors. In the current “back to basics” environment, realistic plans for reducing  
7 debt and improving capitalization ratios have become increasingly important. In  
8 this environment constructive regulatory support for improving a utility’s  
9 financial condition is a key factor.

10 **Q. How is the “optimal” capital structure for a utility measured?**

11 A. In theory, the “optimal” capital structure is the mix of debt and equity that gives  
12 the lowest after-tax cost of capital. Although academic researchers have not  
13 produced a consensus about a generally optimal capital structure, within the  
14 electric utility industry an optimal capital structure range can be defined. This is  
15 so because industry norms for utilities are more consistent than in most other  
16 industries and industry norms play a very significant role in the utility bond rating  
17 process. Also, within given categories of utilities, companies are viewed by bond  
18 investors as close substitutes. In this environment, the cost of utility borrowing  
19 varies directly with the companies’ capital structure percentages and other bond  
20 rating metrics. In my analysis, I use these bond rating criteria and the actual  
21 borrowing costs by bond rating category to demonstrate the optimal capital  
22 structure range.

23 **Q. Please discuss the relationship between bond ratings and the cost of capital.**

1 A. The relationship between bond ratings (risk) and the cost of capital is a  
2 fundamental capital market principle. Specific factors for each company, such as  
3 operating risks and debt and equity percentages (financial risk) determine a  
4 company's total risk. This combination of operating and financial risks ultimately  
5 determines the company's bond rating. For example, fully integrated utilities  
6 with generation, transmission, and distribution functions are considered  
7 operationally more risky than "wires only" transmission and distribution  
8 companies. These and other operating characteristics are reflected in S&P  
9 business profile rankings. In addition to operating risks, a company's additional  
10 financial risk depends on the amounts of debt and equity it uses to finance its  
11 assets. More debt and less equity, for any level of operating risk, will result in a  
12 lower bond rating and higher interest costs for debt.

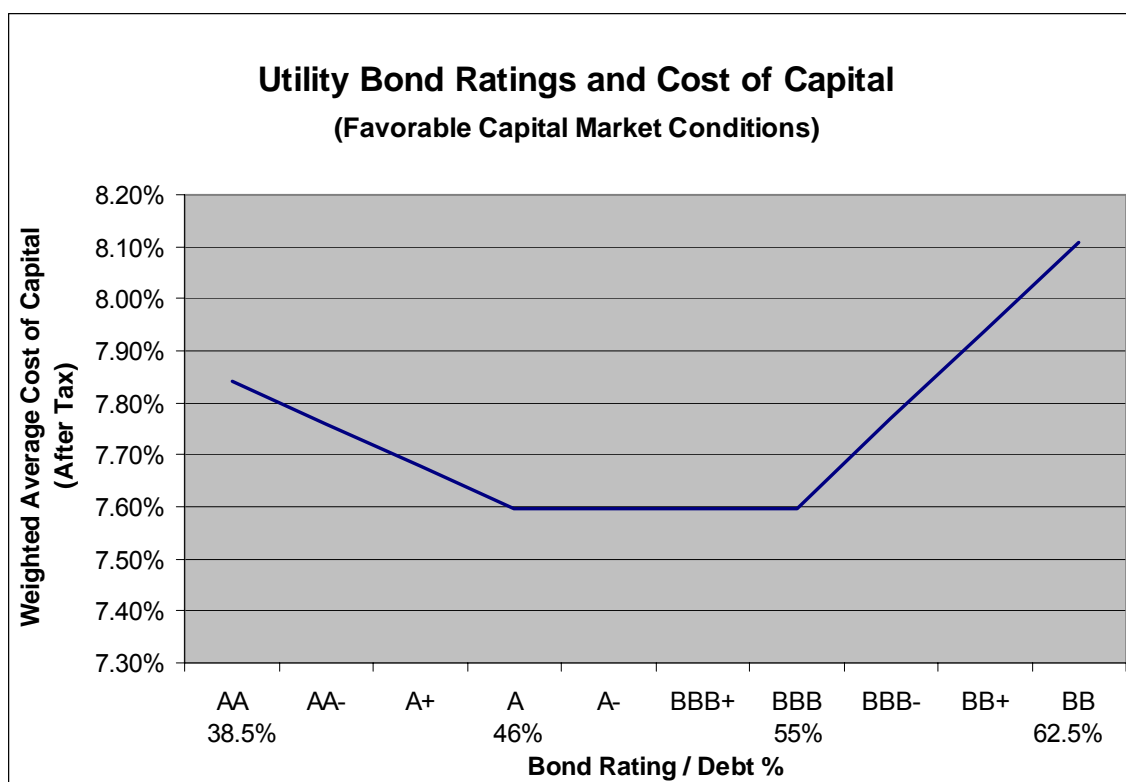
13 **Q. Is there an "optimal" bond rating?**

14 A. Yes, but the optimal bond rating at any point in time depends on both operating  
15 and financial risks, and on existing capital market conditions. During periods of  
16 low interest rates and stable market conditions, investors tend to accept lower  
17 bond ratings (higher risks) with a relatively small increment to required interest  
18 rates. The relative ease or stringency of market conditions can be measured by  
19 the spreads (differences) in interest rates among bond rating categories. When  
20 conditions are more settled, interest rate spreads are typically small, but when  
21 conditions are unsettled, spreads are much wider. For example, with the low rate  
22 environment during 2004, the average spread between Baa and A rated utility  
23 debt was only 24 basis points (the average interest rate for Baa bonds was 6.40

percent versus 6.16 percent for A-rated bonds)<sup>2</sup>. At other times under more stringent market conditions, spreads can be much wider. Under extreme conditions, such as those that existed in the early 1980s, there may be times when no triple-B rated debt can be issued at all.

The bond rating-cost of capital relationship is depicted in the graph below.

The capital structure percentages for the bond ratings shown on the graph are from S&P's Utility Bond Rating Criteria for an average electric utility business risk profile of 5. The interest rate data are the average rates for 2004 for Moody's investment grade utility categories, with spreads estimated for non-investment grade categories and extrapolated within rating groups.



<sup>2</sup> Moody's (Mergent) Bond Record, January, 2005 for investment grade interest rates. Reuters Corporate Spreads for Utilities, <http://bondchannel.bridge.com/publicspreads?Utilities> used to estimate non-investment grade rates.

1 Based on average interest rates for 2004, the lowest overall cost of capital  
2 occurred at debt percentages of between 46 percent and 55 percent, with resulting  
3 bond ratings between single-A and triple-B. For companies with higher debt  
4 percentages, the advantage of low cost debt and interest tax deductions were  
5 overcome by sharply rising interest costs for non-investment grade companies.

6 **Q. What steps have been taken by Aquila to improve its financial condition?**

7 A. Aquila has sold all of its non-domestic investments and it has eliminated most of  
8 its non-regulated activities and contracts. It has also recently announced plans for  
9 further asset sales to include about half of its domestic regulated utility holdings.  
10 I have attached as Schedule SCH-5, portions of the Company's April 1, 2005  
11 presentation to analysts, which outlines the Company's ongoing sales plan. That  
12 plan centers on raising significant further amounts of cash through utility asset  
13 sales and using the cash to pay down as much as \$700 million of existing debt.  
14 Depending on which specific assets are finally sold and the prices they bring, the  
15 asset sale strategy should significantly improve Aquila's balance sheet position  
16 and should provide much improved access to required capital for utility  
17 infrastructure investments.

18 As shown on Schedule SCH-5, the Company's plans to sell its current gas  
19 utility properties in Michigan, Minnesota, and Missouri and its electric utility  
20 properties in Colorado and Kansas as well as the St. Joseph Light & Power  
21 holdings in Missouri. Net utility plant at 12/31/2004 for these properties was  
22 \$874 million. Aquila's remaining utility properties (gas holdings in Colorado,  
23 Kansas, Iowa, and Nebraska and Missouri electric holdings) had a 2004 net plant



1 value of \$1,209 million. The \$874 million of utility properties listed for sale  
2 therefore represent the liquidation of 42 percent of Aquila's remaining domestic  
3 utility net assets. If successfully concluded, these measures should restore  
4 Aquila's financial condition and move its bond rating metrics significantly toward  
5 the Company's investment grade target.

6 **Q. How did you evaluate the requested capital structure?**

7 A. I considered the bond rating and optimal capital structure issues discussed above  
8 and I prepared an analysis of MPS/LP's financial condition under alternative  
9 assumed outcomes from this rate case. In that analysis, I compare MPS/LP's  
10 interest coverage ratios and debt ratios, under alternative rate case results, to the  
11 S&P bond rating criteria discussed previously. This comparison shows the  
12 implied bond ratings from each rate case alternative. The key result is that the  
13 requested hypothetical capital structure is essential for an investment grade bond  
14 rating. Rate case outcomes based on Aquila's consolidated corporate capital  
15 structure produce financial ratios well below those required for an investment  
16 grade rating. Such results are not consistent with using an investment grade  
17 reference group to estimate ROE or using investment grade debt costs to calculate  
18 the allowed overall rate of return. Such a mismatched approach would produce  
19 results that violate the *Hope* and *Bluefield* requirements.

20 **Q. How is your capital structure analysis structured?**

21 A. To prepare the analysis, I developed a model that calculates the key S&P ratios  
22 for alternative rate case outcomes. The results of my analysis are presented in  
23 Schedule SCH-6a. As shown on page 1 of Schedule SCH-6a, Case 1, using the

1 LP requested capital structure and ROE for the steam operations, produces  
2 investment grade financial indicators within the optimal bond rating range  
3 illustrated on page 13 of this testimony.  
4 Case 2, which uses Aquila's consolidated capital structure, is shown on page 2 of  
5 Schedule SCH-6a. Although the scenario produces investment grade level metrics  
6 for both the FFO/Interest and FFO/LT Debt benchmarks, because the  
7 consolidated debt ratio is two levels below investment grade at a level consistent  
8 with a credit rating of single B, the LP steam operations do not come close to  
9 achieving investment grade metrics as group under this scenario. On page 3 of  
10 SCH-6a, in Case 3, I also demonstrate the bond rating indicators that would result  
11 if no rate increase were granted. Under this scenario, all the indicators fall  
12 substantially below investment grade. Clearly the results of either Case 2  
13 (consolidated capital structure) or Case 3 (no rate increase) do not represent  
14 adequate financial integrity.

15 **Q. Is it possible to evaluate the tradeoff between capital structure and ROE?**

16 A. Yes. If, for example, Aquila's consolidated corporate capital structure is used for  
17 setting rates in this case, the ROE would have to be raised to account for the  
18 additional financial risk caused by higher financial leverage resulting from the  
19 increased debt. The tradeoff is measured in the overall rate of return.

20 **Q. Please explain.**

21 A. In Schedule SCH-7, I demonstrate the relationship between capital structure and  
22 ROE. In that analysis, the first panel shows the overall, tax-inclusive rate of  
23 return calculated from the 11.5 percent requested ROE and the reference group

1 capital structure consisting of 48.2 percent equity and 51.8 percent debt. The  
2 overall, tax-inclusive rate of return for MPS, as shown on page 1 of Schedule  
3 SCH-7, is 12.47 percent.

4 In the second panel of Schedule SCH-7, I first recalculate the overall rate  
5 of return using Aquila's consolidated corporate capital structure with 32.7 percent  
6 equity and 67.3 percent debt. I then recalculate for the ROE that is required to  
7 keep the overall, tax-inclusive rate of return at the same 12.47 percent found  
8 previously in panel 1. To keep the overall return at 12.47 percent, the ROE must  
9 be increased to 15.0 percent. Page 2 of Schedule SCH-7, provides the same  
10 analysis using LP's higher cost of debt. The results are similar. In both cases the  
11 ROE must be increased from 11.5 percent to approximately 15 percent when  
12 more debt and less equity are used in the capital structure. These results are  
13 consistent with my previous capital structure discussion and with the fundamental  
14 financial principle of risk and return. In other words, ROE would have to be  
15 raised to about 15 percent to keep MPS/LP at the same revenue level if Aquila's  
16 consolidated capital structure is used.

17 **III. REGULATORY FINANCIAL INTEGRITY ISSUES**

18 **Q. Please define the term "financial integrity" and discuss its role in the**  
19 **regulatory process.**

20 A. "Financial integrity" does not have a precise textbook definition. It generally  
21 means that a company is creditworthy or financially sound, and that its credit is  
22 unimpaired. Companies with sound financial integrity are said to have access to  
23 capital at reasonable rates and on reasonable terms and conditions. Financial

1 integrity may also be defined in terms of bond ratings: Companies with  
2 investment grade bond ratings (triple-B or above) have some degree of financial  
3 integrity; companies with bond ratings below investment grade may be impaired.  
4 Operationally, the meaning of financial integrity depends on the context in which  
5 the term is used.

6 In regulatory practice most discussions of financial integrity center on the  
7 requirements of *Hope* and *Bluefield*. The *Bluefield* decision in 1923 did not  
8 explicitly use the term financial integrity, but instead used the words "financial  
9 soundness" with respect to standards for rate of return:

10 The return should be reasonably sufficient to assure confidence in  
11 the *financial soundness* of the utility and should be adequate, under  
12 efficient and economical management, to maintain and support its  
13 credit and enable it to raise the money necessary for the proper  
14 discharge of its public duties. (emphasis supplied)

15 The *Hope Natural Gas* decision in 1944 reiterated the *Bluefield* rate of return  
16 standard and specifically used the term financial integrity:

17 From the investor or company point of view it is important that  
18 there be enough revenue not only for operating expenses, but also  
19 for the capital costs of the business.... That return, moreover,  
20 should be sufficient to assure confidence in the *financial integrity*  
21 of the enterprise so as to maintain its credit and to attract  
22 capital....(emphasis supplied)

23 Regulatory economists and financial witnesses in regulatory proceedings  
24 routinely rely on the above noted passages. In most situations, "financial  
25 integrity" means that a utility's rates are adequate to support its access to capital  
26 on reasonable terms.

27 **Q. Is there a link between financial integrity and the regulatory process?**

1 A. Yes. Especially during periods of unsettled capital markets and when required  
2 construction budgets are large, the link between financial integrity and the  
3 regulatory process is clear. Financially weak utilities are often foreclosed from  
4 the most economical sources of financing. For example, utilities that fail to meet  
5 indenture earnings tests may be precluded from issuing first mortgage bonds and  
6 may be forced to use unsecured debentures or bank lines of credit. Debentures  
7 are typically rated at least one credit level lower than first mortgage bonds, with  
8 commensurately higher interest costs. Similarly, bank credit lines are typically  
9 more restrictive and administratively more expensive than higher grade forms of  
10 traditional utility financing. I discuss the direct costs of weak utility financial  
11 condition in more detail below.

12 Q. **Does the financial integrity standard have a role in evaluating the overall**  
13 **reasonableness of a utility rate order?**

14 A. Yes. Regulators have the responsibility to ensure that the overall effect of a rate  
15 order is just and reasonable to the utility and its customers. This required focus  
16 on the reasonableness of the "end result" of the rate setting process is reflected in  
17 Supreme Court decisions such as *Hope*, where Justice Douglas concluded:

18 And when the Commission's order is challenged in the courts, the  
19 question is whether that order "*viewed in its entirety*" meets the  
20 requirements of the Act. Under the statutory standard of "just and  
21 reasonable" ... it is the *result reached* not the method employed  
22 which is controlling....320 U.S. at 602. (emphasis supplied)

23 Forty-five years later, the Supreme Court reaffirmed *Hope* in the *Duquesne Light*  
24 *Co.* decision:

25 [I]t is not theory but the impact of the rate order which counts. If  
26 the *total effect* of the rate order cannot be said to be unreasonable,

1           judicial inquiry ... is at an end. 109 S. Ct. at 617.(emphasis  
2           supplied) (quoting *Hope*)

3           In judging the "end result" or "total effect" of a rate order, it is the impact on the  
4           utility's financial integrity, balanced against the customers' interest in reasonable  
5           rates, that must be evaluated: "Rates which enable the company to operate  
6           successfully, to *maintain its financial integrity*, to attract capital, and to  
7           compensate its investors for the risk assumed certainly cannot be condemned as  
8           invalid...." (*Hope*. 320 U.S. at 605) (emphasis supplied). As the regulator weighs  
9           the possible disallowance of expenses essential to the provision of utility service,  
10          the manner in which that discretionary authority is used can very appropriately be  
11          affected by the end result of the decision on the utility's financial integrity.

12   **Q.    What is required to reverse the effects of poor financial condition?**

13   A.    The most important factor is a demonstrated commitment from the company and  
14          its regulators and a consistently improving trend in financial results. For this  
15          reason it typically takes a period of time to reestablish an investment grade bond  
16          rating. To re-obtain an investment grade rating and to convince lenders to provide  
17          capital at lower rates, a utility must demonstrate that its financial integrity has  
18          been restored and that the process going forward can be expected to provide  
19          stability. The mitigation of regulatory uncertainty and the provision of a  
20          consistent plan for financial improvement are key elements in this process.

21   **Q.    Does the electric utility industry's evolution toward competition affect**  
22          **financial integrity?**

23   A.    Yes. Financial integrity and the role of consistent regulatory policy are especially  
24          important as the industry moves toward deregulation. In a deregulated

1 environment, increased business risk from less predictable revenues must be  
2 offset by less financial risk. This means that to maintain a given bond rating a  
3 utility must reduce its debt percentage of capital and improve its other financial  
4 ratios. Electric utilities generally are attempting to accomplish this objective by  
5 improved operating efficiencies and the repayment of debt. Legislative and  
6 regulatory provisions that enhance investor confidence are also important. As  
7 competition expands some utilities will face difficult choices concerning their  
8 own financial health, the level and quality of service they can provide, and a high  
9 level of vulnerability to unforeseen future circumstances. The continuing  
10 consolidation of the industry through mergers and, in some cases, the outright sale  
11 of utility service territory is a direct reflection of this dilemma.

12 **Q. Please summarize your discussion of “financial integrity” and its role in the**  
13 **regulatory process.**

14 A. The term “financial integrity” generally means sound financial condition, which  
15 provides reasonable access to capital markets. A company's level of financial  
16 soundness can be measured with basic financial statistics. To the extent that  
17 existing and projected measures of financial performance are adequate, financial  
18 integrity is reflected in investment grade bond ratings. Companies that cannot  
19 provide sound financial performance find their bond ratings lowered, their access  
20 to capital diminished, and their borrowing costs higher.

