DELMARVA POWER & LIGHT COMPANY
REBUTTAL TESTIMONY OF FRANK J. HANLEY
BEFORE THE DELAWARE PUBLIC SERVICE COMMISSION
CONCERNING AN INCREASE IN GAS BASE RATES
DOCKET NO. 10-237

I. INTRODUCTION AND PURPOSE

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

A: My name is Frank J. Hanley and I am a Principal and Director of AUS Consultants, Inc. My business address is 155 Gaither Drive, Suite A, Mt. Laurel, New Jersey 08054.

2. Q: Are you the same Frank J. Hanley who previously filed direct and supplemental testimony in this proceeding?

A: Yes.

3. Q: What is the purpose of your rebuttal testimony?

A: The purpose of this testimony is to rebut certain aspects of the direct testimonies of Staff of the Delaware Public Service Commission (Staff) Witness James A. Rothschild and the Division of Public Advocate Witness Andrea C. Crane with regard to cost of capital issues. I address deficiencies in their recommended common equity cost rates including their assessments of the impact on the allowed rate of return on common equity capital (ROE) if the Commission approves the Company's requested Modified Fixed Variable (MFV) revenue decoupling mechanism. I also respond to comments made by each witness regarding my direct testimony. This testimony is organized by witness.

4. Q: <u>Have you prepared attachments and schedules in support of this testimony?</u>

A: Yes. There are three Attachments and thirteen Schedules included with my testimony. They are:

Attachment A: Schedule AJK RF-3

Attachment B: Schedule AJK RF-2

Attachment C: Schedule AJK RF-1

All of these attachments are duplicates of Schedules sponsored by Delmarva Witness Anthony J. Kamerick in his supplemental rebuttal testimony in Docket No. 09-414

Schedule FJH R-1: Example of the Inadequacy of DCF Return Rate Related to Book Value When Market Value Exceeds Book Value Based Upon Mr. Rothschild's DCF Cost Rates

Schedule FJH R-2: Excerpt from Ibbotson SBBI <u>Stocks, Bonds, Bills, and Inflation: Valuation Edition 2010 Yearbook</u>, Page 23

Schedule FJH R-3: Graphical Depictions Which Demonstrate the Need to Use the Arithmetic Mean When Estimating the Cost of Capital

Schedule FJH R-4: Excerpt from Ibbotson SBBI <u>Stocks, Bonds, Bills, and Inflation: Valuation Edition 2010 Yearbook</u>, Pages 77-78

Schedule FJH R-5: Excerpt from Ibbotson SBBI <u>Stocks, Bonds, Bills, and Inflation: Valuation Edition 2010 Yearbook</u>, Pages 64 through 66

Schedule FJH R-6: Convenience Copy of Estimated Equity Risk Premia Based Upon Regression Analysis of 622 Fully Litigated Gas and Electric ROEs from January 1, 1989 through May 17, 2010

Schedule FJH R-7: Presentation by Roland Risser, Director Customer Energy Efficiency, Pacific Gas & Electric Company re "Decoupling in California: More than Two Decades of Broad Support and Success" – August 2, 2006

Schedule FJH R-8: Standard & Poor's Global Credit Portal – RatingsDirect re Pacific Gas & Electric Co. – September 29, 2010

Schedule FJH R-9: SNL Financial – Rate Case History/Pending Rate Cases, California Public Utilities Commission as of November 15, 2010

Schedule FJH R-10: Delmarva Power & Light Company: Regression Analysis of Net Gas Revenues and Heating Degree Days, April 2006 through June 2010

Schedule FJH R-11: Reductions in Awarded ROE Due to Decoupling Mechanisms by Regulatory Commissions in Fully Litigated Gas Distribution Cases 12/2007 Through 11/2/2010

Schedule FJH R-12: Excerpt from Principles of Corporate Finance by Richard A. Brealey and Stewart C. Myers, McGraw-Hill, 1996

Schedule FJH R-13: Excerpt from Ibbotson SBBI Stocks, Bonds, Bills, and Inflation: Valuation Edition 2010 Yearbook, Pages 55-56

II. SUMMARY

5. Q: Please set the context for your rebuttal testimony.

A: I will show that the recommended common equity cost rates of both Mr. Rothschild and Ms. Crane are unduly low as a result of applying flawed theory in utilizing their cost of common equity models. In addition, I will explain why Mr. Rothschild's long-term debt cost rate and his deduction to common equity cost rate as the result of "less financial risk" are incorrect. In addition, I will explain why the recommended deductions to common equity cost rate recommended by Mr. Rothschild and Ms. Crane are excessive and have no basis in reality.

6. Q: Please summarize your rebuttal testimony.

A: My testimony will address the following issues related to the testimony of Mr. Rothschild:

- His recommended deduction to the embedded cost of long-term debt as discussed at pages 10-11 of his testimony is unjust and unwarranted.

- His deduction of 0.10%, or 10 basis points, from his recommended common equity cost rate in view of Delmarva's "less financial risk" is without merit.
- His exclusive reliance upon the sustainable growth method (br + sv) is circular in reasoning and inferior to the use of analysts' forecasts of growth in earnings per share in the DCF model.
- The gross inadequacy of utilizing his DCF methodology when such results are applied to the common equity financed portion of Delmarva's original cost jurisdictional rate base.
- His use of the geometric mean in the CAPM is incorrect as well as his failure to consider investor-influencing forward-looking returns.
- The problems associated with his application of the CAPM and market-derived CAPM.
- His utilization of the Ibbotson and Chen buildup model is incorrect.
- His discussion regarding the utilization of allowed rates of return on common equity awarded by other regulatory jurisdictions is misplaced.
- His contention that there is no inverse relationship between interest rates and equity risk premium is incorrect.
- His error in recommending no allowance for flotation costs.
- His position regarding the impact of revenue decoupling on common equity cost rate is incorrect.

The only issue I have with Ms. Crane's testimony relates to the cost rate of common equity capital. She is in accord with the Company's proposed capital structure and long-term debt cost rate.

My testimony will address the following issues related to the testimony of Ms. Crane:

- Her recommended common equity cost rate is unduly low before her recommended deduction as a result of the decoupling mechanism (Delmarva's requested modified fixed variable rate design (MFV).
- Her application of the CAPM is incorrect.
- The failure to utilize the ECAPM exacerbates her understatement of common equity cost rate.
- Her assumptions regarding the requested MFV decoupling mechanism on common equity cost rate are unfounded and have no basis in reality.

In addition to the foregoing, I respond to criticisms made of my direct testimony by Mr. Rothschild and Ms. Crane and explain why such criticisms are without merit.

III. <u>STAFF WITNESS ROTHSCHILD</u>

A. <u>Capital Structure and Cost of Long-Term Debt</u>

7. Q: <u>Is there any difference between the capital structure ratios utilized by Mr. Rothschild and yourself as set forth in your supplemental testimony?</u>

A: No. The capital structure ratios as set forth in my supplemental testimony consisting of 51.72% long-term debt and 48.28% common equity capital are those utilized by Mr. Rothschild.

8. Q: <u>Is there a disagreement with regard to the embedded cost of long-term debt capital?</u>

A: Yes. In my supplemental testimony, the embedded cost of long-term debt capital has declined from 5.33% in the original filing to 5.28% at June 30, 2010 while Mr. Rothschild recommends a long-term debt cost rate of 4.97%.

9. Q: <u>Is the reduction in the embedded cost of long-term debt capital recommended by Mr. Rothschild warranted?</u>

A: No. In its recent electric case, Docket No. 09-414, Delmarva Witness Kamerick explained in detail why it was necessary for Delmarva to raise the $250 million debt issuance in November 2008 for Delmarva's own needs. Indeed, Mr. Kamerick demonstrated via several schedules accompanying his supplemental rebuttal testimony in Docket No. 09-414 that (1) numerous utilities raised debt capital in and around the November 2008 timeframe during which Delmarva raised its $250 million (Attachment A) and (2) even after that financing, which was approved by this Commission in its Order No. 7487 re Docket No. 08-335 dated November 21, 2008 (Attachment B), Delmarva's embedded debt cost rate was lower than 29 of a total of 32 embedded long-term debt cost rates derived from rate orders involving investment grade electric utilities which were issued by regulatory commissions between January 1, 2009 and March 8, 2010 (Attachment C). Moreover, since Delmarva is a regulated public utility company with an obligation to serve, it has an obligation to be sure that it obtains all of the capital required when necessary. The period in the fall of 2008, including the months of September, October and November were indeed dark times. The capital markets were drying up and there was major uncertainty about the future availability and cost of marginal capital. In my opinion, it was prudent to raise the funds necessary because, at that point in time, no one could be sure that capital would be available or at what cost. In other words, when the Company deemed that it was able to raise the capital required, it did so. With all of the uncertainty, exacerbated by speculation of who the next Secretary of the Treasury might be and what the implications on the capital markets could be, fear existed that the adverse conditions could get even worse. The Company should not be penalized for acting prudently by raising required capital when it was available. Second-guessing is not constructive regulation.

10. Q: At page 32 of his testimony, Mr. Rothschild indicates that he reduced his cost of equity results by 0.10% "to recognize that Delmarva's requested capital structure contains a higher percentage of common equity than the companies in the comparative group."

A: Mr. Rothschild relied upon the same proxy groups that I utilized, namely seven natural gas distribution companies and eleven combination electric and gas companies. Reference to page 1 of Schedule FJH-3 accompanying my direct testimony will show that the proxy group of seven natural gas distribution companies in 2009 had a common equity ratio of 53.17% and a total equity ratio of 53.40% when preferred stock is included based on total permanent capital. Reference to Schedule FJH-4, page 1 accompanying my direct testimony will show that in 2009, the proxy group of eleven combination electric and gas companies had a common equity ratio of 47.48% but also employed 0.84%

preferred stock capital, equaling total equity capital of 48.32% based on total permanent capital. These ratios compare to the 48.28% common equity ratio of Delmarva. Clearly, Mr. Rothschild's recommended 0.10% reduction to common equity cost rate is in error, unjustified and should be rejected.

B. Common Equity Cost Rate

11. Q: Mr. Rothschild relies exclusively upon the sustainable growth methodology in order to establish the growth factor for use in the application of the constant growth DCF model. Please comment.

A: The sustainable growth method is circular in nature because it relies upon an expected ROE. In turn, it utilizes that ROE to establish an allowed ROE which is lower than the expected ROE. Moreover, the expected ROE used is determined from Value Line's forecast which is for a five-year period into the future. Yet, Mr. Rothschild's presumption is that such five-year forecasted ROE, which incidentally is the same as analysts' forecasts of growth in earnings per share, i.e., a five-year period, is sustainable into the indefinite future. That in itself is an unrealistic assumption. In addition, it is clear that Value Line Investment Survey is an investor-influencing publication. It is reasonable for investors to expect to earn on book common equity the rate indicated by Value Line, the beginning point of Mr. Rothschild's sustainable growth calculation. In other words, it is the r in the br portion of the br + sv. It is completely unreasonable to assume that a utility will earn, for example, an 11% or 11.5% rate of return into infinity, but recommend a 9.50% return on equity (without regard to the implementation of a decoupling mechanism such as the requested MFV).

Since analysts' forecasts are available for five years into the future (as is Value Line's five-year forecast which Mr. Rothschild incorrectly assumes is sustainable in perpetuity), it makes much more sense to utilize analysts' forecasts rather than employing the illogical circularity associated with the br + sv sustainable growth methodology relied upon by Mr. Rothschild.

Myron Gordon, in his 1974 text, The Cost of Capital to a Public Utility, introduced the constant growth standard DCF model into public utility regulation. In the 1974 book, Gordon advocated the use of the sustainable growth method. However, many years later, Gordon acknowledged that a better method to utilize in employing the model was security analysts' forecasts of growth in earnings per share. For example, the following excerpt was contained in the attachment provided in response to Data Request designated PSC-COC-34 (a). In a presentation entitled, the Pricing of Common Stocks, Myron J. Gordon made at the Spring 1990 Seminar of the Institute for Quantitative Research in Finance, he stated:

> ...the estimates by security analysts must be superior to the estimates derived solely from financial statements. For earnings, we want normalized current earnings and for growth we want expected future growth. It is true that all our knowledge of the future is obtained from the past, and good estimates of Y and G can frequently be obtained from financial statement data. However, such data are available to security analysts, and they have additional information that can be incorporated in their estimates, so that an average over a number of security analysts which eliminates the bias of any one analyst should be superior to exclusive reliance on past financial statement data.

12. Q: <u>In speaking to the DCF model, Mr. Rothschild states at page 31 of his testimony, lines 19 through 21 that "(W)hat the DCF method is all about is</u>

<u>deriving mathematically the relationship between the expected return on book equity and how, based on market price, investors react to that expectation." Please comment.</u>

A: Mr. Rothschild has it exactly backwards. The DCF method is all about determining the rate of return investors expect on market value, i.e., the price they pay for common stock. That is why, in calculating the dividend yield, one utilizes market price, not book value. Since investors expect to earn a return on the market value, i.e., market prices paid for common stock, that is the base upon which they expect to earn their return. I explain clearly at pages 23-24 of my direct testimony that there are many factors which affect market prices of utility common stocks. While investors expect to earn a return on the market prices they pay, the regulated utility is limited to earning on its net book value (depreciated original cost) rate base. Market values can diverge from book values for a myriad of reasons including, but not limited to, earnings per share (EPS) and dividends per share (DPS) expectations, merger / acquisition expectations, interest rates, etc. Thus, when market values are disparate from their book values, a market-based DCF cost rate applied to the book value of common equity will not reflect investors' expected common equity cost rate. It will either overstate the common equity cost rate (without regard to any adjustment for flotation costs which may, at times, be appropriate) when market value is less than book value, or understate the cost rate when market value is above book value.

13. Q. <u>Have you prepared an analysis that shows the impact of Mr. Rothschild's DCF cost rates?</u>

A. Yes. The average midpoint of Mr. Rothschild's recommended range of DCF cost rates for each proxy are shown on Schedule FJH R-1 wherein I demonstrate the inadequacy of Mr. Rothschild's DCF cost rates. It is shown that there is no realistic opportunity to earn those market-based rates of return on their book values. It can be gleaned that the proxy group of gas companies has an average market/book ratio of 176.2% and the investor expects a total return rate of 9.72%, the average of Mr. Rothschild's recommended DCF cost rate range. The 9.72% market-based cost rate implies an annual return of $3.476 consisting of $1.384 in dividends and $2.092 in growth (market-price appreciation). When the 9.72% return rate is applied to the book value of $20.30 which is only 56.8% of market value, an opportunity for a total annual return is just $1.973 on book value. With annual dividends of $1.384, there is an opportunity to earn only $0.589 in market-price appreciation which is a mere 1.65% on market price in contrast to the 5.85% growth in market price expected by investors as reflected in the DCF cost rate. There is no possible way to achieve the expected growth of $2.092, or 5.85% related to an average market price of $35.763. Similar calculations are shown for the proxy group of eleven combination electric and gas companies whose average market/book ratio is 138.5%. It is shown that, when applied to a book value which is just 72.2% of market price, that the opportunity to earn growth of 4.16% on market price is not possible as it is just 1.67% on book value.

In view of the foregoing and because market prices are affected by a myriad of macroeconomic factors as well as industry and company-specific factors, there can be no reasonable determination of DCF cost rate unless market prices equal book value. As stated in my direct testimony, when market price significantly exceeds book value, a market-based DCF cost rate understates the true investor-expected cost rate when it is applied to a lower book value.

14. Q: <u>At page 8, lines 7-8 of his testimony, Mr. Rothschild claims that the great recession has caused investors to settle for lower returns than are available in more normal times. Is he correct?</u>

A: No. Dr. Roger Ibbotson, the principal founder of the annual SBBI publication upon which regulators and cost of capital witnesses (including all three in this Docket) rely, in an interview with Paul D. Kaplan on December 17, 2008[1], the following interchange occurred between Kaplan and Professor Ibbotson:

> **Kaplan**: Dr. Ibbotson, is the economy fundamentally unstable or does it self-stabilize? It is curious that economists of every stripe right now are calling for aggressive government action regardless of what theory they normally subscribe to.
>
> **Ibbotson**: The economy has lots of self-stabilizing features, and it has other features that are destabilizing. Most of the time the economy is stabilizing, but certainly, I won't argue that the situation is stable now; instead, we have discontinuities here of an extreme sort.
>
> But there are also behavioral aspects of this. *I think the risks are definitely much higher than you might think of just looking at standard deviation, not only from the mathematical aspects of other measures of risk, but also from the way people react when they have the bad result. People often have the bad result at the same time they are losing their human capital income. They're losing all of their wealth at the same time, so they tend to be much more risk-averse than standard economics would show them to*

---

1 Morningstar Advisor, February 2, 2009.

be. There is a lot of risk, and there's more risk than we think. (Emphasis added)

* * *

Kaplan: Our readers are getting a lot of questions from their clients about what they should do. What kinds of things should advisors be discussing with their clients?

Ibbotson: *I would be saying that when markets pull out of calamities, they often have their highest returns.* We had the highest return ever in 1933 in the midst of a severe depression. You get the extreme pullout when things start to get a bit better. The markets in general move ahead of what's actually happening in the economy. *The risk premium on stocks has gone way up because of the fact that investors now recognize that there is much more risk in the market than they had recognized.* Stocks may not be done dropping, especially in light of what's happened to the financial system, and I don't know when it's going to start to straighten out, but ultimately, in the long run, stocks are a good investment. (Emphasis added)

The foregoing affirms that investors have and continue to require an equity risk premium commensurate with the greater risk that they face which is in total contrast to Mr. Rothschild's contention.

15. Q: <u>At the top of page 35 of his testimony, Mr. Rothschild discusses his reasoning for making an upward adjustment of twelve basis points to his traditional CAPM cost rate. Is such an adjustment necessary?</u>

A: No. An adjustment is unnecessary because the market prices reflect investor expectations.

16. Q: <u>In his application of the traditional CAPM, Mr. Rothschild utilizes as his risk-free rate the average of short-term Treasury Bills from the SBBI 2010 Yearbook for the period 1926-2009. Is the use of short-term Treasury Bills as the risk-free rate in the CAPM appropriate when estimating the cost of</u>

capital?

