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Issue:	*Rate of Return*
Witness:	*David Murray*
Sponsoring Party:	*MoPSC Staff*
Type of Exhibit:	*Surrebuttal Testimony*
Case No.:	*HR-2005-0450*
Date Testimony Prepared:	*December 13, 2005*

MISSOURI PUBLIC SERVICE COMMISSION

UTILITY SERVICES DIVISION

SURREBUTTAL TESTIMONY

OF

DAVID MURRAY

AQUILA, INC.
d/b/a AQUILA NETWORKS L&P-STEAM

CASE NO. HR-2005-0450

Jefferson City, Missouri
December 2005

Denotes Highly Confidential Information

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BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of the Tariff Filing of Aquila, Inc., to Implement a General Rate Increase for Retail SteamHeat Service Provided to Customers in Its L&P Missouri Service Area.	))))	Case No. HR-2005-0450 Tariff No. YH-2005-1066

AFFIDAVIT OF DAVID MURRAY

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

David Murray, being of lawful age, on his oath states: that he has participated in the preparation of the following Surrebuttal Testimony in question and answer form, consisting of 14 pages to be presented in the above case; that the answers in the following Surrebuttal Testimony were given by him; that he has knowledge of the matters set forth in such answers; and that such matters are true and correct to the best of his knowledge and belief.

David Murray

David Murray

Subscribed and sworn to before me this 12th day of December 2005.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
County of Cole
My Commission Exp. 07/01/2008

D Suzie Mankin

Notary

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DAVID MURRAY

AQUILA, INC.

d/b/a AQUILA NETWORKS L&P STEAM

CASE NO. HR-2005-0450

SURREBUTTAL TESTIMONY

OF

DAVID MURRAY

AQUILA, INC.

d/b/a AQUILA NETWORKS L&P-STEAM

CASE NO. HR-2005-0450

Q. Please state your name.

A. My name is David Murray.

Q. Are you the same David Murray who filed direct and rebuttal testimony in this proceeding for the Staff of the Missouri Public Service Commission (Staff)?

A. Yes, I am.

Q. In your direct testimony, did you recommend a fair and reasonable rate of return on the Missouri jurisdictional electric utility rate base for Aquila, Inc. d/b/a Aquila Networks L&P (L&P)?

A. Yes, I did.

Q. What is the purpose of your surrebuttal testimony?

A. The purpose of my surrebuttal testimony is to respond to the rebuttal testimony of Dr. Samuel C. Hadaway. Dr. Hadaway sponsored rate-of-return direct and rebuttal testimony on behalf of Aquila.

<u>EXECUTIVE SUMMARY</u>

Q. Please summarize your response to Dr. Hadaway's rebuttal testimony.

A. Dr. Hadaway asserts: (1) I did not consider other states' authorized returns in my recommendation, (2) my recommendation is inconsistent with the principles of *Hope* and

Bluefield and (3) the growth rate I relied upon in my DCF model analysis does not reflect investors' long-term expectations for the electric utility industry.

Dr. Hadaway's claim I did not consider other states' authorized returns in my recommendation is true to some extent. My estimate of the cost of capital For L&P is based on my analysis of the current capital market environment for the utility industry. My estimate is based on use of modern financial models, specifically the capital asset pricing model (CAPM) and the discounted cash flow (DCF) model. My analysis using these models is based upon current capital market conditions. However, I did consider other state authorized returns indirectly by reconciling the Commission's most recent decision in The Empire District Electric Company's (Empire) rate case, Case No. ER-2004-0570, to the circumstances present in this case. The Commission's decision in the Empire case was supported in part by authorized returns in other jurisdictions. Consequently, my reconciliation contemplates this information. Dr. Hadaway is correct that this reconciliation is not my recommendation. The reconciliation provides the Commission with more information in making a decision on the authorized return in this case.

Dr. Hadaway indicates that my recommendation is not consistent with *Hope* and *Bluefield*. Basic economic theory claims that if a company earns a return on common equity that is higher than its cost of common equity, then competitors will enter the market until the company's earned return on common equity is equal to its cost of common equity. The cost of common equity is the equity investors' required rate of return on that investment. As I will explain in more detail later, this is what would be considered as a "normal" economic profit. If regulatory commissions are to act as surrogates for competition, then commissions should serve as a substitute for the competitor that enters the market to drive the profit down to a "normal" level.

Finally, Dr. Hadaway indicates that my estimated constant growth rate for the electric utility companies in my comparable group is too low. I disprove Dr. Hadaway's claim and provide supporting academic and "real world" information to support my conclusion.

TRUE-UP OF CAPITAL STRUCTURE AND EMBEDDED COST OF LONG-TERM DEBT

Q. Did you true-up Aquila's capital structure and embedded cost of long-term debt through the true-up period ending October 31, 2005?

A. Yes. I have evaluated Aquila's October 31, 2005 balance sheet, which was provided by Aquila in an updated response to Staff Data Request No. 473. Although there is a separate true-up hearing scheduled in this case, I decided to revise my rate-of-return recommendation based on the true-up information because it was available at the time I wrote this testimony. This should reduce the number of issues in the true-up hearing.

Q. What was Aquila's capital structure as of October 31, 2005?

A. According to Aquila's updated response to Staff Data Request No. 473, Aquila's common equity ratio is 42.43 percent and its long-term debt ratio is 57.57 percent (see Schedule 1 attached to this testimony).

Q. What was Aquila's embedded cost of long-term debt as of October 31, 2005?

A. Aquila's embedded cost of long-term debt was 7.445 percent. This increased from the 7.281 percent embedded cost of long-term debt as of the update period, June 30, 2005.

Q. Why did the embedded cost of long-term debt increase?

A. The major cause for the increase in the embedded cost of long-term debt was an increase in the floating rate assigned to Aquila's $220 million dollar term loan. As I explained on page 23, lines 15 through 23 of my direct testimony, the interest rate applied to Aquila's term loan is based on a margin above the Eurodollar Rate (LIBOR). The margin over the LIBOR has not increased as a result of changes in Aquila's risk profile.

The reason for the increase in the assigned interest rate to this loan is because of recent increases in LIBOR, which in turn are a result of market factors. Although Schedule 10 attached to my direct testimony indicated an adjusted interest rate of 4.010 percent (8.260 – 4.250) for the term loans, Aquila apparently neglected to revise this cost for the update period in its updated response to Staff Data Request No. 26. Consequently, this cost was understated and should have been 4.921 percent (9.171 – 4.250) for the update period.

As of the most recent interest rate reset period on the loan (September 15, 2005), the LIBOR rate had increased from the previous reset period (June 16, 2005) by 45.3 basis points. This increased the assigned interest rate on this loan from 9.171 percent to 9.624 percent as of the true-up period in this case. After making the appropriate 425 basis-point downward adjustment to this interest rate (in order to price the loan as if Aquila were investment grade) the assigned interest rate for purposes of calculating the embedded cost of long-term debt is 5.374 percent as of the true-up period in this case. All of these changes are a result of changes in the market and not a result of changes in Aquila's risk profile due to Aquila's current financial circumstances. Therefore, it is appropriate to allow these increased costs to be included in the allowed rate of return.

RESPONSE TO DR. HADAWAY'S REBUTTAL TESTIMONY

Q. Dr. Hadaway indicates that you ignored authorized returns in other states when you determined your estimated cost of common equity for L&P. Is this true?

A. Yes. I did not take authorized returns in other states into consideration when estimating the cost of common equity to L&P. I used modern capital market models to estimate the cost of common equity because this is the most accurate and reliable methodology to estimate the capital market's indicated required return on an equity investment.