21 For regulated companies financial integrity goes beyond basic financial  
22 statistics, because the regulatory process itself has such a large potential effect on  
23 financial performance. Credit concerns sometimes arise and bond ratings drop

1 based on a regulatory decision before any change is seen in a utility's financial  
2 statistics. Similarly, bond ratings are often maintained by the rating agencies  
3 without supporting financial statistics if it is believed that the regulatory process  
4 will allow improved financial performance in the future.

5 For companies with impaired financial integrity and non-investment grade  
6 bond ratings, access to capital is severely limited and financing costs are much  
7 higher. For such companies traditional sources of utility capital, such as long-  
8 term first mortgage bonds, are often unavailable. Particularly during periods of  
9 market stress, non-investment grade companies may have little access to capital at  
10 all. Also, even when capital is available, the much higher interest rates charged to  
11 non-investment grade companies may foreclose their refinancing opportunities  
12 and prevent their use of other favorable financing methods available to higher  
13 rated companies. All these factors demonstrate the importance of maintaining  
14 financial integrity and the key role that regulation plays in this process.

#### 15 IV. ESTIMATING THE COST OF EQUITY

16 **Q. What is the purpose of this section of your testimony?**

17 A. The purpose of this section is to present a general definition of the “cost of  
18 equity” and to compare the strengths and weaknesses of several of the most  
19 widely used methods for estimating the cost of equity. Estimating the cost of  
20 equity is fundamentally a matter of informed judgment. The various models  
21 provide a concrete link to actual capital market data and assist with defining the  
22 various relationships that underlie the ROE estimation process.



1   **Q.    Please define the term “cost of equity capital” and provide an overview of the**  
2   **cost estimation process.**

3   A.    The cost of equity capital is the profit or rate of return that equity investors expect  
4   to receive. In concept it is no different than the cost of debt or the cost of  
5   preferred stock. The cost of equity is the rate of return that common stockholders  
6   expect, just as interest on bonds and dividends on preferred stock are the returns  
7   that investors in those securities expect. Equity investors expect a return on their  
8   capital commensurate with the risks they take and consistent with returns that  
9   might be available from other similar investments. Unlike returns from debt and  
10   preferred stocks, however, the equity return is not directly observable in advance  
11   and, therefore, it must be estimated or inferred from capital market data and  
12   trading activity.

13           An example helps to illustrate the cost of equity concept. Assume that an  
14   investor buys a share of common stock for \$20 per share. If the stock’s expected  
15   dividend during the coming year is \$1.00, the expected dividend yield is 5 percent  
16   ( $\$1.00 / \$20 = 5.0$  percent). If the stock price is also expected to increase to  
17   \$21.20 after one year, this \$1.20 expected gain adds an additional 6 percent to the  
18   expected total rate of return ( $\$1.20 / \$20 = 6$  percent). Therefore, buying the  
19   stock at \$20 per share, the investor expects a total return of 11 percent: 5 percent  
20   dividend yield, plus 6 percent price appreciation. In this example, the total  
21   expected rate of return at 11 percent is the appropriate measure of the cost of  
22   equity capital, because it is this rate of return that caused the investor to commit  
23   the \$20 of equity capital in the first place. If the stock were riskier, or if expected

1 returns from other investments were higher, investors would have required a  
2 higher rate of return from the stock, which would have resulted in a lower initial  
3 purchase price in market trading.

4 Each day, market rates of return and prices change to reflect new investor  
5 expectations and requirements. For example, when interest rates on bonds and  
6 savings accounts rise, utility stock prices usually fall. This is true, at least in part,  
7 because higher interest rates on these alternative investments make utility stocks  
8 relatively less attractive, which causes utility stock prices to decline in market  
9 trading. This competitive market adjustment process is quick and continuous, so  
10 that market prices generally reflect investor expectations and the relative  
11 attractiveness of one investment versus another. In this context, to estimate the  
12 cost of equity one must apply informed judgment about the relative risk of the  
13 Company in question and knowledge about the risk and expected rate of return  
14 characteristics of other available investments as well.

15 **Q. How does the market account for risk differences among the various**  
16 **investments?**

17 A. Risk-return tradeoffs among capital market investments have been the subject of  
18 extensive financial research. Literally dozens of textbooks and hundreds of  
19 academic articles have addressed the issue. Generally, such research confirms the  
20 common sense conclusion that investors will take additional risks only if they  
21 expect to receive a higher rate of return. Empirical tests consistently show that  
22 returns from low risk securities, such as U.S. Treasury bills, are the lowest; that  
23 returns from longer-term Treasury bonds and corporate bonds are increasingly

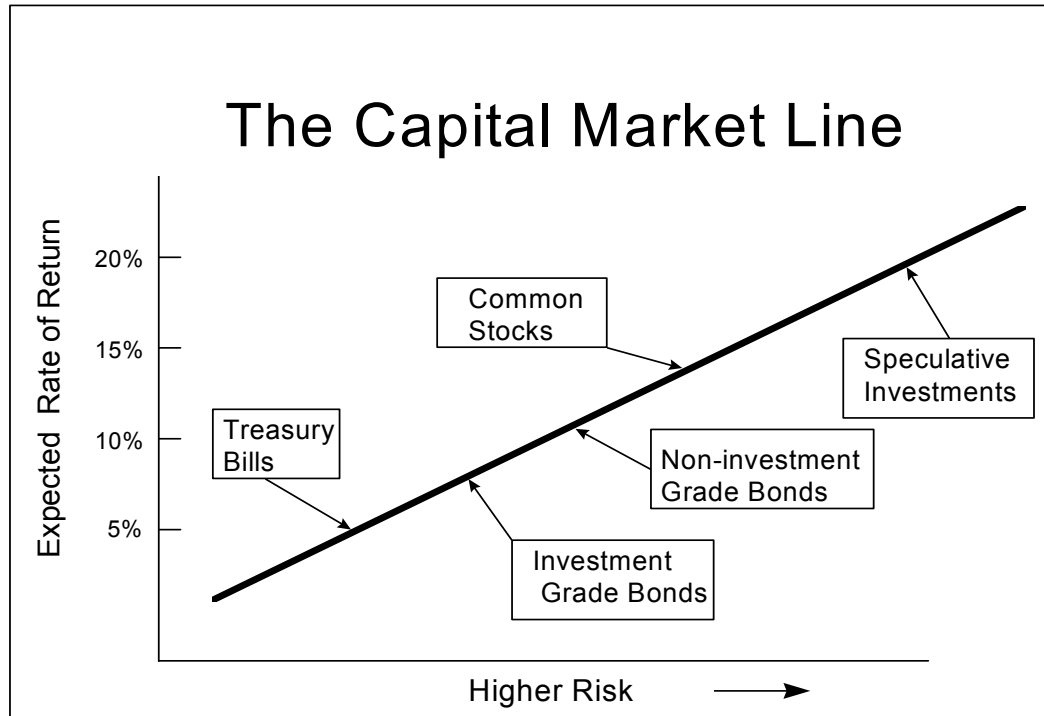
1 higher as risks increase; and generally, returns from common stocks and other  
2 more risky investments are even higher. These observations provide a sound  
3 theoretical foundation for both the DCF and risk premium methods for estimating  
4 the cost of equity capital. These methods attempt to capture the well-founded  
5 risk-return principle and explicitly measure investors' rate of return requirements.

6 **Q. Can you illustrate the capital market risk-return principle that you just**  
7 **described?**

8 A. Yes. The following graph depicts the risk-return relationship that has become  
9 widely known as the Capital Market Line ("CML"). The CML offers a graphical  
10 representation of the capital market risk-return principle. The graph is not meant  
11 to illustrate the actual expected rate of return for any particular investment, but  
12 merely to illustrate in a general way the risk-return relationship.

1

## Risk-Return Tradeoffs



2 As a continuum, the CML can be viewed as an available opportunity set  
3 for investors. Those investors with low risk tolerance or investment objectives  
4 that mandate a low risk profile should invest in assets depicted in the lower left-  
5 hand portion of the graph. Investments in this area, such as Treasury bills and  
6 short-maturity, high quality corporate commercial paper, offer a high degree of  
7 investor certainty. In nominal terms (before considering the potential effects of  
8 inflation), such assets are virtually risk-free.

9 Investment risks increase as one moves up and to the right along the CML.  
10 A higher degree of uncertainty exists about the level of investment value at any  
11 point in time and about the level of income payments that may be received.  
12 Among these investments, long-term bonds and preferred stocks, which offer

1 priority claims to assets and income payments, are relatively low risk, but they are  
2 not risk-free. The market value of long-term bonds, even those issued by the U.S.  
3 Treasury, often fluctuates widely when government policies or other factors cause  
4 interest rates to change.

5 Farther up the CML continuum, common stocks are exposed to even more  
6 risk, depending on the nature of the underlying business and the financial strength  
7 of the issuing corporation. Common stock risks include market-wide factors,  
8 such as general changes in capital costs, as well as industry and company specific  
9 elements that may add further to the volatility of a given company's performance.  
10 As I will illustrate in my risk premium analysis, common stocks typically are  
11 more volatile (have higher risk) than high quality bond investments and,  
12 therefore, they reside above and to the right of bonds on the CML graph. Other  
13 more speculative investments, such as stock options and commodity futures  
14 contracts, offer even higher risks (and higher potential returns). The CML's  
15 depiction of the risk-return tradeoffs available in the capital markets provides a  
16 useful perspective for estimating investors' required rates of return.

17 **Q. How is the fair rate of return in the regulatory process related to the**  
18 **estimated cost of equity capital?**

19 A. As I have discussed previously, the regulatory process is guided by fair rate of  
20 return principles established in the U.S. Supreme Court cases, *Bluefield*

21 *Waterworks* and *Hope Natural Gas*:

22 A public utility is entitled to such rates as will permit it to earn a  
23 return on the value of the property which it employs for the  
24 convenience of the public equal to that generally being made at the  
25 same time and in the same general part of the country on

1 investments in other business undertakings which are attended by  
2 corresponding risks and uncertainties; but it has no constitutional  
3 right to profits such as are realized or anticipated in highly  
4 profitable enterprises or speculative ventures. *Bluefield*  
5 *Waterworks & Imp. Co. v. West Virginia Public Service*  
6 *Commission*, 262 U.S. 679, 692-693 (1923).

7 From the investor or company point of view, it is important that  
8 there be enough revenue not only for operating expenses, but also  
9 for the capital costs of the business. These include service on the  
10 debt and dividends on the stock. By that standard the return to the  
11 equity owner should be commensurate with returns on investments  
12 in other enterprises having corresponding risks. That return,  
13 moreover, should be sufficient to assure confidence in the financial  
14 integrity of the enterprise, so as to maintain its credit and to attract  
15 capital. *Federal Power Comm. v. Hope Natural Gas Co.*, 320 U.S.  
16 591, 603 (1944).

17 Based on these principles, the fair rate of return should closely parallel  
18 investor opportunity costs as discussed above. If a utility earns its market  
19 cost of equity, neither its stockholders nor its customers should be  
20 disadvantaged.

21 **Q. What specific methods and capital market data are used to evaluate the cost**  
22 **of equity?**

23 A. Given the requirement to find the required rate of return for companies with  
24 similar risk, models that employ market-based data for comparable utilities are the  
25 most widely used. The DCF model, and sometimes other models, applied to a  
26 reference group of investment grade utilities as I have done is the most  
27 appropriate for ensuring that the *Hope* and *Bluefield* standards are met. Specific  
28 modeling techniques typically fall into three groups: comparable earnings  
29 methods, risk premium methods, and DCF methods. Comparable earnings  
30 methods have evolved over time. The original comparable earnings methods  
31 were based on book accounting returns. This approach developed ROE estimates

1 by reviewing accounting returns for unregulated companies thought to have risks  
2 similar to those of the regulated company in question. These methods generally  
3 have been rejected because they assume that the unregulated group is earning its  
4 actual cost of capital, and that its equity book value is the same as its market  
5 value. In most situations these assumptions are not valid and, therefore,  
6 accounting-based methods generally do not provide reliable cost of equity  
7 estimates.

8 More recent comparable earnings methods are based on historical stock  
9 market returns rather than book accounting returns. While this approach has  
10 some merit, it too has been criticized because there can be no assurance that  
11 historical returns actually reflect current or future market requirements. Also, in  
12 practical application, earned market returns tend to fluctuate widely from year to  
13 year. For these reasons, a current cost of equity estimate (based on the DCF  
14 model or a risk premium analysis) is usually required.

15 The second set of estimation techniques is grouped under the heading of  
16 risk premium methods. These methods begin with currently observable market  
17 returns, such as yields on government or corporate bonds, and add an increment to  
18 account for the additional equity risk. The capital asset pricing model ("CAPM")  
19 and arbitrage pricing theory ("APT") model are more sophisticated risk premium  
20 approaches. The CAPM and APT methods estimate the cost of equity directly by  
21 combining the "risk-free" government bond rate with explicit risk measures to  
22 determine the risk premium required by the market. Although these methods are  
23 widely used in academic cost of capital research, their additional data

1 requirements and their potentially questionable underlying assumptions have  
2 detracted from their use in most regulatory jurisdictions. .

3 The DCF model is the most widely used approach in regulatory  
4 proceedings. Like the risk premium method, the DCF model has a sound basis in  
5 theory, and many argue that it has the additional advantage of simplicity. I will  
6 describe the DCF model in detail below, but in essence its estimate of ROE is  
7 simply the sum of the expected dividend yield and the expected long-term  
8 dividend (or price) growth rate. While dividend yields are readily available, long-  
9 term growth estimates are more difficult to obtain. Because the constant growth  
10 DCF model requires very long-term growth estimates (technically to infinity),  
11 some argue that its application is subjective and that more explicit multistage  
12 growth DCF models are preferred. In the final analysis, ROE estimates are  
13 subjective and should be based on sound, informed judgment. To accomplish this  
14 task, I apply several versions of the DCF and risk premium models, which results  
15 in an ROE range that I believe brackets the fair cost of equity capital.

16 **Q. Please explain the DCF model.**

17 A. The DCF model is predicated on the concept, or in fact the definition, that a  
18 stock's price represents the present value of all future cash flows expected from  
19 the stock. In the most general form, the model is expressed in the following  
20 formula:

21 
$$P_0 = D_1/(1+k) + D_2/(1+k)^2 + \dots + D_\infty/(1+k)^\infty \quad (1)$$

22 where  $P_0$  is today's stock price;  $D_1$ ,  $D_2$ , etc. are all expected future dividends and  
23  $k$  is the discount rate, or the investor's required rate of return on equity. Equation



1 (1) is a routine present value calculation with the difficult data requirement of  
2 estimating all future dividends. (As a practical matter, the present value of  
3 dividends expected in the very distant future is typically insignificant, and  
4 operationally the DCF model can be reasonably estimated by discounting a long,  
5 but finite dividend stream, or with the assumption that the stock will be sold for  
6 some estimated price in the future.)

7 Under the additional assumption that dividends are expected to grow at a  
8 constant rate “g,” equation (1) can be solved for k and rearranged into the simple  
9 form:

10 
$$k = D_1/P_0 + g \quad (2)$$

11 Equation (2) is the familiar constant growth DCF model for cost of equity  
12 estimation, where  $D_1/P_0$  is the expected dividend yield and g is the long-term  
13 expected dividend growth rate.

14 Under circumstances when growth rates are expected to fluctuate or when  
15 future growth rates are highly uncertain, the constant growth model may be  
16 questionable, and explicit changing growth estimates may be required. Although  
17 the DCF model itself is still valid (equation (1) is mathematically correct), under  
18 the assumption of fluctuating growth the simplified form of the model must be  
19 modified to capture market expectations accurately.

20 **Q. How is the DCF model applied when the growth rates fluctuate?**

21 A. When growth rates are expected to fluctuate, the more general version of the  
22 model represented in equation (1) should be solved explicitly over a finite  
23 “transition” period while uncertainty prevails. The constant growth version of the

1 model can then be applied after the transition period, under the assumption that  
2 more stable conditions will prevail in the future. There are two alternatives for  
3 dealing with the nonconstant growth transition period.

4 Under the “Market Price” version of the DCF model, equation (1) is  
5 written in a slightly different form:

6 
$$P_0 = D_1/(1+k) + D_2/(1+k)^2 + \dots + P_T/(1+k)^T \quad (3)$$

7 where the variables are the same as in equation (1) except that  $P_T$  is the estimated  
8 Market Price at the end of the transition period T. Under the assumption that  
9 constant growth resumes after the transition period, the price  $P_T$  is then expected  
10 to be based on constant growth assumptions. As with the general form of the  
11 DCF model in equation (1), in the Market Price approach the current stock price  
12 ( $P_0$ ) is the present value of expected cash inflows, but the cash flows are  
13 comprised of dividends and an ultimate selling price for the stock. The estimated  
14 cost of equity,  $k$ , is just the rate of return that investors would expect if they  
15 bought the stock at today’s price, held it and received dividends through the  
16 transition period (until period T), and then sold it for price  $P_T$ .

17 Under the “Multistage” growth DCF approach, equation (1) is expanded to  
18 incorporate two or more growth rate periods, with the assumption that a  
19 permanent constant growth rate can be estimated for some point in the future:

20 
$$P_0 = D_0(1+g_1)/(1+k) + \dots + D_0(1+g_2)^n/(1+k)^n +$$
  
21 
$$\dots + D_0(1+g_T)^{(T+1)}/(k-g_T) \quad (4)$$

22 where the variables are the same as in equation (1), but  $g_1$  represents the growth  
23 rate for the first period,  $g_2$  for a second period, and  $g_T$  for the period from year T  
24 (the end of the transition period) to infinity. The first two growth rates are

1 estimates of fluctuating growth over “n” years (typically 5 or 10 years), and  $g_T$  is  
2 a constant growth rate assumed to prevail forever after year T.