A: No. Pages 42 and 43 of my direct testimony contain explicit quotations from the Ibbotson SBBI 2010 Valuation Yearbook. It is made quite clear that when valuing a business that is being treated as a going concern, the appropriate Treasury yield should be that of a long-term Treasury Bond. Moreover, since Mr. Rothschild is so concerned with sustainable growth in the DCF model (which he presumes to be effective into infinity), he has a complete mismatch. He should have used long-term Treasury Bond yield in the CAPM. I will address *infra* why the use of the geometric mean is inappropriate when estimating the cost of capital.

Moreover, Diana R. Harrington, in her book Modern Portfolio Theory and the Capital Asset Pricing Model[2] states this about the use of a 90-day (13-week) Treasury Bill:

> Anyone using the CAPM must choose the Rf proxy with great care. *The most widely used proxies, 30- or 90-day Treasury Bill rates, are empirically inadequate and theoretically suspect.* (Emphasis added)

Moreover, I have shown on Schedule FJH R-2, page 2, which is page 23 from the SBBI 2010 Valuation Yearbook that the serial correlation of the income returns on long-term government bonds is 0.96, even greater than the inappropriate proxy of short-term Treasury Bills which has a serial correlation of 0.91. I will explain *infra* on page 15 why the use of income returns is appropriate when utilizing the long-term Treasury Bonds as the proxy for risk-free rate in the CAPM.

---

2 Harrington, Diana R., Modern Portfolio Theory and the Capital Asset Pricing Model, Prentice-Hall, Inc., 1983, p. 108.

17. Q: <u>Why is the income return appropriate to use when employing the long-term Treasury Bond as the risk-free rate in the CAPM?</u>

A: Morningstar, in its Ibbotson SBBI <u>2010 Valuation Yearbook</u>, at page 55 explain clearly and precisely why the income return should be utilized. They state:

> Another point to keep in mind when calculating the equity risk premium is that the income return on the appropriate-horizon Treasury Security, rather than the total return is used in the calculation. The total return is comprised of three return components: the income return, the capital appreciation return, and the reinvestment return. The income return is defined as the portion of the total return that results from the periodic cashflow or, in this case, the bond coupon payment. The capital appreciation return results from the price change of a bond over a specific period. Bond prices generally change in reaction to unexpected fluctuations in yields. Reinvestment return is the return on a given month's investment income when reinvested into the same asset class in the subsequent months of the year. *The income return is thus used in the estimation of the equity risk premium because it represents the truly riskless portion of the return.* (Emphasis added)

In view of the foregoing, it should be clear that the income return on long-term Treasury Bonds is the appropriate risk-free rate to be used in the application of the CAPM and Mr. Rothschild's recommended use of the yield on short-term Treasury Bills is inappropriate and should be rejected.

18. Q: <u>Mr. Rothschild did not use any investor-expected return based upon investor-influencing forecasts in the application of his CAPM. Please comment.</u>

A: Mr. Rothschild's failure to utilize investor-expected return is inconsistent with the whole concept of the cost of capital, which is expectational. In other words, investors commit capital with the expectation to earn a certain rate of return. Reliance upon the past is certainly valid to examine, but it should be in conjunction with analysts' forecasts of the future. Mr. Rothschild relies heavily upon Value Line data in the computation of his sustainable growth for use in the DCF model. The sustainable growth comes from the Value Line econometric forecast into the future for the same period of time as the forecasts in market prices and market price appreciation. Clearly, such data also influence investors and should have been taken into account. As a result, his CAPM calculation is flawed. It is also flawed because of his failure to employ the Empirical Capital Asset Pricing Model (ECAPM) which is substantiated by many empirical studies which confirm that the traditional CAPM understates common equity cost rate for companies whose beta is less than one even when an adjusted beta is utilized. The theoretical basis of the ECAPM is explained at pages 40-42 of my direct testimony including an explanation of why the ECAPM does not double-count the Value Line beta adjustment.

19. Q: <u>You have stated, *supra*, at page 4 that the use of compound, or geometric returns utilized by Witness Rothschild, and discussed for many pages in his testimony, is incorrect to use when estimating the cost of capital. Please explain.</u>

A: I explain in detail in my direct testimony beginning at page 36, line 11 through page 37, line 11 why the use of only the arithmetic mean is appropriate when calculating the cost of capital, or discounting future cashflows. At pages 2 and 3 of Schedule FJH-15 accompanying my direct testimony, Morningstar in its Ibbotson SBBI <u>2010 Valuation Yearbook</u> state:

> *The arithmetic average equity risk premium can be demonstrated to be most appropriate when discounting future cashflows.* For use as the expected equity risk premium in either the CAPM or the building block approach, the arithmetic mean or simple difference of the arithmetic mean of stock market returns and riskless rates is the relevant number. This is because both the CAPM and the building block approach are added to models, in which the cost of capital is the sum of the parts. The geometric average is more appropriate for reporting past performance since it represents the compound average return.
>
> The argument for using the arithmetic average is quite straight-forward. In looking at projected cashflows, the equity risk premium that should be employed is the equity risk premium that is expected to actually be incurred over the future time periods.

On Schedule FJH R-3, which consists of three pages, I have shown that the total returns on large company common stocks between the period 1926 through 2009 have been extremely volatile. This is observed by reference to page 1 of Schedule FJH R-3. On page 2, I have arrayed the total returns over the period by year. As can be seen, it is a normal distribution which indicates that the equity risk premium derived therefrom is unpredictable from period to period, that is, random. Its randomness is confirmed by the Ibbotson data shown on Schedule FJH-15, page 4 accompanying my direct testimony, at page 4 where the serial correlation is 0.02 for large stock total returns and equity risk premium, thereby confirming that both total returns and equity risk premium are random. Because they are random, the best expectation of a future equity risk premium is that which takes into account all of the past observed returns which can only be accomplished through use of the arithmetic mean.

In contrast to the foregoing, observe on page 3 of Schedule FJH R-3 where a geometric return, which measures strictly past performance, would take into account only the initial and terminal years, namely 1926 and 2009. The change between the two periods is then calculated geometrically, or compound, to a constant rate from which initial investment in 1926 would have grown to that in 2009. Such a constant rate of growth is a good measure of past performance, but not a good one to estimate future equity risk premium which is random and as such, by definition, is unpredictable.

20. Q. <u>Is there additional evidence in the financial literature which confirms that only the arithmetic mean of past returns should be used when estimating the equity risk premium in the CAPM or the RP?</u>

A: The financial literature is clear that business risk is measured by the variability of expected pretax returns, i.e., the probability distribution of returns.[3] Weston & Brigham[4] define the riskiness of an asset as "the *likely variability of future returns from the asset.*" (Emphasis added.)

Jeremy J. Siegel[5] defines risk as "the *standard deviation* of *average real annual returns* for stocks, bonds and bills based on the historical sample of nearly 200 years. *This is the measure of risk used in portfolio theory and asset allocation models.*" (Emphasis added.)

Finally, in a note at the top of Table 1-1 on page 13 of the same text, Siegel further notes that:

---

3 Eugene F. Brigham, *Fundamentals of Financial Management*, Fifth Edition, The Dryden Press, 1989, p. 639.

4 J. Fred Weston and Eugene F. Brigham, *Essentials of Managerial Finance*, Third Edition, The Dryden Press, 1974, p. 272.

5 Jeremy J. Siegel, *Stocks for the Long Run – The Definitive Guide to Financial Market Returns for Long-Term Investment Strategies*, McGraw-Hill, Third Edition, 2002, p. 32.

Risk = standard deviation of *arithmetic returns*.
(Emphasis added.)

Thus, it is clear that the use of the geometric mean is incorrect <u>when estimating the cost of capital</u>.

21. Q. **<u>At page 47, lines 12 through 16, Mr. Rothschild discusses the many differences between the conditions of 1926 and 2009 and he states, "One must consider the impact of the Great Recession when applying debt-based methods in the current financial environment." Do you agree?</u>**

A: Yes. That is precisely why it is wrong to utilize the geometric mean of the data between the years 1926 through 2009. Only the arithmetic mean takes into account all the factors. Mr. Rothschild concerns himself with the Great Recession, but then when utilizing historical data, relies upon the geometric mean which takes into account only the years 1926 and 2009. In contrast, the arithmetic mean of all the data during the entire period takes into account factors such as the Great Depression, World War II, the Korean War, the Vietnam Conflict, periods of hyper-inflation and deflation, the terror attack of September 11, 2001 and its implications, the conflicts in Iraq and Afghanistan, as well as the Great Recession.

22. Q. **<u>Please comment upon Mr. Rothschild's "market-derived CAPM".</u>**

A: The model utilized by Mr. Rothschild is not a CAPM. In the CAPM, a Security Market Line (SML) is a line that shows the relationship between risk as measured by beta and the required rate of return for individual securities.[6] In

---

6 Eugene F. Brigham, <u>Fundamentals of Financial Management, Fifth Edition</u>, The Dryden Press, 1989, p. 129.

contrast, the Rothschild model shows a line that is not an SML, but rather one that represents the difference in the compound returns from 1926 through 2009 related to the betas of 10 portfolios of stocks ranged by deciles based on size. The SML has <u>its origin</u> at the risk-free rate, i.e., the intercept, whereas the Rothschild model estimates an intercept that is <u>claimed</u> to be the risk-free rate.

23. Q. <u>Based on the graphs shown on page 53 of his testimony and the data on Schedule JAR 8, page 4, Mr. Rothschild regresses the compound returns for 10 deciles based on size over the period 1926-2009. He then relates those returns over the 84-year period to current betas. Please comment.</u>

A. I have discussed *supra* at pages 16-19 why the use of compound returns over the long-term historical period is incorrect for purposes of estimating the cost of capital. However, the betas for each decile are those calculated over the entire period, January 1926 through December 2009, or 84 years. A comparison of five-year betas with those over the entire 84-year period is completely invalid. For example, a comparison of recent five-year betas with those of the 84-year betas as shown on Schedule FJH R-4, which consists of three pages. As can be seen on page 2, there are substantial differences. For every decile except the first, the long-term betas over the 84 years are substantially lower than those over the recent five years. Drawing inferences from compound returns and rolling 84-year betas to impute a return related to current five-year betas is like comparing the physical strength, coordination and dexterity of a 20-year old Olympian to a senior citizen. There is just no valid comparison. Indeed, Ibbotson SBBI states, on page 3 of Schedule FJH R-4:

> The traditional beta regression assumes that the beta of a company is related to current market movements. This is why the regression formula compares returns of the security for a given period to the returns of the market for that same period.

24. Q. <u>At page 69 of his testimony, at lines 20 through 28, Mr. Rothschild discusses the supply, or buildup, method of estimating common equity cost rate contained in the Ibbotson SBBI 2010 Classic Yearbook. He utilizes an 8.44% market cost rate to which he adds his unnecessary Great Recession adjustment of 0.12% to derive 8.56% indicated for a company or group of companies with an average risk and a beta of 1.0. Please comment.</u>

A: I must say that I am surprised that Mr. Rothschild, and indeed even Ms. Crane do not utilize, or choose to ignore, the Ibbotson SBBI <u>2010 Valuation Yearbook</u>. For example, in the introduction to the <u>2010 Valuation Yearbook</u>, at page 1, Ibbotson SBBI states:

> The Ibbotson SBBI <u>Classic Yearbook</u> has become a standard reference publication in both the investment and business valuation communities. As the field of finance has progressed, the demands have also increased for SBBI to serve a more diverse audience.
>
> *In an effort to better serve the different markets for SBBI, Ibbotson Associates produced a separate version of the publication targeted to people involved in the valuation of businesses, the Ibbotson® Stocks, Bonds, Bills and Inflation (SBBI®) Valuation Yearbook.* (Emphasis added)

In Schedule FJH R-5, which consists of four pages, I have included pages 64 through 66 from the SBBI <u>2010 Valuation Yearbook</u>. In discussing the Ibbotson and Chen supply model, the authors show the calculation of the 8.44% geometric cost rate (page 65 of original document). Note, however, on page 4 of

Schedule FJH R-5 (original document page 66) that the authors clearly state that the arithmetic mean is most appropriate. They state:

> The supply side equity risk premium calculated earlier is a geometric calculation. *An arithmetic calculation, as mentioned earlier in the chapter is most appropriate when discounting future cashflows. For use as the expected equity risk premium in either the CAPM or the buildup approach, the arithmetic calculation is the relevant number*. (Emphasis added)

At the bottom of page 4 of Schedule FJH R-5, the authors show that the conversion of the supply side equity risk premium of 3.08% on a geometric basis results in a 5.18% equity risk premium on an arithmetic mean basis. Consequently, for purposes of an expectational cost of capital (for use in either the CAPM or the buildup approach as per the authors), the indicated common equity cost rate is 10.54% (8.44% + (5.18% - 3.08%)).

25. Q. <u>At page 70 of his testimony, Mr. Rothschild suggests that it would be improper for utility commissions to determine the cost of equity by simply coming up with an allowed return "that is in alignment with what other commissions are allowing." Do you agree?</u>

A: I agree that it would be incorrect for a regulatory commission to simply base its decision of an allowed ROE upon what other commissions have allowed. However, after analyzing all market-based equity cost rates of record, such information is certainly useful before a commission renders a decision because awarded ROEs by other regulatory commissions provide a meaningful reality check.

26. Q: <u>At pages 73-74 of his testimony, Mr. Rothschild suggests that there is no empirical data to confirm that interest rates and equity risk premia move inversely. Is his analysis correct?</u>

A: No. He states that empirical data points to the contrary. But he is wrong. Empirical data points to the fact that there is an inverse relationship between interest rates and equity risk premia as discussed *infra* on this page and pages 24-25.

Mr. Rothschild has performed no empirical analyses to demonstrate that his position is correct. Moreover, he makes an invalid assumption not based on any empirical evidence whatsoever that yields on BB rated bonds are close to the risk of common equity capital for a typical regulated public utility. He also states that there is a considerable decrease in the risk of BB rated bonds. Yields on junk rated bonds have decreased substantially as acknowledged widely in the financial press. That decrease is attributable to the overall decline in interest rate levels. As a consequence, investors have been so desperate to obtain higher yields that they even have "chased" junk bonds thereby causing abnormally higher prices and lower yields. However, there is no empirical evidence whatsoever that equity risk premia are declining. Recall the discussion between Dr. Roger Ibbotson and Paul Kaplan *supra* at pages 12-13 whose publications are relied upon by all the witnesses in this proceeding such as Ibbotson SBBI <u>Classic</u> and <u>Valuation Yearbooks</u>.

27. Q: <u>At pages 74-75 of his testimony, Mr. Rothschild suggests that there is a problem with using regression analysis to reach a conclusion of equity risk</u>

<u>premium and the inverse relationship. He states that statistics texts recognize that statistical models should have a theoretical basis and that they should have a logically plausible model that motivates the regression equation. Please comment.</u>

A: Utilities are very capital-intensive. As a result, there are frequent needs to raise external capital. Because of the relative stability of being price-regulated, utilities tend to have higher long-term debt ratios on average than the majority of non-price regulated enterprises. Consequently, investors are aware of the significance of the need to raise long-term debt capital when needed and on a reasonable basis relative to the capital market conditions at the time when capital is required. Moreover, regulators, when making their decisions of allowed rates of return on common equity capital rely upon market-based evidence of common equity cost rate. Consequently, the empirical evidence that I produced relative to 622 fully litigated gas and electric rate Orders demonstrates that there is indeed an inverse relationship between equity risk premia and long-term interest rates. I have attached to this testimony for convenience purposes, Schedule FJH R-6, which consists of seven pages. It is a duplicate of Schedule FJH-14 which accompanied my direct testimony. In addition to my own study, there are others who have demonstrated empirically that there is indeed an inverse relationship between equity risk premia and interest rates.[7]

In view of the foregoing, it should be clear that 1) there is indeed an inverse relationship between interest rates and equity risk premia; and 2) basing the relationship between the allowed equity returns derived from market-based cost of equity models and yield on long-term A rated public utility bonds is logical and valid in view of the capital intensity of regulated public utilities.

28. Q: <u>At the top of page 75, lines 1-3, Mr. Rothschild suggests that your regression analysis was based upon time series data. Is he correct?</u>

A: Absolutely not. My regression analysis, provided once again for convenience as Schedule FJH R-6, is based upon a cross-section of observations of awarded ROEs. That is, bond yields at the time of the issuance of rate Orders whenever they occurred related to the associated yield on A rated public utility bonds. Moreover, Mr. Rothschild seems inherently confused by referring to "both independent variables". My regression contains an independent variable, namely the A rated public utility bond yield and a dependent variable, namely the equity risk premium.

Mr. Rothschild's comments are erroneous and should be disregarded.

---

7 For example,
"The Market Risk Premium: Expectational Estimates Using Analysts' Forecasts", Robert S. Harris and Felicia C. Marsten, Journal of Applied Finance, Volume 11, No. 1, 2001.
"An Empirical Study of Ex-Ante Risk Premiums for the Electric Utility Industry", Farris M. Maddox, Donna P. Pippert and Rodney N. Sullivan, Financial Management, Vol. 24, No. 3, Autumn 1995.
"The Risk Premium Approach to Measuring a Utility's Cost of Equity", Eugene F. Brigham, Dilip K. Shome and Steve R. Vinson, Financial Management, Spring 1985.

29. Q: <u>At pages 75-79 of his testimony, Mr. Rothschild discusses why he believes no allowance for flotation costs should be allowed. He claims that such costs are relatively negligible and because utility companies' common stocks are selling in excess of their book value, a flotation cost adjustment is unnecessary. Is he correct?</u>

A: No. A flotation cost adjustment is warranted even if the market/book ratio is greater than 1.00 times. In the ratemaking paradigm, there is no other mechanism by which the essential costs associated with raising a new issuance of common stock can be recouped by the utility short of adjusting the common equity cost rate. This can be analogized to the necessary costs of issuance for a long-term debt issue. As discussed in my direct testimony and *supra* at pages 10-12, there are many factors which affect market prices, many of which are beyond the control of rate regulation. Shareholders should not be punished by depriving recovery of legitimate costs associated with the essential raising of common stock when it is required. Equitable treatment mandates recovery of such costs in accordance with the methodology specified by Brigham and Daves as shown in Schedule FJH-19 accompanying my direct testimony. That methodology is to adjust dividend yield. In Schedule FJH-19, I have shown the details of all four issuances since the formation of Pepco Holdings in 2002. As indicated on page 1 of Schedule FJH-19, that adjustment ranges from 0.21% based upon the proxy group of seven natural gas distribution companies and 0.25% based upon the proxy group of eleven combination electric and gas companies.