Q. Did you consider the Commission's reliance on authorized returns in the recent Empire rate case, Case No. ER-2004-0570, in your analysis in this case?

A. Yes. In my direct testimony in this case I attempted to reconcile the Commission's decision in the recent Empire rate case to the current capital market environment and my recommendation in this case. I estimated a range of return on common equity of 10.20 percent to 11.20 percent as being reasonable based on my understanding of the basis for the Commission's decision in the Empire case. The high end of this range is based on the Commission's authorization in the Empire rate case being 170 basis points higher than the high end of my estimated cost of common equity in that case. I reconciled the lower utility debt yields during the time I did my analysis in this case to the higher utility debt yields during the time I did my analysis in the Empire rate case to determine the low end of this range. Because the Commission's authorization in the Empire rate case relied, at least in part, on authorized ROEs, the reconciliation that I provided also relied indirectly on authorized ROEs.

Q. If you performed this reconciliation, why wasn't your recommended cost of common equity based on this reconciliation?

A. I do not believe that this accurately reflects the cost of common equity to L&P. For that same reason I do not agree that the use of allowed returns on common equity in other states will provide a reliable estimation of the cost of common equity. However, because the Commission has recently indicated its rationale for an authorized ROE for Empire, I decided that reconciling that decision to the circumstances in this case may be beneficial to the Commission.

Q. In your direct testimony you provided information on authorized returns on common equity for electric utilities published by Regulatory Research Associates (RRA). Have there been any updates to this publication since you prepared that testimony?

A. Yes. RRA provided an update to the third quarter of 2005 in an October 4, 2005 update to its regulatory survey. The average authorized return on common equity for the first three quarters of 2005 was 10.41 percent (18 decisions). The average authorized return on common equity for the third quarter of 2005 was 10.84 percent (4 decisions). If the Commission were to rely on authorized returns again in its decision in this case, then there may be some support to lower its authorized ROE from the 11 percent that was authorized in the Empire rate case because the Commission relied, in part, on the 11 percent average authorized ROE from the first quarter of 2004. However, the Commission should also be aware that the authorized ROEs had declined into the low to mid 10 percent range during the second and third quarter of 2004, which if this information had been in the record in the Empire case, the Commission may have approached its decision differently. The Commission should take extreme caution when relying on any one quarter's average authorized ROE to support its authorization. For example, the average authorized ROE for the third quarter of 2003 was 9.95 percent, where the other three quarters had an average authorized ROE above 11 percent.

Q. Dr. Hadaway indicates that your recommendation falls short of complying with the principles set forth in the *Hope* and *Bluefield* cases. How do you respond?

A. I disagree. The objective of rate regulation of utilities is to act as a surrogate for competition. In a competitive market, if a company is earning a return on its common equity that is higher than its cost of common equity, then this will attract competitors, which will reduce the pricing power of the company and drive its profits down to a "normal" level. (A "normal" profit is a profit that equals the cost of the capital to the company.) Consequently, authorizing a return on common equity based on the cost of common equity does not result in an inability to attract capital. In fact, it results in an equilibrium in the market, where there are no competitors entering or leaving the market because of no abnormal profits or losses. (see *Economics: Private & Public Choice*, Thomson South-Western, 2003.)

Dr. Hadaway also suggests I should have analyzed various financial ratios to determine L&P's abilities to cover their interest payments and therefore, be able to maintain their credit standings. I addressed this topic in detail in the most recent Aquila rate case, Case No. ER-2004-0034. However, I will explain some of these issues again in this case.

Q. If Aquila would have preferred that L&P be treated as a stand-alone entity for purposes of determining its creditworthiness, then what should Aquila have done?

A. If Aquila had spun-off L&P into a separate subsidiary and this subsidiary was ring-fenced from the rest of Aquila, then Staff and the Company would have been able to more effectively evaluate the stand-alone creditworthiness of L&P. However, this is not possible because L&P is an operating division of Aquila, which means that it is not a separate legal entity. Consequently, any debate over the possible creditworthiness of L&P is highly speculative.

Q. If Aquila had set up L&P as a separate subsidiary rather than as a division and effectively ring-fenced the subsidiary, then would L&P have had trouble attracting capital at a reasonable cost for its Missouri property?

A. No. If L&P were a separate subsidiary and it had been ring-fenced from the rest of Aquila, then the Commission and Aquila could have taken proactive steps to ensure that Aquila's non-regulated activities did not adversely affect the capital attraction of the regulated utilities or even the danger of these utilities being a part of the parent company's bankruptcy filing.

This is exactly why Portland General Electric (PGE) was able to maintain an investment grade credit rating even when its parent, Enron, filed for bankruptcy. There were many structural, legal, economic and regulatory constraints that kept PGE from ever having a credit rating below investment grade during the Enron bankruptcy. The detail of these mechanisms is beyond the scope of this testimony.

Q. Dr. Hadaway indicates that your use of analysts' "low near-term forecasts" for growth in your DCF model "likely bears no relationship to investors long-term expectations for the future." Do you believe your estimated growth-rate of 3.9 to 4.9 percent is not reflective of investors' long-term expectations for the future?

A. I believe that the upper end of my growth rate range is actually too high to be considered a sustainable growth rate for the electric utility industry. Therefore, if I were to perform a two-stage DCF model, as Dr. Hadaway did in his direct testimony, I would use a lower long-term growth rate than the near-term forecasts that I used for my constant-growth DCF. In the financial textbooks that I have read, the discussion of the use of two-stage DCF models only contemplates a scenario in which the first stage of growth is anticipated to be higher than the long-term constant growth rate.

Q. Do you have any support for a lower long-term growth rate expectation by investors for the utility industry?

A. Yes. Although I believe it is common sense that investors will not expect growth rates much above three percent for a mature industry such as the electric utility industry, I did cite a quotation in my rebuttal testimony that OPC witness Travis Allen used in the most recent Empire rate case. Expected growth for the electric utility industry in this citation was about three to four percent. This citation not only provided an indication of investors' expectations of growth for the electric utility industry in the long-term, but it also indicates that the higher growth rate expectations in the past for the electric utility industry were driven largely by non-regulated business ventures. It is not appropriate to use growth rate expectations driven by non-regulated investments as a barometer of what would be acceptable for long-term sustainable growth for regulated electric utilities.

Q. Are you aware of any other sources that provide some insight as to the potential growth rate of the electric utility industry?

A. Yes. The October 2004 edition of *Public Utilities Fortnightly* contains an article entitled, "The Dividend Yield Trap – Higher payouts aren't enough over the long term," which discusses many issues relating to the valuation levels of utility stocks. I have attached this article as Schedule 4 to this surrebuttal testimony. This article was written by

George Bilicic, managing director of the Global Power & Utilities Group of Lazard, and Ian Connor, director of the same group. Lazard is a world-recognized investment bank that is most widely known for its roles in mergers and acquisitions and restructuring activities.

This article indicates that the regulated electric utility industry's growth prospects are about 1 to 3 percent, which is the typical amount of increase in rate base. This article further suggests that the U.S. electric utility industry's current average long-term growth rate of 4.6 percent is too optimistic and that the industry's "true long-term growth proposition is closer to 2 to 3 percent."

This article also indicates that during the past 30 years the industry has achieved an average compound growth rate of only 1 percent. Consequently, I would have used a lower growth rate for the perpetual growth rate, and certainly a lower growth rate than Dr. Hadaway's growth rate of 6.6 percent, if I had performed a two-stage DCF model. This would have resulted in an even lower cost of common equity estimate.