3 Although less convenient for exposition purposes, the nonconstant growth  
4 models are based on the same valid capital market assumptions as the constant  
5 growth version. The nonconstant growth approach simply requires more explicit  
6 data inputs and more work to solve for the discount rate,  $k$ . Fortunately, the  
7 required data are generally available from investment and economic forecasting  
8 services, and computer algorithms can easily produce the required solutions.  
9 Both constant and nonconstant growth DCF analyses are presented in the  
10 following section.

11 **Q. Please explain the risk premium methodology.**

12 A. Risk premium methods are based on the assumption that equity securities are  
13 riskier than debt and, therefore, that equity investors require a higher rate of  
14 return. This basic premise is well supported by legal and economic distinctions  
15 between debt and equity securities, and it is widely accepted as a fundamental  
16 capital market principle. For example, debt holders’ claims to the earnings and  
17 assets have priority over all claims of equity investors. The contractual interest on  
18 mortgage debt generally must be paid in full before any dividends can be paid to  
19 shareholders, and secured mortgage claims must be fully satisfied before any  
20 assets can be distributed to shareholders in bankruptcy. Also, the guaranteed,  
21 fixed-income nature of interest payments on debt makes year-to-year returns from  
22 bonds typically more stable than capital gains and dividend payments on stocks.  
23 All these factors support the proposition that stockholders are exposed to more

1 risk and that shareholders should reasonably expect a positive equity risk  
2 premium.

3 **Q. Are risk premium estimates of the cost of equity consistent with other**  
4 **current capital market costs?**

5 A. Yes. The risk premium approach is especially useful because it is founded on  
6 current market interest rates, which are directly observable. This feature assures  
7 that risk premium estimates of the cost of equity begin with a sound basis, which  
8 is tied directly to current capital market costs.

9 **Q. Is there similar consensus about how risk premium data should be**  
10 **employed?**

11 A. No. In regulatory practice, there is often considerable debate about how risk  
12 premium data should be interpreted and used. Since the analyst's basic task is to  
13 gauge investors' required returns on long-term investments, some argue that the  
14 estimated equity spread should be based on the longest possible time period.  
15 Others argue that market relationships between debt and equity from several  
16 decades ago are irrelevant and that recent debt-equity observations should be  
17 given more weight in estimating investor requirements. There is no consensus on  
18 this issue. Since analysts cannot observe or measure investors' actual  
19 expectations, it is not possible to know exactly how such expectations are formed  
20 or, therefore, exactly what time period is most appropriate in a risk premium  
21 analysis.

22 The important question to answer is the following: "What rate of return  
23 should equity investors reasonably expect relative to returns currently available

1 from long-term bonds?” The risk premium studies and analyses I discuss in  
2 Section IV address this question. My risk premium recommendation is based on  
3 an intermediate position that avoids some of the problems and concerns that have  
4 been expressed about both very long and very short periods of analysis with the  
5 risk premium model.

6 **Q. Please summarize your discussion of cost of equity estimation techniques.**

7 A. Estimating the cost of equity is a controversial issue in utility ratemaking.  
8 Because actual investor requirements are not directly observable, analysts have  
9 developed several methods to assist in the process. The comparable earnings  
10 method is the oldest but perhaps least reliable. Its use of accounting rates of  
11 return, or even historical market returns may or may not reflect current investor  
12 requirements. Differences in accounting methods among companies and issues of  
13 comparability also detract from this approach.

14 The DCF and market-based risk premium methods are more widely  
15 accepted in regulatory practice. I believe that a combination of the DCF model  
16 and a review of risk premium data provide the most reliable approach. While the  
17 DCF model requires judgment about future growth rates, the dividend yield  
18 portion of the model is straightforward, and the model’s results are generally  
19 consistent with actual capital market behavior. For these reasons, I apply various  
20 versions of the DCF model to the reference company group, and I test the  
21 reasonableness of the DCF results by comparing to market-based risk premiums.  
22 I believe this approach is the most reliable was to assess the rate of return that

1 investors expect from investment alternatives of similar risk as required by the  
2 *Hope* and *Bluefield* standards.

3 **V. FUNDAMENTAL FACTORS THAT AFFECT THE COST OF EQUITY**

4 Q. What is the purpose of this section of your testimony?

5 A. The purpose of this section is to review recent and future capital market costs and  
6 conditions as well as industry- and company-specific factors that should be  
7 reflected in the cost of equity estimate.

8 **Q. What has been the recent experience in the U.S. capital markets?**

9 A. Schedule SCH-8, page 1 provides a review of annual interest rates and rates of  
10 inflation in the U.S. economy over the past ten years. During that time period,  
11 inflation and capital market costs have declined and, generally, have been lower  
12 than rates that prevailed in the previous decade. Inflation, as measured by the  
13 Consumer Price Index, has remained at historically low levels not seen  
14 consistently since the early 1960s. Until early 2004, the uneven pace of economic  
15 recovery kept consumer price increases in check and resulted in the lowest  
16 interest rates in four decades. Since then, however, economic growth and  
17 concerns about renewed inflation have led to fluctuating interest rates. Estimates  
18 for the next 12 months are for continued economic growth and further interest rate  
19 increases.

20 Schedule SCH-8, page 2, provides a summary of Moody's Average Utility  
21 and Baa Utility Bond Yields. For the most recent three months ended March  
22 2005, Moody's Average Utility Rate was 5.79 percent and the Baa Utility Rate  
23 was 5.90 percent.

1           Schedule SCH-8, page 3, provides S&P's *Economic Trends & Projections*  
2           for April 21, 2005. The forecast data show clear expectations for continuing  
3           economic growth, with growth in real Gross Domestic Product (GDP) for 2005  
4           projected at 3.7 percent. This projected GDP growth rate compares to rates of  
5           less than 2 percent in 2001, 2.4 percent for 2002, and 3 percent for 2003.  
6           Consistent with sound economic conditions, S&P also forecasts that the  
7           unemployment rate will drop to 5.1 percent and that interest rates will rise an  
8           additional 80-100 basis points from current levels. The 10-year Treasury Note is  
9           projected to increase from its current level of about 4.3 percent to 5.3 percent by  
10          the 2nd quarter of 2006. Long-term Treasury Bonds are projected to increase  
11          from current levels of about 4.8 percent to 5.7 percent, and Corporate Bonds are  
12          projected to increase from current levels of about 5.3 percent to 6.2 percent.  
13          These increasing interest rate trends offer important perspective for judging the  
14          cost of capital in the present case.

15          Schedule SCH-8, page 4, provides economic and interest rate projections  
16          from *Value Line's* latest long-term forecast. For 2006, *Value Line's* interest rate  
17          projections are similar to S&P's. The *Value Line* forecasts also shows that rates  
18          are expected to continue increasing for the next several years.

19   **Q.   What are the key factors currently affecting electric utility investments?**

20   A.   Although electric utilities are returning to their core businesses and are expected  
21          to see more stable results over the next several years, expectations for utility  
22          stocks are negative based on projections for higher interest rates. In its most  
23          recent edition covering electric utilities, *Value Line* reflected its concerns:

**Investment Advice**

Many of the utility stocks in this issue are trading at or near their 52-week highs. But if *Value Line*'s projection of rising interest rates is on target, share prices of these equities may decline. Too, the industry's Timeliness rank remains near the bottom of all industries we follow. At this juncture, more attractive investments are available elsewhere. (*Value Line Investment Survey*, April 1, 2005, p. 695.)

Expectations for rising interest rates also make it more difficult to estimate utilities' cost of capital. In this environment of increased interest rates, the traditional DCF model does not produce reasonable cost of capital estimates.

**Q. Is Aquila affected by these same market uncertainties and concerns?**

A. Yes. To varying extents, all utilities are affected by market uncertainties and the changes affecting the energy industry. As Aquila's MPS/LP operating divisions have entered into a construction cycle over the next few years, the capital requirements for these divisions are projected to be \$850-\$900 million cumulatively from the end of 2004 through the year 2010. This level of expenditure will have the impact of increasing net plant by approximately 81 percent over this period, which is at a level that is significantly in excess of the reference company projected average over the same period. These construction needs are more fully described in the testimony of Aquila witness, Jon Empson. Demands to expand the transmission and distribution resources are also growing rapidly. This situation also drives increased capital investment needs. In this setting it is essential for MPS/LP to improve their financial condition and to have a sound utility earnings base to support their capital investment requirements.

**Q. How do capital market concerns affect the cost of equity capital?**



1 A. As I discussed previously in Section IV, equity investors respond to changing  
2 assessments of risk and financial prospects by changing the price they are willing  
3 to pay for a given security. When the risk perceptions increase or financial  
4 prospects decline, investors refuse to pay the previously existing market price for  
5 a company's securities, and market supply and demand forces then establish a new  
6 lower price. The lower market price typically translates into a higher cost of  
7 capital through a higher dividend yield requirement as well as the potential for  
8 increased capital gains if prospects improve. In addition to market losses for prior  
9 shareholders, the higher cost of capital is transmitted directly to the company by  
10 the need to issue more shares to raise any given amount of capital for future  
11 investment. The additional shares also impose additional future dividend  
12 requirements and reduce future earnings per share growth prospects.

13 **VI. COST OF EQUITY CAPITAL FOR MPS/LP**

14 **Q. What is the purpose of this section of your testimony?**

15 A. The purpose of this section is to present my quantitative studies of the cost of  
16 equity capital for MPS/LP and to discuss the details and results of my analyses.

17 **Q. How are your studies organized?**

18 A. In the first part of my analysis, I apply alternative versions of the constant growth  
19 DCF and multistage DCF model to a reference company group of electric utilities.  
20 For inclusion in the group, each company is required to have at least an  
21 investment grade bond rating, to have at least 70 percent of its revenues from  
22 regulated utility sales, to have consistent financial records not affected by recent  
23 mergers or restructuring, and to have a consistent dividend payment record with

1 no recent dividend reductions or eliminations. Application of the minimum 70  
2 percent regulated utility revenues filter results in a group *average* percentage of  
3 revenues from regulated utility sales of 86 percent, which helps to assure that non-  
4 regulated activities are not a significant influence for the group. The results of my  
5 DCF analyses are shown in Schedule SCH-9. In total, the DCF models produce  
6 an ROE range of 9.5 percent to 11.1 percent for the reference group of  
7 comparable companies. As discussed previously, the 9.5 percent result from the  
8 traditional constant growth DCF model is not consistent with risk premium  
9 checks of reasonableness or other consensus economic forecasts for higher  
10 interest rates. Therefore, I do not include that result in my estimated DCF range.  
11 The appropriate range from the remaining DCF models is 10.6 percent to 11.1  
12 percent.

13 In the second part of my analysis, I develop and review cost of capital  
14 estimates based on the risk premium methodology. I present my risk premium  
15 study in Schedule 10. That analysis, based on allowed regulatory ROEs relative  
16 to contemporaneous utility debt costs, indicates that a cost of equity of 11.0  
17 percent is appropriate. Other risk premium approaches indicate ROEs as high as  
18 11.8 percent. Given current market and utility industry conditions, the risk  
19 premium approach adds useful perspective for judging investor requirements.  
20 Based on the DCF and risk premium results, and with consideration for current  
21 market, industry, and company-specific factors appropriate for the present case, I  
22 estimate the cost of equity for MPS/LP at 11.5 percent.

1    **A.     Discounted Cash Flow Analysis**

2    **Q.     What stock prices are used in your DCF analyses?**

3    A.     My analysis is based on the average of high and low stock prices for each  
4           company for each of three recent months (January-March 2005). Although in  
5           theory either average or “spot” stock prices can be used in a DCF analysis, a  
6           reasonably current price consistent with present market conditions and with the  
7           other data employed in the analysis is most appropriate. Since the cost of equity  
8           is a current and forward-looking concept, the important issue is that the price  
9           should be representative of current market conditions and not unduly influenced  
10          by unusual or special circumstances.

11   **Q.     Please summarize the results of your reference company DCF analyses.**

12   A.     I apply three versions of the DCF model to estimate ROE. The traditional  
13          Constant Growth version of the DCF model produces an ROE estimate of only  
14          9.5 percent. As shown in Schedule SCH-9, page 2 the average dividend yield in  
15          this model is about 4.5 percent and the average growth rate is 5.0 percent. The  
16          average growth rate is derived from traditional sources for estimating growth in  
17          the DCF model. Specifically, equal weight is given to (1) the sustainable growth  
18          “b times r” method, (2) Zacks' survey of individual company 5-year analysts’  
19          earnings estimates, (3) *Value Line*’s projected 3-to-5 year earnings growth rate,  
20          and (4) long-term growth in nominal Gross Domestic Product (GDP). The “b  
21          times r” method and the analyst and *Value Line* earnings projections are  
22          significantly and negatively influenced by the uncertainties, discussed previously,  
23          that are currently affecting the industry. The “b times r,” Zacks, and *Value Line*

1 growth rates average only about 4.4 percent, which is only two-thirds of the 6.6  
2 percent growth rate for long-term GDP. The 9.5 percent ROE estimate from the  
3 traditional constant growth DCF approach is not consistent with consensus  
4 economic projections for higher interest rates and is 1.5 percent to 2.3 percent  
5 below current risk premium checks of reasonableness. For these reasons, I do not  
6 include the traditional constant growth DCF result in my recommended ROE  
7 range.

8           The non-constant growth Two-Stage DCF model indicates an ROE of 10.6  
9 percent to 10.7 percent. For stage one of this model (years 1 through 4), the  
10 growth rate is based on *Value Line's* projected dividends. The average growth  
11 rate for stage 1 of this model is only 3.35 percent. The growth rate for stage 2 is  
12 the nominal growth rate in GDP noted above. In combination with the 4.5 percent  
13 average dividend yield, the 10.6 percent to 10.7 percent ROE range from this  
14 model implies an overall growth expectation of 6.1 percent to 6.2 percent. This  
15 implied growth rate is based on the traditional yield plus growth DCF format  
16 (10.6 percent ROE = 4.5 percent yield + 6.1 percent growth; 10.7 percent ROE =  
17 4.5 percent yield + 6.2 percent growth).

18           My third DCF model is based on the constant growth approach, but with  
19 the growth rate strictly proxied by the 6.6 percent long-term GDP growth rate.  
20 That model indicates an ROE of 11.1 percent. As discussed previously, based on  
21 expected further increases in market interest rates and other capital market costs,  
22 it is my judgment that the fair cost of equity range should be based on the Two-  
23 Stage growth DCF model and the Constant Growth model with long-term GDP

1       used as a proxy for long-term investor growth rate expectations. Based on these  
2       two versions of the DCF model, the ROE range is 10.6 percent to 11.1 percent.

3       **B.     Risk Premium Analysis**

4       **Q.     How is your risk premium study structured?**

5       A.     In my risk premium analysis, I compare authorized electric utility ROEs to  
6       contemporaneous long-term interest rates on utility bonds. The equity risk  
7       premium then is measured by the difference between the average authorized ROE  
8       and the average debt cost for each year. This calculation for the period, 1980-  
9       2004, is presented in Schedule SCH-10. The data show that risk premiums are  
10      smaller when interest rates are high and larger when interest rates are low. For  
11      example, in the early 1980s when utility interest rates exceeded fifteen percent,  
12      allowed equity risk premiums were generally less than two percent. In more  
13      recent years, with lower interest rates, allowed regulatory risk premiums have  
14      generally been in the three- to four-percent range.

15             The inverse relationship between risk premiums and interest rate levels is  
16      well documented in numerous, well-respected academic studies. (See, for  
17      example, Robert S. Harris and Felicia C. Marston, "Estimating Shareholder Risk  
18      Premia Using Analysts' Growth Forecasts," Financial Management, Summer  
19      1992.)

20             These studies typically use regression analysis or other statistical methods  
21      to predict or measure the risk premium relationship under varying interest rate  
22      conditions. In Schedule SCH-10, page 2, I present a regression analysis of the  
23      allowed annual equity risk premiums relative to interest rate levels. The

1 regression coefficient of -42.18 percent confirms the inverse relationship between  
2 risk premiums and interest rates and indicates that risk premiums expand and  
3 contract by about fifty-eight percent of the change in interest rates. This means  
4 that when interest rates rise by one percentage point, the cost of equity increases  
5 by only 0.58 of a percentage point, because the risk premium declines by about  
6 0.42 percentage points. Similarly, when interest rates decline by one percentage  
7 point, the cost of equity declines by only 0.58 of a percentage point. I use the -  
8 42.18 percent interest rate change coefficient in conjunction with current interest  
9 rates to establish the appropriate current equity risk premium. This calculation is  
10 shown in the lower portion of page 1 of Schedule SCH-10. When the resulting  
11 risk premium of 4.25 percent is added to the projected single-A utility debt cost of  
12 6.7 percent, the indicated ROE is 11.0 percent ( $4.25\% + 6.7\% = 10.95\%$ ).

13 **Q. How do the results of your risk premium studies compare to levels found in**  
14 **other risk premium studies?**

15 A. My risk premium estimate is lower than those often found in other risk premium  
16 studies. From the most widely followed data published by Ibbotson Associates  
17 (Ibbotson Associates, *Stocks, Bonds, Bills and Inflation 2004 Yearbook*), for the  
18 period 1926-2003, the indicated arithmetic mean risk premium for common  
19 stocks versus long-term corporate bonds is 6.2 percent. Under the more  
20 conservative assumption of geometric mean compounding, the Ibbotson risk  
21 premium is 4.5 percent. Ibbotson argues extensively for the arithmetic mean  
22 approach as the appropriate basis for estimating the cost of equity. Even with the  
23 more conservative geometric mean risk premium, Ibbotson's data indicate a

1 single-A cost of equity of 11.2 percent (6.7 percent debt cost + 4.5 percent risk  
2 premium = 11.2 percent).

3 The Harris and Marston ("H&M") study noted above also provides  
4 specific equity risk premium estimates. Using analysts' growth estimates to  
5 estimate equity returns, H&M found equity risk premiums of 6.47 percent relative  
6 to U.S. Government bonds and 5.13 percent relative to yields on corporate debt.  
7 H&M's equity risk premium relative to corporate debt indicates a current single-  
8 A cost of equity of 11.8 percent (6.7 percent debt cost + 5.13 percent risk  
9 premium = 11.83 percent).