Such costs are based upon actual experience and the adjustments calculated in conformance with the academic literature. Equitable treatment mandates the opportunity for recovery of such costs.

C. <u>Revenue Decoupling and Impact on Common Equity Cost Rate</u>

30. Q: <u>At pages 79-83 of his testimony, Mr. Rothschild discusses the impact of revenue decoupling and its implication on common equity cost rate. He states that the requested MFV "will substantially minimize non-diversifiable risk." Is he correct?</u>

A: No. This is a matter of common sense. A MFV mechanism will help to stabilize revenues, but it does not guarantee a level of revenues. Non-diversifiable systematic risk is that which by definition one cannot eliminate through diversification. Moreover, in the instant matter, we are looking for a proper rate of return on the common equity financed portion of Delmarva's Delaware jurisdictional gas rate base and not on a portfolio of assets. Mr. Rothschild moves away from his contention about eliminating non-diversifiable risk when he states at page 80, lines 12-13, "revenue decoupling would attenuate the correlation of overall economic growth to Delmarva's earnings and the contribution those earnings have to PHI's stock price." A result of the requested MFV is stabilized revenues. Stabilizing revenues would, of course, relate to diversifiable risk which is the largest part of total risk for the proxy groups.

31. Q: <u>If Mr. Rothschild's contention were correct, namely that the MFV would substantially minimize non-diversifiable risk, what implication would that have with regard to the volatility of market price relative to a market index?</u>

A: If Mr. Rothschild's contention were correct, where such revenue decoupling provisions were in effect, the companies should have betas of essentially zero, since they would have virtually no non-diversifiable risk. However, such is not the case. For example, California has had in place revenue decoupling mechanisms such as the Electric Revenue Adjustment Mechanism (ERAM) for more than three decades. Yet, the betas of California energy companies are not, and have not been, even remotely close to zero. Even prior to the re-structuring of the electric industry in California, betas were still fairly high. For example, in 1996, the Value Line beta for Pacific Gas & Electric Company (PG&E) was 0.75. Yet, an ERAM had been in place for many years. Even currently, its Value Line beta is 0.55, still far from zero. Mr. Rothschild's contention of virtually eliminating non-diversifiable risk is without merit and should be disregarded.

32. Q: Previously, you refer to Mr. Rothschild's mention of the impact of such a mechanism on earnings and stock price. You also stated that would be an impact on diversifiable risk, which comprises the majority of total risk. Why would such a mechanism be an element of diversifiable risk?

A: The classic definition of business risk (which is diversifiable) is the volatility of earnings before interest and income taxes[8].

---

8 Eugene F. Brigham, *Fundamentals of Financial Management*, Fifth Edition, The Dryden Press, 1989, p. 639-641.

33. Q: **<u>Have you looked at a California utility company for insight into the validity of Mr. Rothschild's contention regarding the magnitude of impact of a MFV or its equivalent?</u>**

A: I have prepared Schedule FJH R-7, which consists of three pages. They are excerpts from a presentation made by Roland Risser, Director – Customer Energy Efficiency, Pacific Gas & Electric Company on August 2, 2006. It can be determined from page 2 of Schedule FJH R-7 that decoupling of revenues and sales for non-fuel costs began in California in 1978 for natural gas and in 1982 for electric. It can also be determined by reference to page 3 of Schedule FJH R-7 that nearly all of PG&E revenues are now decoupled; namely, only about 6% of electric revenues are at risk and only about 4.2% of natural gas revenues are at risk.

34. Q: **<u>You have addressed and pointed out the error of Mr. Rothschild's contention regarding the MFV (or its equivalent) on non-diversifiable risk. Would the implementation of the requested MFV result in the reduction of a level of risk to the extent that the common equity return rate would be equivalent to an AA or even AAA bond cost rate such as the 4.26% AAA bond rate discussed at page 83 of his testimony?</u>**

A: No. Such a proposition is preposterous for several reasons. First, revenues would be stabilized but not guaranteed, e.g., the loss of customers or the shifting of customers between rate classes. Second, expenses have a significant impact on earnings and their potential for variability, consistent with the definition of business risk. Third, while there is some reduction in risk attributable to a compression of volatility of revenues and EBIT, it is far from eliminated. Thus, there is still the need to earn an ROE commensurate with the real risk perceived by investors and reflected in the cost of capital, including bond ratings/yields. I have prepared Schedule FJH R-8 which consists of five pages. It is a copy of the September 29, 2010 rating rationale from Standard & Poor's RatingsDirect relative to PG&E. As can be seen, its credit rating is BBB+, despite the fact that it has had decoupling mechanisms (equivalent to a MFV) in effect since 1978 for gas and since 1982 for electric. As noted on page 2 of Schedule FJH R-9, the current authorized ROE for most energy companies subject to the jurisdiction of the California Public Utilities Commission (CPUC) is 11.35%, despite the fact that PG&E and all other electric and gas companies have had revenue decoupling mechanisms in effect for approximately three decades.

35. Q: <u>Has PG&E, which has had decoupling in effect for decades, recently received a rate increase?</u>

A: Yes. As shown on Schedule FJH R-9, an electric rate increase was authorized March 21, 2007 which included a return of 11.35% relative to a common equity ratio of 52%.

I believe the foregoing data confirms that there is no merit to Mr. Rothschild's contention as to the implications of a decoupling mechanism on the cost of common equity capital.

36. Q: <u>At page 82, lines 8 through 19 of his testimony, Mr. Rothschild criticizes your analysis regarding the utilities in your proxy groups that have decoupling mechanisms. Please respond to Mr. Rothschild's comments.</u>

A: Mr. Rothschild attempts to obfuscate reality. In gas distribution companies, as well as the gas operations of combination companies, residential customers represent the overwhelming number of customers as well as percentage of sales. Moreover, most decoupling mechanisms relate to residential and commercial customers. Revenue stabilization is shown to be highly related to weather and almost all gas distribution companies and gas operations of combination companies have protection from the weather, i.e., some type of weather normalization adjustment mechanism, or weather as an integral part of a decoupling mechanism as opposed to having two separate mechanisms. I have prepared Schedule FJH R-10, which is a regression analysis which proves weather is the major factor in the variability of net gas revenues for Delmarva. As can be seen, I have regressed heating degree days as the independent variable against total net gas revenues as the dependent variable by month for each month from April 2006 through June 2010. As can be seen, the R-squared, or coefficient of determination, is 0.9665 which is extraordinarily high. What this means is that weather accounts for all but about 3.35% of the variation in net gas revenues. Thus, there is no merit to Mr. Rothschild's claim that, absent a separate breakout of commercial and industrial customers subject to decoupling, my analysis is irrelevant because of the magnitude of weather upon net gas revenues and hence earnings. Moreover, large industrial customers are invariably not subject to decoupling mechanisms. Such mechanisms typically apply to residential and commercial customers. Since the vast majority of the total customers of gas distribution companies are residential, Mr. Rothschild's proposition is of no relevance.

37. Q: **Mr. Rothschild suggests by oblique inference that somehow the granting of decoupling mechanism such as the requested MFV in this proceeding results in such a level of risk reduction as to warrant the issuance of debt equivalent to the type of debt issued to securitize stranded costs namely in the AAA category. Is that realistic?**

A: Absolutely not. Evidence introduced above with regard to California and specifically PG&E, is prima facie evidence that Mr. Rothschild's proposition is ludicrous. Moreover, in response to Interrogatory No. 2 addressed to Mr. Rothschild by the Company to specify all instances where a utility was granted a revenue decoupling mechanism and where a commission made a downward adjustment similar in magnitude to the 100 basis points he proposed, Mr. Rothschild indicated he had not conducted such an analysis. He also indicated he was unaware of any instance where a regulatory commission made no downward adjustment to the cost of common equity due to the presence of a revenue decoupling mechanism because he had not conducted such an analysis. Finally, with regard to the third part of Mr. Rothschild's response to Interrogatory No. 2, he indicated that he had performed no analysis which would indicate a utility received an upgrade in bond rating shortly after receiving approval to implement a revenue decoupling mechanism.

38. Q: <u>Have you performed an analysis of the decisions of regulatory commissions where a decoupling mechanism was awarded or already in place and the implications on the allowed cost rate of common equity capital?</u>

A: Yes, I have. An examination of 15 rate Orders for all of the instances for which I am aware between December 2007 and November 2, 2010 are shown on Schedule FJH R-11. Of the 15 instances, there is one where a Straight Fixed Variable (SFV) decoupling mechanism had already been in place. That was Missouri Gas Energy Company. In its Order of February 10, 2010, the Missouri Public Service Commission permitted continuance of SFV rate design and made no downward adjustment to common equity cost rate because the risk reduction attributable to decoupling mechanisms was already reflected in the proxy companies' market-based cost rates which were utilized to establish the allowed common equity cost rate. In three instances of the Massachusetts Commission, namely Bay State Gas Company, Boston Gas Company and Colonial Gas Company, decoupling mechanisms were allowed but the Orders did not specify whether or if any reduction to common equity cost rate was made. If any were made, they were implicit. The remaining 11 Orders ranged from zero deduction to a maximum deduction of 25 basis points from common equity cost rate including Missouri Gas Energy which already had an SFV mechanism in place which it was permitted to continue. The number of companies where the impact on common equity cost rate was specified is 12 and the average of all 12 is 8 basis points or 0.08%. The reality of the foregoing facts clearly demonstrate that Mr. Rothschild's absence of empirical analyses resulted in his unsupported assumption that the degree of risk reduction attributable to such a mechanism is 100 basis points. In view of the foregoing empirical evidence in contrast to Mr. Rothschild's lack of empirical evidence, his recommended reduction to common equity cost rate if this Commission approves Delmarva's requested MFV mechanism should be rejected.

D. <u>Response to Mr. Rothschild's Comments on Mr. Hanley's Testimony</u>

39. Q: <u>Mr. Rothschild criticizes your use of analysts' forecasts in earnings per share and he suggests at page 92 that his br + sv methodology is superior. How do you respond?</u>

A: I have discussed *supra* at pages 8-9 the problems associated with the sustainable growth approach. Moreover, I also discussed *supra* at page 9 that Myron Gordon himself in 1990 acknowledged the superiority of analysts' forecasts of growth in earnings per share. In addition, the bold type on lines 25-26 of Mr. Rothschild's page 92 do not obviate the conclusions of Gordon, Gordon and Gould (in 1989 prior to Gordon's presentation in 1990 discussed *supra* at page 9) that such method is superior to analysts' forecasts. Indeed, Mr. Rothschild has not performed an analysis of a large number of firms virtually encompassing the industry as suggested by the comments of the authors as indicated on lines 26-27 on page 92 of his testimony. Accordingly, Mr. Rothschild's criticism is moot and should be disregarded.

40. Q: **<u>Please address Mr. Rothschild's criticism of your hypothetical example of the inadequacy of DCF return rate related to book value when market value is greater or less than book value.</u>**

A: Mr. Rothschild totally misses the point. My hypothetical example on Schedule FJH-8 accompanying my direct testimony as well as the actual examples based upon Mr. Rothschild's own data shown on Schedule FJH R-1 illustrate precisely why the market-determined common equity cost rate cannot be achieved when it is applied to a book value of common equity when the market price is in excess of the book value. As explained *supra* at pages 10-12, a DCF cost rate is the rate investors expect to earn on market price, not on book value. Because there are many factors which influence market price and, as confirmed in the academic literature, regulation, while it has an influence on market values, cannot control them, which should be obvious because of the myriad of factors which influence market prices. Mr. Rothschild is incorrect in his proposition.

41. Q: **<u>At the top of page 98, Mr. Rothschild states, "I am not faulting Mr. Hanley for failing to forecast interest rates. I am, however, faulting him for thinking that the Blue Chip forecast is smarter than the consensus opinion in the market." How do you respond?</u>**

A: This is another example where Mr. Rothschild is incorrect. The so-called consensus opinion in the market is the result of what investors anticipate. The cost of capital is expectational. It is clear that analysts' forecasts, including the consensus forecasts of the trend in interest rates by the 50 or so most prominent economists in America, are without a doubt, investor-influencing. It matters little in hindsight whether those forecasts were entirely accurate. No one has a crystal ball and can perfectly forecast future events and interest rates. Mr. Rothschild's comment in this regard is misplaced and should be ignored.

42. Q: At pages 98-99 of his testimony, Mr. Rothschild criticizes your use of the arithmetic mean in quantifying equity risk premium. Please comment.

A: I have discussed at length *supra* at pages 16-19 why the use of the arithmetic mean is appropriate when estimating the cost of capital and why the geometric mean is incorrect when estimating the cost of capital. Such discussion need not be repeated.

43. Q: Please respond to Mr. Rothschild's criticism of your second approach to computing the risk premium as described at page 99, line 15 through page 100, line 11.

A: Mr. Rothschild's criticism is incorrect. He does not realize in his criticism of me, the circularity of his sustainable growth method. How he can call my use of the Value Line forecast of total market return circular is unbelievable when he uses Value Line's five-year forecast to project a sustainable growth rate into infinity. Moreover, I use Value Line's total annual forecasted market return to estimate total market price appreciation, not market price appreciation of individual companies. Mr. Rothschild's comments are inaccurate and should be disregarded.

44. Q: <u>On page 101 of his testimony, Mr. Rothschild criticizes your use of the long-term Treasury Bond rate as the risk-free rate in the CAPM. Is his criticism valid?</u>

A: No. I have discussed *supra* at pages 21-22 why the academic literature including Ibbotson SBBI in its <u>2010 Yearbook Valuation Edition</u>, specifies that those who are interested in valuing businesses (like cost of capital experts) should rely upon the income return of the long-term Treasury for the risk-free rate especially for going concerns. Mr. Rothschild's criticism is unwarranted.

45. Q: <u>Is Mr. Rothschild correct in the way he discusses your adjustment of 0.55% in your risk premium analysis beginning at line 24, page 101 through line 12 of page 102 of his testimony?</u>

A: No. Once again, Mr. Rothschild is incorrect. The adjustment of 0.55% shown on line 2, page 1 of Schedule FJH-13 accompanying my direct testimony is to make the yield on AAA rated <u>corporate</u> bonds equivalent to the yield on A rated <u>public utility</u> bonds. He apparently does not understand the basis of the equity risk premium of 4.42% on Line No. 6, page 1 of Schedule FJH-13 which is the result of three separate studies which are set forth on page 5 of Schedule FJH-13. Those studies are discussed at length in my direct testimony at pages 32 through 39.

46. Q: <u>How do you respond to Mr. Rothschild's testimony beginning at line 17, page 104 through line 5 of page 105 wherein he suggests somehow that the SBBI Valuation Edition has not been adjusted to reflect changes in the Classic Edition?</u>

A: I have addressed *supra* at pages 21-22 the fact that the SBBI Valuation Yearbook was created specifically to serve different markets including targeting people involved in the valuation of businesses, as stated in the introduction to the SBBI 2010 Valuation Yearbook. Moreover, the SBBI Valuation Yearbook has been published for many years and consistently has specified that only the arithmetic mean is correct when estimating future cashflows for cost of capital purposes. I also have provided in Schedule FJH R-5 an excerpt from SBBI's 2010 Valuation Yearbook wherein Dr. Ibbotson and Peng Chen specify that only the arithmetic mean is appropriate when discounting future cashflows and for use as the expected equity risk premium in either the CAPM or the buildup approach. Mr. Rothschild's contention is erroneous.

47. Q: At page 106 of his testimony, Mr. Rothschild suggests that there is no basis for your recommended range of adjustment for flotation costs. Please comment.

A: I have discussed this issue *supra* at pages 26-27 and there is no need for it to be repeated.

48. Q: At pages 106-107 of his testimony, Mr. Rothschild takes issue with your recommendation of a size adjustment. How do you respond?

A: The overall rate of return which Delmarva will be afforded an opportunity to earn resulting from this rate proceeding will and can only be applied to Delmarva's Delaware jurisdictional gas rate base. I have shown as Schedule FJH R-12, which consists of five pages, an excerpt from *Principles of Corporate*

Finance, Fifth Edition by Richard A. Brealey and Stewart C. Myers. In discussing capital budgeting and risk at pages 3 and 4, the authors state:

> *But the company cost of capital rule can also get a firm into trouble if the new projects are more or less risky than its existing business. Each project should be evaluated at its own opportunity cost of capital.* This is a clear implication of the value-additivity principle introduced in Chapter 7. For a firm composed of assets A and B, the firm value is
>
> Firm Value = PV (AB) = PV (A) + PV(B) = sum of separate asset values
>
> Here PV(A) and PV(B) are valued just as if they were mini-firms in which stockholders could invest directly ...If the firm considers investing in a third project C, it should also value C as if C were a mini-firm. That is, the firm should discount the cash flows of C at the expected rate of return that investors would demand to make a separate investment in C. *The true cost of capital depends on the use to which the capital is put.*

(Emphasis in the first quoted paragraph is added. Emphasis in the last quoted paragraph contained in the original text.)

Clearly, because the true cost of capital depends on the use to which the capital is put, in this instance, Delmarva's gas operations' Delaware jurisdictional rate base, it is clear that size is an issue that must be considered.

49. Q: <u>Mr. Rothschild states that a size premium makes no sense because investors generally own securities as part of larger portfolios rather than individually. Please comment.</u>

A: Clearly, Mr. Rothschild does not subscribe to the basic financial principle that risk relates to where capital is put or invested. In this proceeding, we are not supposed to be looking at what the composite return of a large portfolio of stocks is, but rather the risk which relates to an individual investment, i.e., Delmarva's gas jurisdictional rate base and the common equity financed portion thereof. Mr. Rothschild is incorrect in his proposition and it should be rejected.

IV. <u>DIVISION OF THE PUBLIC ADVOCATE WITNESS CRANE</u>

A. <u>Cost of Common Equity Capital</u>

50. Q: <u>Since there is no issue of difference in the capital structure and long-term debt cost rate adopted by Ms. Crane, is it correct that the only issue you have is with regard to her recommended common equity cost rates?</u>

A: Yes. Her recommended common equity cost rate, without regard to decoupling approval is 9.07% and 7.17% if the requested MFV rate design is approved. Both rates are incredulously low and predicated upon faulty assumptions and unsupportable calculations.