Q. What has Aquila itself indicated about its growth rate goals for its "back to basics" strategy?

A. ** ____

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This is much lower than the 6.6 percent growth rate used in Dr. Hadaway's constant growth DCF using his estimate of GDP growth and the 6.1 percent implied growth rate from his use of a two-stage DCF model.

Q. Dr. Hadaway uses the recent KCPL "Experimental Regulatory Plan" approval in Case No. EO-2005-0329 to support his position that the Commission should allow increased cash flow to maintain certain credit metrics during the period of Aquila's "heavy construction program over the next five years." Do you have any concerns about Dr. Hadaway's use of this case to attempt to support his position?

A. Yes. First, Aquila filed an Application on March 2, 2005 (Case No. EO-2005-0293) for approval of an experimental regulatory plan similar to that of KCPL's Experimental Regulatory Plan. Aquila's Application requested additional amortization in order to maintain the necessary cash flow to its Missouri utilities to support investment grade credit metrics. Specifically, the original Application requested the following:

> Additional amortization as may also be required to maintain the cash flow to the utility necessary to support investment grade metrics during the construction period. Beginning with the in-service date of Iatan Unit 2, the resulting additional amortization reserve will be reversed through equal monthly accounting entries over a 40 year period.

However, after discussions between Aquila and the other parties to the case after Aquila filed its original Application, Aquila decided to limit its requested relief and filed its First Amended Application on March 25, 2005. In its First Amended Application, Aquila made no request for additional amortizations. Aquila limited its requested relief to (1) the authority to encumber Aquila's MPS properties to secure the financing needed to participate in construction related to the Iatan Unit II project and Iatan Unit I air pollution control upgrades and (2) permission, approval and a certificate of public convenience and necessity (CCN) to participate in the construction, ownership, operation, maintenance, removal, replacement, control and management of Iatan Unit II. On June 10, 2005, Aquila filed a Second Amended Application that further limited the relief it sought by eliminating the request for a CCN.

Neither of the amended Applications explained why Aquila removed its request for amortizations within its requested relief, but as a result of Aquila's removal of the amortization request, no such relief was granted to Aquila. Although the caption of the case did not change with Aquila's filing of its Second Amended Application, Case No. EO-2005-0293 became a Section 393.190 case rather than remaining an experimental regulatory plan case as that term is used for the KCPL Experimental Regulatory Plan and The Empire District Electric Company Experimental Regulatory Plan. Thus, Dr. Hadaway is seriously misapplying the provision in the KCPL Experimental Regulatory Plan for additional amortizations to attempt to influence the outcome of this rate case.

Second, it is inappropriate for Aquila to rely on any part of the regulatory plan from Case No. EO-2005-0329 as support for its position in this case. Aquila was a Signatory Party to the Stipulation and Agreement that embodies KCPL's regulatory plan which the Commission approved. Paragraphs III.B.10.a., b., d. and g. of that Stipulation and Agreement specifically state:

> a. None of the Signatory Parties shall be deemed to have approved or acquiesced in any . . . cost of capital methodology, . . . ratemaking principle, . . . cost of service methodology or determination, . . . that may underlie this Agreement, or for which provision is made in this Agreement. . . .
>
> b. This Agreement is based on the unique circumstances presented by KCPL to the Signatory Parties. This Agreement shall not be construed to have precedential impact in any other Commission proceeding.
>
> . . . .
>
> d. This Agreement represents a negotiated settlement. Except as specified herein, the Signatory Parties to this Agreement shall not be prejudiced, bound by, or in any way affected by the terms of this Agreement: (a) in any future proceeding; (b) in any proceeding currently pending under a separate docket; and/or (c) in this proceeding should the Commission decide not to approve this

> Agreement in the instant proceeding, or in any way condition its approval of same.
>
> . . . .
>
> g. This Agreement does not constitute as contract with the Commission. . . .

Third, it is my understanding that the final accepted methodology for determining additional amortization in the KCPL Experimental Regulatory Plan was a result of extensive negotiations between the parties to that case. The negotiation of the procedure to use for KCPL was complex and even though some of these same principles could apply if Aquila had continued to seek the relief of additional amortization in Case No. EO-2005-0329, Aquila's circumstances are, and were, far different than those present in the KCPL case. L&P is only an operating division of Aquila, whereas KCPL is a separate subsidiary of Great Plains Energy. Aquila's different corporate structure would require extensive analysis, discussions and negotiations in order to come to determine whether there could be agreement on an equitable method for additional amortizations. Even if Aquila had continued to seek this relief in Case No. EO-2005-0293, there is no guarantee that the parties could or would have reached an agreement.

Fourth, another significant item in the Stipulation and Agreement in Case No. EO-2005-0329 not noted by Dr. Hadaway is that any additional amortizations will be accumulated until the plant goes into service and then the total amount of the additional amortizations will be used as a rate base offset. Specifically, Paragraph III.B.1.p. Amortizations: Ten (10) Year Recognition of Future Benefits, from the KCPL Stipulation and Agreement, states the following:

> In order to ensure that the benefits of offsetting the rate base related to the amortizations contained in this Agreement accrue to KCPL's customers in future rate proceedings, KCPL agrees that any such

> benefits shall be reflected in its rates, notwithstanding any future changes in the statutory provisions contained in Chapter 386 and 393 RSMo, for at least ten (10) years following the effective date of the Order Approving Stipulation and Agreement in this proceeding.

If the Commission were to allow a higher authorized return in this case to improve cash flow during Aquila's construction period, then ratepayers would not benefit from a lower rate base in the future because Aquila and Dr. Hadaway have ignored this provision in the KCPL Experimental Regulatory Plan.

In summary, Aquila has inappropriately sought to use the Stipulation and Agreement in the KCPL Experimental Regulatory Plan case to support a higher rate of return in this case. It is my understanding that counsel for the Staff will also address Aquila's inappropriate use of the Stipulation and Agreement in the KCPL Experimental Regulatory Plan case.

Q. On page 15, lines 8 through 15 of his rebuttal testimony, Dr. Hadaway cites Brigham, Gapenski and Ehrhardt's textbook, *Financial Management*, to support his position that a projected nominal GDP growth rate should be used for the perpetual growth rate in the DCF model. Is there anything in that citation that should have been explained further?

A. Yes. The citation indicates that one might expect the dividend of an "average, or 'normal,' company" to grow at the nominal GDP growth rate. In order to arrive at any conclusions from this citation, one would need to have a definition of an "average" or "normal" company. In response to Staff Data Request No. 500, Dr. Hadaway provided a copy of the entire chapter of the textbook in which this citation resided. I could not find the textbook's definition of an "average" or "normal" company in this chapter, but I would consider an "average" or "normal" company as being one that is similar to the stock market as a whole, such as the S&P 500. As I explained in my rebuttal testimony, electric utilities are not considered to be similar to that of the overall market. It is a mature, slower-growth industry.

Q. Did you find anything else in the text of the chapter in which this citation resided that should be brought to the attention of the Commission?

A. Yes. On page 339 of the same textbook, under the heading "Supernormal, or Nonconstant, Growth," the text states the following:

> Firms typically go through *life cycles*. During the early part of their lives, their growth is much faster than that of the economy as a whole; then they match the economy's growth; and finally their growth is slower than that of the economy.

The electric utility industry is in the stage of its *life cycle* in which its growth is slower than that of the economy.

Q. Beginning on page 15, line 19 of his rebuttal testimony, Dr. Hadaway provides a citation from an article in the April 2003 edition of *The Journal of Finance*. Do you have any comments regarding this citation?