10 **Q. Please summarize the results of your cost of equity analysis.**

11 A. The following table summarizes my results:

Summary of Cost of Equity Estimates	
<u>DCF Analysis</u>	<u>Indicated Cost</u>
Constant Growth Model (traditional growth)*	9.5%
Constant Growth Model (GDP growth)	11.1%
Two-Stage Growth Model	10.6% - 10.7%
Estimated DCF Model Range	<u>10.6% - 11.1%</u>
<hr/>	
Risk Premium Analysis	
Utility Debt + Risk Premium	
Risk Premium Analysis (6.7% + 4.25%)	11.0%
Ibbotson Risk Premium Analysis	
Risk Premium (6.7% + 4.5%)	11.2%
Harris-Marston Risk Premium	
Risk Premium (6.7% + 5.13%)	11.8%
<hr/>	
Reference Group Cost of Equity Capital	<u>11.0%</u>

30 \*Because the traditional Constant Growth DCF model result is more than 100  
31 basis points below any of the other models that result fails a basic test of  
32 reasonableness and is therefore excluded from the estimated DCF range.

1   **Q.    How should these results be interpreted to determine the fair cost of equity**  
2       **for MPS/LP?**

3    A.    The reference group ROE should be adjusted upward by 50 basis points, to 11.5  
4       percent, to account for MPS/LP's higher construction and operating risks.  
5       MPL/LP's required investments in Missouri over the next five years are expected  
6       to equal 81 percent of current net plant. This compares to average expected  
7       investments for the reference group companies equal to 49 percent of net plant.  
8       Also, continuing uncertainty with respect to the fuel and purchased power  
9       adjustment clause in Missouri and MPS/LP's smaller size further increase  
10      perceived operating risks. By considering these additional risk characteristics for  
11      MPS/LP in conjunction with the reference group estimated ROE, the Commission  
12      has a sound basis for setting a fair cost of equity that is consistent consensus  
13      economic projections and with the requirements of *Hope* and *Bluefield*.

14   **Q.    Does this conclude your direct testimony?**

15   A.    Yes.



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**SUMMARY OF QUALIFICATIONS**

- Principal, Financial Analysis Consultants (FINANCO, Inc.).
- Ph.D. in Finance and Econometrics.
- Extensive expert witness testimony in court and before regulatory agencies.
- Management of professional research staff in academic and regulatory organizations.
- Professional presentations before executive development groups, the National Rate of Return Analysts' Forum, and the New York Society of Security Analysts.
- Financial Management Association, Vice President for Practitioner Services.

**EDUCATION**

**The University of Texas at Austin  
Ph.D., Finance and Econometrics  
January 1975**

*Dissertation: An Evaluation of the  
Original and Recent Variants of the  
Capital Asset Pricing Model.*

**The University of Texas at Austin  
MBA, Finance  
June 1973**

*Thesis: The Pricing of Risk on the  
New York Stock Exchange.*

**Southern Methodist University  
BA, Economics  
June 1969**

Honors program. Departmental  
distinction.

**OTHER EXPERIENCE**

**University of Texas at Austin  
Adjunct Associate Professor  
1985-1988, 2004-Present**

Corporate Financial Management,  
Investments, and Integrative Finance  
Cases.

**Texas State University San Marcos  
Associate Professor of Finance  
1983-1984, 2003-2004**

Graduate and undergraduate courses  
in Financial Management, Managerial  
Economics, and Investment Analysis.

**Public Utility Commission of Texas  
Chief Economist and Director of  
Economic Research Division  
August 1980-August 1983**

Lead financial witness. Supervised  
Commission staff in research and  
testimony on rate of return, financial  
condition, and economic analysis.

**Assistant Professor of Finance  
Texas Tech University  
July 1978-July 1980  
University of Alabama  
January 1975-June 1978**

Member of graduate faculty. Conducted  
Ph.D. seminars and directed doctoral  
dissertations in capital market theory.  
Served as consultant to industry,  
church and governmental organizations.

**FINANCIAL AND ECONOMIC TESTIMONY IN REGULATORY PROCEEDINGS (Client in parenthesis)**

**Cost of Money Testimony:**

- Louisiana Public Service Commission, Docket No. U-23327, January 18, 2005 (Southwestern Electric Power Company, American Electric Power Company)
- Idaho Public Utilities Commission, Case No. PAC-E-05-1, January 14, 2005 (PacifiCorp)
- Arkansas Public Service Commission, Docket No. 04-121-U, December 3, 2004 (CenterPoint Arkla)
- Oregon Public Utility Commission, Case No. UE- , November 12, 2004 (PacifiCorp).
- Texas Public Utility Commission, Docket No. 29206, November 8, 2004 (Texas-New Mexico Power Company).
- Texas Railroad Commission, Gas Utilities Division Nos. 9533 and 9534, October 13, 2004 (CenterPoint Energy Entex).
- Texas Public Utility Commission, Docket No. 29526, August 18 and September 2, 2004 (CenterPoint Energy Houston Electric).
- Utah Public Service Commission, Docket No. 04-2035-, August 4, 2004 (PacifiCorp).
- Oklahoma Corporation Commission, Cause No. PUD-200400187, July 2, 2004, (CenterPoint Energy Arkla).
- Minnesota Public Utilities Commission, Docket No. G-008/GR-04-901, July 2004, (CenterPoint Energy Minnegasco).
- Washington Utilities and Transportation Commission, Docket ,UE-032065/General Rate Case, December 2003 (PacifiCorp).
- Washington Utilities and Transportation Commission, Docket ,UG-031885, November 2003 (Northwest Natural Gas Company.).
- Wyoming Public Service Commission, Docket No. 20000-ER-03-198, May 2003 (PacifiCorp).
- Public Service Commission of Utah, Docket No. 03-2035-02, May 2003 (PacifiCorp)
- Public Utility Commission of Oregon, Case. UE-147, March 2003 (PacifiCorp)
- Wyoming Public Service Commission, Docket No. 20000-ER-00-162, May 2002 (PacifiCorp).
- Public Utility Commission of Oregon, UG-152, November 2002 (Northwest Natural).
- Massachusetts Department of Telecommunications and Energy, D.T.E. 02-24/24, May 2002 (Fitchburg Gas and Electric Light Company).
- New Hampshire Public Utilities Commission, Docket No. DE 01-247, January 2002 (Unitil Corporation).
- Washington Utilities and Transportation Commission, Docket UE-011569,70,UG-011571, November 2001 (Puget Sound Energy, Inc.).
- California Public Utilities Commission, Docket No. 01-03-026, September and December 2001 (PacifiCorp).
- New Mexico Public Regulation Commission, Docket No. 3643, July 2001 (Texas-New Mexico Power Company).
- Texas Natural Resources Conservation Commission, Docket No. 2001-1074/5-URC, May 2001 (AquaSource Utility, Inc.).
- Massachusetts Department of Telecommunications and Energy, Docket No. 99-118, May 2001 (Fitchburg Gas and Electric Light Company).
- Public Service Commission of Utah, Docket No. 01-035-01, January 2001 (PacifiCorp)
- Federal Energy Regulatory Commission, Docket No. ER-01-651, January 2001 (Southwestern Electric Power Company).
- Wyoming Public Service Commission, Docket No. 20000-ER-00-162, December 2000 (PacifiCorp).
- Public Utility Commission of Oregon, Case. UE-116, November 2000, (PacifiCorp)
- Public Utility Commission of Texas, Docket No. 22344, September 2000, (AEP Texas Companies, Entergy Gulf States, Inc., Reliant Energy HL&P, Texas-New Mexico Power Company, TXU Electric Company)

- Public Utility Commission of Oregon, Case UE-111, August 2000, (PacifiCorp)
- Texas Public Utility Commission, Docket Nos. 22352,3,4, March 2000 (Central Power and Light Co., Southwestern Electric Power Co., West Texas Utilities Co.).
- Texas Public Utility Commission, Docket No. 22355, March 2000 (Reliant Energy, Inc.).
- Texas Public Utility Commission, Docket No. 22349, March 2000 (Texas-New Mexico Power Co.).
- Texas Public Utility Commission, Docket No. 22350, March 2000 (TXU Electric).
- Washington Utilities and Transportation Commission, Docket UE-991831, November 1999 (PacifiCorp).
- Public Service Commission of Utah, Docket No. 99-035-10, September 1999 (PacifiCorp)
- Louisiana Public Service Commission Docket No. U-23029, August 1999 (Southwestern Electric Power Company)
- Wyoming Public Service Commission, Docket No. 2000-ER-99-145, July 1999, January 2000 (PacifiCorp, dba Pacific Power and Light Company).
- Texas PUC Docket No. 20150, March 1999 (Entergy Gulf States, Inc.)
- Federal Energy Regulatory Commission Docket No. ER-98-3177-00, May and December 1998 (Southwestern Electric Power Company).
- Public Service Commission of Utah, Docket No. 97-035-01, June 1998 (PacifiCorp, dba Utah Power and Light Company).
- Massachusetts Dept. of Telecommunications and Energy, Docket No. DTE 98-51, May 1998, (Fitchburg Gas and Electric Light Company, a subsidiary of Unitil Corp.)
- Texas PUC, Docket No. 18490, March 1998, (Texas Utilities Electric Company)
- Texas PUC Docket No. 17751, March 1998 and July 1997 (Texas-New Mexico Power Company).
- Federal Energy Regulatory Commission Docket No. RP-97, February 1998 and May 1997 (Koch Gateway Pipeline Company).
- Federal Energy Regulatory Commission Docket No. ER-97-4468-000, December 1997 (Puget Sound Power & Light).
- Oklahoma Corporation Commission, Cause No. PUD 960000214, August 1997 (Public Service Company of Oklahoma).
- Oregon Public Utility Commission Docket No. UE-94, April 1996, (PacifiCorp).
- Texas PUC Docket No. 15643, May and September 1996, (Central Power and Light and West Texas Utilities Company).
- Federal Energy Regulatory Commission Docket No. ER-96, April 1996 (Puget Sound Power & Light).
- Federal Energy Regulatory Commission Docket No. ER96, February 1996, (Central and South West Corporation).
- Washington Utilities & Transportation Commission Docket No. UE-951270, November 1995 (Puget Sound Power & Light).
- Texas PUC Docket No. 14965, November 1995, (Central Power and Light).
- Texas PUC Docket No. 13369, February 1995 (West Texas Utilities).
- Texas PUC Docket No. 12065, July and December 1994, (Houston Lighting & Power).
- Texas PUC, Docket No. 12820, July and November 1994, (Central Power and Light).
- Texas PUC Docket No. 12900, March 1994, and New Mexico PUC Case No. 2531, August 1993, (TNP Enterprises).
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- Florida Public Service Commission, Docket No. 930987-EI, December 1993, (TECO Energy).
- Iowa Department of Commerce, Docket No. RPU-93-9, December 1993, (US West Communications).
- Texas PUC Dkt. No. 11735, May and September 1993, (Texas Utilities Electric Company)

- Oklahoma Corporation Commission, Cause No. PUD 001342, October 1992 (Public Service Company of Oklahoma).
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- Texas PUC Dkt. Nos. 8480/8482, January 1989; City of Austin Dkt. No. 1, August 1988 and July 1987, (City of Austin Electric Department).
- Missouri Public Service Commission Case No. ER-90-101, July 1990 (UtiliCorp).
- Texas PUC Dkt. No. 9945, December 1990; Texas PUC Dkt. No. 9165, November 1989, (El Paso Electric Company).
- Texas PUC Dkt. No. 9427, July 1990, (Lower Colorado River Authority Association of Wholesale Customers).
- Oregon Public Utility Commission, March 1990, (Pacific Power & Light Company).
- Utah Public Service Commission, November 1989, (Utah Power & Light Company).
- Texas PUC Dkt. No. 5610, September 1988, (GTE Southwest).
- Iowa State Utilities Board, September 1988, (Northwestern Bell Telephone Company).
- Texas Water Commission, Dkt. Nos. RC-022 and RC-023, November 1986, (City of Houston Water Department).
- Pennsylvania PUC Dkt. Nos. R-842770 and R-842771, May 1985, (Bethlehem Steel).

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- Federal Energy Regulatory Commission Docket No. RP-97, May 1997 (Koch Gateway Pipeline Company).
- Illinois Commerce Commission Dkt. No. 93-0252 Remand, July 1996, (Sprint).
- California PUC (Appl. No. 92-05-004) April 1993 and May 1993, (Pacific Telesis).
- Montana PSC, Dkt. No. 90.12.86, November 1991, (US West Communications).
- Massachusetts PUC Dkt. No. 86-33, June 1987, (New England Telephone Company).
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#### **Regulatory Policy and Other Regulatory Issues:**

- New Hampshire PUC Docket No. DE 03-086, May 2003, (Unitil Corporation).
- Texas PUC Docket No. 26194, May 2003 (El Paso Electric Company)
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- Texas PUC, Dkt. No. 12700/12701 and Federal Energy Regulatory Commission, Docket No. EC94-000, January 1994, (El Paso Electric Company).
- Florida Public Service Commission Generic Purchased Power Proceedings, October 1993 (TECO Energy).
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- Texas PUC Dkt. No. 10894, January and June 1992, (Gulf States Utilities Company).
- State Corporation Commission of Kansas, Dkt. No. 175,456-U, August 1991, (UtiliCorp United).

- Texas PUC Dkt. No. 9561, May 1990; Texas PUC Dkt. Nos. 6668/8646, July 1989 and February 1990, (Central Power and Light Company).
- Texas PUC Dkt. No. 9300, April 1990 and June 1990, (Texas Utilities Electric Co.).
- Texas PUC Dkt. No. 10200, August 1991, (Texas-New Mexico Power Company).
- Texas PUC Dkt. No. 7289, May 1987, (West Texas Utilities Company).
- Texas PUC Dkt. No. 7195, January 1987, (North Star Steel Texas).
- New Mexico PSC Case No. 1916, April 1986, (Public Service Company of New Mexico).
- Texas PUC Dkt. No. 6525, March 1986, (North Star Steel Texas).
- Texas PUC Dkt. No. 6375, November 1985, (Valley Industrial Council).
- Texas PUC Dkt. No. 6220, April 1985, (North Star Steel Texas).
- Texas PUC Dkt. No. 5940, March 1985, (West Texas Municipal Power Agency).
- Texas PUC Dkt. No. 5820, October 1984, (North Star Steel Texas).
- Texas PUC Dkt. No. 5779, September 1984, (Texas Industrial Energy Consumers).
- Texas PUC Dkt. No. 5560, April 1984, (North Star Steel Texas).
- Arizona PSC Dkt. No. U-1345-83-155, January 1984 and May 1984 (Arizona Public Service Company Shareholders Association).

#### **Insurance Rate Testimony:**

- Texas Department of Insurance, Docket No. 2394, November 1999, (Texas Title Insurance Agents).
- Senate Interim Committee on Title Insurance of the Texas Legislature, February 6, 1998
- Texas Department of Insurance, Docket No. 2279, October 1997, (Texas Title Insurance Agents).
- Texas Department of Insurance, January 1996, (Independent Metropolitan Title Insurance Agents of Texas).
- Texas Insurance Board, January 1992, (Texas Land Title Association).
- Texas Insurance Board, December 1990, (Texas Land Title Association).
- Texas Insurance Board, November 1989, (Texas Land Title Association).
- Texas Insurance Board, December 1987, (Texas Land Title Association).

#### **Testimony On Behalf Of Texas PUC Staff:**

- Texland Electric Cooperative, Dkt. No. 3896, February 1983
- El Paso Electric Company, Dkt. No. 4620, September 1982.
- Southwestern Bell Telephone Company, Dkt. No. 4545, August 1982.
- Central Power and Light Company, Dkt. No. 4400, May 1982.
- Texas-New Mexico Power Company, Dkt. 4240, March 1982.
- Texas Power and Light Company, Dkt. No. 3780, May 1981.
- General Telephone Company of the Southwest, Dkt. No. 3690, April 1981.
- Mid-South Electric Cooperative, Dkt. No. 3656, March 1981.
- West Texas Utilities Company, Dkt. No. 3473, December 1980.
- Houston Lighting & Power Company, Dkt. No. 3320, September 1980.

### **ECONOMIC ANALYSIS AND TESTIMONY**

#### **Antitrust Litigation:**

- Marginal Cost Analysis of Concrete Production/Predatory Pricing (Stiles)
- Analysis of Lost Business Opportunity due to denial of Waste Disposal Site Permit (Browning-Ferris Industries, Inc.).
- Analysis of Electric Power Transmission Costs in Purchased Power Dispute (City of College Station, Texas).

**Contract Litigation:**

- Analysis of Cogeneration Contract/Economic Viability Issues(Texas-New Mexico Power Company)
- Definition of Electric Sales/Franchise Fee Contract Dispute (Reliant Energy HL&P)
- Analysis of Purchased Power Agreement/Breach of Contract (Texas-New Mexico Power Company)
- Regulatory Commission Provisions in Franchise Fee Ordinance Dispute (Central Power & Light Company)
- Analysis of Economic Damages resulting from attempted Acquisition of Highway Construction Company (Dillingham Construction Corporation).
- Analysis of Economic Damages due to Contract Interference in Acquisition of Electric Utility Cooperative (PacifiCorp).
- Analysis of Economic Damages due to Patent Infringement of Boiler Cleaning Process (Dowell-Schlumberger/The Dow Chemical Company).

**Lender Liability/Securities Litigation:**

- ERISA Valuation of Retail Drug Store Chain (Sommers Drug Stores Company).
- Analysis of Lost Business Opportunities in Failed Businesses where Lenders Refused to Extend or Foreclosed Loans (FirstCity Bank Texas, McAllen State Bank, General Electric Credit Corporation).
- Usury and Punitive Damages Analysis based on Property Valuation in Failed Real Estate Venture (Tomen America, Inc.).

**Personal Injury/Wrongful Death/Lost Earnings Capacity Litigation:**

- Analysis of Lost Earnings Capacity and Punitive Damages due to Industrial Accident (Worsham, Forsythe and Wooldridge).
- Analysis of Lost Earnings Capacity due to Improper Termination (Lloyd Gosselink, Ryan & Fowler).
- Present Value Analysis of Lost Earnings and Future Medical Costs due to Medical Malpractice (Sierra Medical Center).