51. Q: <u>At the top of page 22 of her testimony, Ms. Crane refers to a DCF indicated cost rate of common equity capital for Empire District Electric Company shown on Schedule FJH-9 accompanying your direct testimony and compares it to an 8.4% overall cost of capital awarded by the Kansas Commission as a result of a settlement. Please comment.</u>

A: I should point out that the range of indicated DCF cost rates for my proxy group of eleven combination electric and gas companies shown on Schedule FJH-9 ranged from 8.93% to the high of 14.21%. I relied upon the median cost rate of 11.10%. More importantly, however, is the fact that it is a completely invalid comparison between an indicated common equity cost rate derived from the application of one methodology, DCF, at an entirely different point in time and the overall weighted cost of capital allowed by a commission in a settlement from a rate case which was based upon market data for a number of proxy utilities at an entirely different past point in time.

52. Q: <u>At page 23, lines 16-19 of her testimony, Ms. Crane indicates that she relies upon a spot yield on long-term U.S. government bonds for the risk-free rate in her application of the CAPM. Please comment.</u>

A: As discussed *supra* at pages 15-16, the cost of capital and the ratemaking process are prospective. Therefore, it is inappropriate to use an <u>historical</u> yield as the risk-free rate in a CAPM analysis, especially based upon a single day. The appropriate yield to use as the risk-free rate is the <u>prospective</u> yield on 30-year U. S. Treasury Bonds such as shown in Schedule FJH-16 accompanying my direct testimony based upon the consensus average forecast yield on U.S. Treasury bonds by about 50 of the U.S. leading economists as reported in <u>Blue Chip Financial Forecasts</u>. A prospective yield should be utilized because the cost of capital and ratemaking are prospective.

53. Q. <u>Ms. Crane, in her application of the CAPM, relies upon the geometric mean. Is her reliance upon the geometric mean appropriate when estimating the cost of capital?</u>

A. No. I have explained in detail *supra* at pages 16-19 why Mr. Rothschild's use of the geometric mean is incorrect. That discussion need not be repeated.

54. Q. <u>At page 24, line 9 through page 25, line 6 of her testimony, Ms. Crane provides a mathematical example in support of her exclusive use of geometric mean returns. Please comment on her example.</u>

A: Ms. Crane's mathematical example is flawed because it does not take into account the probability of each outcome, i.e., an increase of 100% in one year and a decrease of 50% in the next. As discussed *supra*, at page 18, the financial literature makes it clear that risk is measured by the variability of expected returns, i.e., the probability distribution of returns. As explained *supra* at pages 16-17, and by Ibbotson SBBI in its <u>2010 Valuation Yearbook</u> at Schedule FJH-15, pages 2 and 3 accompanying my direct testimony and at Schedule FJH R-5 at page 4, only the arithmetic mean provides insight into the variance and standard deviation of returns and is appropriate to use when estimating future cashflows and cost of capital.

55. Q: <u>You have clearly explained why only the arithmetic mean is appropriate when estimating the cost of capital. Please address Ms. Crane's approach to the determination of market equity risk premium for use in her CAPM.</u>

A: Unfortunately, Ms. Crane apparently relies exclusively upon the SBBI <u>Classic Yearbook</u> for her historical market data. As discussed *supra* at pages 21-22 with regard to Mr. Rothschild, Ibbotson SBBI explains that its <u>Valuation Yearbook</u> has been geared to "better serve the different markets for SBBI … targeted to people involved in the valuation of businesses." I show as Schedule FJH R-13 from the Ibbotson SBBI <u>2010 Valuation Yearbook</u>, its explanation as to why the income return on Treasury securities is the appropriate return to use in the application of the estimation of the equity risk premium "because it represents the truly riskless portion of the return." Ms. Crane, therefore, inappropriately relied upon the geometric mean returns for large company and small company stocks as well as the inappropriate reliance upon total return on long-term government bonds. Ms. Crane should have relied upon the arithmetic mean return on large company stocks of 11.8% and on small company stocks of 16.6% for a total market return average of 14.2% from which she should have subtracted the income return on long-term government bonds of 5.2% which would indicate an historical market risk premium of 9.0%. All of these returns can be seen by reference to page 2 of Schedule FJH R-2.

56. Q: <u>Did Ms. Crane also utilize the ECAPM?</u>

A: No, she did not. As a result, her already grossly understated CAPM result is even more understated. The ECAPM is appropriate and essential for the reasons discussed in my direct testimony at pages 40-42.

57. Q: <u>Is there another failure by Ms. Crane which results in a gross understatement of CAPM cost rate?</u>

A: Yes, Ms. Crane, like Mr. Rothschild, failed to take into account the impact on investors of expected market return. As discussed *supra* at pages 8-9, 15-16, and 41 and in my direct testimony at pages 37-38, it is imperative to take into account information that investors receive, and are clearly influenced by, from an investor-influencing publication such as Value Line upon which all witnesses in this proceeding rely.

58. Q: <u>Please summarize the flaws associated with Ms. Crane's application of the CAPM.</u>

A: Ms. Crane's risk-free rate is understated because she failed to take into account the expected yield on long-term U.S. Treasury Bonds and a grossly understated historical market return due to her failure to utilize the arithmetic mean of total returns and the income return on long-term U.S. Treasury Bonds. It is also understated due to her failure to take into account investors' consideration of projected future market return by the investor-influencing Value Line Investment Survey upon which all witnesses in this proceeding rely.

B. <u>Revenue Decoupling and Impact on Common Equity Cost Rate</u>

59. Q: <u>At the bottom of page 7 and the top of page 8 of her testimony, Ms. Crane, in making comparison between the Company's recent electric case and the current gas case, states that arguments relative to reduction in ROE cost rate attributable to the implementation of the requested decoupling mechanisms are "even more egregious" in the instant case. Please respond.</u>

A: Ms. Crane's comparison is flawed. In the recent electric rate case, the Company offered a reduction of 25 basis points because use of revenue decoupling mechanisms in the electric industry was not yet as prevalent as in the gas industry at the time testimony in the case was prepared. In contrast, in the instant proceeding, which is a gas rate case, evidence which I have produced in Schedule FJH-5 and explained in detail at pages 12-15 of my direct testimony shows that gas distribution companies overwhelmingly have various forms of decoupling mechanisms in place. Moreover, as discussed *supra* at pages 31-32 with regard to Mr. Rothschild, I have shown that weather is the predominant factor which contributes to change in net gas revenues for Delmarva. That pattern is true for gas distribution companies generally. In addition, I have shown at Schedule FJH R-11, that the average deduction to ROE in cases where decoupling mechanisms have been approved has been only eight basis points.

Moreover, in response to Interrogatory No. 2 addressed to Ms. Crane, she responded that she has not prepared a comprehensive report on all of the companies "in Mr. Hanley's proxy groups." Ms. Crane seems to have ignored the details contained in Schedule FJH-5 accompanying my direct testimony of the significance of weather upon the variation in net gas revenues.

Ms. Crane's comments regarding the recent electric case and the instant case are grossly inaccurate and should be rejected.

60. Q: <u>At page 14, line 19 through page 15, line 9, Ms. Crane suggests that a 25 basis point differential is wholly inadequate to reflect approval of the requested MFV decoupling mechanism. Please comment.</u>

A: Because of the significant degree to which the proxy gas distribution companies have revenues which are decoupled in whole or in large measure, the suggested minimal deducts as shown on Line No. 9, Schedule FJH-1, page 2 of 2 accompanying my direct testimony and explained in Note 8 on the same page, are reasonable. They are reasonable especially since weather is such a significant portion of the change in net gas revenues as demonstrated in Schedule FJH R-10.

61. Q: <u>At page 15, line 11 through page 16, line 4, Ms. Crane suggests, especially at lines 1 and 2 on page 16, that the risk reduction attributable to the implementation of the proposed MFV rate structure would shift risk to ratepayers. How do you respond to her claim?</u>

A: Her claim is in error. It is a popular misconception that every reduction in utility risk is matched by an equivalent increase in ratepayer risk. I have demonstrated how weather conditions produce variability in customer's bills and net gas revenues. Such a factor is common sense as any residential customer, especially one that is not on a budget billing basis, knows how weather affects their gas bill. Under a traditional gas distribution utility tariff, an unusually cold winter month causes both customers' distribution bills and utility distribution revenues to increase, while an unusually mild winter month will cause both customers' distribution bills and utility distribution revenues to be lower than forecast. Weather normalization adjustment clauses which recover fixed costs through fixed customer charges or via a mechanism such as the requested MFV also reduce customers' weather risk. Increased volatility equals greater uncertainty which equals greater risk. Conversely, less volatility in ratepayers' utility distribution bills equals less risk to them as well as less risk to the utility from more stable revenues. Risk is thus reduced for customers as well as the utility.

62. Q: <u>Please comment on Ms. Crane's recommended reduction to common equity cost rate of "189" basis points attributable to implementation of the requested MFV as described at page 16, lines 5 through 16.</u>

A: Ms. Crane's recommendation, which is actually 190 basis points (9.07% - 7.17%), is arbitrary and devoid of factual merit. I have shown empirical evidence of the magnitude of impact on ROE for gas distribution companies where decoupling mechanisms have been placed into effect in the past three years. That information is shown on Schedule FJH R-11 and is totally consistent with my recommendation in this proceeding. Indeed, because of the myriad of factors which influence market prices, it is impossible to empirically quantify with precision the impact on common equity cost rate of a single factor such as a decoupling mechanism on the market prices that investors pay. It is for this reason that experts and regulators have utilized informed, expert judgment, none of which has resulted in ROE adjustments anywhere near the magnitude suggested by Ms. Crane, as well as Mr. Rothschild. Ms. Crane's approach to the quantification is without precedent and entirely arbitrary. There is no basis in fact to assume, even if her estimate of common equity cost rate without regard to decoupling were correct, which it is not, that there is any nexus between the value of a decoupling mechanism and the differential between a current cost rate of common equity capital and a company's embedded cost rate of long-term debt capital. Even more shocking is her assumption that the impact is 50% of such irrelevant differential, or 190 basis points. Such a recommendation is not only without foundation but totally out of touch with reality. A reality check as to magnitude can be found at Schedule FJH R-11 where an average has been just eight basis points, or 0.08%. I should point out once again that in the case of Missouri Gas Energy, in a decision of February 10, 2010 where SFV rate design was permitted to continue to be in effect, the Commission made no deduction to the allowed common equity cost rate as a result of a fully litigated rate proceeding. It made no deduction to common equity cost rate because it acknowledged the overwhelming reflection of decoupling mechanisms in the common equity cost rates derived from the proxy gas distribution companies utilized to establish the allowed common equity cost rate.

C. <u>Response to Ms. Crane's Comments on Mr. Hanley's Testimony</u>

63. Q: <u>At the bottom of page 26 and the top of page 27 of her testimony, Ms. Crane states that she completely discounted the results of your cost of equity models applied to comparable risk, domestic, non-price regulated companies. How do you respond?</u>

A: Ms. Crane provides no valid reason. The basis of selection of those companies was made from statistics derived from regression analyses which derived betas. Those market prices reflect investors' expectation of total risk. The systematic risk (beta) is comparable to the proxy groups of utility companies' systematic risk. The diversifiable, non-systematic risk (standard error) is comparable to the proxy groups of utility companies. Consequently, those domestic, non-price regulated companies are similar in total risk to the proxy groups of utility companies. Application of the DCF, RP, and CAPM/ECAPM models are entirely appropriate for all of the reasons explained at pages 45 through 49 of my direct testimony.

Since those companies are comparable in total risk to the proxy groups of utility companies and since the U.S. Supreme Court landmark *Hope* and *Bluefield* cases do not specify that the companies of similar risk must be utilities they should be considered because they are indeed similar in total risk to the utilities. Ms. Crane's comments should be rejected.

64. Q: <u>At page 27, lines 6-8, Ms. Crane discusses flotation costs, but made no provision for same in her recommendation. Please comment.</u>

A: I have discussed *supra* at pages 26-27 with regard to Mr. Rothschild why an allowance for flotation costs should be permitted. That discussion need not be repeated.

65. Q. <u>Ms. Crane states at page 27, lines 8 and 9 that this Commission has previously rejected a small company premium. Please respond.</u>

A. Ms. Crane makes no provision for a size adjustment, but she has recommended small size premium ranging from 25 to 75 basis points in three of Tidewater Utilities, Inc.'s recent base rate cases. In Docket No. 04-152 a settlement was reached. Thus, the issue of a small size premium was not addressed. However, Docket Nos. 02-28 and 99-466 were fully litigated and a small size premium was adopted in each Docket. In both Dockets, Ms. Crane recommended a 75 basis point small size premium. In addition, in both Dockets, the Hearing Examiner recommended that Ms. Crane's small size premium of 75 basis points be adopted by the DPSC. In Order No. 5592 issued November 21, 2000 in Docket No. 99-466, re: Tidewater Utilities, Inc. (TUI) the Commission adopted the Hearing Examiner's recommendation which included a small size premium of 0.75%.

Ms. Crane has recommended small size premia in prior cases before this Commission. Evidence shown in Exhibit FJH-20, discussed at pages 54-57 of my direct testimony and supported by evidence that risk relates to where capital is invested shown in Schedule FJH R-12 and discussed *supra* at pages 38-40 confirm that a size adjustment is warranted in this Docket.

66. Q. **<u>How do you respond to Ms. Crane's testimony at page 28, line 18 through page 30, line 4 wherein she discusses your "claim" that your comparable groups include companies that have decoupling mechanisms in place?</u>**

A. Ms. Crane's reasoning is flawed. She discusses that the natural gas companies included in my proxy group were included in Delmarva's last gas base rate case. I was not the witness in the last gas base rate case. Moreover, while I have not gone back to check, it has been four years since that gas base rate was filed. There may well have been significant differences in the extent to which decoupling was reflected at that point in time. This witness can only address what is now and based on this expert witness's testimony and the evidence that I have presented which shows that the gas distribution proxy companies utilized have revenues which are overwhelmingly decoupled.

Ms. Crane incorrectly states on page 29 at lines 8-10 that "DPL is taking the position that no downward adjustment is required." That is incorrect. This witness recommends a deduction of 3 basis points to the proxy group of natural gas distribution companies because of the overwhelming extent of decoupling which exists for that group. This is shown on Schedule FJH-1, page 2, Line No. 9 and explained in Note 8 accompanying my direct testimony. Also explained in Note 8 on the same page and line number, is a recommended deduction of 19 basis points for the proxy group of eleven combination electric and gas companies which is consistent with the Company's recent position in the electric rate proceeding. As can be seen by reference to Schedule FJH-5, page 1 accompanying my direct testimony, there is a smaller percentage (24.38%) of customers that are decoupled for the proxy group of eleven combination electric and gas companies in contrast to 88.81% for the proxy group of seven natural gas distribution companies.

In view of the foregoing, it is clear that the Company has not had any second thoughts about the impact on common equity cost rate relative to the implementation of the requested decoupling mechanisms in either the recent electric or current gas case.

67. Q: <u>How do you respond to Ms. Crane's discussion of the companies with which she is familiar, South Jersey Industries and New Jersey Natural Resources discussed at page 29, lines 13 through 18.</u>

A: My initial reaction, based upon her recommendation of a 190 basis points reduction in ROE attributable to the implementation of the requested MFV, is incredulity. Due to her familiarity with gas distribution companies, Ms. Crane should have acknowledged that the overwhelming percentage of changes in net gas revenues are attributable to weather and that virtually every gas distribution company has protection from the vagaries of weather, including South Jersey Industries and New Jersey Natural. Both of those companies currently have protection from the vagaries of weather which is built into their Conservation Incentive Programs (CIP), but is separate from the conservation portion of those programs. Since weather is the overwhelmingly predominant factor which drives net gas revenues, the revenues of those gas distribution operations are substantially decoupled regardless of the portion affected by conservation. The fact that these companies do not have "straight fixed variable rate design" is really irrelevant. What is relevant is that they have substantial decoupling that breaks the link between weather and customer usage. Moreover, any concern about savings being shared with ratepayers over and above the specified ROE is also irrelevant because Delmarva has similar sharing related to excess revenues from its pipeline capacity. Ms. Crane surely must be aware of the fact that gas distribution companies have significant revenue decoupling which is largely driven by weather. Even in those instances where companies do not have total revenue decoupling, the partial revenue decoupling attributable to weather normalization adjustment clauses is substantial. Ms. Crane's recommended downward ROE adjustment lacks foundation and is devoid of factual merit.

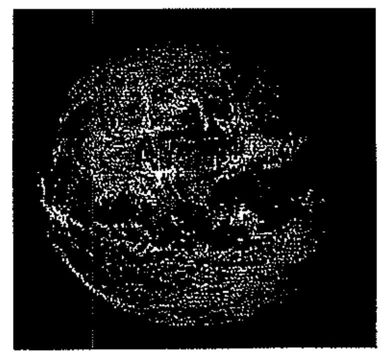
One thing Ms. Crane is correct about is that changing the Company's rate of return witness does not change the underlying fundamentals of the companies in the Company's comparable groups. She should have acknowledged that the revenues of gas distribution companies are overwhelmingly decoupled and that any warranted downward adjustment to ROE, which this witness makes as discussed *supra* at pages 50-51, is minimal indeed.

68. Q: <u>Does that conclude your rebuttal testimony?</u>

A: Yes, it does.