A. Yes, it should have been qualified. The cited material indicates the median growth rate is for *all* domestic firms listed on the New York, American, and Nasdaq markets with data from Compustat. It is an indication of the central tendency for the entire sample. As is indicated in the citation, a 2.5 percent dividend yield was subtracted from the overall growth rate to determine the real growth rate for all companies. Because the utility industry has a higher dividend payout ratio and a higher dividend yield, the real growth in the utility industry will be lower than that of the overall economy. Consequently, it is not appropriate to use the growth rate in the overall economy as a proxy for the growth of the electric utility industry.

Q. Is there anything else from this citation that should be noted?

A. Yes. The citation indicates that analysts' growth estimates tend to be "overly optimistic." However, the article also indicates that this overestimation is less pronounced for "mature industries whose growth prospects are relatively unexciting." The article goes on to state that utilities are such an industry. Consequently, even though analysts' growth rates may be considered somewhat overly optimistic, I have determined that these growth rates are fairly reasonable in this case.

Q. Did you notice anything else in this article to which you wish to direct the Commission's attention?

A. Yes in the paragraph immediately following the one that Dr. Hadaway cited, the authors of this article state the following:

> Looking forward, if we project future growth using the median of the distribution of historical growth rates, the implication is that the expected future return on stocks is not very high. For example, in a simple dividend discount model with constant growth rates and constant payout ratio, the expected return is equal to the dividend yield plus the expected future growth rate of earnings. Given the low level of current dividend yields (below 1.5 percent) and expected inflation of 2.5 percent, the expected return is only about 7.5 percent. This is lower than the consensus forecast of professional economists (see Welch (2000)), but is in line with Fama and French (2002).

Consequently, this article corroborates my direct testimony in which I cited many experts in the finance field that believe the current valuation level of stocks have resulted in much lower required equity risk premiums. In fact, this article even mentions a study of one of the individuals (Kenneth French) who I mentioned in my direct testimony.

Q. Is Dr. Hadaway's use of nominal GDP growth for a constant growth rate to estimate the cost of common equity logical?

A. No. According to Dr. Hadaway's position that the expected growth rate in nominal GDP is the appropriate perpetual growth rate to use when estimating the cost of common equity for any company (not just utilities), the determination of the cost of common equity is simply this growth rate added to the current dividend yield. Of course, other companies that have more investment opportunities are going to retain more of their earnings and therefore, have a lower dividend yield and more growth.

For example, according to the November 2005 issue of the Standard & Poor's (S&P) *Stock Guide*, the dividend yield on the S&P 500 was 1.9 percent as of the end of October 2005. If one were to add Dr. Hadaway's estimate of nominal GDP growth of 6.6 percent to this dividend yield, then the cost of common equity to the market (S&P 500) would be approximately 8.5 percent compared to the 11.1 percent Dr. Hadaway estimated for electric utilities. This defies the basic logic of risk and return, which states that additional risk will result in a higher required return on common equity. I am not aware of any finance expert that would argue electric utilities have as much risk as the overall market.

Although applying this growth rate to utilities provides results that violate the basic tenets of finance, it is interesting to note the lower results achieved if this growth rate is applied to a proxy of the overall market, such as the S&P 500. I explained in my rebuttal testimony it may be logical to use an estimated growth rate of the overall economy for an average risk company (companies with similar risk as the entire market). In this case, adding this growth rate to the S&P 500's dividend yield provides results consistent with many of the studies I have reviewed that predict overall market returns in the 8 percent range. In fact, if I were to add a more reasonable projection for nominal GDP growth of 5 to 5.5 percent, then the expected return on the S&P 500 would be in the 7 to 7.5 percent range, which is close to the expected return in the study Dr. Hadaway cited in his rebuttal testimony.

Q. You have discussed why you believe it is appropriate to expect that the utility industry will grow at a slower pace than the economy. Do you have any citations from academic sources that support your position?

A. Yes. In the textbook INVESTMENT VALUATION: Tools and Techniques for Determining the Value of *Any* Asset, 1996, by Aswath Damodaran, Associate Professor of Finance at New York University's Leonard N. Stern School of Business, the following appears at page 193:

> Can a stable growth rate be much lower than the growth rate in the economy? There are no logical or mathematical limits on the downside. Firms that have a stable growth rate much lower than the growth rate in the economy will become smaller in proportion to the economy over time. Since there is no economic basis for arguing that this cannot happen, there is no reason to prevent analysts from using a stable growth rate much lower than the nominal growth rate in the economy.

This supports my position that a mature industry, such as the electric utility industry, would not be expected to grow at the same rate as the economy. I also have cited sources from the investment community that confirm that they do not expect electric utilities to grow anywhere close to the 6.6 percent growth rate Dr. Hadaway uses in his DCF cost of common equity estimations.

SUMMARY AND CONCLUSIONS

Q. Please summarize the conclusions you present in this testimony.

A. My conclusions regarding the capital structure, embedded cost of debt and cost of common equity are listed below.

1. The capital structure should be updated to reflect Aquila's actual capital structure on October 31, 2005 (the true-up date), that Aquila made

available to me at the time I wrote this testimony. The cost of capital for L&P as of the true-up period, October 31, 2005, as shown on Schedule 3 attached to this surrebuttal testimony, is now in the range of 7.90 percent to 8.32 percent.

2. The embedded cost of long-term debt as of the true-up date is 7.445 percent. This is now reflected in my recommended rate of return.

3. My recommended cost of common equity of 8.50 percent to 9.50 percent would produce a fair and reasonable rate of return of 7.90 percent to 8.32 percent for the Missouri jurisdictional electric utility rate base for MPS and L&P.

Q. Does this conclude your surrebuttal testimony?

A. Yes, it does.

Capital Structure as of October 31, 2005
for Aquila, Inc.

Capital Component	Amount in Dollars		Percentage of Capital
Common Stock Equity	$1,436,400,000		42.43%
Preferred Stock	0		0.00%
Long-Term Debt	1,949,225,865	*	57.57%
Short-Term Debt	0		0.00%
Total Capitalization	**$3,385,625,865**		**100.00%**

Electric Financial Ratio Benchmark
Total Debt / Total Capital

Standard & Poor's Corporation's RatingsDirect,	BBB Credit Rating based on a "6" Business Profile
Revised Financial Guidelines as of June 2, 2004	48% to 58%

Note: *Net proceeds as indicated on Schedule 2.

Source: Aquila, Inc.'s updated response to Staff Data Request No. MPSC-473.