**Product Warranty/Liability Litigation:**

- Analysis of Lost Profits due to Equipment Failure in Cogeneration Facility (WF Energy/Travelers Insurance Company).
- Analysis of Economic Damages due to Grain Elevator Explosion (Degesch Chemical Company).
- Analysis of Economic Damages due to failure of Plastic Pipe Water Lines (Western Plastics, Inc.)
- Analysis of Rail Car Repair and Maintenance Costs in Product Warranty Dispute (Youngstown Steel Door Company).

**Property Tax Litigation:**

- Evaluation of Electric Utility Distribution System (Jasper-Newton Electric Cooperative).
- Evaluations of Electric Utility Generating Plants (West Texas Utilities Company).

**Various Valuations of Closely Held Businesses in Domestic Affairs Proceedings and for Federal Estate Tax Planning Purposes.**

## **PROFESSIONAL PRESENTATIONS**

- "Fundamentals of Financial Management and Reporting for Non-Financial Managers," Austin Energy, July 2000.
- "Fundamentals of Finance and Accounting," the IC<sup>2</sup> Institute, University of Texas at Austin, December 1996 and 1997.
- "Fundamentals of Financial Analysis and Project Evaluation," Central and South West Companies, April, May, and June 1997.
- "Fundamentals of Financial Management and Valuation," West Texas Utilities Company, November 1995.
- "Financial Modeling: Testing the Reasonableness of Regulatory Results," University of Texas Center for Legal and Regulatory Studies Conference, June 1991.
- "Estimating the Cost of Equity Capital," University of Texas at Austin Utilities Conference, June 1989, June 1990.
- "Regulation: The Bottom Line," Texas Society of Certified Public Accountants, Annual Utilities Conference, Austin, Texas, April 1990.
- "Alternative Treatments of Large Plant Additions -- Modeling the Alternatives," University of Texas at Dallas Public Utilities Conference, July 1989.
- "Industrial Customer Electrical Requirements," Edison Electric Institute Financial Conference, Scottsdale, Arizona, October 1988.
- "Acquisitions and Consolidations in the Electric Power Industry," Conference on Emerging Issues of Competition in the Electric Utility Industry, University of Texas at Austin, May 1988.
- "The General Fund Transfer - Is It A Tax? Is It A Dividend Payout? Is It Fair?" The Texas Public Power Association Annual Meeting, Austin, May 1984.
- "Avoiding 'Rate Shock' - Preoperational Phase-In Through CWIP in Rate Base," Edison Electric Institute, Finance Committee Annual Meeting, May 1983.
- "A Cost-Benefit Analysis of Alternative Bond Ratings Among Electric Utility Companies in Texas," (with B.L. Heidebrecht and J.L. Nash), Texas Senate Subcommittee on Consumer Affairs, December 1982.
- "Texas PUC Rate of Return and Construction Work in Progress Methods," New York Society of Security Analysts, New York, August 1982.
- "In Support of Debt Service Requirements as a Guide to Setting Rates of Return for Subsidiaries," Financial Forum, National Society of Rate of Return Analysts, Washington, D.C., May 1982.

## **PUBLICATIONS**

- "Institutional Constraints on Public Fund Performance," (with B.L. Hadaway) *Journal of Portfolio Management*, Winter 1989.

- "Implications of Savings and Loan Conversions in a Deregulated World," (with B.L. Hadaway) *Journal of Bank Research*, Spring 1984.
- "Regulatory Treatment of Construction Work in Progress," abstract, (with B.L. Heidebrecht and J. L. Nash), *Rate & Regulation Review*, Edison Electric Institute, December 20, 1982.
- "Financial Integrity and Market-to-Book Ratios in an Efficient Market," (with W. L. Beedles), *Gas Pricing & Ratemaking*, December 7, 1982.
- "An Analysis of the Performance Characteristics of Converted Savings and Loan Associations," (with B.L. Hadaway) *Journal of Financial Research*, Fall 1981.
- "Inflation Protection from Multi-Asset Sector Investments: A Long-Run Examination of Correlation Relationships with Inflation Rates," (with B.L. Hadaway), *Review of Business and Economic Research*, Spring 1981.
- "Converting to a Stock Company-Association Characteristics Before and After Conversion," (with B.L. Hadaway), *Federal Home Loan Bank Board Journal*, October 1980.
- "A Large-Sample Comparative Test for Seasonality in Individual Common Stocks," (with D.P. Rochester), *Journal of Economics and Business*, Fall 1980.
- "Diversification Possibilities in Agricultural Land Investments," *Appraisal Journal*, October 1978.
- "Further Evidence on Seasonality in Common Stocks," (with D.P. Rochester), *Journal of Financial and Quantitative Analysis*, March 1978.



**Aquila Missouri**  
**Capital Spending Relative to Net Plant**  
(\$millions unless otherwise noted)

No.	Reference Company	2004 Net Plant	Common Shares Outstanding			Capital Spending Per Share			Total Capital Spending 2005 -2010	Spending % of 2004 Net Plant
			2005	2006	2007-2010	2005	2006	2007-2010		
1	Alliant Energy Co.	4,805	117.6	119.2	124.0	5.45	5.15	19.40	3,660	76.2%
2	Ameren	11,085	196.0	199.0	208.0	3.30	3.25	12.60	3,914	35.3%
3	American Elec. Pwr.	22,790	389.0	389.0	389.0	6.90	7.70	23.00	14,626	64.2%
4	CH Energy Group	745	15.8	15.8	15.0	4.10	4.10	17.00	385	51.6%
5	Cent. Vermont P.S.	290	12.5	12.7	13.0	1.45	1.40	5.60	109	37.5%
6	CINERGY	9,930	200.0	202.7	209.8	4.70	4.65	4.50	2,827	28.5%
7	Cleco Corporation	1,060	49.3	49.5	50.3	1.40	1.40	6.00	440	41.5%
8	Con. Edison	15,830	244.6	247.0	254.2	6.55	6.50	23.60	9,207	58.2%
9	DTE Energy Co.	10,491	176.0	172.0	164.0	5.95	5.80	28.00	6,637	63.3%
10	Duquesne Light	1,465	78.0	85.5	88.5	3.55	3.20	4.00	905	61.7%
11	Empire District	857	26.0	26.3	27.2	2.65	3.25	10.00	426	49.8%
12	Energy East Corp.	5,825	148.0	149.0	152.0	2.30	2.05	8.00	1,862	32.0%
13	Entergy Corp.	18,900	215.0	216.0	216.0	7.00	5.55	18.60	6,721	35.6%
14	Exelon Corp.	21,482	665.0	665.0	665.0	2.85	2.85	11.40	11,372	52.9%
15	FPL Group, Inc.	20,605	392.6	396.0	405.6	4.50	4.10	12.80	8,582	41.6%
16	FirstEnergy	13,478	329.8	329.8	329.8	3.30	3.60	12.00	6,234	46.3%
17	Green Mtn. Power	235	5.2	5.3	5.4	3.85	3.80	11.20	101	42.8%
18	Hawaiian Electric	2,395	81.0	81.0	81.8	2.45	2.45	9.00	1,133	47.3%
19	MGE Energy, Inc.	607	20.4	20.4	20.4	4.55	4.00	9.00	358	58.9%
20	NiSource Inc.	9,385	272.0	273.0	276.0	2.30	2.20	9.00	3,710	39.5%
21	NSTAR	3,580	53.6	54.0	54.0	7.45	5.80	18.00	1,685	47.1%
22	Pinnacle West	7,620	91.6	91.6	91.6	8.85	8.85	28.40	4,223	55.4%
23	Progress Energy	14,615	250.0	252.0	258.0	5.25	4.80	18.60	7,321	50.1%
24	Puget Energy, Inc.	4,135	100.5	100.5	102.0	3.90	3.90	14.00	2,212	53.5%
25	SCANA Corp.	6,762	114.3	116.0	122.0	3.25	4.25	14.00	2,572	38.0%
26	Southern Co.	28,975	750.0	760.0	780.0	3.00	3.20	12.00	14,042	48.5%
27	Vectren Corp.	2,130	76.2	76.5	77.4	2.95	3.05	12.40	1,418	66.6%
28	Westar Energy	3,911	86.4	86.8	88.0	2.45	2.90	12.80	1,590	40.6%
29	Xcel Energy Inc.	14,085	402.5	402.5	434.0	3.10	3.10	13.00	8,138	57.8%
Average										49.0%
	Aquila-MPS/LP Operations	1,082							874	80.8%

Source: Value Line Investment Survey, Electric Utility (East), Mar 4, 2005; (Central), Apr 1, 2005; (West), Feb 11, 2005

**Aquila Missouri**  
**Reference Company Adjustment Clauses**  
**May 2005**

<b>No.</b>	<b>Reference Company</b>	<b>Operating Company By Jurisdiction</b>	<b>Adjustment Clause?</b>	<b>Comment</b>
1	<b>Alliant Energy Co.</b>	Interstate Power & Light (IA)	<b>Yes</b>	Energy Adjustment Clauses are modified monthly based on forecasted energy costs (fuel & purchased power) for two months.
		Wisconsin Power & Light (WI)	<b>Yes</b>	Fuel clause effective outside of +/- 3% bandwidth
2	<b>Ameren</b>	CIPSCO, CILCO, Ill. Pwr (IL)	<b>No</b>	No fuel adjustment clauses in IL or MO
		Union Electric (MO)	<b>No</b>	
3	<b>American Elec. Pwr.</b>	Columbus South, Ohio Pwr (OH)	<b>No</b>	Rates frozen under rate stabilization plan
		Public Svc. Co. of Oklahoma (OK)	<b>Yes</b>	Traditional fuel & purch power adjustment clause
		AEP Texas Central, North (TX)	<b>n/a</b>	Retail service provided through unaffiliated REPs
		SWEPCO (TX)	<b>Yes</b>	Traditional fuel & purch power adjustment clause
		Indiana Michigan Pwr Co. (IN)	<b>No</b>	Pending extension of fuel clause rate caps
		Appalachian Pwr Co. (VA)	<b>Yes</b>	Traditional fuel & purch power adjustment clause
		Kentucky Pwr Co. (KY)	<b>Yes</b>	Traditional fuel & purch power adjustment clause
4	<b>CH Energy Group</b>	Central Hudson G&E (NY)	<b>Yes</b>	Traditional fuel & purch power adjustment clause
5	<b>Cent. Vermont P.S.</b>	Cent. Vermont P.S. (VT)	<b>No</b>	No fuel adjustment clause in VT
6	<b>CINERGY</b>	Cincinnati G&E (OH)	<b>No</b>	Rates frozen under rate stabilization plan
		PSI Energy (IN)	<b>Yes</b>	Traditional fuel & purch power adjustment clause
7	<b>Cleco Corporation</b>	CLECO Power (LA)	<b>Yes</b>	Traditional fuel & purch power adjustment clause
8	<b>Con. Edison Co.</b>	Con. Ed., Orange & Rockland (NY)	<b>Yes</b>	Traditional fuel & purch power adjustment clause
9	<b>DTE Energy Co.</b>	Detroit Edison (MI)	<b>Yes</b>	Power Supply Cost Rec clause resumed in Dec 2003
10	<b>Duquesne Light</b>	Duquesne Light (PA)	<b>No</b>	Rates deregulated
11	<b>Empire District</b>	Empire District Electric Co. (MO)	<b>No</b>	No fuel adjustment clauses in MO
12	<b>Energy East Corp.</b>	Central Maine Power (ME)	<b>Yes</b>	Traditional fuel & purch power adjustment clause
		Rochester G&E, NYSEG (NY)	<b>Yes</b>	Electric Supply Reconciliation mechanism
13	<b>Entergy Corp.</b>	Energy Arkansas (AR)	<b>Yes</b>	Traditional fuel & purch power adjustment clause
		Entergy Gulf States (TX)	<b>Yes</b>	Traditional fuel & purch power adjustment clause
		Entergy Gulf States, LA, NO (LA)	<b>Yes</b>	Traditional fuel & purch power adjustment clause
		Entergy Mississippi (MS)	<b>Yes</b>	Traditional fuel & purch power adjustment clause
14	<b>Exelon Corp.</b>	Commonwealth Edison (IL)	<b>No</b>	Rate caps
		PECO Energy (PA)	<b>No</b>	Rate caps

## Aquila Missouri Reference Company Adjustment Clauses (cont'd)

No.	Reference Company	Operating Company By Jurisdiction	Adjustment Clause?	Comment
15	FPL Group, Inc.	Florida P&L (FL)	Yes	Traditional fuel & purch power adjustment clause
16	FirstEnergy	Ohio Edison, Clev. El, Tol Ed (OH)	No	Rate caps
		Penn Pwr, Met Ed, Penn Elec (PA)	No	Rate caps
		Jersey Central (NJ)	Yes	Deferred pass-throughs
17	Green Mtn. Power	Green Mt. Power (VT)	No	No fuel adjustment clause in VT
18	Hawaiian Electric	Hawaiian Electric (HI)	Yes	Traditional fuel & purch power adjustment clause
19	MGE Energy, Inc.	Madison G&E (WI)	Yes	Fuel clause effective outside of +/- 3% bandwidth
20	NiSource Inc.	NIPSCO (IN)	Yes	Traditional fuel & purch power adjustment clause
21	NSTAR	Boston Edison, Comm Elec, Cambridge Elec (MA)	Yes	All electricity supply costs recovered, through deferral mechanism if necessary
22	Pinnacle West	APS (AZ)	Yes	Power supply adjuster part of rate settlement
23	Progress Energy	Progress Energy Carolina (NC)	Yes	Traditional fuel & purch power adjustment clause
		Progress Energy Florida (FL)	Yes	Traditional fuel & purch power adjustment clause
24	Puget Energy, Inc.	Puget Sound Energy (WA)	Yes	Power Cost Adjustment
25	SCANA Corp.	South Carolina E&G (SC)	Yes	Traditional fuel & purch power adjustment clause
26	Southern Co.	Alabama Power (AL)	Yes	Traditional fuel & purch power adjustment clause
		Georgia Power, Sav Pwr (GA)	Yes	Traditional fuel & purch power adjustment clause
		Gulf Power (FL)	Yes	Traditional fuel & purch power adjustment clause
		Mississippi Power (MS)	Yes	Traditional fuel & purch power adjustment clause
27	Vectren Corp.	Southern Indiana G&E (IN)	Yes	Traditional fuel & purch power adjustment clause
28	Westar Energy	Westar Energy	No	Fuel & PP addressed in context of general rate case
29	Xcel Energy Inc.	NSP-Minnesota (MN)	Yes	Traditional fuel & purch power adjustment clause
		NSP-Wisconsin (WI)	Yes	Fuel clause effective outside of +/- 3% bandwidth
		PSC Colorado (CO)	Yes	Through Electric Commodity Adjustment
		Southwestern Public Service (TX)	Yes	Traditional fuel & purch power adjustment clause
	<b>Summary of Results</b>	Comparable Cos with Trackers	<b>19</b>	
		Comparable Cos w/o Trackers	<b>7</b>	
		Comparable Cos with both	<b>3</b>	
		Total Comparable Cos	<b>29</b>	

Source: Company 10-K's

Aquila Missouri  
Weighted Average Cost of Debt: MPS  
December 2004

<u>Assigned Debt</u>	<u>Effective Rate</u>	<u>224001-103 MPD Gas</u>	<u>224001-122 MPD Elec Dist</u>	<u>224001-121 MPD Elec Trans</u>	<u>224001-123 MPG</u>	<u>MPS Total</u>	<u>MO Electric Assigned Debt</u>	<u>MO Electric Annual Interest</u>	<u>MO Electric Weighted Avg Cost of Debt</u>
15 Yr 9.03%, Due 12/1/05 Effective Rate 9.312%	9.312%	0	3,574,203	6,314,033	1,800,288	11,688,524	11,688,524	1,088,435	
30 Yr 8.27%, Due 11/15/21 Effective Rate 8.502%	8.502%	2,280,000	12,771,000	3,494,000	7,755,000	26,300,000	24,020,000	2,042,180	
15 Yr 8.2%, Due 1/15/07 Effective Rate 8.284%	8.284%	1,643,000	9,629,000	2,517,000	2,756,000	16,545,000	14,902,000	1,234,482	
30 Yr 8.0%, Due 3/1/23 Effective Rate 8.129%	8.129%	4,703,000	7,421,000	1,452,000	3,224,000	16,800,000	12,097,000	983,365	
Sr 6.70%, Due 10/15/06 Effective Rate 6.745%	6.745%	8,245,084	35,619,752	12,208,967	10,967,712	67,041,515	58,796,431	3,965,819	
Sr 11.875% (downgrade 14.875%), Due 7/1/12 Effective Rate 5.35% (10/01/04)	5.350%	1,263,000	69,954,461	16,976,000	21,133,500	109,326,961	108,063,961	5,781,422	
Wamego 96, Due 3/1/26 Effective Rate 1.698%	1.698%	685,000	2,921,000	1,050,000	2,644,000	7,300,000	6,615,000	112,323	
Environ Improve, Due 5/1/28 Effective Rate 1.688%	1.688%	0	0	0	5,000,000	5,000,000	5,000,000	84,400	
Sanwa Bank Loan, Due 12/9/09 Effective Rate 7.02%	7.020%	0	0	0	3,862,102	3,862,102	3,862,102	271,120	
Sr 11.875% (downgrade 14.875%), Due 7/1/12 Effective Rate 6.05% (7/15/04)	6.050%	5,086,000	59,655,000	121,000	6,395,000	71,257,000	66,171,000	4,003,346	
Sr 7.625%, Due 11/15/09 Effective Rate 7.742%	7.742%	2,767,916	10,591,084	6,800,000	24,600,000	44,759,000	41,991,084	3,250,950	
Sr 7.95% (downgrade 9.95%), Due 2/1/11 Effective Rate 8.01%	8.010%		17,863,000			17,863,000	17,863,000	1,430,826	
Sr 7.625%, Due 11/15/09 Effective Rate 7.742%	7.742%				9,174,000	9,174,000	9,174,000	710,251	
30 Yr 8.27%, Due 11/15/21 Effective Rate 8.502%	8.502%				134,962	134,962	134,962	11,474	
Sr 7.95% (downgrade 9.95%), Due 2/1/11 Effective Rate 8.01%	8.010%				38,029,038	38,029,038	38,029,038	3,046,126	
30 Yr 8.0%, Due 3/1/23 Effective Rate 8.129%	8.129%				462,000	462,000	462,000	37,556	
<b>Total</b>		<b>26,673,000</b>	<b>229,999,500</b>	<b>50,933,000</b>	<b>137,937,602</b>	<b>445,543,102</b>	<b>418,870,102</b>	<b>28,054,075</b>	<b>6.698%</b>