Strictly Private and Confidential

Global Power Financing: Annual Review for 2008 and Prospects for 2009



February 2009

Schedule AJK - 3

Schedule AJK - 3

Electric Utility Debt Financing in 2008

Offer Date	Company	Issue	Structure	Amt ($MM)	Type	Moody/S&P Ratings	MW Call	Yield	Gross Spread	Reoffer Spread	Managers
12/22	FPL Group Capital (Reopening: 106.861%)	Debentures 7.885% due 12/15/2015	7 NC/L	$50	Holdco	A2/A-	T+50	6.627%	0.625%	+515	BAS/CITI/DB/MIZ//BNY/MITSU/ WELLS
12/19	Southern Connecticut Gas Group (144A)	First Mortgage Bonds 7.500% due 12/15/2018	10 NC/L	$50	Secured	A3(N)/A	T+50	7.500%	N/A	+539.8	BAS
12/19	Rochester Gas & Electric (144A)	First Mortgage Bonds 8.000% due 12/15/2033	25 NC/L	$150	Secured	A3(N)/A	T+50	8.000%	N/A	+545.7	BAS/JPM
12/10	Monongahela Power Co. (144A)	First Mortgage Bonds 7.950% due 12/15/2013	5 NC/L	$300	Secured	Baa2/BBB+	T+50	8.000%	N/A	+639.4	BAS/CS/SCOT//Commerz/JPM/ WED
12/09	FPL Group Capital	Debentures 7.885% due 12/15/2015	7 NC/L	$450	Holdco	A2/A-	T+50	7.875%	0.625%	+596.7	BAS/CITI/DB/MIZ//BNY/MITSU/ WELLS
12/08	Oklahoma Gas & Electric Co.	Senior Notes 8.250% due 1/15/2019	10 NC/L	$250	Unsecured	A2/BBB+(p)	T+50	8.250%	0.650%	+549.2	MIZ/RBS/UBS//CITI/WED/KEY/ US Bank
12/08	Wisconsin Electric Power Co.	Debentures 6.250% due 12/01/2015	7 NC/L	$250	Unsecured	A1/A-(p)	T+50	6.261%	0.625%	+425	BAS/GS/MS/SUN
12/04	Central Illinois Light Company	Senior Secured Notes 8.875% due 12/15/2013	5 NC/L	$150	Secured	Baa2(p)/BBB+	T+50	8.875%	0.600%	+734.9	BNP/GS
12/03	Potomac Electric Power Co.	First Mortgage Bonds 7.900% due 12/15/2038	30 NC/L	$250	Secured	Baa1/BBB+	T+50	7.900%	0.875%	+462.7	JPM/MS/SCOT/SUN/WACH
12/02	Consolidated Edison of NY	Debentures 7.125% due 12/01/2018	10 NC/L	$600	Unsecured	A1(n)/A-	T+50	7.176%	0.650%	+450	CITI/JPM/UBS//HSBC/LOOP/ Williams
12/01	Wisconsin Public Service Corp.	Senior Notes 6.375% due 12/01/2015	7 NC/L	$125	Secured	Aa3/A+(n)	T+50	6.375%	0.625%	+434.5	BAS/CITI/JPM/UBS
11/25	Dominion Resources, Inc.	Senior Notes 8.875% due 01/15/2019	10 Put 5	$600	Holdco	Baa2/A-	T+50	8.875%	0.600%	+678.9	BARC/JPM//CS/DB/KEY/BB&T/ SCOT/SUN/UCI
11/24	Public Service Electric & Gas	Secured Medium-Term Notes 6.330% due 11/01/2013	5 NC/L	$275	Secured	A3/A-	T+50	6.339%	0.600%	+412.5	BAS/MIZ/UBS//WED/Williams
11/18	Westar Energy	First Mortgage Bond 8.625% due 12/01/2018	10 NC/L	$300	Secured	Baa2/BBB	T+50	8.750%	0.650%	+521.3	DB/JPM//BNY/USB/BNP/Citi/CS
11/18	Southern California Gas Co	First Mortgage Bond 5.500% due 03/15/2014	5.5 NC/L	$250	Secured	A1/A+	T+50	5.535%	0.600%	+332	BNP/CALY/JPM//Blay/Cabrera
11/18	Delmarva Power & Light Co	First Mortgage Bond 6.400% due 12/01/2013	5 NC/L	$250	Secured	Baa1/A-	T+50	6.448%	0.600%	+420	BAS/JPM/MS//Key/Scot
11/17	Sempra Energy	Notes 8.900% due 11/15/2013	5 NC/L	$250	Holdco	Baa1/BBB+(N)	T+50	9.000%	0.600%	+670	BAS/DB/GS/RBSGC//BBVA/ Wedbush
11/17	Sempra Energy	Notes 9.800% due 11/15/2019	11 NC/L	$500	Holdco	Baa1/BBB+(N)	T+50	9.875%	0.650%	+618.9	BAS/DB/GS/RBSGC//BBVA/ Wedbush

Ratings legend: N: Review for downgrade; P: Review for upgrade; n: negative outlook; p: positive outlook.

Electric Utility Debt Financing in 2008 (continued)

Offer Date	Company	Issue	Structure	Amt ($MM)	Type	Moody/S&P Ratings	MW Call	Yield	Gross Spread	Reoffer Spread	Managers
11/14	Southwestern Public Services	Senior Notes 8.750% due 12/01/2018	10 NC/L	$250	Unsecured	Baa1/BBB+	T+50	8.875%	0.650%	+515.5	JPM//Wells
11/14	Mississippi Power Company	Senior Notes 6.000% due 11/15/2013	5 NC/L	$50	Unsecured	A1/A	T+50	6.067%	0.600%	+375	JPM
11/14	Alabama Power Company	Senior Notes 5.800% due 11/15/2013	5 NC/L	$250	Unsecured	A2/A	T+50	5.834%	0.600%	+355	BNY/DB/JPM//HBSC/Scot
11/13	Central Hudson Gas & Electric	Senior Medium-Term Notes 6.854% due 10/31/2013	5 NC/L	$30	Unsecured	A2(n)/A	—	6.854%	0.600%	+450	BAS/JPM//Key
11/13	Cleveland Electric Illuminating Co	First Mortgage Bonds 8.875% due 11/15/2018	10 NC/L	$300	Secured	Baa2/BBB+	T+50	8.875%	0.650%	+513.6	BARC/CS/RBSGC/MS/SCOT// Mizuho/Key
11/13	Pacific Gas & Electric Co.	Senior Notes 6.250% due 12/01/2013	5 NC/L	$400	Unsecured	A3/BBB+	T+50	6.424%	0.600%	+410	JPM/MS/RBSGC//Loop/WFC/ Williams
11/13	Pacific Gas & Electric Co. (Reopening: 104.475%)	Senior Notes 8.250% due 10/15/2018	10 NC/L	$200	Unsecured	A3/BBB+	T+50	7.589%	0.650%	+395	JPM/MS/RBSGC//Loop/WFC/ Williams
11/12	Georgia Power	Senior Notes 6.000% due 11/01/2013	5 NC/L	$400	Unsecured	A2/A	T+50	6.016%	0.600%	+360	BAS/BARC/GS//Mitsu/RBSGC
11/12	Georgia Power	Senior Notes 8.200% due 11/01/2048	40 NC/5	$100	Unsecured	A2/A	—	8.200%	3.150%	NA	CITI/MS/UBS
11/12	Duke Energy Carolinas	F&R Mortgage Bonds 5.750% due 11/15/2013	5 NC/L	$400	Secured	A2/A(p)	T+50	5.804%	0.600%	+345	BARC/CITI/CS//BBVA/BNP/Key/ Mitsu/Cabrera/Wells
11/12	Duke Energy Carolinas	F&R Mortgage Bonds 7.000% due 11/15/2018	10 NC/L	$500	Secured	A2/A(p)	T+50	7.041%	0.650%	+340	BARC/CITI/CS//BBVA/BNP/Key/ Mitsubishi/Cabrera/Wells
11/06	Atlantic City Electric Co.	First Mortgage Bonds 7.750% due 11/15/2018	10 NC/L	$250	Secured	A3(n)/A-	T+50	7.817%	0.650%	+412.5	JPM/MS/RBS//SCO
11/03	Virginia Electric and Power Co.	Senior Notes 8.875% due 11/15/2038	30 NC/L	$700	Unsecured	Baa1/A-	T+50	8.875%	0.875%	+456.3	CITI/GS/RBS//DB/UBS/BNY/ KBC/SCO/Williams
10/20	Illinois Power (144A w/RR)	Senior Secured Notes 9.750% due 11/15/2018	10 NC/L	$400	Secured	Baa3(p)/BBB	T+50	10.000%	0.650%	+609.3	BARC/JPM/UBS
10/16	Pacific Gas & Electric Co.	Senior Notes 8.250% due 10/15/2018	10 NC/L	$600	Unsecured	A3/BBB+	T+50	8.500%	0.650%	+455.7	BAC/CITI/DB//BNY/Cabrera/ Siebert/USBank
10/16	Ohio Edison Company	First Mortgage Bonds 8.250% due 10/15/2018	10 NC/L	$25	Secured	Baa1/BBB+	T+50	8.500%	0.875%	+456.3	CS/JPM/MS/BARC/RBS/SCO// Miz/SUN
10/15	Ohio Edison Company	First Mortgage Bonds 8.250% due 10/15/2038	30 NC/L	$275	Secured	Baa1/BBB+	T+50	8.500%	0.875%	+427.3	CS/JPM/MS/BARC/RBS/SCO// Miz/SUN
10/14	PPL Electric Utilities	Senior Secured Bonds 7.125% due 11/30/2013	5 NC/L	$375 $25	Secured	A3/A-	T+50	7.142% 7.100%	0.600%	+412.5	BARC/BNP/Laz/SCO//BNY/ PNC/USB

 Ratings legend: N: Review for downgrade; P: Review for upgrade; n: negative outlook; p: positive outlook.

citi

Schedule AJK - 3

Electric Utility Debt Financing in 2008 (continued)

Offer Date	Company	Issue	Structure	Amt ($MM)	Type	Moody/S&P Ratings	MW Call	Yield	Gross Spread	Reoffer Spread	Managers
10/07	Southern California Edison Co.	F&R Mortgage Bonds 5.750% due 03/15/2014	5.5 NC/L	$500	Secured	A2/A	T+50	5.862%	0.600%	+340	BAS/CITI/DB/JPM/UBS/ Cabrera/SL Hare
10/07	The Detroit Edison Co.	Senior Notes 6.400% due 10/01/2013	5 NC/L	$250	Secured	A3/A-	T+50	6.462%	0.600%	+400	BARC/CITI/RBS/SCO
10/01	Interstate Power & Light	Senior Debentures 7.250% due 10/01/2018	10 NC/L	$250	Unsecured	A3/BBB+	T+50	7.375%	0.600%	+358.2	BARC/CITI//JPM/BNY Mellon/Laz/RBS
10/01	Wisconsin Power & Light	Debentures 7.600% due 10/01/2038	30 NC/L	$250	Unsecured	A2/A-	T+50	7.750%	0.650%	+349.9	BARC/CITI/JPM//BNY Mellon/Laz/RBS
09/25	PECO Energy Company	F&R Mortgage Bonds 5.600% due 10/15/2013	5 NC/L	$300	Secured	A2/A	T+45	5.664%	0.600%	+262.5	BAC/MS/SCO//BNP/Cabrera/ KEY/LAZ/RBS/SUN
09/25	South Carolina Electric & Gas	First Mortgage Bonds 6.500% due 11/01/2018	10 NC./L	$300	Secured	A2/A-(n)	T+40	6.500%	0.650%	+265	BAC/CS/WB
09/25	Wisconsin Electric Power Co.	Debentures 6.000% due 04/01/2014	5.5 NC/L	$300	Unsecured	A1/A-(p)	T+45	6.042%	0.600%	+300	CITI/WACH//Wells/SUN
09/08	Consumers Energy Company	First Mortgage Bonds 6.125% due 03/15/2019	10.5 NC/L	$350	Secured	Baa1/BBB	T+45	6.134%	0.650%	+245	CITI/JPM/UBS/WACH//BAS/CS/ SUN/DAIWA/FTS/Huntington
09/04	Ohio Power Company	Senior Notes 5.750% due 09/01/2013	5 NC/L	$250	Unsecured	A3(n)/BBB	T+45	5.769%	0.600%	+290	Calyon/CITI/UBS//Key
09/04	Oklahoma Gas and Electric Co.	Senior Notes 6.350% due 09/01/2018	10 NC/L	$250	Unsecured	A2/BBB+	T+45	6.399%	0.650%	+275	UBS/WACH
09/03	Oncor Electric Delivery Co.	Senior Secured Bonds 5.950% due 09/01/2013	5 NC/L	$650	Secured	Baa3/BBB+	T+50	5.982%	0.600%	+305	CS/GS/LEH/JPM//BOA/BARC/ Calyon/CITI/DBS/KKR/MS
09/03	Oncor Electric Delivery Co.	Senior Secured Bonds 6.800% due 09/01/2018	10 NC/L	$550	Secured	Baa3/BBB+	T+50	6.815%	0.650%	+312.5	CS/GS/LEH/JPM//BOA/BARC/ Calyon/CITI/DBS/KKR/MS
09/03	Oncor Electric Delivery Co.	Senior Secured Bonds 7.500% due 09/01/2038	30 NC/L	$300	Secured	Baa3/BBB+	T+50	7.526%	0.875%	+320	CS/GS/LEH/JPM//BOA/BARC/ Calyon/CITI/DBS/KKR/MS
09/03	Northern States Power-Wisconsin	First Mortgage Bonds 6.375% due 09/01/2038	30 NC/L	$200	Secured	A2/A	T+35	6.433%	0.875%	+210	BOA/BNY//Key
08/27	Sierra Pacific Power Co.	G&R Mortgage Notes 5.450% due 09/01/2013	5 NC/L	$250	Secured	Baa3/BBB	T+40	5.494%	0.600%	+247	CS/LEH//SocGen/WF
08/20	Orange and Rockland Utilities (144A)	Debentures 6.150% due 09/01/2018	10 NC/L	$50	Unsecured	A2(n)/A-	T+40	6.174%	0.650%	+237.5	CITI
08/15	Duke Energy Indiana	First Mortgage Bonds 6.350% due 08/15/2038	30 NC/L	$400	Secured	A3/A	T+35	6.374%	0.875%	+193	DBS/ML/UBS//BNP/BNY/Key/ MUFJ/SunT/WF/Williams/Blay
08/13	Southern Co.	Floating Rate Senior Notes 3mL+70 bp due 08/20/2010	2 NC/L	$600	Holdco	A3/A-	–	3mL+70 bp	0.250%	–	JPM/LEH
08/11	Southern California Edison Co.	F&R Mortgage Bonds 5.500% due 08/15/2018	10 NC/L	$400	Secured	A2/A	T+25	5.575%	0.650%	+155	CS/RBS/ ML//BOA/DBS/GS/ CastleOak/Ramirez

Ratings legend: N: Review for downgrade; P: Review for upgrade; n: negative outlook; p: positive outlook.

citi

Electric Utility Debt Financing in 2008 (continued)

Offer Date	Company	Issue	Structure	Amt ($MM)	Type	Moody/S&P Ratings	MW Call	Yield	Gross Spread	Reoffer Spread	Managers
08/11	Entergy Louisiana, LLC	First Mortgage Bonds 6.500% due 09/01/2018	10 NC/L	$300	Secured	Baa1/A-	T+40	6.509%	0.650%	+248	Key/LEH/WACH//Cayon/CITI/ LAZ
08/06	Public Service Company of Colorado	First Mortgage Bonds 5.800% due 08/01/2018	10 NC/L	$300	Secured	A3/A-	T+25	5.820%	0.650%	+175	GS/LEH//BMO/Mitsubishi/ SCO
08/06	Public Service Company of Colorado	First Mortgage Bonds 6.500% due 08/01/2038	30 NC/L	$300	Secured	A3/A-	T+25	6.531%	0.875%	+185	GS/LEH//BMO/Mitsubishi/ SCO
07/25	Nevada Power Company	G&R Mortgage Notes 6.500% due 08/01/2018	10 NC/L	$500	Secured	Baa3/BBB	T+40	6.545%	0.650%	+245	BOA/BARC/CITI//PJ/SCO/ Wedbush/WILL
07/14	PacifiCorp	First Mortgage Bonds 5.650% due 07/15/2018	10 NC/L	$500	Secured	A3/A-	T+30	5.674%	0.650%	+180	LEH/JPM/RBS/WACH//SCO/ BARC/BNP/GS/BOA/CITI/ CS/PJ/SunT/Wedbush/WF
07/14	PacifiCorp	First Mortgage Bonds 6.350% due 07/15/2038	30 NC/L	$300	Secured	A3/A-	T+30	6.392%	0.875%	+192	LEH/JPM/RBS/WACH//SCO/ BARC/BNP/GS/BOA/CITI/ CS/PJ/SunT/Wedbush/WF
07/14	Entergy Arkansas, Inc.	First Mortgage Bonds 5.400% due 08/01/2018	5 NC/L	$300	Secured	Baa1/A-	T+35	5.401%	0.600%	+223	BNY/BARC/JPM//KEY/SCO/ Stephens
07/07	Idaho Power Company	First Mortgage Bonds 6.025% due 07/15/2018	10 NC/L	$120	Secured	A3(n)/A	T+35	6.025%	0.625%	+215	BAS/JPM/WACH//KEY//RBS/ Wedbush/Wells
06/23	Baltimore Gas and Electric Co.	Notes 6.125% due 07/01/2013	5 NC/L	$400	Unsecured	Baa2/BBB+(n)	T+35	6.127%	0.600%	+250	BAS/JPM/RBS//BARC/DB/ SCO
06/17	South Carolina Electric & Gas (Reopening: 95.122%)	First Mortgage Bonds 6.050% due 01/15/2038	30 NC/L	$110	Secured	A2/A-(n)	T+30	6.420%	0.875%	+165	WACH
06/12	Dominion Resources, Inc.	Floating Rate Senior Notes 3mL+105 bp due 06/17/2010	2 NC/L	$300	Holdco	Baa2/A-	--	3mL+105 bp	0.250%	--	CITI/BARC/JPM/ML//CS/KEY/ UBS/BNP/LAZ/MIZ/SCO
06/12	Dominion Resources, Inc.	Senior Notes 6.400% due 06/15/2018	10 NC/L	$500	Holdco	Baa2/A-	T+35	6.413%	0.650%	+220	CITI/BARC/JPM/ML//CS/KEY/ UBS/BNP/LAZ/MIZ/SCO
06/12	Dominion Resources, Inc.	Senior Notes 7.000% due 06/15/2038	30 NC/L	$400	Holdco	Baa2/A-	T+40	7.062%	0.875%	+230	CITI/BARC/JPM/ML//CS/KEY/ UBS/BNP/LAZ/MIZ/SCO
06/12	Union Electric (d/b/a AmerenUE)	Senior Secured Notes 6.700% due 02/01/2019	10.6 NC/L	$450	Secured	Baa1/BBB	T+40	6.737%	0.650%	+253	BARC/BNY/JPM//BNP/LAZ
06/11	Duke Energy Corp.	Senior Notes 5.650% due 06/15/2013	5 NC/L	$250	Holdco	Baa2/BBB+	T+40	5.696%	0.600%	+220	CS/GS/LEH//CITI/LAZ/SCO/ SUN
06/11	Duke Energy Corp.	Senior Notes 6.250% due 06/15/2018	10 NC/L	$250	Holdco	Baa2/BBB+	T+40	6.285%	0.650%	+220	CS/GS/LEH//CITI/LAZ/SCO/ SUN
06/11	Florida Power Corp. d/b/a Progress Energy Florida, Inc.	First Mortgage Bonds 5.650% due 06/15/2018	10 NC/L	$500	Secured	A2/A-	T+30	5.698%	0.650%	+163	CITI/BARC/RBS//LAZ/MS/SUN/ BAS/DB/GS/BNY/UBS/BBT
06/11	Florida Power Corp. d/b/a Progress Energy Florida, Inc.	First Mortgage Bonds 6.400% due 06/15/2038	30 NC/L	$1,000	Secured	A2/A-	T+30	6.432%	0.875%	+175	CITI/BARC/RBS//LAZ/MS/SUN/ BAS/DB/GS/BNY/UBS/BBT