Aquila, Inc. Weighted Average Cost of Debt
as of October 31, 2005

LONG-TERM DEBT	ISSUE DATE YR/MO/DAY	DUE DATE YR/MO/DAY	INTEREST RATE	A ORIGINAL ISSUE	B AMOUNT OUTSTANDING	C DISCOUNT/PREMIUM & ISSUE COSTS	D=B/A*C RELATIVE COSTS	B-D NET PROCEEDS	ANNUAL INTEREST	COST OF MONEY
Convertible Subordinated Debentures	July 24, 1986	July 1, 2011	6.625%	50,000,000	2,158,001	2,626,347	113,353	2,044,648	142,968	6.992%
Wamego, KS Pollution Control Bonds	March 1, 1996	March 1, 2026	2.700%	7,300,000	7,300,000	422,982	422,982	6,877,018	197,100	2.866%
Senior Notes, 9.0% Series	November 25, 1991	November 15, 2021	9.000%	150,000,000	5,000,000	3,018,294	100,610	4,899,390	450,000	9.185%
Senior Notes, 8.2% Series	January 29, 1992	January 15, 2007	8.200%	130,000,000	36,905,000	13,042,943	3,702,691	33,202,309	3,026,210	9.114%
Senior Notes, 8.0% Series	March 3, 1993	March 1, 2023	8.000%	125,000,000	51,500,000	1,982,502	816,791	50,683,209	4,120,000	8.129%
Environmental Improvement Bonds	May 26, 1993	May 1, 2028	2.760%	5,000,000	5,000,000	111,563	111,563	4,888,437	138,000	2.823%
Sanwa Bus CC	December 9, 1995	December 9, 2009	6.990%	8,190,000	3,533,280	35,000	15,099	3,518,181	246,976	7.020%
Senior Notes, 6.7% Series	October 17, 1996	October 15, 2006	6.700%	100,000,000	85,900,000	666,537	572,555	85,327,445	5,755,300	6.745%
Senior Notes, 8.27% Series	March 31, 1999	November 15, 2021	8.270%	131,750,000	80,850,000	3,591,143	2,203,749	78,646,251	6,686,295	8.502%
Senior Notes, 9.03% Series	March 31, 1999	December 1, 2005	9.030%	20,232,000	19,057,000	613,622	577,985	18,479,015	1,720,847	9.312%
Senior Notes, 7.625% Series	November 15, 1999	November 15, 2009	7.625%	200,000,000	199,000,000	3,025,739	3,010,610	195,989,390	15,173,750	7.742%
SJLP FMB	November 25, 1991	February 1, 2021	9.440%	22,500,000	18,000,000	664,653	531,722	17,468,278	1,699,200	9.727%
SJLP Unsecured MTN	December 6, 1993	December 1, 2023	7.170%	7,000,000	7,000,000	382,259	382,259	6,617,741	501,900	7.584%
SJLP Unsecured MTN	November 30, 1993	November 30, 2023	7.330%	3,000,000	3,000,000	163,606	163,606	2,836,394	219,900	7.753%
SJLP Unsecured MTN	November 30, 1993	November 29, 2013	7.160%	9,000,000	9,000,000	490,738	490,738	8,509,262	644,400	7.573%
SJLP Unsecured MTN	November 30, 1993	November 29, 2013	7.130%	1,000,000	1,000,000	54,526	54,526	945,474	71,300	7.541%
SJLP Unsecured Pollution Control Bonds	June 4, 1995	February 1, 2013	5.850%	5,600,000	5,600,000	913,838	913,838	4,686,162	327,600	6.991%
Senior Notes, 7.95% Series (downgrade 9.95%)	February 1, 2001	February 1, 2011	7.950%	250,000,000	250,000,000	1,880,959	1,880,959	248,119,041	19,875,000	8.010%
Senior Notes, 11.875% Series (downgrade 14.875%)	July 3, 2002	July 1, 2012	6.700%	500,000,000	500,000,000	9,365,205	9,365,205	490,634,795	33,500,000	6.828%
QUIBS	February 28, 2002	March 1, 2032	7.875%	287,500,000	287,500,000	9,432,634	9,432,634	278,067,366	22,640,625	8.142%
Manditorily Convertible Senior Notes (PIES) **(A)**	August 24, 2004	September 15, 2007	6.750%	345,000,000	2,598,875	10,699,751	80,601	2,518,274	175,424	6.966%
Term Loan	September 20, 2004	September 19, 2009	5.374%	220,000,000	220,000,000	5,839,825	5,839,825	214,160,175	11,822,800	5.521%
Everest Term Loan	April 28, 2004	April 1, 2007	7.25%	7,500,000	7,500,000	65,681	65,681	7,434,319	543,750	7.314%
MZ Partners	December 1, 2004	January 2, 2010	4.75%	2,715,000	1,446,037	34,847	18,560	1,427,477	68,687	4.812%
MZ Partners Nebraska	June 9, 1994	July 1, 2009	7.88%	3,640,000	1,366,948	63,865	23,984	1,342,964	107,647	8.016%
UCFC 7.75% Senior Notes	June 20, 2001	June 15, 2011	7.750%	200,000,000	197,000,000	17,357,512	17,097,149	179,902,851	15,267,500	8.487%
Total Aquila Long-Term Debt				**2,791,927,000**	**2,007,215,141**			**1,949,225,865**	**145,123,179**	**7.445%**

Source: Updated Response to Staff's Data Request No. 0026 (response to Staff's Data Request 480).

Notes:
July 3, 2002 11.875% senior note adjusted downward to more closely match the cost of a senior note that Empire issued during the same year.
September 20, 2004 Term Loan adjusted downward to reflect the margin that would be charged if Aquila were investement grade.

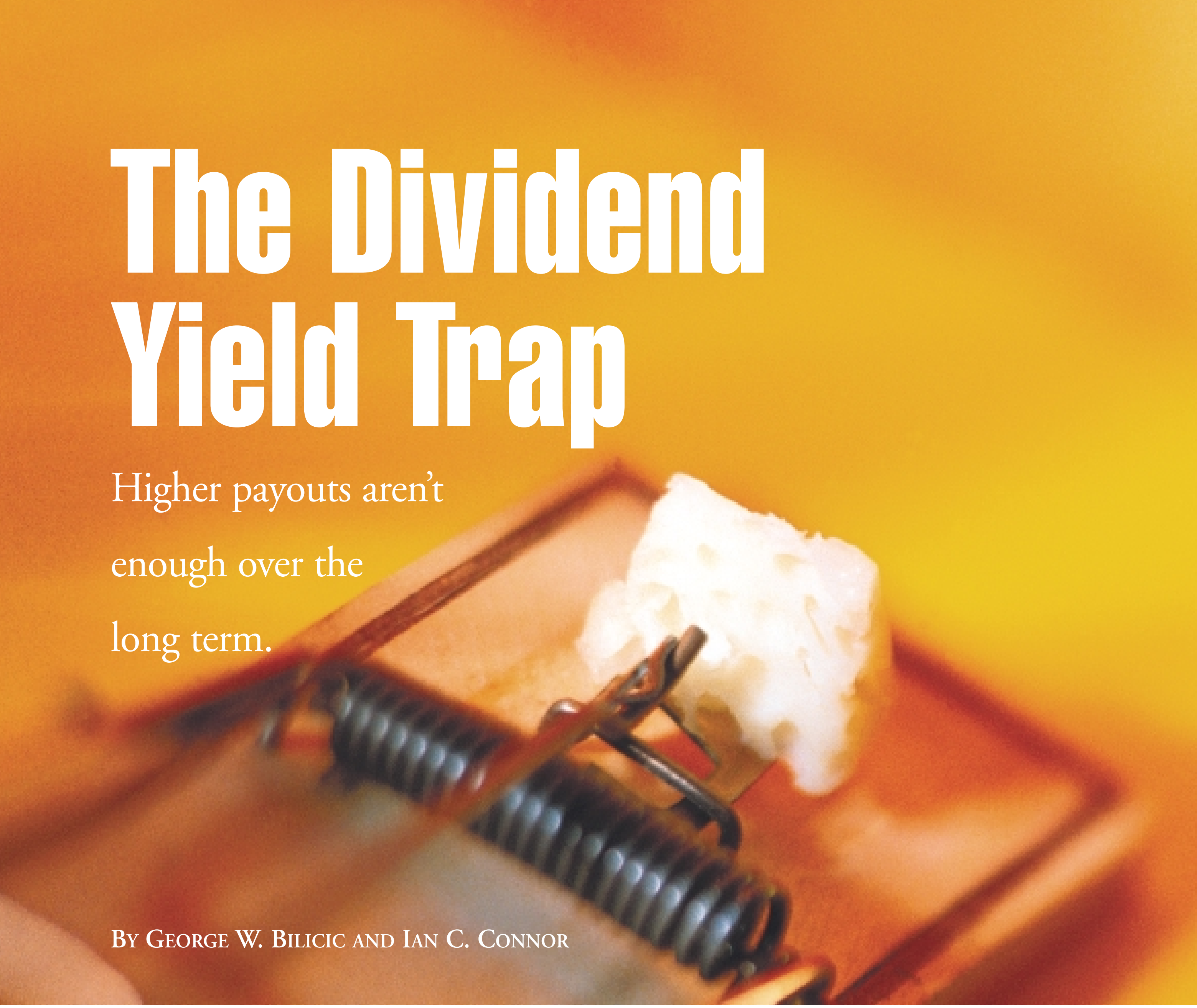
Weighted Cost of Capital as of October 31, 2005
For Aquila, Inc. d/b/a Aquila Networks L&P