**Aquila Missouri**  
**Weighted Average Cost of Debt: SJLP**  
December 2004

<u>Assigned Debt</u>	<u>Gas</u> <u>224001-103</u> <u>SJD</u>	<u>Electric</u> <u>224001-122</u> <u>SJD</u>	<u>Generation</u> <u>224001-123</u> <u>SJG</u>	<u>Transmission</u> <u>224001-121</u> <u>SJLP</u>	<u>SJLP</u> <u>Total</u>	<u>SJLP Electric</u> <u>Assigned</u> <u>Debt</u>	<u>SJLP Electric</u> <u>Annual</u> <u>Interest</u>	<u>SJLP Electric</u> <u>Weighted Avg</u> <u>Cost of Debt</u>
Poll Cntrl Bonds 5.85%, Due 2/1/13 Effective Rate 6.467%	-	-	5,600,000	-	5,600,000	5,600,000	362,152	
20 Yr MTN 7.13%, Due 11/29/13 Effective Rate 7.373%		1,000,000	-	-	1,000,000	1,000,000	73,730	
20 Yr MTN 7.16%, Due 11/29/13 Effective Rate 7.404%	1,300,000	6,000,000	1,700,000	-	9,000,000	7,700,000	570,108	
30 Yr MTN 7.17%, Due 12/1/23 Effective Rate 7.414%		7,000,000	-	-	7,000,000	7,000,000	518,980	
30 Yr MTN 7.33%, Due 11/30/23 Effective Rate 7.579%		-	3,000,000	-	3,000,000	3,000,000	227,370	
10 Yr MTN 8.36%, Due 3/15/05 Effective Rate 8.421%	2,000,000	-	18,000,000	-	20,000,000	18,000,000	1,515,780	
Sr 7.625%, Due 11/15/09 Effective Rate 7.742%		60,600,000	23,600,000	2,700,000	86,900,000	86,900,000	6,727,798	
Sr 7.95% (downgrade 9.95%), Due 2/1/11 Effective Rate 8.01%		1,661,000			1,661,000	1,661,000	133,046	
<b>Total</b>	<b>3,300,000</b>	<b>76,261,000</b>	<b>51,900,000</b>	<b>2,700,000</b>	<b>134,161,000</b>	<b>130,861,000</b>	<b>10,128,964</b>	
9.44% FMB, Due 2/1/2021 Effective Rate 9.487%	Debt on SJD books - assumes 100% Electric					19,125,000	1,814,346	
						<b>149,986,000</b>	<b>11,943,310</b>	<b>7.963%</b>

**Aquila Missouri**  
**Comparable Company Capital Structure**

**Schedule SCH-3**

Company	YE 2004			Value Line 08-10 Estimate		
	Common Equity Ratio	Long-Term Debt Ratio	Preferred Stock Ratio	Common Equity Ratio	Long-Term Debt Ratio	Preferred Stock Ratio
1 Alliant Energy Co.	50.5%	44.5%	5.0%	55.0%	40.5%	4.5%
2 Ameren	53.0%	45.0%	2.0%	52.5%	46.0%	1.5%
3 American Elec. Pwr.	43.5%	55.9%	0.6%	47.5%	52.0%	0.5%
4 CH Energy Group	59.1%	38.3%	2.6%	58.0%	39.5%	2.5%
5 Cent. Vermont P.S.	60.0%	36.0%	4.0%	65.0%	33.0%	2.0%
6 CINERGY	49.0%	50.3%	0.7%	53.0%	46.5%	0.5%
7 Cleco Corporation	53.0%	44.5%	2.5%	46.5%	51.5%	2.0%
8 Con. Edison	51.0%	47.5%	1.5%	51.5%	47.5%	1.0%
9 DTE Energy Co.	42.8%	57.2%	0.0%	50.5%	49.5%	0.0%
10 Duquesne Light	35.5%	56.0%	8.5%	45.0%	48.0%	7.0%
11 Empire District	48.7%	51.3%	0.0%	52.5%	47.5%	0.0%
12 Energy East Corp.	40.5%	58.5%	1.0%	46.5%	52.5%	1.0%
13 Entergy Corp.	53.0%	45.0%	2.0%	56.5%	41.5%	2.0%
14 Exelon Corp.	43.5%	56.1%	0.4%	54.0%	46.0%	0.0%
15 FPL Group, Inc.	48.5%	51.5%	0.0%	54.5%	45.5%	0.0%
16 FirstEnergy	45.6%	53.1%	1.3%	55.5%	43.5%	1.0%
17 Green Mtn. Power	52.0%	48.0%	0.0%	50.5%	49.5%	0.0%
18 Hawaiian Electric	52.0%	46.5%	1.5%	55.5%	43.0%	1.5%
19 MGE Energy, Inc.	62.6%	37.4%	0.0%	65.0%	35.0%	0.0%
20 NiSource Inc.	49.3%	49.8%	0.9%	51.0%	48.5%	0.5%
21 NSTAR	40.0%	58.5%	1.5%	53.5%	45.5%	1.0%
22 Pinnacle West	50.0%	50.0%	0.0%	53.0%	47.0%	0.0%
23 Progress Energy	44.5%	55.0%	0.5%	49.5%	50.0%	0.5%
24 Puget Energy, Inc.	42.5%	57.5%	0.0%	48.5%	51.5%	0.0%
25 SCANA Corp.	42.6%	55.4%	2.0%	53.0%	45.5%	1.5%
26 Southern Co.	44.0%	53.5%	2.5%	49.5%	49.0%	1.5%
27 Vectren Corp.	50.5%	49.5%	0.0%	55.5%	44.5%	0.0%
28 Westar Energy	45.5%	53.8%	0.7%	51.0%	48.5%	0.5%
29 Xcel Energy Inc.	44.5%	54.5%	1.0%	51.0%	48.0%	1.0%
Average	48.2%	50.3%	1.5%	52.8%	46.1%	1.2%

Source: Value Line Investment Survey, Electric Utility (East), Mar 4, 2005; (Central), Apr 1, 2005; (West), Feb 11, 2005

**AQUILA MISSOURI**  
**BOND RATINGS CRITERIA**  
**RATIO GUIDELINES**

**STANDARD & POOR'S**  
 (Business Profile 6)

Ratio	Bond Rating			
	AA	A	BBB	BB
FFO Interest Coverage*	5.2-6.0x	4.2-5.2x	3.0-4.2x	2.0-3.0x
FFO/Total Debt	35-45%	28-35%	18-28%	12-18%
Total Debt/ Total Capital	32-40%	40-48%	48-58%	58-62%

\*Flow of Funds from Operations (FFO) is net income from continuing operations plus non-cash items such as depreciation, amortization, and deferred income taxes.

SOURCE: *Standard & Poor's Rating Criteria*, October 28, 2004.

## AQUILA MISSOURI

### ***Rate Base Investment – To Meet Customer Needs***

(\$ Millions)	Over the Next 5 Years <sup>(1)</sup>
Plant	\$ 250
Environmental	120
South Harper	150
Other – Generation, Transmission, & Electric and Gas Distribution	130
<b>Total</b>	<b>\$ \$650</b>

<sup>(1)</sup>Schedule represents capital expenditures in excess of annual depreciation range of \$140 – 150 million.

### ***Maturing and Callable Debt – Through 2007***

<u>Maturities:</u> (\$ Millions)	
9.03% Series due December 1, 2005	\$ 19.1
6.70% Series due October 15, 2006	85.9
8.20% Series due January 15, 2007	36.9
	<u>141.9</u>
<u>Debt with Call Features:</u>	
QUIBS	\$ 287.5
Term Loan	220.0
8.00% Series due March 1, 20023	51.5
	<u>559.0</u>
<b>Total</b>	<b>\$ 700.9</b>

### ***Utility Statistics***

<b>Not Held for Sale</b>		<b>Potential Divestitures</b>	
	12/31/2004		12/31/2004
(\$Millions)	Net Plant		Net Plant
Missouri Electric	\$ 859.4	Michigan Gas	\$ 148.1
Colorado Gas	41.0	Minnesota Gas	151.9
Iowa Gas	111.0	Missouri Gas	48.2
Kansas Gas	81.5	Colorado Electric	130.5
Nebraska Gas	115.9	Kansas Electric	203.7
		SJL&P	191.5
<b>Total</b>	<b>\$ 1,208.8</b>	<b>Total</b>	<b>\$ 874.0</b>

Aquila Future Repositioning Plans, March 14, 2005.



**Aquila Missouri**  
**Financial Ratio Analysis**  
(\$millions unless otherwise noted)

Case 1: Comparable Group Equity Ratio, 11.50% ROE

	<b>SJLP Retail</b>	<b>MPS Retail</b>	<b>Steam</b>
<b>Revenue Requirement</b>	<b>Jurisdictional</b>	<b>Jurisdictional</b>	<b>Jurisdictional</b>
Rate Base	187,577,582	833,641,918	6,476,104
ROE	11.50%	11.50%	11.50%
Equity Ratio	48.20%	48.20%	48.20%
Debt Ratio	51.80%	51.80%	51.80%
Cost of Debt	7.963%	6.698%	7.963%
Income Tax Rate	38.39%	38.39%	38.39%
WACC	9.67%	9.01%	9.67%
Net Operating Income (NOI) Requirement	18,134,689	75,132,511	626,099
NOI Available	12,250,718	23,272,286	(2,332,126)
Additional NOI Needed	5,883,971	51,860,225	2,958,225
Additional Current Tax Required	3,666,380	32,314,787	1,843,309
Additional Gross Revenue Requirement	9,550,351	84,175,012	4,801,534
<b>Funds from Operations (FFO)/Total Debt</b>			
Net Income Requested	10,397,425	46,208,772	358,970
Regulatory Disallowances (after-tax)	0	0	
Depreciation & Amortization	11,696,560	50,755,320	623,997
Deferred Taxes & ITC	(482,295)	(789,138)	(4,003)
Funds from Operations (FFO)	21,611,690	96,174,954	978,964
Long-Term Debt	97,165,187	431,826,514	3,354,622
FFO/Total Debt	22.24%	22.27%	29.18%
<i>Implied S&amp;P Bond Rating (Business Position: 6)</i>	<i>BBB</i>	<i>BBB</i>	<i>A</i>
<b>Funds from Operations (FFO) Interest Coverage</b>			
Funds from Operations (FFO)	21,611,690	96,174,954	978,964
Interest Expense	7,737,264	28,923,740	267,129
FFO Interest Coverage	3.79	4.33	4.66
<i>Implied S&amp;P Bond Rating (Business Position: 6)</i>	<i>BBB</i>	<i>A</i>	<i>A</i>
<b>Total Debt/Total Capital</b>			
Total Debt/Total Capital	51.80%	51.80%	51.80%
<i>Implied S&amp;P Bond Rating (Business Position: 6)</i>	<i>BBB</i>	<i>BBB</i>	<i>BBB</i>

**Aquila Missouri**  
**Financial Ratio Analysis**  
(\$millions unless otherwise noted)

Case 2: Aquila Consolidated Equity Ratio, 11.50% ROE

	<b>SJLP Retail</b>	<b>MPS Retail</b>	<b>Steam</b>
<b>Revenue Requirement</b>	<b>Jurisdictional</b>	<b>Jurisdictional</b>	<b>Jurisdictional</b>
Rate Base	187,577,582	833,641,918	6,476,104
ROE	11.50%	11.50%	11.50%
Equity Ratio	32.69%	32.69%	32.69%
Debt Ratio	67.31%	67.31%	67.31%
Cost of Debt	7.963%	6.700%	7.963%
Income Tax Rate	38.39%	38.39%	38.39%
WACC	9.12%	8.27%	9.12%
Net Operating Income (NOI) Requirement	17,105,660	68,934,851	590,572
NOI Available	13,140,067	26,601,192	(2,299,385)
Additional NOI Needed	3,965,593	42,333,659	2,889,957
Additional Current Tax Required	2,471,013	26,378,659	1,800,770
Additional Gross Revenue Requirement	6,436,606	68,712,317	4,690,727
<b>Funds from Operations (FFO)/Total Debt</b>			
Net Income Requested	7,051,698	31,339,517	243,459
Regulatory Disallowances (after-tax)	0	0	0
Depreciation & Amortization	11,696,560	50,755,320	623,997
Deferred Taxes & ITC	(482,295)	(789,138)	(4,003)
Funds from Operations (FFO)	18,265,963	81,305,699	863,453
Long-Term Debt	126,258,470	561,124,375	4,359,066
FFO/Total Debt	14.47%	14.49%	19.81%
<i>Implied S&amp;P Bond Rating (Business Position: 6)</i>	<i>BB</i>	<i>BB</i>	<i>BBB</i>
<b>Funds from Operations (FFO) Interest Coverage</b>			
Funds from Operations (FFO)	18,265,963	81,305,699	863,453
Interest Expense	10,053,962	37,595,333	347,112
FFO Interest Coverage	2.82	3.16	3.49
<i>Implied S&amp;P Bond Rating (Business Position: 6)</i>	<i>BB</i>	<i>BBB</i>	<i>BBB</i>
<b>Total Debt/Total Capital</b>			
Total Debt/Total Capital	67.31%	67.31%	67.31%
<i>Implied S&amp;P Bond Rating (Business Position: 6)</i>	<i>B</i>	<i>B</i>	<i>B</i>

**Aquila Missouri**  
**Financial Ratio Analysis**  
(\$millions unless otherwise noted)

Case 3: Aquila Consolidated Equity Ratio, No Rate Increase

	<b>SJLP Retail</b>	<b>MPS Retail</b>	<b>Steam</b>
<b>Revenue Requirement</b>	<b>Jurisdictional</b>	<b>Jurisdictional</b>	<b>Jurisdictional</b>
Rate Base	187,577,582	833,641,918	6,476,104
ROE	11.50%	11.50%	11.50%
Equity Ratio	32.69%	32.69%	32.69%
Debt Ratio	67.31%	67.31%	67.31%
Cost of Debt	7.963%	6.700%	7.963%
Income Tax Rate	38.39%	38.39%	38.39%
WACC	9.12%	8.27%	9.12%
Net Operating Income (NOI) Requirement	17,105,660	68,934,851	590,572
NOI Available	13,140,067	26,601,192	(2,299,385)
Additional NOI Needed	3,965,593	42,333,659	2,889,957
Additional Current Tax Required	2,471,013	26,378,659	1,800,770
Additional Gross Revenue Requirement	6,436,606	68,712,317	4,690,727
<b>Funds from Operations (FFO)/Total Debt</b>			
Net Income Requested	7,051,698	31,339,517	243,459
Regulatory Disallowances (after-tax)	(3,965,593)	(42,333,659)	(2,889,957)
Depreciation & Amortization	11,696,560	50,755,320	623,997
Deferred Taxes & ITC	(482,295)	(789,138)	(4,003)
Funds from Operations (FFO)	14,300,370	38,972,041	(2,026,504)
Long-Term Debt	126,258,470	561,124,375	4,359,066
FFO/Total Debt	11.33%	6.95%	-46.49%
<i>Implied S&amp;P Bond Rating (Business Position: 6)</i>	<i>B</i>	<i>B</i>	<i>B</i>
<b>Funds from Operations (FFO) Interest Coverage</b>			
Funds from Operations (FFO)	14,300,370	38,972,041	(2,026,504)
Interest Expense	10,053,962	37,595,333	347,112
FFO Interest Coverage	2.42	2.04	(4.84)
<i>Implied S&amp;P Bond Rating (Business Position: 6)</i>	<i>BB</i>	<i>BB</i>	<i>B</i>
<b>Total Debt/Total Capital</b>			
Total Debt/Total Capital	67.31%	67.31%	67.31%
<i>Implied S&amp;P Bond Rating (Business Position: 6)</i>	<i>B</i>	<i>B</i>	<i>B</i>

**Aquila Missouri**  
**Capital Structure-ROE Tradeoff**  
**Missouri Public Service Cost of Debt**

**Case 1: Company Case As-Filed**

Capital Component	Percent	Cost Rate	Weighted Cost	Tax Inclusive Cost
Debt	51.80%	6.70%	3.47%	3.47%
Equity	48.20%	11.50%	5.54%	9.00%
	100.00%		9.01%	<b>12.47%</b>

**Case 2: Consolidated Capital Structure; Adjusted ROE to Yield Equivalent Tax-Inclusive Rate of Return**

	Percent	Cost Rate	Weighted Cost	Tax Inclusive Cost
Debt	67.31%	6.70%	4.51%	4.51%
Equity	32.69%	<b>15.00%</b>	4.91%	7.96%
	100.00%		9.41%	<b>12.47%</b>

Note: Tax rate = 38.39%

**Aquila Missouri**  
**Capital Structure-ROE Tradeoff**  
**St. Joseph Light & Power Cost of Debt**

**Case 1: Company Case As-Filed**

Capital Component	Percent	Cost Rate	Weighted Cost	Tax Inclusive Cost
Debt	51.80%	7.96%	4.12%	4.12%
Equity	48.20%	11.50%	5.54%	9.00%
	100.00%		9.67%	<b>13.12%</b>

**Case 2: Consolidated Capital Structure; Adjusted ROE to Yield Equivalent Tax-Inclusive Rate of Return**

	Percent	Cost Rate	Weighted Cost	Tax Inclusive Cost
Debt	67.31%	7.96%	5.36%	5.36%
Equity	32.69%	<b>14.63%</b>	4.78%	7.76%
	100.00%		10.14%	<b>13.12%</b>