Ratings legend: N: Review for downgrade; P: Review for upgrade; n: negative outlook; p: positive outlook.c

citi

Schedule AJK - 3

Electric Utility Debt Financing in 2008 (continued)

Offer Date	Company	Issue	Structure	Amt ($MM)	Type	Moody/S&P Ratings	MW Call	Yield	Gross Spread	Reoffer Spread	Managers
06/11	FPL Group Capital Inc	Floating Rate Debentures 3mL+88 bp due 06/17/2011	3 NC/L	$250	Holdco	A2/A-	–	3mL+88 bp	0.350%	NA	CS/BARC/LEH/RBS//LAZ/MK
06/11	FPL Group Capital Inc	Debentures 5.350% due 06/15/2013	5 NC/L	$250	Holdco	A2/A-	T+30	5.352%	0.600%	+188	CS/BARC/LEH/RBS//LAZ/MK
06/09	Sempra Energy	Notes 6.150% due 06/15/2018	10 NC/L	$500	Holdco	Baa1/BBB+	T+35	6.155%	0.650%	+215	CITI/JPM/MS//HSBC/LAZ/SG/ WILL
06/04	Southwestern Electric Power Co.	Senior Notes 6.450% due 01/15/2019	10.6 NC/L	$400	Unsecured	Baa1(n)/BBB	T+50	6.465%	0.650%	+255	BNP/CS/JPM//RBS
06/04	The Detroit Edison Company	Senior Notes 5.600% due 06/15/2018	10 NC/L	$300	Secured	A3/A-	T+30	5.619%	0.650%	+170	CITI/KEY//BNY/UBS
06/02	Northeast Utilities	Senior Notes 5.650% due 06/01/2013	5 NC/L	$250	Holdco	Baa2/BBB-	T+35	5.659%	0.600%	+240	JPM/LEH//BAS/BNY/Wells
05/29	El Paso Electric Company	Senior Notes 7.500% due 06/01/2038	30 NC/L	$150	Unsecured	Baa2/BBB	T+50	7.574%	0.875%	+280	CS
05/28	Cleco Power LLC	Notes 6.650% due 06/15/2018	10 NC/L	$250	Unsecured	Baa1/BBB	T+40	6.699%	0.650%	+268	BNY/CALY/KEY
05/27	Georgia Power Company	Senior Notes 5.400% due 06/01/2018	10 NC/L	$250	Unsecured	A2/A	T+25	5.458%	0.650%	+155	BAS/MS//DB/HSBC/SCO/ WILL
05/19	Public Service Co. of New Hampshire	First Mortgage Bonds 6.000% due 05/01/2018	10 NC/L	$110	Secured	Baa1/BBB+	T+35	6.033%	0.650%	+215	BARC/BNY//TD/Wedbush
05/19	The Connecticut Light and Power Company	F&R Mortgage Bonds 5.650% due 05/01/2018	10 NC/L	$300	Secured	A3/BBB+	T+30	5.683%	0.650%	+180	BARC/CITI/WACH//BAS/TD/ WILL/Wedbush
05/15	NiSource Finance Corp. (Reopening: 100.378%)	Notes 6.150% due 03/01/2013	4.8 NC/L	$200	Holdco	Baa3(n)/BBB-	T+35	6.055%	0.600%	+292	BAS/JPM/WACH//BMO/KEY/ Commerz/MIZ
05/15	NiSource Finance Corp.	Notes 6.800% due 01/15/2019	10.7 NC/L	$500	Holdco	Baa3(n)/BBB-	T+50	6.834%	0.650%	+297	BAS/JPM/WACH//BMO/KEY/ Commerz/MIZ
05/13	The Empire District Electric Co.	First Mortgage Bonds 6.375% due 06/01/2018	10 NC/L	$90	Secured	Baa1(n)/BBB+	T+37.5	6.382%	0.650%	+248	UBS
05/13	Columbus Southern Power Co.	Senior Notes 6.050% due 05/01/2018	10 NC/L	$350	Unsecured	A3/BBB	T+35	6.081%	0.650%	+220	BNY/GS/LEH//SUN/NatCity/ FITB
05/13	Tampa Electric Company	Notes 6.100% due 05/15/2018	10 NC/L	$150	Unsecured	Baa2(p)/BBB-	T+35	6.100%	0.650%	+225	BNP/MS//FITB/MK/SG/ Wedbush
05/12	Entergy Gulf States Louisiana (144A w/RR)	First Mortgage Bonds 6.000% due 05/01/2018	10 NC/L	$375	Secured	Baa3(p)/BBB+(n)	T+40	6.060%	NA	+230	MS/MIZ/RBS//CS/KEY/Wells
05/09	PNM Resources	Senior Notes 9.250% due 05/15/2015	7 NC/L	$350	Holdco	Ba2(N)/BB-	–	9.250%	1.500%	+588	LEH/BAS/ML/MS/WACH//CITI DB/JPM/RBC/Wedbush
05/08	Public Service Co. of New Mexico	Senior Unsecured Notes 7.950% due 05/15/2018	10 NC/L	$350	Unsecured	Baa3(N)/BB+	T+60	7.950%	1.000%	+418.5	LEH/ML/CITI/DB/MS/RBC/ WACH//BAS/JPM/UBOC/CS

Ratings legend: N: Review for downgrade; P: Review for upgrade; n: negative outlook; p: positive outlook.

Electric Utility Debt Financing in 2008 (continued)

Offer Date	Company	Issue	Structure	Amt ($MM)	Type	Moody/S&P Ratings	MW Call	Yield	Gross Spread	Reoffer Spread	Managers
05/08	Alabama Power Company	Senior Notes 6.125% due 05/15/2038	30 NC/L	$300	Unsecured	A2/A	T+25	6.144%	0.875%	+155	CITI/LEH//CALY/LAZ/MIZ/ TOUS
05/01	CenterPoint Energy Inc.	Senior Notes 6.500% due 05/01/2018	10 NC/L	$300	Holdco	Ba1/BBB-	T+45	6.571%	0.650%	+282	LEH/RBS/WACH//BARC/ HSBC/LAZ/RBC/SUN/Wells
04/15	E.ON International Finance BV (144A w/RR)	Notes 5.800% due 04/30/2018	10 NC/L	$2,000	Holdco	A2/A	T+35	5.856%	NA	+225	BAS/DB/GS/JPM
04/15	E.ON International Finance BV (144A w/RR)	Notes 6.650% due 04/30/2038	30 NC/L	$1,000	Holdco	A2/A	T+35	6.683%	NA	+225	BAS/DB/GS/JPM
04/14	Virginia Electric and Power Co.	Senior Notes 5.400% due 04/30/2018	10 NC/L	$600	Unsecured	Baa1/A-	T+35	5.429%	0.650%	+195	BARC/RBS/WACH//BAS/DB/ BNP/BNY/MIZ/SCO
04/11	Korea Southern Power Co. (144A w/RR)	Senior Notes 5.375% due 04/18/2013	5 NC/L	$300	Unsecured	A1/A-	—	5.465%	NA	+289.6	ABN/CITI/DB
04/10	Public Service Electric and Gas	Secured Medium-Term Notes 5.300% due 05/01/2018	10 NC/L	$400	Secured	A3(n)/A-	T+30	5.310%	0.600%	+178	BNP/RBS/SCO
04/09	Duke Energy Carolinas	F&R Mortgage Bonds 5.100% due 04/15/2018	10 NC/L	$300	Secured	A2/A	T+30	5.119%	0.650%	+165	BAS/BARC/RBS//BNP/BNY/ LAZ/KEY/SUN
04/09	Duke Energy Carolinas	F&R Mortgage Bonds 6.050% due 04/15/2038	30 NC/L	$600	Secured	A2/A	T+30	6.070%	0.875%	+177	BAS/BARC/RBS//BNP/BNY/ LAZ/KEY/SUN
04/02	IPALCO Enterprises (144A)	Senior Secured Notes 7.250% due 04/01/2016	8 NC/L	$400	Secured	Ba1/BB	T+50	7.500%	NA	+412	ML/LEH//BAS/JPM/SCO
04/01	Con Edison of NY	Debentures 5.850% due 04/01/2018	10 NC/L	$600	Unsecured	A1(n)/A-	T+35	5.856%	0.650%	+230	BNY/ML/RBS//BLAY/COM/ KEY/LAZ/MIZ/RAM/Wells
04/01	Con Edison of NY	Debentures 6.750% due 04/01/2038	30 NC/L	$600	Unsecured	A1(n)/A-	T+35	6.773%	0.875%	+240	BNY/ML/RBS//BLAY/COM/ KEY/LAZ/MIZ/RAM/Wells
04/01	Union Electric (d/b/a AmerenUE)	Senior Secured Notes 6.000% due 04/01/2018	10 NC/L	$250	Secured	A3/BBB	T+40	6.041%	0.650%	+250	GS/JPM//LAZ/MK
04/01	Illinois Power (144A w/RR)	Senior Secured Notes 6.250% due 04/01/2018	10 NC/L	$337	Secured	Baa3(p)/BBB-(p)	T+45	6.282%	0.650%	+275	BARC/BNP/LEH//FITB/USB
03/27	Avista Corp.	First Mortgage Bonds 5.950% due 06/01/2018	10 NC/L	$250	Secured	Baa2/BBB+	T+37.5	5.992%	0.650%	+250	UBS/BNY/GS//BAS/KEY/Wed/ Wells
03/25	MidAmerican Energy Holdings (144A w/RR)	Senior Notes 5.750% due 04/01/2018	10 NC/L	$650	Holdco	Baa1/BBB+	T+35	5.774%	0.550%	+225	LEH/BARC/RBS/WACH//BNP/ CITI/SUN/UBOC/Wed/Wells
03/25	International Transmission Co. (144A w/RR)	First Mortgage Bonds 5.750% due 04/01/2018	10 NC/L	$100	Secured	A3(p)/A-(p)	T+35	5.765%	NA	+225	BAS
03/24	Potomac Electric Power Company (Reopening: 96.917%)	Senior Notes 6.500% due 11/15/2037	29.7 NC/L	$250	Secured	Baa1/BBB+	T+35	6.741%	0.875%	+245	CITI/JPM//SUN/BNY/MIZ/ WACH/WILL

Ratings legend: N: Review for downgrade; P: Review for upgrade; n: negative outlook; p: positive outlook.

Electric Utility Debt Financing in 2008 (continued)

Offer Date	Company	Issue	Structure	Amt ($MM)	Type	Moody/S&P Ratings	MW Call	Yield	Gross Spread	Reoffer Spread	Managers
03/19	MidAmerican Energy	Senior Notes 5.300% due 03/15/2018	10 NC/L	$350	Unsecured	A2/A-	T+30	5.345%	0.650%	+190	LEH/RBS//BARC/UBS/WACH
03/19	Appalachian Power	Senior Notes 7.000% due 04/15/2038	30 NC/L	$500	Unsecured	Baa2(n)/BBB	T+50	7.053%	0.875%	+280	BARC/JPM/RBS//CALY/LAZ/ MIZ/UBS
03/19	Commonwealth Edison	First Mortgage Bonds 5.800% due 03/15/2018	10 NC/L	$700	Secured	Baa2/BBB(p)	T+40	5.826%	0.650%	+245	BAS/BARC/RBS//BNP/JPM/ SCO/SUN/Loop/SBK
03/12	Georgia Power	Floating Rate Senior Notes 3mL+55 bp due 03/17/2010	2 NC/L	$250	Unsecured	A2/A	–	3mL+55	0.250%	NA	JPM/WACH//BAS/SUN
03/11	Northern States Power (Minn)	First Mortgage Bonds 5.250% due 03/01/2018	10 NC/L	$500	Secured	A2/A	T+25	5.290%	0.650%	+170	BARC/JPM//RBS/Wells
03/10	Consumers Energy	First Mortgage Bonds 5.650% due 09/15/2018	10.5 NC/L	$250	Secured	Baa1/BBB	T+45	5.699%	0.650%	+225	BARC/BNP/SCO//RBS/WED/ Comerica/Wells/WILL
03/10	Carolina Power & Light d/b/a Progress Energy Carolinas	First Mortgage Bonds 6.300% due 04/01/2038	30 NC/L	$325	Secured	A2/A-	T+30	6.313%	0.875%	+185	JPM/WACH//BNY/CAB/GS/ LAZ/MS/SUN
03/06	Kansas City Power & Light Co.	Notes 6.375% due 03/01/2018	10 NC/L	$350	Unsecured	A3(n)/BBB(N)	T+45	6.375%	0.650%	+275.8	JPM/BAS//BNP/WACH/KEY/ Ram/SCO
03/05	Vectren Utility Holdings, Inc.	Senior Monthly Notes 6.250% due 04/01/2039	31 NC/5	$125	Unsecured	Baa1/A-	–	6.250%	3.150%	+176	EdJ
03/05	SCANA Corp.	Medium Term Notes 6.250% due 04/01/2020	12 NC/L	$250	Holdco	Baa1/BBB+(n)	T+40	6.291%	0.650%	+260	BAS/BBT/UBS//Wells
03/05	Public Service Electric and Gas	F&R Mortgage Bonds 3mL+87.5 due 03/12/2010	2 NC/6mo	$300	Secured	A3(n)/A-	–	3mL+87.5	0.250%	NA	BARC//MIZ/UBS
02/26	Pacific Gas and Electric (Reopening: 101.550%)	Senior Notes 5.625% due 11/30/2017	10 NC/L	$200	Unsecured	A3/BBB+	T+30	5.417%	0.650%	+155	GS/LEH/UBS//Blay/CastleOak /MIZ
02/26	Pacific Gas and Electric	Senior Notes 6.350% due 02/15/2038	30 NC/L	$400	Unsecured	A3/BBB+	T+30	6.361%	0.875%	+170	GS/LEH/UBS//Blay/CastleOak /MIZ
02/25	PECO Energy	F&R Mortgage Bonds 5.350% due 03/01/2018	10 NC/L	$500	Secured	A2/A	T+25	5.372%	0.650%	+147	GS/LEH/BNY(passive)//MIZ/R BS/WILL/Toussaint
01/28	Oklahoma Gas and Electric	Senior Notes 6.450% due 02/01/2038	30 NC/L	$200	Unsecured	A2/BBB+	T+35	6.491%	0.875%	+220	BNY/RBS//KEY/MIZ/Piper/ UMB/Wed
01/15	ITC Midwest LLC (144A)	First Mortgage Bonds 6.150% due 01/31/2038	30 NC/L	$175	Secured	A3(p)/A-(p)	T+30	6.172%	NA	+187.5	CS/LEH//BAS/Comerica/JPM
01/15	ITC Holdings Corp (144A)	Senior Notes 6.050% due 01/31/2018	10 NC/L	$385	Holdco	Baa3(p)/BBB-(p)	T+35	6.105%	NA	+240	CS/LEH//BAS/Comerica/JPM

Ratings legend: N: Review for downgrade; P: Review for upgrade; n: negative outlook; p: positive outlook.

Electric Utility Debt Financing in 2008 (continued)

Offer Date	Company	Issue	Structure	Amt ($MM)	Type	Moody/S&P Ratings	MW Call	Yield	Gross Spread	Reoffer Spread	Managers
01/14	Southern California Edison	F&R Mortgage Bonds 5.950% due 02/01/2038	30 NC/L	$600	Secured	A2/A	T+25	5.983%	0.875%	+160	BNY/CITI/LEH/JPM/WED/ Wells/BLAY/CAB
01/10	Florida Power & Light	First Mortgage Bonds 5.950% due 02/01/2038	30 NC/L	$600	Secured	Aa3/A	T+25	5.989%	0.875%	+158	CALY/CITI/MS/WACH//BNY/ DB/HSBC/KEY/LAZ/Wells
01/09	Commonwealth Edison	First Mortgage Bonds 6.450% due 01/15/2038	30 NC/L	$450	Secured	Baa2/BBB(p)	T+35	6.473%	0.875%	+215	DB/ML/UBS//BNP/SCO/SUN/ UBOC
01/08	Alabama Power (Reopening: 100.542%)	Senior Notes 4.850% due 12/15/2012	5 NC/L	$300	Unsecured	A2/A	T+25	4.724%	0.600%	+153	BARC/JPM//BNY/MK/Ram/ RBS
01/07	South Carolina Electric & Gas	First Mortgage Bonds 6.050% due 01/15/2038	30 NC/L	$250	Secured	A2/A-(n)	T+30	6.057%	0.875%	+172	BNY/CS/MS//MIZ
01/07	Duke Energy Carolinas	F&R Mortgage Bonds 5.250% due 01/15/2018	10 NC/L	$400	Secured	A2(p)/A	T+25	5.294%	0.650%	+145	JPM/WACH//CS/DB/RBS/LEH
01/07	Duke Energy Carolinas	F&R Mortgage Bonds 6.000% due 01/15/2038	30 NC/L	$500	Secured	A2(p)/A	T+30	6.005%	0.875%	+165	JPM/WACH//CS/DB/RBS/LEH

Ratings legend: N: Review for downgrade; P: Review for upgrade; n: negative outlook; p: positive outlook.