			Weighted Cost of Capital Using Common Equity Return of:		
Capital Component	Percentage of Capital	Embedded Cost	**8.50%**	**9.00%**	**9.50%**
Common Stock Equity	42.43%	-----	3.61%	3.82%	4.03%
Long-Term Debt	57.57%	7.445%	4.29%	4.29%	4.29%
Short-Term Debt	0.00%	0.00%	0.00%	0.00%	0.00%
	100.00%		**7.90%**	**8.11%**	**8.32%**

Notes:

See Schedule 1 for the Capital Structure Ratios.

See Schedule 2 for the Embedded Cost of Long-Term Debt.



The Dividend Yield Trap

Higher payouts aren't enough over the long term.

By George W. Bilicic and Ian C. Connor

The past two years witnessed the ascendancy of dividend yield in the valuations of U.S. electric utilities. The recent primacy of yield in utility-industry valuations is the product of a unique confluence of factors. The collapse of most of the industry's non-regulated growth initiatives has resulted in a market that attributes little value to the industry's growth prospects beyond that which has been historically generated by the expansion of rate base—1 to 3 percent. To the degree that non-regulated growth is credited in the current market, such credit is principally limited to conservative, incremental strategies and even then such strategies are often discounted by the market.

The industry's low regulated growth profile, coupled with the absence of credible, broad-based non-regulated growth strategies, remains the most important strategic issue confronting the industry today.

Dividend Yield: Current and Long-Term Valuation Considerations

The significant value implications to the industry of its persistent growth issue are masked by the market's current pursuit of yield, which has marginalized such considerations. Such an exaggerated bias toward yield, however, is episodic: a temporary displacement of fundamental considerations of value based on total return by current U.S. economic policies, principal among them being historically low interest rates and the 2003 dividend tax cut. The former phenomenon is a function of federal stimulus policies reflecting the broader economic uncertainties, which have proven unexpectedly trenchant. In an environment where the benchmark 10-year Treasury is yielding only 4.3 percent and the S&P 500 offers only equivocal returns, the bond-substitute properties of a regulated utility with a comparable or superior dividend yield present a compelling alternative to investors.

Such a low interest-rate environment, however, is not sustainable over the long term. As interest rates rise, the industry's yield proposition will diminish relative to government securities, compressing values (*see Figure 1, p. 69*). More importantly, with yield no longer being the principal investment proposition, investors will again begin to discriminate among utilities based upon fundamental considerations of long-term growth and, by extension, total return.

The 2003 Dividend Tax Cut: Dividend Policies Revisited

Of long-term significance to the U.S. electric utility industry are the value and financial policy implications of the 2003 dividend tax cut. At a minimum, the equalizing of the taxation of dividend yield and capital gain has enhanced the value proposition of the industry. On an absolute basis, the after-tax total return of an illustrative utility with an 8 percent total return comprised of 4 percent dividend yield and 4 percent long-term earnings growth improved from 5.8 percent to 6.8 percent, or 17 percent. On a relative basis, the impact is equally significant. For example, consider two utilities with the same nominal total returns of 8 percent: One utility's return is comprised of 3 percent dividend yield and 5 percent earnings growth; the other utility's return is comprised of 5 percent dividend yield and 3 percent earnings growth. Prior to the dividend tax cut, the higher growth utility's after-tax total return was 6.1 percent, while the higher yielding utility's was 5.6 percent, a 10 percent differential. After the dividend tax cut, each utility offers the same 6.8 percent after-tax total return.[1]

Further, while on a nominal basis the returns of these two illustrative utilities are now the same on a pre- and after-tax basis, the higher dividend-yielding utility arguably offers the better investment proposition on a risk adjusted basis (assuming a sustainable dividend policy). In fact, adjusting for risk, utilities that offer total returns balanced heavily toward dividend yield theoretically may offer better returns than other investments with nominally higher returns but which are weighted significantly toward presumptively riskier non-regulated growth.

Thus, on a risk adjusted basis, a utility offering an 8 percent total return comprised of 5 percent yield and 3 percent growth may be a better return proposition than a utility or other investment opportunity offering a 10 percent total return comprised of 7 percent non-regulated growth and 3 percent yield. The 2003 tax cut accordingly represents a fundamental shift in traditional conceptions of utility total return and valuation that the industry must now consider in aligning their financial, investment, and capital policies.

Capital Structure Implications

The parameters of this realignment, while important, are not as significant as they might initially appear, however. Indeed, for most of the U.S. electric utility industry that already has a balanced, sustainable dividend policy with payout ratios and growth in line with their peers and the broader industry, there likely is little, if any, need for adjustment. Certainly utilities should avoid exaggerated, unsustainable payout policies to enhance yield to court higher valuations in response to short-term market valuation phenomena, such as the current historically low interest-rate environment.

Conversely, those utilities that have either regulated or non-regulated growth strategies that are viable and receive significant capital markets credit may not have any need for competitive dividend policies from a total return perspective. Nor, in most instances, do such utilities have the capital resources to fund the capital investment of such superior growth strategies as well as sustain dividend payout policies in line with those utilities with lower growth capital requirements.

Finally, in addition to the embedded 2008 sunset provision, current dividend tax policies are subject to political risk, either in the form of the 2004 political elections or fiscal pressure resulting from the United States' currently high deficits. Over-committing to dividend yield exposes a utility to potentially significant adverse consequences if current dividend taxation policies are reversed or amended; such political bets are not in the interests of utilities or their shareholders.

The utilities for which an adjustment of dividend policies is perhaps necessary are those that have traditionally, or recently, neglected yield. Such relative neglect of yield in favor of growth investment was to a significant degree an outgrowth of the unequal tax treatment of dividend versus capital gain income, which discouraged distributing cash directly to shareholders in the form of dividends. However, as noted above, available non-regulated investment opportunities have decreased, and along with them the claims such initiatives once made on utilities' cash flows. As a result, such utilities may still have attractive relative long-term growth rates of 4 to 5 percent based on some residual and viable non-regulated businesses, but their dividend yields are typically only in the range of 2 to 3 percent, resulting in deficient yield and total return propositions relative to their peers and the broader industry, particularly on a risk-adjusted basis. As a result, in the current market environment, such utilities may find themselves trading at a discount.

Catch-22

Such a valuation discount carries important implications for a utility's equity currency, cost-of-capital, and strategic leverage.

Schedule 4-2

In some respects, they are caught in a catch-22. Largely foreclosed from pursuing meaningful growth through non-regulated investment, their constrained dividend yield policies, initially conceived with the object of redirecting free cash flow toward such growth investment, now results in a trading discount, impairing the ability of such utilities to pursue the one viable, credible growth strategy that remains accessible to the broader industry: mergers and acquisitions.