Note: Tax rate = 38.39%

**Aquila Missouri**  
**Historical Capital Market Costs**

	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
<b>Prime Rate</b>	8.8%	8.3%	8.4%	8.4%	8.0%	9.2%	6.9%	4.7%	4.1%	4.3%
<b>Consumer Price Index</b>	2.8%	2.9%	2.3%	1.6%	2.2%	3.4%	2.8%	1.6%	2.3%	2.7%
<b>Long-Term Treasuries</b>	6.9%	6.7%	6.6%	5.6%	5.9%	5.9%	5.5%	5.4%	5.0%	5.1%
<b>Moody's Avg Utility Debt</b>	7.9%	7.7%	7.6%	7.0%	7.6%	8.1%	7.7%	7.5%	6.6%	6.2%
<b>Moody's A Utility Debt</b>	7.9%	7.8%	7.6%	7.0%	7.6%	8.2%	7.8%	7.4%	6.6%	6.2%

**SOURCES:**

Prime Interest Rate - Federal Reserve Bank of St. Louis website  
Consumer Price Index - Federal Reserve Bank of St. Louis website  
Long-Term Treasuries - Federal Reserve Bank of St. Louis website  
Moody's Average Utility Debt - Moody's (Mergent) Bond Record  
Moody's Baa Utility Debt - Moody's (Mergent) Bond Record

**Aquila Missouri**  
**Three-Month Average Moody's Utility Bond Yields**

<u>MONTH</u>	<u>MOODY'S Baa UTILITY BOND YIELD</u>	<u>MOODY'S AVERAGE UTILITY BOND YIELD</u>
Jan-05	5.95%	5.93%
Feb-05	5.76%	5.64%
Mar-05	5.99%	5.81%
AVERAGE	5.90%	5.79%

Source: Mergent Bond Record

## Economic Indicators

Seasonally Adjusted Annual Rates — Dollar Figures in Billions

	Annual % Change				2004				E2005				E2006			
	2004	E2005	E2006		2004	3Q	4Q		2004	1Q	2Q	3Q	4Q	1Q	2Q	
<b>Gross Domestic Product</b>																
GDP (current dollars)	\$11,735.0	\$12,467.0	\$13,129.0	6.6	6.2	5.3			\$11,815.0	\$11,995.0	\$12,207.0	\$12,395.0	\$12,558.0	\$12,706.0	\$12,882.0	\$13,062.0
Annual rate of increase (%)	6.6	6.2	5.3	-	-	-			5.5	6.2	7.3	6.3	5.4	4.8	5.7	5.7
Annual rate of increase—real GDP (%)	4.4	3.7	3.0	-	-	-			4.0	3.9	4.1	3.8	3.3	2.4	3.3	3.4
Annual rate of increase—GDP deflator (%)	2.2	2.4	2.2	-	-	-			1.4	2.3	2.8	2.4	2.0	2.3	2.3	2.2
<b>* Components of Real GDP</b>																
Personal consumption expenditures	\$7,633.0	\$7,895.0	\$8,116.0	3.8	3.4	2.8			\$7,668.0	\$7,747.0	\$7,816.0	\$7,866.0	\$7,921.0	\$7,978.0	\$8,030.0	\$8,092.0
% change	3.8	3.4	2.8	-	-	-			5.1	4.2	3.6	2.6	2.9	2.9	2.7	3.1
Durable goods	1,099.3	1,137.1	1,170.1	6.7	3.4	2.9			1,118.3	1,129.0	1,125.9	1,129.1	1,138.8	1,154.6	1,155.5	1,167.2
Nondurable goods	2,208.5	2,304.1	2,366.6	4.6	4.3	2.7			2,213.2	2,245.3	2,283.7	2,293.3	2,312.5	2,326.7	2,343.2	2,359.8
Services	4,338.3	4,468.8	4,594.6	2.8	3.0	2.8			4,352.5	4,389.2	4,421.0	4,457.2	4,484.5	4,512.4	4,546.0	4,580.4
Nonresidential fixed investment	1,228.6	1,360.0	1,461.6	10.6	10.7	7.5			1,245.3	1,288.3	1,313.9	1,342.6	1,377.7	1,405.7	1,429.6	1,455.4
% change	10.6	10.7	7.5	-	-	-			13.0	14.5	8.2	9.0	10.9	8.4	7.0	7.4
Producers durable equipment	998.6	1,125.1	1,201.0	13.6	12.7	6.8			1,015.6	1,059.5	1,086.1	1,115.5	1,140.7	1,158.2	1,173.7	1,193.3
Residential fixed investment	551.5	565.4	538.0	9.7	2.5	(4.9)			556.7	561.2	569.2	575.7	565.3	551.5	546.8	540.9
% change	9.7	2.5	(4.9)	-	-	-			1.5	3.3	5.8	4.6	(7.0)	(9.4)	(3.4)	(4.2)
Net change in business inventories	45.7	46.0	41.1	-	-	-			34.5	47.2	61.5	48.5	41.4	32.5	41.8	43.0
Gov't purchases of goods & services	1,946.6	1,991.3	2,033.7	2.0	2.3	2.1			1,949.9	1,954.0	1,968.9	1,983.0	2,000.5	2,012.7	2,022.1	2,031.4
Federal	721.7	747.9	761.2	4.7	3.6	1.8			726.6	728.8	737.4	745.3	752.1	757.0	758.9	760.6
State & local	1,224.8	1,243.3	1,272.3	0.4	1.5	2.3			1,223.2	1,225.1	1,231.4	1,237.6	1,248.4	1,255.7	1,263.0	1,270.8
Net exports	(583.7)	(624.9)	(602.4)	-	-	-			(583.2)	(621.1)	(641.6)	(620.9)	(617.8)	(619.1)	(614.6)	(606.8)
Exports	1,120.3	1,194.6	1,295.7	8.6	6.6	8.5			1,131.1	1,140.0	1,160.4	1,181.2	1,205.8	1,231.0	1,255.5	1,280.2
Imports	1,704.0	1,819.4	1,898.1	9.9	6.8	4.3			1,714.3	1,761.2	1,801.9	1,802.1	1,823.6	1,850.2	1,870.2	1,886.9
<b>** Income &amp; Profits</b>																
Personal income	\$9,673.0	\$10,222.0	\$10,840.0	5.6	5.7	6.1			\$9,700.0	\$9,954.0	\$9,997.0	\$10,155.0	\$10,297.0	\$10,437.0	\$10,615.0	\$10,771.0
Disposable personal income	8,634.0	9,074.0	9,573.0	5.8	5.1	5.5			8,652.0	8,894.0	8,913.0	9,032.0	9,125.0	9,228.0	9,383.0	9,515.0
Savings rate (%)	1.2	0.4	0.8	-	-	-			0.7	1.6	0.5	0.5	0.4	0.2	0.7	0.8
Corporate profits before taxes	985.4	1,408.9	1,361.4	12.7	43.0	(3.4)			932.8	1,057.9	1,418.0	1,438.7	1,408.1	1,370.8	1,347.8	1,370.1
Corporate profits after taxes	716.1	1,061.8	1,008.9	12.0	48.3	(5.0)			679.5	762.1	1,072.3	1,084.9	1,059.9	1,030.0	1,000.4	1,015.7
†Earnings per share (S&P 500)	58.40	67.60	74.80	20.2	15.2	11.0			57.86	58.60	60.40	62.10	65.40	67.40	70.50	73.00
<b>† Prices &amp; Interest Rates</b>																
Consumer price index	2.7	2.7	2.0	-	-	-			1.6	3.6	2.4	3.1	1.5	2.6	1.6	2.1
Treasury bills	1.4	3.2	4.2	-	-	-			1.5	2.0	2.5	2.9	3.4	3.9	4.2	4.2
10-yr notes	4.3	4.7	5.3	-	-	-			4.3	4.2	4.3	4.5	4.8	5.1	5.3	5.3
30-yr bonds	5.1	5.1	5.8	-	-	-			5.2	4.9	4.7	4.9	5.2	5.5	5.7	5.7
New issue rate—corporate bonds	5.6	5.7	6.3	-	-	-			5.6	5.5	5.3	5.5	5.7	6.1	6.2	6.2
<b>Other Key Indicators</b>																
Housing starts (1,000 units SAAR)	1,950.0	1,970.0	1,790.0	5.4	1.2	(9.6)			1,970.0	1,980.0	2,150.0	2,000.0	1,880.0	1,860.0	1,820.0	1,790.0
Auto & truck sales (1,000,000 units)	16.8	16.8	17.0	0.9	0.0	1.5			17.1	17.0	16.4	16.8	16.9	17.1	17.0	17.0
Unemployment rate (%)	5.5	5.1	5.1	-	-	-			5.4	5.4	5.3	5.1	5.0	5.0	5.0	5.0
\$U.S. dollar	(8.2)	(7.2)	(6.1)	-	-	-			(6.8)	(19.8)	(2.9)	(4.9)	(9.0)	(6.1)	(6.6)	(5.1)

Note: Annual changes are from prior year and quarterly changes are from prior quarter. Figures may not add to totals because of rounding. A—Advance data. P—Preliminary. E—Estimated. R—Revised. \*1996 Chain-weighted dollars. \*\*Current dollars. †Trailing 4 quarters. ‡Average for period. \$Quarterly % changes at quarterly rates. This forecast prepared by Standard & Poor's.



# Value Line Forecast for the U.S. Economy

	ACTUAL				ESTIMATED					
	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
<b>GROSS DOMESTIC PRODUCT AND ITS COMPONENTS</b>										
<b>(2000 CHAIN WEIGHTED \$) BILLIONS OF DOLLARS</b>										
Final Sales	9760	9921	10063	10380	10790	11161	11530	11899	12291	12709
Total Consumption	6739	6910	7123	7356	7635	7891	8128	8372	8615	8856
Nonresidential Fixed Investment	1232	1180	1076	1111	1226	1342	1435	1543	1659	1791
Structures	313	306	252	237	240	249	269	283	300	318
Equipment & Software	919	874	826	879	997	1109	1164	1245	1339	1446
Residential Fixed Investment	447	448	470	511	560	560	537	526	532	542
Exports	1096	1037	1012	1032	1115	1181	1304	1448	1600	1752
Imports	1476	1436	1484	1550	1702	1801	1873	1958	2046	2148
Federal Government	579	601	647	690	722	744	758	764	771	777
State & Local Governments	1143	1179	1211	1220	1225	1240	1263	1284	1306	1329
Gross Domestic Product	9817	10128	10487	11004	11728	12366	12994	13689	14449	15264
Real GDP (2000 Chain Weighted \$)	9817	9891	10075	10381	10837	11218	11589	11983	12390	12824
<b>PRICES AND WAGES-ANNUAL RATES OF CHANGE</b>										
GDP Deflator	2.2	2.4	1.7	1.8	2.1	1.7	1.8	1.8	1.9	2.0
CPI-All Urban Consumers	3.4	2.8	1.6	2.3	2.7	2.3	2.4	2.4	2.5	2.5
PPI-Finished Goods	3.7	2.0	-1.3	3.2	3.6	2.0	1.7	1.5	1.6	1.8
Employment Cost Index—Total Comp.	4.6	4.1	3.8	4.0	3.8	3.6	3.7	3.8	3.8	4.0
Productivity	2.7	2.2	4.9	4.5	4.0	1.9	2.2	2.5	2.7	2.8
<b>PRODUCTION AND OTHER KEY MEASURES</b>										
Industrial Prod. (% Change)	4.4	-3.4	-0.6	0.0	4.1	3.1	3.0	3.5	3.8	4.0
Factory Operating Rate (%)	81.1	75.4	73.9	73.7	76.7	78.3	78.7	79.0	79.5	80.0
Nonfarm Inven. Chg. (2000 Chain Weighted \$)	57.8	-31.8	13.5	-1.1	41.7	50.0	35.0	45.0	50.0	55.0
Housing Starts (Mill. Units)	1.57	1.60	1.71	1.85	1.95	1.88	1.75	1.73	1.72	1.70
Existing House Sales (Mill. Units)	5.16	5.29	5.59	6.10	6.61	6.36	6.10	6.00	5.90	5.80
Total Light Vehicle Sales (Mill. Units)	17.4	17.1	16.8	16.6	16.8	16.9	17.0	17.3	17.5	17.7
National Unemployment Rate (%)	4.0	4.8	5.8	6.0	5.5	5.2	5.2	5.2	5.3	5.3
Federal Budget Surplus (Unified, FY, \$Bill)	236.9	127.3	-157.8	-377.0	-412.0	-350.0	-315.0	-300.0	-295.0	-270.0
Price of Oil (\$Bbl., U.S. Refiners' Cost)	28.21	22.95	24.00	28.60	37.03	41.00	33.50	32.25	31.75	31.75
<b>MONEY AND INTEREST RATES</b>										
3-Month Treasury Bill Rate (%)	5.8	3.4	1.6	1.0	1.4	3.0	3.4	3.5	3.7	3.8
Federal Funds Rate (%)	6.2	3.9	1.7	1.1	1.4	2.9	3.6	3.8	4.0	4.3
10-Year Treasury Note Rate (%)	6.0	5.0	4.6	4.0	4.3	4.6	5.1	5.4	5.5	5.7
Long-Term Treasury Bond Rate (%)	5.9	5.5	5.4	5.0	5.1	5.1	5.7	6.0	6.1	6.3
AAA Corporate Bond Rate (%)	7.6	7.1	6.5	5.7	5.6	5.7	6.2	6.5	6.6	6.8
Prime Rate (%)	9.2	6.9	4.7	4.1	4.3	5.9	6.3	6.5	7.0	7.5
<b>INCOMES</b>										
Personal Income (% Change)	8.0	3.5	1.8	3.2	5.4	4.1	5.0	5.3	5.6	5.8
Real Disp. Inc. (% Change)	4.8	1.9	3.1	2.3	3.4	2.8	3.8	3.5	3.3	3.3
Personal Savings Rate (%)	2.4	1.8	2.0	1.4	1.0	0.5	0.5	0.8	1.0	1.3
Pretax Corporate Profits (\$Bill)	773.0	708.0	758.0	874.0	973.0	1235.0	1321.0	1427.0	1541.0	1680.0
Aftertax Corporate Profits (\$Bill)	508.0	504.0	574.0	640.0	709.0	803.0	859.0	928.0	1002.0	1092.0
Yr-to-Yr % Change	-1.7	-0.9	14.0	11.4	10.8	13.2	7.0	8.0	8.0	9.0
<b>COMPOSITION OF REAL GDP-ANNUAL RATES OF CHANGE</b>										
Gross Domestic Product	3.7	0.8	1.9	3.0	4.4	3.5	3.3	3.4	3.4	3.5
Final Sales	3.8	1.6	1.4	3.2	4.0	3.4	3.3	3.2	3.3	3.4
Total Consumption	4.7	2.5	3.1	3.3	3.8	3.4	3.0	3.0	2.9	2.8
Nonresidential Fixed Investment	8.7	-4.2	-8.8	3.3	10.3	9.5	7.0	7.5	7.5	8.0
Structures	6.8	-2.2	-17.6	-5.6	1.0	4.1	8.0	5.0	6.0	6.0
Equipment & Software	9.4	-4.9	-5.5	6.4	13.4	11.2	5.0	7.0	7.5	8.0
Residential Fixed Investment	0.7	0.2	4.9	8.7	9.5	0.0	-4.0	-2.0	1.0	2.0
Exports	8.7	-5.4	-2.4	2.0	8.1	5.9	10.4	11.0	10.5	9.5
Imports	13.2	-2.7	3.3	4.4	9.8	5.9	4.0	4.5	4.5	5.0
Federal Government	0.9	3.8	7.7	6.6	4.6	3.1	1.8	0.9	0.8	0.8
State & Local Governments	2.7	3.1	2.7	0.7	0.4	1.3	1.8	1.7	1.7	1.8

**Aquila Missouri**  
**Discounted Cash Flow Analysis**  
**Summary Of DCF Model Results**

Company	Traditional Constant Growth DCF Model	Constant Growth DCF Model Long-Term GDP Growth	Low Near-Term Growth Two-Stage Growth DCF Model
1 Alliant Energy Co.	8.3%	10.8%	10.6%
2 Ameren	8.3%	11.7%	10.9%
3 American Elec. Pwr.	8.1%	10.8%	10.5%
4 CH Energy Group	8.1%	11.2%	10.5%
5 Cent. Vermont P.S.	10.0%	10.8%	10.5%
6 CINERGY	9.9%	11.4%	10.9%
7 Cleco Corporation	8.3%	11.0%	10.3%
8 Con. Edison	9.2%	11.9%	11.2%
9 DTE Energy Co.	10.7%	11.3%	10.6%
10 Duquesne Light	11.3%	12.0%	11.3%
11 Empire District	11.2%	12.2%	11.3%
12 Energy East Corp.	8.9%	11.3%	11.2%
13 Entergy Corp.	9.7%	10.1%	10.2%
14 Exelon Corp.	10.3%	10.4%	10.2%
15 FPL Group, Inc.	9.0%	10.6%	10.6%
16 FirstEnergy	10.5%	10.9%	10.7%
17 Green Mtn. Power	8.7%	10.3%	10.3%
18 Hawaiian Electric	9.4%	11.2%	10.6%
19 MGE Energy, Inc.	9.9%	10.5%	10.0%
20 NiSource Inc.	9.1%	10.9%	10.6%
21 NSTAR	9.2%	10.9%	10.6%
22 Pinnacle West	9.3%	11.3%	11.0%
23 Progress Energy	9.7%	12.2%	11.4%
24 Puget Energy, Inc.	11.0%	11.1%	10.7%
25 SCANA Corp.	9.5%	10.9%	10.7%
26 Southern Co.	9.6%	11.2%	10.9%
27 Vectren Corp.	9.7%	11.2%	10.8%
28 Westar Energy	9.3%	10.9%	10.6%
29 Xcel Energy Inc.	9.7%	11.9%	11.8%
GROUP AVERAGE	9.5%	11.1%	10.7%
GROUP MEDIAN	9.5%	11.1%	10.6%