Schedule AJK RF-2

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF DELAWARE

IN THE MATTER OF THE APPLICATION OF DELMARVA POWER & LIGHT COMPANY FOR EXPEDITED APPROVAL TO ISSUE UP TO $250 MILLION OF DEBT SECURITIES (FILED OCTOBER 17, 2008)	)))))	PSC DOCKET NO. 08-335

ORDER NO. 7487

AND NOW, to-wit, this 21st day of November, 2008, the Applicant, Delmarva Power & Light Company ("Delmarva" or the "Applicant") having on October 17, 2008, filed an application pursuant to *26 Del. C. § 215* seeking to have the Commission approve the issuance of up to $250 million of first-term mortgage debt securities; and

WHEREAS, the Commission having examined the filed application and having made such investigation in connection therewith as deemed necessary under the circumstances; and

WHEREAS, the Commission having found the proposal of Applicant to issue the debt securities to be in accordance with law, for a proper purpose, and consistent with the public interest; and

WHEREAS, the Commission has previously entered, on the 5th day of November, 2008, an Order granting the Application but reserving certain conditions, which the Applicant has agreed to in connection with the issuance of that Order;

Now, therefore, **IT IS ORDERED**:

1. That the Application of Delmarva Power & Light Company filed with the Commission in this matter on October 17, 2008, is approved effective November 5, 2008.

2. That Delmarva Power & Light Company agrees that the proceeds from the debt issuance shall only be used in the following manner:

(a) One Hundred Fifty Million Dollars ($150,000,000) of the proceeds shall be used to reduce Delmarva Power & Light Company's portion of the $625 million utility credit facility;

(b) That $34 million of the proceeds shall be used to pay off Delmarva Power & Light Company's short-term commercial paper obligations; and

(c) The remainder of the $250 million proceeds ($66 million) shall be put in a money market account designated exclusively for the use by Delmarva Power & Light Company for its utility operations.

3. In addition, Delmarva Power & Light Company agrees to provide Commission Staff with the following quarterly reports beginning January 2009 through June 2009:

(a) Within twenty (20) days after the end of each quarter, a forecast of capital expenditure requirements;

b) Within twenty (20) days after the end of each quarter, a report of the sources and uses (cash flow) for its utility business from January 2009; and

(c) A Rate of Return Report.

4. In addition, Delmarva Power & Light Company agrees to quarterly meetings with Staff regarding financial conditions through June 2009, to be renewed if necessary.

5. That approval of this application by the Commission is not to be construed as approving the capitalization ratios that result for any purposes or procedures involving ratemaking, nor are the Commission's rules relative to proving the merits of any related issue hereby waived. Approval of this application shall not be construed as endorsing any ratemaking treatment of these transactions in any future rate case.

6. That nothing in this Order shall be construed as any guarantee, warranty, or representation by the State of Delaware or by any agency, commission, or department thereof, with respect to the securities to be issued pursuant to this Order.

7. That the Commission reserves the jurisdiction and authority to enter such further Orders in this matter as may be deemed necessary or proper.

BY ORDER OF THE COMMISSION:

/s/ Arnetta McRae
Chair

/s/ Dallas Winslow
Commissioner

Schedule AJK RF-2

/s/ Joann T. Conaway
Commissioner

Commissioner

/s/ Jeffrey J. Clark
Commissioner

ATTEST:

/s/ Karen J. Nickerson
Secretary

Attachment C

Ratemaking Cost Rate of Long Term Debt
As Reported By Regulatory Research Associates
Investment Grade Electric Utilities
January 1, 2009 to March 8, 2010

	State	Company	Case Identification	Service	Increase Authorized Date	LTD Cost Rate %
	Delaware	Delmarva Power and Light Co.	09-414/09-276T	Electric		5.45
1	New York	Central Hudson Gas & Electric	C-08-E-0887	Electric	6/22/2009	4.86
2	Virginia	Kentucky Utilities Co.	PUE-2009-00029	Electric	3/4/2010	4.90
3	Wisconsin	Wisconsin Electric Power Co.	D-5-UR-104 (WEP-EL)	Electric	12/18/2009	5.36
4	Michigan	Consumers Energy Co.	C-U-15645	Electric	11/2/2009	5.69
5	Arizona	Arizona Public Service Co.	D-E-01345A-08-0172	Electric	12/16/2009	5.77
6	Missouri	Union Electric Co.	C-ER-2008-0318	Electric	1/27/2009	5.77
7	New York	Consolidated Edison Co. of NY	C-08-E-0539	Electric	4/24/2009	5.79
8	North Carolina	Duke Energy Carolinas LLC	D-E-7, Sub 909	Electric	12/7/2009	5.82
9	South Carolina	Duke Energy Carolinas LLC	D-2009-226-E	Electric	1/27/2010	5.82
10	Idaho	Idaho Power Co.	C-IPC-E-08-10	Electric	1/30/2009	5.93
11	Oregon	Idaho Power Co.	D-UE-213	Electric	2/24/2010	5.96
12	Indiana	Indiana Michigan Power Co.	Ca-43306	Electric	3/4/2009	5.98
13	Michigan	Detroit Edison Co.	C-U-15768	Electric	1/11/2010	6.00
14	Arkansas	Southwestern Electric Power Co	D-09-008-U	Electric	11/24/2009	6.02
15	Utah	PacifiCorp	D-08-035-38	Electric	4/21/2009	6.02
16	Wisconsin	Madison Gas and Electric Co.	D-3270-UR-116 (elec)	Electric	12/22/2009	6.13
17	Colorado	Public Service Co. of CO	D-09AL-299E	Electric	12/3/2009	6.21
18	California	Southern California Edison Co.	Ap-07-11-011	Electric	3/12/2009	6.22
19	Wisconsin	Northern States Power Co - WI	D-4220-UR-116 (elec)	Electric	12/22/2009	6.26
20	North Dakota	Otter Tail Corp.	C-PU-08-862	Electric	11/25/2009	6.33
21	Wisconsin	Wisconsin Power and Light Co	D-6680 UR-117 (elec)	Electric	12/18/2009	6.39
22	Connecticut	United Illuminating Co.	D-08-07-04	Electric	2/4/2009	6.42
23	Ohio	Duke Energy Ohio Inc.	C-08-0709-EL-AIR	Electric	7/8/2009	6.45
24	Ohio	Cleveland Elec Illuminating Co	C-07-0551-EL-AIR (CEI)	Electric	1/21/2009	6.54
25	Ohio	Ohio Edison Co.	C-07-0551-EL-AIR (OE)	Electric	1/21/2009	6.54
26	Ohio	Toledo Edison Co.	C-07-0551-EL-AIR (TE)	Electric	1/21/2009	6.54
27	Idaho	Avista Corp.	C-AVU-E-09-01	Electric	7/17/2009	6.60
28	Oklahoma	Public Service Co. of OK	Ca-PUD-200800144	Electric	1/14/2009	6.60
29	Minnesota	Northern States Power Co. - MN	D-E-002/GR-08-1065	Electric	10/23/2009	6.61
30	Florida	Tampa Electric Co.	D-080317-EI	Electric	3/17/2009	6.80
31	Iowa	Interstate Power & Light Co.	D-RPU-2009-0002	Electric	1/4/2010	6.84
32	Texas	Oncor Electric Delivery Co.	D-35717	Electric	8/31/2009	6.97
					Average	6.13

Source: Regulatory Research Associates via SNL website March 8, 2010

Delmarva Power and Light Company
Example of the Inadequacy of
DCF Return Rate Related to Book Value
When Market Value Exceeds Book Value

Line No.		Based on Mr. Rothschild's Proxy Group of Gas Companies		Based on Mr. Rothschild's Proxy Group of Combination Gas and Electric Companies	
		Market Value	Book Value	Market Value	Book Value
1.	Per Share	$ 35.763 (1)	$ 20.300 (2)	$ 36.398 (3)	$ 26.280 (4)
2.	DCF Cost Rate (1)	9.72% (5)	9.72% (5)	8.94% (6)	8.94% (6)
3.	Return in Dollars	$ 3.476	$ 1.973	$ 3.252	$ 2.348
4.	Dividends	$ 1.384 (7)	$ 1.384 (7)	$ 1.740 (8)	$ 1.740 (8)
5.	Growth in Dollars	$ 2.092	$ 0.589	$ 1.512	$ 0.608
6.	Return on Market Value	9.72%	5.52% (9)	8.93%	6.45% (10)
7.	Rate of Growth on Market Value	5.85% (11)	1.65% (12)	4.16% (13)	1.67% (14)

Notes:
(1) Based on an average of the spot and average yearly price of Mr. Rothschild's gas proxy group shown on Schedule JAR 3, page 1
(2) Average book value per share of Mr. Rothschild's gas proxy group at December 2009 as shown on Schedule JAR 3, page 1.
(3) Based on an average of the spot and average yearly price of Mr. Rothschild's combination gas and electric proxy group shown on Schedule JAR 3, page 1
(4) Average book value per share of Mr. Rothschild's combination gas and electric proxy group at December 2009 as shown on Schedule JAR 3, page 1.
(5) Average of Mr. Rothschild's conclusions of DCF cost rate applied to his gas proxy group shown on Schedule JAR 5, page 2.
(6) Average of Mr. Rothschild's conclusions of DCF cost rate applied to his combination gas and electric proxy group shown on Schedule JAR 5, page 1.
(7) Dividends per share based upon a 3.87% dividend yield. $1.384 = $35.763 * 3.87%.
(8) Dividends per share based upon a 4.78% dividend yield. $1.740 = $36.398 * 4.78%.
(9) $1.973 / $35.763.
(10) $2.348 / $36.398.
(11) Average growth rate used by Rothschild in applying the DCF to his gas proxy group. (including 0.11 growth in dividend yield)
(12) Actual rate of growth when DCF cost rate is applied to book value ($3.476 possible earnings - $1.384 dividends = $0.589 for growth / $35.763 market value = 1.65%).
(13) Average growth rate used by Rothschild in applying the DCF to his combination gas and electric proxy group. (including 0.10 growth in dividend yield)
(14) Actual rate of growth when DCF cost rate is applied to book value ($3.252 possible earnings - $1.740 dividends = $0.608 for growth / $36.398 market value = 1.67%).

Ibbotson® SBBI®
2010 Valuation Yearbook

Market Results for
Stocks, Bonds, Bills, and Inflation
1926–2009

MORNINGSTAR®

Table 2-1: Total Returns, Income Returns, and Capital Appreciation of the Basic Asset Classes: Summary Statistics of Annual Returns

Series	Geometric Mean (%)	Arithmetic Mean (%)	Standard Deviation (%)	Serial Correlation
Large Company Stocks				
Total Returns	9.8	11.8	20.5	0.02
Income	4.1	4.1	1.6	0.90
Capital Appreciation	5.5	7.4	19.8	0.01
Ibbotson Small Company Stocks				
Total Returns	11.9	16.6	32.8	0.06
Mid-Cap Stocks*				
Total Returns	10.9	13.7	25.0	-0.04
Income	3.9	4.0	1.7	0.90
Capital Appreciation	6.7	9.5	24.3	-0.05
Low-Cap Stocks*				
Total Returns	11.3	15.2	29.4	0.02
Income	3.6	3.6	2.0	0.89
Capital Appreciation	7.5	11.4	28.7	0.01
Micro-Cap Stocks*				
Total Returns	12.1	18.2	39.2	0.07
Income	2.5	2.5	1.7	0.91
Capital Appreciation	9.5	15.6	38.6	0.06
Long-Term Corporate Bonds				
Total Returns	5.9	6.2	8.3	0.08
Long-Term Government Bonds				
Total Returns	5.4	5.8	9.6	-0.12
Income	5.1	5.2	2.7	0.96
Capital Appreciation	0.1	0.4	8.4	-0.26
Intermediate-Term Government Bonds				
Total Returns	5.3	5.5	5.7	0.13
Income	4.7	4.7	2.9	0.96
Capital Appreciation	0.5	0.6	4.5	-0.18
Treasury Bills				
Total Returns	3.7	3.7	3.1	0.91
Inflation	3.0	3.1	4.2	0.64

Data from 1926–2009. Total return is equal to the sum of three component returns: income return, capital appreciation return, and reinvestment return.

*Source: Morningstar and CRSP. Calculated (or Derived) based on data from CRSP US Stock Database and CRSP US Indices Database ©2010 Center for Research in Security Prices (CRSP®), The University of Chicago Booth School of Business. Used with permission.

Annual Total Returns

Annual and monthly total returns for large company stocks, small company stocks, long-term corporate bonds, long-term government bonds, intermediate-term government bonds, Treasury bills, and inflation rates are for the full 84-year time period presented in Appendix B. Those tables can be used to compare the performance of each asset class on both a monthly and an annual basis.

Real Rates versus Nominal Rates

The cost of capital embodies a number of different concepts or elements of risk. Two of the most basic concepts in finance are real and nominal returns. The nominal return includes both the real return and the impact of inflation.

The real rate of interest represents the exchange rate between current and future purchasing power. An increase in the real rate indicates that the cost of current consumption has risen in terms of future goods. It is the real rate of interest that measures the opportunity cost of foregoing consumption.

The relationship between real rates and nominal rates can be expressed in the following equation:

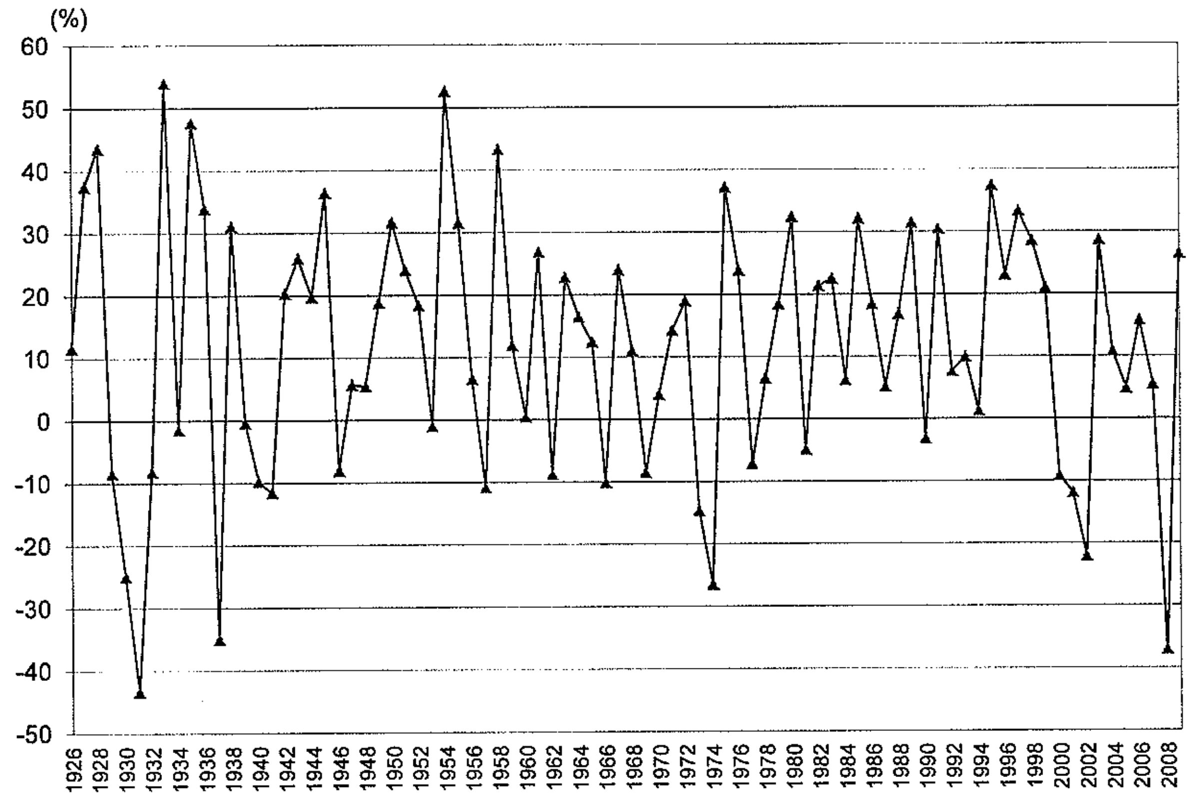
$$\text{Real} = \left[\frac{1+\text{Nominal}}{1+\text{Inflation}}\right] - 1$$

$$\text{Nominal} = \left[(1+\text{Real}) \times (1+\text{Inflation})\right] - 1$$

It is important to note that the conversion of nominal and real rates is not an additive process; rather, it is a geometric calculation. The arithmetic sum or difference is calculated by adding or subtracting one number from the other. As illustrated in the above equation, the real rate of return involves taking the geometric difference of the nominal rate of return and the rate of inflation. Conversely, the nominal rate of return can be determined by taking the geometric sum of the real rate of return and the rate of inflation. For example, if the real rate is 2.5 percent and the inflation rate is 5.0 percent, the nominal rate of interest is not 7.5 percent (2.5+5.0) but 7.625 percent, or $[(1.025)\times(1.05)-1]$. Similarly, if the nominal rate is 7.625 percent and the inflation rate is 2.5 percent, the real rate is not 5.125 percent (7.625−2.5) but 5.0 percent, $[(1.07625/1.025)-1]$.

Discount rates are most often expressed in nominal terms. That is, they usually have an inflation estimate included in them. Unless stated otherwise, the cost of capital data presented in this book are expressed in nominal terms.

Delmarva Power and Light Company
Large Company Stock Returns
From 1926 to 2009



Source of Information:
Ibbotson® SBBI® - 2010 Valuation Yearbook - Market Results for Stocks Bonds Bills and Inflation - 1926-2009, Morningstar, Inc., 2010 Chicago, IL.