Until recently, industry leaders Exelon and FPL were representative of this class of utilities described above. Each was characterized by above-average long-term growth rates, lower-than-average dividend payout, and significant free cash flow after dividends. And, most important, as a result of their low yield and lower total return, each correspondingly traded at a discount to its peers and the broader industry indexes.

Exelon provides a particularly instructive example in this regard. Exelon traded at a persistent discount to its peers and the broader industry since 2003 (and the enactment of the dividend tax cut). Conventional wisdom attributed this discount to its potential 2007 earnings cliff associated with the expiration of the CTC revenue collection. However, from a total return perspective, Exelon's 1.4x P/E-to-total-return ratio was in line with its peers and the broader industry. Notwithstanding its strong long-term earnings growth rate, its dividend yield based on a payout ratio of only 40 percent was 3.3 percent, approximately 15 percent below its peers. Exelon's resulting total return was 8.5 percent, a 9 percent discount to its peers' median of approximately 9.3 percent, or the same discount reflected in its forward P/E. Thus, irrespective of the market's current dividend yield bias in valuations, Exelon properly should have traded at a discount based on fundamental considerations of total return.

Perhaps recognizing this, Exelon, on July 28, 2004, rechanneled a portion of its significant free cash flow to announce that it was raising its dividend 11 percent, to $1.22 per share, and targeting a payout ratio in 2005 of 50 to 60 percent, in line with its peers and the industry. Since Exelon's announcement, its share price has increased approximately 12 percent, creating in excess of $2.7 billion in incremental equity value for its shareholders. Further, Exelon's trading discount to its peers and the broader industry has largely dissipated. Exelon currently trades at a 2005 P/E of 12.6x; a dividend yield of 4.4 percent (based on a 2005 payout ratio of 55 percent); and, based on a *pro forma* 2005 projected total return of 9.7 percent, a P/E-to-total return ratio of 1.3x.[2] Each of these metrics is approximately in line with its peers. As importantly, Exelon's strategic leverage and flexibility to pursue growth also is improved.

A nearly identical set of circumstances and results occurred in respect to FPL and its recent dividend enhancement initiative. By bringing its dividend payout and yield in line with its peers and the broader industry, FPL also effectively addressed its equity discount in the market, and, thereby, improved its strategic leverage and flexibility.

The Long-Term Premium Determinant: Growth

Notwithstanding the current primacy of yield, once utilities properly calibrate their dividend policies to reflect the new return realities of the dividend tax cut and/or valuation drivers move away from yield as a result of changes in interest rates or otherwise, the long-term growth component of total return will re-emerge as a determinant factor in the industry's sustainable valuation levels and, most importantly, will dictate which utilities are able to command a premium valuation in the market. As noted above, unlike dividend yield deficiencies that (assuming sufficient cash flow generative capacities) can be addressed through the adjustment of financial policies, the avenues available to pursue long-term growth that surpass regulated return levels of 1 to 3 percent are limited. Further, it is almost certainly the case that the current average long-term growth rate for the U.S. electric industry of 4.6 percent is too optimistic.[3] The industry's true long-term growth proposition is closer to 2 to 3 percent, and then only if the industry is able to successfully execute on cost-cutting initiatives. In this regard, it is worth noting that during the past 30 years the industry has achieved a compound average growth rate of only 1 percent.[4]

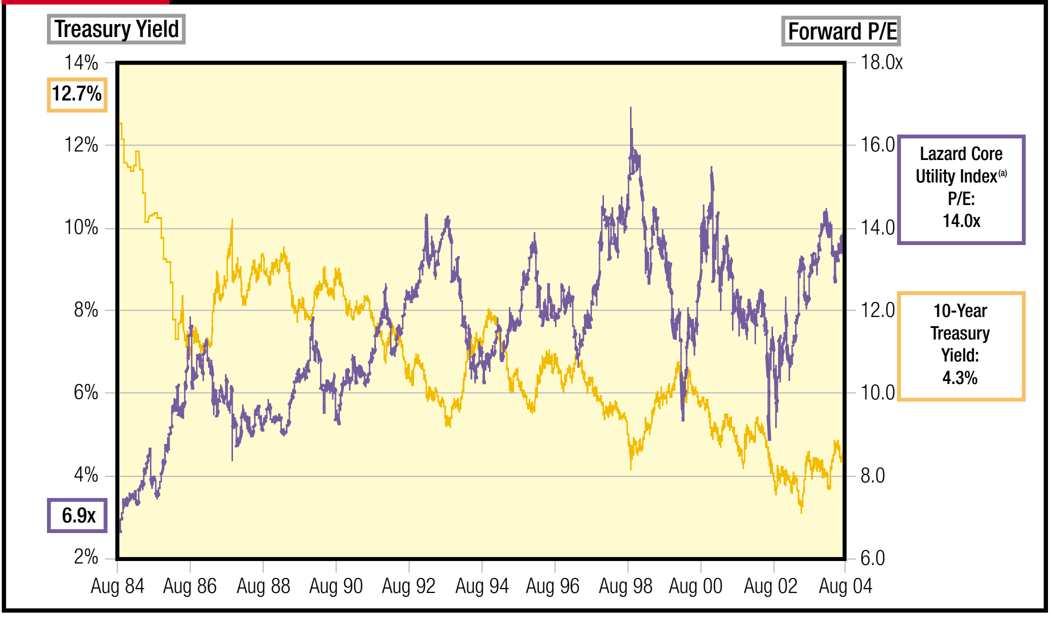
With current trading multiples implying long-term growth rates for the industry of approximately 4.5 to 6 percent, this apparent growth expectations gap translates into significant potential value compression risk in the industry should the current market's dividend yield bias begin to abate and more balanced considerations of growth and total return re-emerge as appropriately weighted components of industry valuations. With the truncation of the industry's non-regulated growth strategies, there is only one strategy that credibly presents to the industry a broad-based, accessible means of generating meaningful growth to address this deficiency: mergers and acquisitions.

The Growth Proposition: Mergers & Acquisitions

The value proposition of merger and acquisition strategies is manifest. Cost savings and synergies, derived principally from non-fuel operations and management savings but also variously from the benefits of scale and the transfer of best practices, among others, form the core of the proposition. Such transactions also provide other, less quantifiable, but no less important, benefits, including diversification of market and regulatory risk as well as the financial scale and resources to address the likely future significant capital requirements of the industry

Schedule 4-3

FIGURE 1 A NEGATIVE CORRELATION: TREASURY YIELD TO UTILITY INDUSTRY P/E



Source: I/B/E/S and FactSet.

(a) Lazard Core Utility Index (LCUI) is comprised of Ameren, American Electric Power, Cinergy, Consolidated Edison, Constellation, Dominion, DTE, Duke Energy, Entergy, Exelon, FirstEnergy, FPL, KeySpan, Pinnacle West, PPL, Progress, PSEG, SCANA, Sempra, Southern, Wisconsin Energy, Xcel Energy.

and withstand material adverse operational and financial events.

Even those transactions that are retrospectively deemed unsuccessful were in fact generally able to realize significant synergy and cost saving benefits, often in excess of the targets set at each transaction's public announcement. Where such mergers and acquisitions generally foundered were either in the failure to achieve broader strategic objectives, such as convergence or other revenue-synergies-based strategies, or in simple regulatory or strategic miscalculation. And, while the broader strategic objectives may have proven illusory, the embedded value propositions of cost savings, synergies, and scale remain compelling.