**Aquila Missouri**  
**Discounted Cash Flow Analysis**  
**Traditional Constant Growth DCF Model**

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Company	Recent Price(P0)	Next Year's Div(D1)	Dividend Yield	Projected Growth Rate Analysis										ROE K=Div Yld+G (Cols 3+13)
				Year 2009 "BR" Growth Rate Calculation						Zacks	Value Line	GDP Growth	Average Growth (Cols 9-12)	
				DPS	EPS	Retention Rate (B)	NBV	ROE (R)	B*R Growth					
1 Alliant Energy Co.	27.20	1.14	4.19%	1.32	2.10	37.14%	26.30	7.98%	2.97%	4.00%	3.00%	6.60%	4.14%	8.3%
2 Ameren	49.95	2.54	5.09%	2.54	3.15	19.37%	33.85	9.31%	1.80%	3.90%	0.50%	6.60%	3.20%	8.3%
3 American Elec. Pwr.	34.00	1.44	4.24%	1.60	3.00	46.67%	27.75	10.81%	5.05%	3.40%	0.50%	6.60%	3.89%	8.1%
4 CH Energy Group	46.53	2.16	4.64%	2.20	3.00	26.67%	33.50	8.96%	2.39%	NA	1.50%	6.60%	3.50%	8.1%
5 Cent. Vermont P.S.	22.71	0.96	4.23%	1.08	2.00	46.00%	21.30	9.39%	4.32%	NA	6.50%	6.60%	5.81%	10.0%
6 CENERGY	40.57	1.96	4.83%	2.08	3.15	33.97%	28.65	10.99%	3.73%	4.60%	5.50%	6.60%	5.11%	9.9%
7 Cleco Corporation	20.36	0.90	4.42%	0.90	1.50	40.00%	13.75	10.91%	4.36%	4.00%	0.50%	6.60%	3.87%	8.3%
8 Con. Edison	43.00	2.30	5.35%	2.36	2.95	20.00%	32.60	9.05%	1.81%	3.00%	NA	6.60%	3.80%	9.2%
9 DTE Energy Co.	44.14	2.06	4.67%	2.10	4.75	55.79%	40.75	11.66%	6.50%	4.00%	7.00%	6.60%	6.03%	10.7%
10 Duquesne Light	18.49	1.00	5.41%	1.04	1.45	28.28%	10.45	13.88%	3.92%	5.00%	8.00%	6.60%	5.88%	11.3%
11 Empire District	22.74	1.28	5.63%	1.28	1.75	26.86%	16.50	10.61%	2.85%	5.00%	8.00%	6.60%	5.61%	11.2%
12 Energy East Corp.	26.02	1.21	4.65%	1.45	2.00	27.50%	21.50	9.30%	2.56%	5.00%	3.00%	6.60%	4.29%	8.9%
13 Entergy Corp.	68.78	2.41	3.50%	3.01	5.40	44.26%	49.80	10.84%	4.80%	6.90%	6.50%	6.60%	6.20%	9.7%
14 Exelon Corp.	44.44	1.68	3.78%	1.92	3.60	46.67%	21.95	16.40%	7.65%	5.40%	6.50%	6.60%	6.54%	10.3%
15 FPL Group, Inc.	38.77	1.54	3.97%	1.90	2.95	35.59%	26.45	11.15%	3.97%	5.40%	4.00%	6.60%	4.99%	9.0%
16 FirstEnergy	40.27	1.72	4.27%	2.00	4.00	50.00%	35.00	11.43%	5.71%	4.10%	8.50%	6.60%	6.23%	10.5%
17 Green Mtn. Power	29.12	1.08	3.71%	1.32	2.45	46.12%	23.60	10.38%	4.79%	NA	3.50%	6.60%	4.96%	8.7%
18 Hawaiian Electric	27.47	1.26	4.59%	1.32	2.10	37.14%	17.57	11.95%	4.44%	3.80%	4.30%	6.60%	4.79%	9.4%
19 MGE Energy, Inc.	35.06	1.38	3.94%	1.44	2.45	41.22%	18.85	13.00%	5.36%	NA	6.00%	6.60%	5.99%	9.9%
20 NiSource Inc.	22.55	0.96	4.26%	1.10	2.00	45.00%	21.50	9.30%	4.19%	4.40%	4.00%	6.60%	4.80%	9.1%
21 NSTAR	55.65	2.42	4.35%	2.70	4.25	36.47%	34.25	12.41%	4.53%	4.80%	3.50%	6.60%	4.86%	9.2%
22 Pinnacle West	42.43	1.99	4.69%	2.23	3.20	30.31%	36.88	8.68%	2.63%	5.20%	3.90%	6.60%	4.58%	9.3%
23 Progress Energy	43.30	2.44	5.63%	2.50	3.20	21.88%	35.65	8.98%	1.96%	3.70%	NA	6.60%	4.09%	9.7%
24 Puget Energy, Inc.	23.28	1.04	4.47%	1.16	2.15	46.05%	20.80	10.34%	4.76%	5.00%	9.70%	6.60%	6.51%	11.0%
25 SCANA Corp.	38.55	1.66	4.31%	1.90	3.25	41.54%	29.00	11.21%	4.66%	4.50%	5.00%	6.60%	5.19%	9.5%
26 Southern Co.	32.70	1.52	4.65%	1.70	2.50	32.00%	18.65	13.40%	4.29%	4.50%	4.50%	6.60%	4.97%	9.6%
27 Vectren Corp.	26.90	1.23	4.57%	1.35	1.95	30.77%	17.25	11.30%	3.48%	5.90%	4.50%	6.60%	5.12%	9.7%
28 Westar Energy	22.72	0.98	4.31%	1.10	1.75	37.14%	19.45	9.00%	3.34%	4.00%	6.00%	6.60%	4.99%	9.3%
29 Xcel Energy Inc.	17.65	0.93	5.27%	1.11	1.58	29.89%	15.17	10.44%	3.12%	3.90%	4.00%	6.60%	4.41%	9.7%
GROUP AVERAGE	35.81	1.59	4.54%	1.75	2.85	37.11%	26.74	10.83%	4.00%	4.54%	4.76%	6.60%	4.98%	9.5%
GROUP MEDIAN			4.47%											9.5%

Sources: Value Line Investment Survey, Electric Utility (East), Mar 4, 2005; (Central), Apr 1, 2005; (West), Feb 11, 2005

NOTE: SEE PAGE 5 OF THIS SCHEDULE FOR FURTHER EXPLANATION OF EACH COLUMN

**Aquila Missouri**  
**Discounted Cash Flow Analysis**  
**Constant Growth DCF Model**  
**Long-Term GDP Growth**

	(15)	(16)	(17)	(18)	(19)
Company	Recent Price(P0)	Next Year's Div(D1)	Dividend Yield	GDP Growth	ROE K=Div Yld+G (Cols 17+18)
1 Alliant Energy Co.	27.20	1.14	4.19%	6.60%	10.8%
2 Ameren	49.95	2.54	5.09%	6.60%	11.7%
3 American Elec. Pwr.	34.00	1.44	4.24%	6.60%	10.8%
4 CH Energy Group	46.53	2.16	4.64%	6.60%	11.2%
5 Cent. Vermont P.S.	22.71	0.96	4.23%	6.60%	10.8%
6 CINERGY	40.57	1.96	4.83%	6.60%	11.4%
7 Cleco Corporation	20.36	0.90	4.42%	6.60%	11.0%
8 Con. Edison	43.00	2.30	5.35%	6.60%	11.9%
9 DTE Energy Co.	44.14	2.06	4.67%	6.60%	11.3%
10 Duquesne Light	18.49	1.00	5.41%	6.60%	12.0%
11 Empire District	22.74	1.28	5.63%	6.60%	12.2%
12 Energy East Corp.	26.02	1.21	4.65%	6.60%	11.3%
13 Entergy Corp.	68.78	2.41	3.50%	6.60%	10.1%
14 Exelon Corp.	44.44	1.68	3.78%	6.60%	10.4%
15 FPL Group, Inc.	38.77	1.54	3.97%	6.60%	10.6%
16 FirstEnergy	40.27	1.72	4.27%	6.60%	10.9%
17 Green Mtn. Power	29.12	1.08	3.71%	6.60%	10.3%
18 Hawaiian Electric	27.47	1.26	4.59%	6.60%	11.2%
19 MGE Energy, Inc.	35.06	1.38	3.94%	6.60%	10.5%
20 NiSource Inc.	22.55	0.96	4.26%	6.60%	10.9%
21 NSTAR	55.65	2.42	4.35%	6.60%	10.9%
22 Pinnacle West	42.43	1.99	4.69%	6.60%	11.3%
23 Progress Energy	43.30	2.44	5.63%	6.60%	12.2%
24 Puget Energy, Inc.	23.28	1.04	4.47%	6.60%	11.1%
25 SCANA Corp.	38.55	1.66	4.31%	6.60%	10.9%
26 Southern Co.	32.70	1.52	4.65%	6.60%	11.2%
27 Vectren Corp.	26.90	1.23	4.57%	6.60%	11.2%
28 Westar Energy	22.72	0.98	4.31%	6.60%	10.9%
29 Xcel Energy Inc.	17.65	0.93	5.27%	6.60%	11.9%
GROUP AVERAGE	35.81	1.59	4.54%	6.60%	11.1%
GROUP MEDIAN			4.47%		11.1%

Sources: Value Line Investment Survey, Electric Utility (East), Mar 4, 2005; (Central), Apr 1, 2005; (West), Feb 11, 2005

NOTE: SEE PAGE 5 OF THIS SCHEDULE FOR FURTHER EXPLANATION OF EACH COLUMN

**Aquila Missouri**  
**Discounted Cash Flow Analysis**  
**Low Near-Term Growth**  
**Two-Stage Growth DCF Model**

	(20)	(21)	(22)	(23)	(24)	(25)	(26)	(27)	(28)	(29)	(30)
Company	Next	Annual	Change to 2009	CASH FLOWS							ROE=Internal Rate of Return (Yrs 0-150)
	Year's Div	2009 Div		Recent Price	Year 1 Div	Year 2 Div	Year 3 Div	Year 4 Div	Year 5 Div	Year 5-150 Div Growth	
1 Alliant Energy Co.	1.14	1.32	0.06	-27.20	1.14	1.20	1.26	1.32	1.41	6.60%	10.6%
2 Ameren	2.54	2.54	0.00	-49.95	2.54	2.54	2.54	2.54	2.71	6.60%	10.9%
3 American Elec. Pwr.	1.44	1.60	0.05	-34.00	1.44	1.49	1.55	1.60	1.71	6.60%	10.5%
4 CH Energy Group	2.16	2.20	0.01	-46.53	2.16	2.17	2.19	2.20	2.35	6.60%	10.5%
5 Cent. Vermont P.S.	0.96	1.08	0.04	-22.71	0.96	1.00	1.04	1.08	1.15	6.60%	10.5%
6 CENERGY	1.96	2.08	0.04	-40.57	1.96	2.00	2.04	2.08	2.22	6.60%	10.9%
7 Cleco Corporation	0.90	0.90	0.00	-20.36	0.90	0.90	0.90	0.90	0.96	6.60%	10.3%
8 Con. Edison	2.30	2.36	0.02	-43.00	2.30	2.32	2.34	2.36	2.52	6.60%	11.2%
9 DTE Energy Co.	2.06	2.10	0.01	-44.14	2.06	2.07	2.09	2.10	2.24	6.60%	10.6%
10 Duquesne Light	1.00	1.04	0.01	-18.49	1.00	1.01	1.03	1.04	1.11	6.60%	11.3%
11 Empire District	1.28	1.28	0.00	-22.74	1.28	1.28	1.28	1.28	1.36	6.60%	11.3%
12 Energy East Corp.	1.21	1.45	0.08	-26.02	1.21	1.29	1.37	1.45	1.55	6.60%	11.2%
13 Entergy Corp.	2.41	3.01	0.20	-68.78	2.41	2.61	2.81	3.01	3.21	6.60%	10.2%
14 Exelon Corp.	1.68	1.92	0.08	-44.44	1.68	1.76	1.84	1.92	2.05	6.60%	10.2%
15 FPL Group, Inc.	1.54	1.90	0.12	-38.77	1.54	1.66	1.78	1.90	2.03	6.60%	10.6%
16 FirstEnergy	1.72	2.00	0.09	-40.27	1.72	1.81	1.91	2.00	2.13	6.60%	10.7%
17 Green Mtn. Power	1.08	1.32	0.08	-29.12	1.08	1.16	1.24	1.32	1.41	6.60%	10.3%
18 Hawaiian Electric	1.26	1.32	0.02	-27.47	1.26	1.28	1.30	1.32	1.41	6.60%	10.6%
19 MGE Energy, Inc.	1.38	1.44	0.02	-35.06	1.38	1.40	1.42	1.44	1.54	6.60%	10.0%
20 NiSource Inc.	0.96	1.10	0.05	-22.55	0.96	1.01	1.05	1.10	1.17	6.60%	10.6%
21 NSTAR	2.42	2.70	0.09	-55.65	2.42	2.51	2.61	2.70	2.88	6.60%	10.6%
22 Pinnacle West	1.99	2.23	0.08	-42.43	1.99	2.07	2.15	2.23	2.38	6.60%	11.0%
23 Progress Energy	2.44	2.50	0.02	-43.30	2.44	2.46	2.48	2.50	2.67	6.60%	11.4%
24 Puget Energy, Inc.	1.04	1.16	0.04	-23.28	1.04	1.08	1.12	1.16	1.24	6.60%	10.7%
25 SCANA Corp.	1.66	1.90	0.08	-38.55	1.66	1.74	1.82	1.90	2.03	6.60%	10.7%
26 Southern Co.	1.52	1.70	0.06	-32.70	1.52	1.58	1.64	1.70	1.81	6.60%	10.9%
27 Vectren Corp.	1.23	1.35	0.04	-26.90	1.23	1.27	1.31	1.35	1.44	6.60%	10.8%
28 Westar Energy	0.98	1.10	0.04	-22.72	0.98	1.02	1.06	1.10	1.17	6.60%	10.6%
29 Xcel Energy Inc.	0.93	1.11	0.06	-17.65	0.93	0.99	1.05	1.11	1.18	6.60%	11.8%
GROUP AVERAGE	1.59	1.75	0.05	-35.81							10.7%
GROUP MEDIAN											10.6%

Sources: Value Line Investment Survey, Electric Utility (East), Mar 4, 2005; (Central), Apr 1, 2005; (West), Feb 11, 2005

NOTE: SEE PAGE 5 OF THIS SCHEDULE FOR FURTHER EXPLANATION OF EACH COLUMN

**Aquila Missouri**  
**Discounted Cash Flow Analysis**  
**DCF Analysis Column Descriptions**

Column 1: Three-month Average Price per Share (Jan-Mar 2005)	Column 17: Column 16 Divided by Column 15
Column 2: Estimated 2006 Dividends per Share from Value Line	Column 18: See Average Growth Rate shown at the Bottom of Column 12
Column 3: Column 2 Divided by Column 1	Column 19: Column 17 Plus Column 18
Column 4: Estimated 2009 Dividends per Share from Value Line	Column 20: See Column 2
Column 5: Estimated 2009 Earnings per Share from Value Line	Column 21: See Column 4
Column 6: One Minus (Column 4 Divided by Column 5)	Column 22: (Column 21 Minus Column 20) Divided by Three
Column 7: Estimated 2009 Net Book Value per Share from Value Line	Column 23: See Column 1
Column 8: Column 5 Divided by Column 7	Column 24: See Column 20
Column 9: Column 6 Multiplied by Column 8	Column 25: Column 24 Plus Column 22
Column 10: "Next 5 Years" Company Growth Estimate as Reported by Zacks.com	Column 26: Column 25 Plus Column 22
Column 11: "Est'D 02-04 To 08-10" Earnings Growth as Reported by Value Line.	Column 27: Column 26 Plus Column 22
Column 12: Average of GDP Growth During the Last 10 year, 20 year, 30 year, and 40 year growth periods.	Column 28: Column 27 Increased by the Growth Rate Shown in Column 29
Column 13: Average of Columns 9-12	Column 29: See Average Growth Rate shown at the Bottom of Column 12
Column 14: Column 3 Plus Column 13	Column 30: The Internal Rate of Return of the Cash Flows in Columns 23-28 along with the Dividends for the Years 6-150 Implied by the Growth Rates shown in Column 29
Column 15: See Column 1	
Column 16: See Column 2	

## Aquila Missouri

### Risk Premium Analysis

	MOODY'S AVERAGE PUBLIC UTILITY BOND YIELD (1)	AUTHORIZED ELECTRIC RETURNS (2)	INDICATED RISK PREMIUM
1980	13.15%	14.23%	1.08%
1981	15.62%	15.22%	-0.40%
1982	15.33%	15.78%	0.45%
1983	13.31%	15.36%	2.05%
1984	14.03%	15.32%	1.29%
1985	12.29%	15.20%	2.91%
1986	9.46%	13.93%	4.47%
1987	9.98%	12.99%	3.01%
1988	10.45%	12.79%	2.34%
1989	9.66%	12.97%	3.31%
1990	9.76%	12.70%	2.94%
1991	9.21%	12.55%	3.34%
1992	8.57%	12.09%	3.52%
1993	7.56%	11.41%	3.85%
1994	8.30%	11.34%	3.04%
1995	7.91%	11.55%	3.64%
1996	7.74%	11.39%	3.65%
1997	7.63%	11.40%	3.77%
1998	7.00%	11.66%	4.66%
1999	7.55%	10.77%	3.22%
2000	8.14%	11.43%	3.29%
2001	7.72%	11.09%	3.37%
2002	7.53%	11.16%	3.63%
2003	6.61%	10.97%	4.36%
2004	6.20%	10.73%	4.53%
AVERAGE	9.63%	12.64%	3.01%

#### **INDICATED COST OF EQUITY**

PROJECTED AVG UTILITY BOND YIELD	6.70%
MOODY'S AVG ANNUAL YIELD DURING STUDY	9.63%
INTEREST RATE DIFFERENCE	-2.93%

INTEREST RATE CHANGE COEFFICIENT	-42.18%
ADJUSTMENT TO AVG RISK PREMIUM	1.24%

BASIC RISK PREMIUM	3.01%
INTEREST RATE ADJUSTMENT	1.24%
EQUITY RISK PREMIUM	4.25%

PROJECTED AVG UTILITY BOND YIELD	6.70%
<b>INDICATED EQUITY RETURN</b>	<b>10.95%</b>

Sources:

(1) Moody's Investors Service

(2) Regulatory Focus, Regulatory Research Associates, Inc.

**Aquila Missouri**  
Risk Premium Analysis