However, the parameters of success in mergers and acquisitions, while manifest and meaningful, are exacting. As a result, such strategies require excellence of conception and execution. The strategic rationales of such transactions must be compelling and accessible to a skeptical investor base, particularly as compared with executing on other growth strategies or even the *status quo*. In this regard, the potential returns must be compelling enough to overcome ostensibly lower-risk means of enhancing shareholder returns, namely share repurchase initiatives.

Share Repurchase Initiatives: Comparative Return Proposition

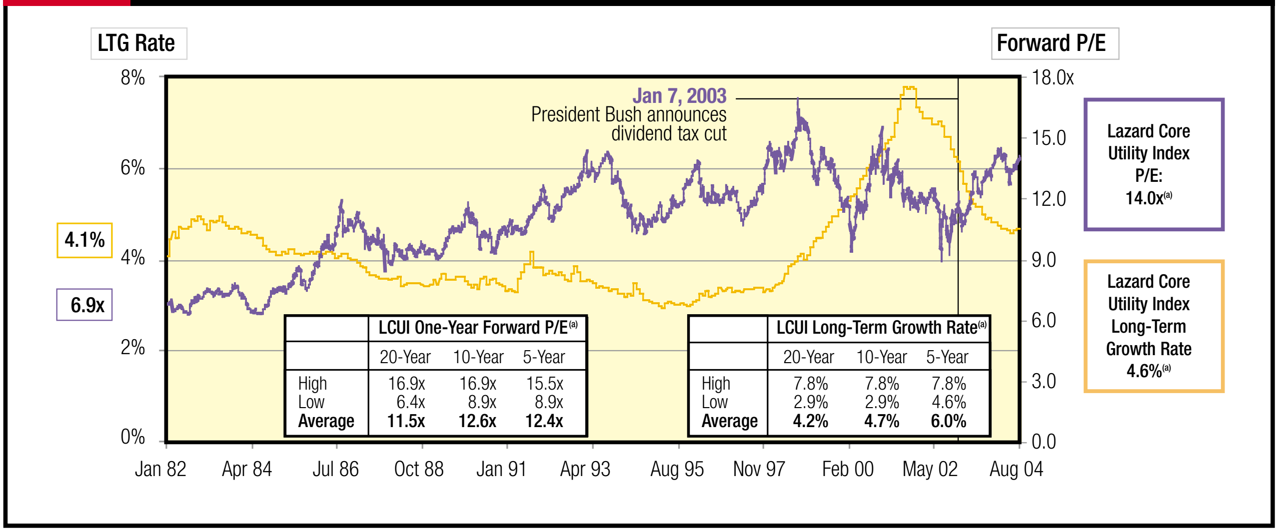
The potential emergence of share repurchase initiatives signals and reinforces several important emerging trends in the U.S. utility industry. The first stems from the industry's successful and significant financial and operational retrenchment over the past several years. Industry credit quality has improved and continues to improve markedly (though it is still below pre-1990 levels) as cash flow and earnings increase and debt levels are reduced. The second relates to the limited non-regulated growth strategies available to the industry, which constrain capital investment outlets and create a free cash flow surplus for the industry. Current estimates forecast that the U.S. electric utility industry will generate more than $15 billion annually in free cash flow through 2010.[5] European utilities face a similar projected cash situation, with E.ON alone projected to generate approximately $5 billion to $6 billion annually in free cash flow. As a result, merger and acquisitions strategies (as well as any other growth investment strategies) must compete with capital structure initiatives, such as share repurchase programs, as the most viable means to deliver superior returns and value to shareholders.

The financial proposition of share repurchase programs is relatively straightforward. Such strategies represent an alternative to dividends to distribute excess free cash flow to investors (though the historical tax efficiency component of share repurchase programs relative to dividends was effectively eliminated by the 2003 dividend tax cut). The share repurchase value proposition is effectively a financial mechanism to achieve earnings-per-share accretion by using a lower cost-of-capital (cash/debt) to buy-in a higher cost-of-capital (public market equity), effectively leveraging the capital structure (and inviting negative credit scrutiny) to increase equity returns.

However, while a share repurchase strategy is certainly advisable and beneficial in certain circumstances to enhance equity value, it is also limited and limiting in important respects. While accretive to earnings, such strategies do not alter the fundamental growth profile of a utility, nor do they create incremental enterprise value. Any EPS accretion is effectively "one time" in nature, limited to the duration of the program unless it is fixed and long-term in nature. And even these equity benefits are usually discounted in the market given the typically indicative, changeable parameters and soft commit-

Schedule 4-4

FIGURE 2 **UTILITY INDUSTRY HISTORICAL VALUATION LEVELS**



(a) Lazard Core Utility Index (LCUI) is comprised of Ameren, American Electric Power, Cinergy, Consolidated Edison, Constellation, Dominion, DTE, Duke Energy, Entergy, Exelon, FirstEnergy, FPL, KeySpan, Pinnacle West, PPL, Progress, PSEG, SCANA, Sempra, Southern, Wisconsin Energy, Xcel Energy.

ments that characterize such initiatives, both in terms of timing and magnitude. It is not unusual for companies to announce their intentions to execute a share repurchase program only to later fail to follow through, or to do so at materially lower levels than initially indicated.

Nor are share repurchase programs immune from execution risk. As with any other investment, share repurchases can potentially destroy value to the degree that they are executed at inflated valuations. This is an important consideration for the utility industry in particular at present. As noted previously, the industry currently trades at premium valuation levels relative to historical parameters. Whereas the average one-year forward P/E for the industry during the past 20 years implies sustainable P/E levels of approximately 12.0x, the industry today is trading at a P/E of approximately 13.5-14.0x. (*see Figure 2*).[6] An additional indicator that the industry may be fully valued at present is its relative P/E to that of the S&P 500. The industry historically has traded on a P/E basis at approximately 0.7x the S&P 500; currently, it is trading at approximately 0.9x, a 20 percent premium to historical levels.[7]

As in the case of dividends, then, while share repurchase programs may be tactically or financially appropriate in certain circumstances to enhance total return and shareholder value, they are not typically viable or sustainable strategies to deliver long-term growth and shareholder value, particularly as compared with investment in growth initiatives or mergers and acquisitions. Certainly, with respect to merger and acquisition strategies, share repurchase programs do not capture the same incremental multi-dimensional benefits—most notably the compound strengths of enhanced scale, including cost-of-capital efficiencies, greater regulatory influence, and fuel, geographic and operational diversity, among others.

The More Things Change...

Ultimately, though the collapse of non-regulated strategies as a solution to the industry's low growth characteristics and the 2003 dividend tax cut have altered the parameters of U.S. utilities in evaluating strategies to increase shareholder value, in many respects the fundamental issue confronting the industry remains unchanged: how to achieve superior long-term growth in an intrinsically low-growth industry. While utilities should continue to evaluate their financial policies and capital structures in respect of dividend yield and share repurchase policies, the answer to the industry's long-term growth issues continues to be the successful execution of merger and acquisition strategies.

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Endnotes

1. Recognizing that for certain institutional investors such relative tax considerations are immaterial.
2. As of Sept. 3, 2004.
3. Based on average long-term growth rate of component utilities in Lazard Core Utility Index.
4. Source: Bernstein Research Report dated June 2004.
5. Free cash flow defined as cash from operations less capital expenditures.
6. Based on Lazard Core Utility Index.
7. Neither of these historical benchmarks are adjusted for the potential impact of the dividend tax cut on industry values.

Schedule 4-5