Delmarva Power and Light Company
Total Returns on Large Company Stocks
1926 to 2009

Large Company Stocks

						2006				
						2004	$\boxed{2009}$			
					2007	1988	2003	1997		
				1990	2005	1986	1999	1995		
				1981	1994	1979	1998	1991		
				1977	1993	1972	1996	1989		
				1969	1992	1971	1983	1985		
				1962	1987	1968	1982	1980		
				1953	1984	1965	1976	1975		
			2001	1946	1978	1964	1967	1955		
			2000	1940	1970	1959	1963	1950		
			1973	1939	1960	1952	1961	1945		
		2002	1966	1934	1956	1949	1951	1938	1958	
	2008	1974	1957	1932	1948	1944	1943	1936	1935	1954
1931	1937	1930	1941	1929	1947	$\boxed{1926}$	1942	1927	1928	1933

-50% -40% -30% -20% - 10% 0% 10% 20% 30% 40% 50% 60%

Arithmetic Mean: $r_A = \sum_{t=1}^{n} r_t \,/\, n$

Source : Ibbotson® SBBI ® – 2010 Valuation Yearbook – Market Results for Stocks, Bonds, Bills, and Inflation –1926-2009, pp. 164-167
Morningstar, Inc., 2010 Chicago, IL

Delmarva Power and Light Company
Total Returns on Large Company Stocks
1926 to 2009

Large Company Stocks

1926 2009

-50% -40% -30% -20% - 10% 0% 10% 20% 30% 40% 50% 60%

Geometric Mean: $r_G = \left[V_n \;/\; V_0 \right]^{1/n} - 1$

Source : Ibbotson® SBBI ® – 2010 Valuation Yearbook – Market Results for Stocks, Bonds, Bills, and Inflation –1926-2009, pp. 164-167
Morningstar, Inc., 2010 Chicago, IL

Ibbotson® SBBI®
2010 Valuation Yearbook

Market Results for
Stocks, Bonds, Bills, and Inflation
1926–2009

MORNINGSTAR®

The Vasicek adjustment process focuses on the standard error of the beta estimate—the higher the standard error, the lower the statistical significance of the beta estimate. Therefore, a company beta with a high standard error should have a greater adjustment than a company beta with a low standard error. The Vasicek formula is as follows:

$$\beta_{s1} = \frac{\sigma^2_{\beta s0}}{\sigma^2_{\beta 0} + \sigma^2_{\beta s0}} \beta_0 + \frac{\sigma^2_{\beta 0}}{\sigma^2_{\beta 0} + \sigma^2_{\beta s0}} \beta_{s0}$$

where:

β_{s1} = the Vasicek adjusted beta for security s;
β_{s0} = the historical beta for security s;
β_0 = the beta of the market, industry, or peer group;
$\sigma^2_{\beta 0}$ = the variance of betas in the market, industry, or peer group; and
$\sigma^2_{\beta s0}$ = the square of the standard error of the historical beta for security s.

While the Vasicek formula looks intimidating, it is really quite simple. The adjusted beta for a company is a weighted average of the company's historical beta and the beta of the market, industry, or peer group. How much weight is given to the company and historical beta depends on the statistical significance of the company beta statistic. If a company beta has a low standard error, then it will have higher weighting in the Vasicek formula. If a company beta has a high standard error, then it will have lower weighting in the Vasicek formula. In all cases, the Vasicek weights will sum to one.

An advantage of this adjustment methodology is that it does not force an adjustment to the market as a whole. Instead, the adjustment can be toward an industry or some other peer group. This is most useful in looking at companies in industries that on average have high or low betas. If evaluating the beta for a company in the petroleum refining industry, which traditionally has had betas below one, it may be more desirable to adjust the beta of that company toward the industry average rather than toward the market average of one.

Because this method varies by company and allows for adjustment toward industry averages, we have selected the Vasicek adjustment technique for our beta calculations.

Sum Beta (Including Lag)

Motivation

In calculating betas for the *Ibbotson® SBBI® Valuation Yearbook*, we began to notice that the betas of the small company portfolios, though higher than the betas of the large company portfolios, were not high enough to explain all of the excess returns historically found in small stocks.[4] In addition, while calculating betas for the first *Ibbotson Cost of Capital Quarterly* and the first *Ibbotson® Beta Book* publications, we found that the betas of individual small companies tend to be lower than those of large companies. For the beta population from the *Ibbotson Cost of Capital Quarterly* and *Beta Book*, it appears that the standard ordinary least squares (OLS) regression technique is calculating betas that are too low for smaller companies.

Possible Measurement Error in Small Company Betas

As will be discussed in Chapter 7, there is a relationship between risk and return. Small companies are generally considered riskier investments than large companies. Therefore, we should expect small company betas to be, on average, higher than large company betas.

Table 6-7 shows the ordinary least squares betas for each of the size portfolios over the most recent 60-month period and over the entire history of data available. Decile 1 contains the largest companies, ranked by market capitalization, and decile 10 contains the smallest companies (for additional information on how these deciles are constructed, see Chapter 7). Based on these statistics, it is clear that there is a relationship between risk and return. Though the expected relationship between the betas of the large and small portfolios exists over the long period, the small portfolio betas are still not large enough to account for all of the excess return exhibited by these small stocks. There are several possible explanations for these results.

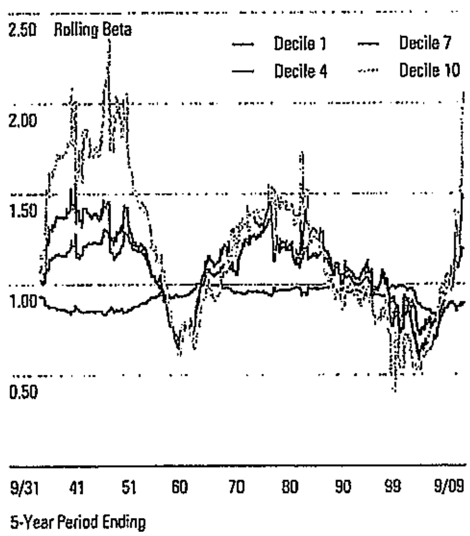
Table 6-7: Ordinary Least Squares Betas for the NYSE Size Portfolios

Decile	Jan. 2005–Dec. 2009	1926–2009
1	0.90	0.90
2	1.11	1.02
3	1.15	1.08
4	1.19	1.11
5	1.20	1.14
6	1.42	1.16
7	1.46	1.22
8	1.52	1.28
9	1.65	1.33
10	2.02	1.42

1926–2009.

By looking at the same analysis over a number of 60-month periods, the relationship between the betas of large and small companies becomes clearer. Graph 6-5 shows rolling 60-month betas for selected NYSE deciles. The beta of each decile is calculated over the 60-month period October 1, 1926 through September 30, 1931, then the calculation is carried forward for each consecutive 60-month period through September 30, 2009. While the portfolio containing the largest companies has a stable beta, the portfolio containing the smallest companies has periods where the beta is high and periods where it is low.

Graph 6-5: 60-Month Rolling Ordinary Least Squares Betas by NYSE Size Decile



Data from October 1926–September 2009.

The lower-capitalization decile betas from both the most recent and long-term time periods tend to be lower than expected. For all but the largest companies, the prices of individual stocks tend to react in part with a lag to movements in the overall market; the smaller the company, the greater the lagged price reaction. The lagged price reaction of small company stocks has been documented by a number of researchers.[5]

There are a number of explanations for the low betas exhibited by small stocks. One common explanation is the infrequent trading that often accompanies small company stocks. Many securities do not trade everyday. The market for some securities is so thin that they may not trade for several days. If a stock is not trading, its stock price is not reflecting the movement of the market, which drives down the covariance with the market, creating an artificially low beta.

Note that this is only the apparent covariance. Because the security is not actively trading, the posted price is that of the last trade or some combination of the bid and ask prices. Inactive trading makes calculating accurate betas for these companies quite difficult.

One way to lessen the impact of lagged price reaction and infrequent trading in small stocks is to modify the beta calculation to include a term for the lagged reaction of small company prices to market movements. The remainder of this section will focus on the correction for this lagged reaction to market movements.

Possible Solution

The traditional beta regression assumes that the beta of a company is related to current market movements. This is why the regression formula compares returns of the security for a given period to the returns of the market for that same period.

What if the company is thinly traded? The fact that a company is thinly traded would mean that changes in the price of the stock might lag the market. Therefore, in calculating beta for thinly traded companies, it may be useful to compare the returns of the security against the returns of the market in the current period as well as the returns of the market in the prior period by performing a multiple regression. The security returns at time zero could be regressed with both the market returns at time zero and the market returns for the prior period.

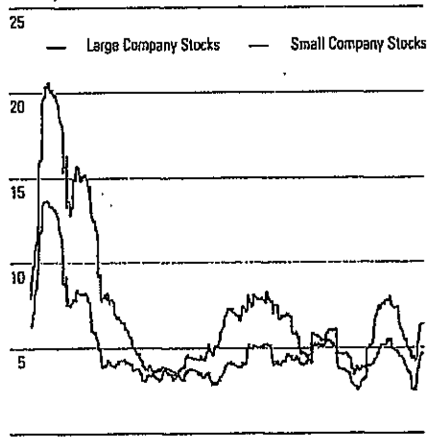
Methods for calculating betas for the lagged price effect were first proposed by Scholes, Williams, and Dimson.[6] Our methodology, developed by Ibbotson, Kaplan, and Peterson, calculates a current and lagged beta coefficient in a multiple regression.[7] We then sum the two coefficients to arrive at the beta estimate that we call sum beta.

Ibbotson® SBBI®
2010 Valuation Yearbook

Market Results for
Stocks, Bonds, Bills, and Inflation
1926–2009

MORNINGSTAR®

Graph 5-8: Rolling 60-Month Standard Deviation for Large and Small Stocks



Data from January 1926–December 2009.

There are two arguments against this rationale. First, it could easily be argued that we have moved through a series of market regimes during the 84-year history of the equity risk premium calculation window used in this book. Given that markets and investor attitudes have changed over time and the equity risk premium has remained relatively constant, there is no reason to believe that a new market regime will have any greater or lesser impact than any other time period.

A second argument relates to the demand for investments. If investors are more comfortable with the market and with stock investing, they will probably place more money into the market. This influx of funds will increase the demand for stocks, which will ultimately increase, not decrease, the equity risk premium.

Supply Model

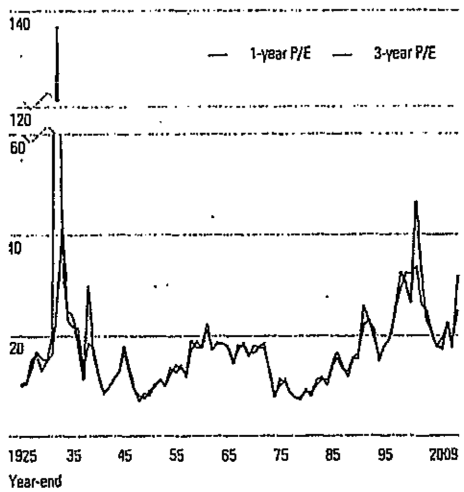
Long-term expected equity returns can be forecasted by the use of supply side models. The supply of stock market returns is generated by the productivity of the corporations in the real economy. Investors should not expect a much higher or lower return than that produced by the companies in the real economy. Thus, over the long run, equity returns should be close to the long-run supply estimate.

Roger G. Ibbotson and Peng Chen forecast the equity risk premium through a supply side model using historical data.[10] They utilized an earnings model as the basis for their supply side estimate; historically, the growth in corporate earnings has been in line with the growth of overall economic productivity. The earnings model breaks historical returns into four pieces, with only three historically being supplied by companies: inflation, income return, and growth in real earnings per share. The growth in the P/E ratio, the fourth piece, is a reflection of investors' changing prediction of future earnings growth. The past supply of corporate growth is forecasted to continue; however, a change in investors' predictions is not. P/E rose dramatically from 1980 through 2001 because people believed that corporate earnings were going to grow faster in the future. This growth of P/E drove a small portion of the rise in equity returns over the same period.

Graph 5-9 illustrates the price to earnings ratio calculated using one-year and three-year average earnings from 1926 to 2009. The P/E ratio, using one-year average earnings, was 10.22 at the beginning of 1926 and ended the year 2009 at 25.06—an average increase of 1.07 percent per year. The highest P/E was 136.55 recorded in 1932, while the lowest was 7.07 recorded in 1948.

Ibbotson Associates revised the calculation of the P/E ratio from a one-year to a three-year average earnings for use in equity forecasting. This is because reported earnings are affected not only by the long-term productivity, but also by "one-time" items that do not necessarily have the same consistent impact year after year. The three-year average is more reflective of the long-term trend than the year-by-year numbers. The P/E ratio calculated using the three-year average of earnings had an increase of 1.31 percent per year.

Graph 5-9: Large Company Stocks



The historical P/E growth factor using three-year earnings of 1.31 percent per year is subtracted from the forecast because it is not believed that P/E will continue to increase in the future. The market serves as the cue. The current P/E ratio is the market's best guess for the future of corporate earnings and there is no reason to believe, at this time, that the market will change its mind.

Thus, the supply of equity returns only includes inflation, the growth in real earnings per share, and income return:

$$SR = [(1+CPI)\times(1+g_{REPS})-1]+Inc+Rinv$$

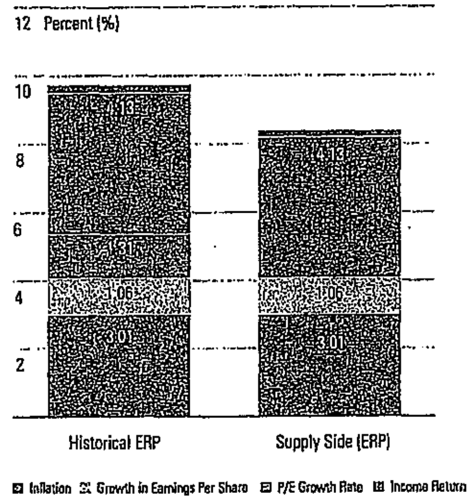
$$8.44\% = [(1+3.01\%)\times(1+1.06\%)-1]+4.13\%+0.21\%$$

where:

- SR = the supply of the equity return;
- CPI = Consumer Price Index (inflation);
- g_{REPS} = the growth in real earning per share;
- Inc = the income return;
- Rinv = the reinvestment return.

The forward-looking earnings model calculates the long-term supply of U.S. equity returns to be 8.44 percent.

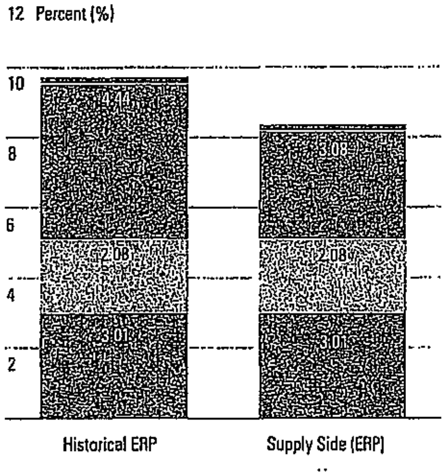
Graph 5-10: Historical and Forecast Equity Returns Based on Earnings Model



Data from 1926–2009. Results add up geometrically, not arithmetically. The darkest shade in the graph represents reinvested returns and an interaction factor between the return components.

Graph 5-10 illustrates the decomposition of historical equity returns from 1926–2009. It also illustrates the historical components that are supplied by companies: inflation, income return, and growth in real earnings per share. Once again the main difference between the historical and forecast equity returns is the exclusion of growth in P/E ratio in the forecasted earnings model.

Graph 5-11: Historical and Forecast Equity Risk Premium



Data from 1926–2009. Results add up geometrically, not arithmetically. The darkest shade in the graph represents reinvested returns and an interaction factor between the return components.

Table 5-6: Supply Side and Historical Equity Risk Premium Over Time

Period Length (Yrs.)	Period Dates	g(P/E)	Arithmetic Average Supply Side Equity Risk Premium (%)	Arithmetic Average Historical Equity Risk Premium (%)
84	1926–2009	1.31	5.18	6.67
83	1926–2008	0.60	5.73	6.47
82	1926–2007	0.67	6.23	7.05
81	1926–2006	0.63	6.35	7.13
80	1926–2005	0.65	6.29	7.08
79	1926–2004	0.83	6.18	7.17
78	1926–2003	1.09	5.93	7.19
77	1926–2002	1.17	5.64	6.97
76	1926–2001	1.53	5.71	7.42
75	1926–2000	1.49	6.06	7.76
74	1926–1999	1.52	6.32	8.07
73	1926–1998	1.40	6.35	7.97
72	1926–1997	1.20	6.37	7.76
71	1926–1996	0.88	6.45	7.50
70	1926–1995	0.74	6.47	7.36
69	1926–1994	0.59	6.32	7.04
68	1926–1993	0.90	6.17	7.22
67	1926–1992	1.15	5.98	7.28
66	1926–1991	1.12	6.11	7.39
65	1926–1990	0.67	6.36	7.16
64	1926–1989	0.60	6.71	7.45
63	1926–1988	0.32	6.78	7.21
62	1926–1987	0.36	6.73	7.20
61	1926–1986	0.63	6.61	7.36

Data from 1926–2009.

The Supply Side equity risk premium is calculated to be 3.08 percent on a geometric basis.

$$SERP = \frac{(1+SR)}{(1+CPI)\times(1+RRf)} - 1$$

$$3.08\%^{*} = \frac{(1+8.44\%)}{(1+3.01\%)\times(1+2.08\%)} - 1$$

*difference due to rounding

where:
SERP = the supply side equity risk premium;
SR = the supply of the equity return;
CPI = Consumer Price Index (inflation);
RRf = the real risk-free rate.

Graph 5-11 compares the historical equity risk premium, which includes the P/E ratio, to the supply side equity risk premium calculated from 1926 to 2009 on a geometric basis. Contrary to several recent studies on equity risk premium that declare the forward-looking equity risk premium to be close to zero, or even negative, Ibbotson and Chen have found the long-term supply of equity risk premium to be only slightly lower than the straight historical estimate.

The supply side equity risk premium calculated earlier is a geometric calculation. An arithmetic calculation, as mentioned earlier in the chapter, is most appropriate when discounting future cash flows. For use as the expected equity risk premium in either the CAPM or the buildup approach, the arithmetic calculation is the relevant number. There are several ways to convert the geometric average into an arithmetic average. One method is to assume the returns are independently lognormally distributed over time, where the arithmetic and geometric averages roughly follow the following relationship:

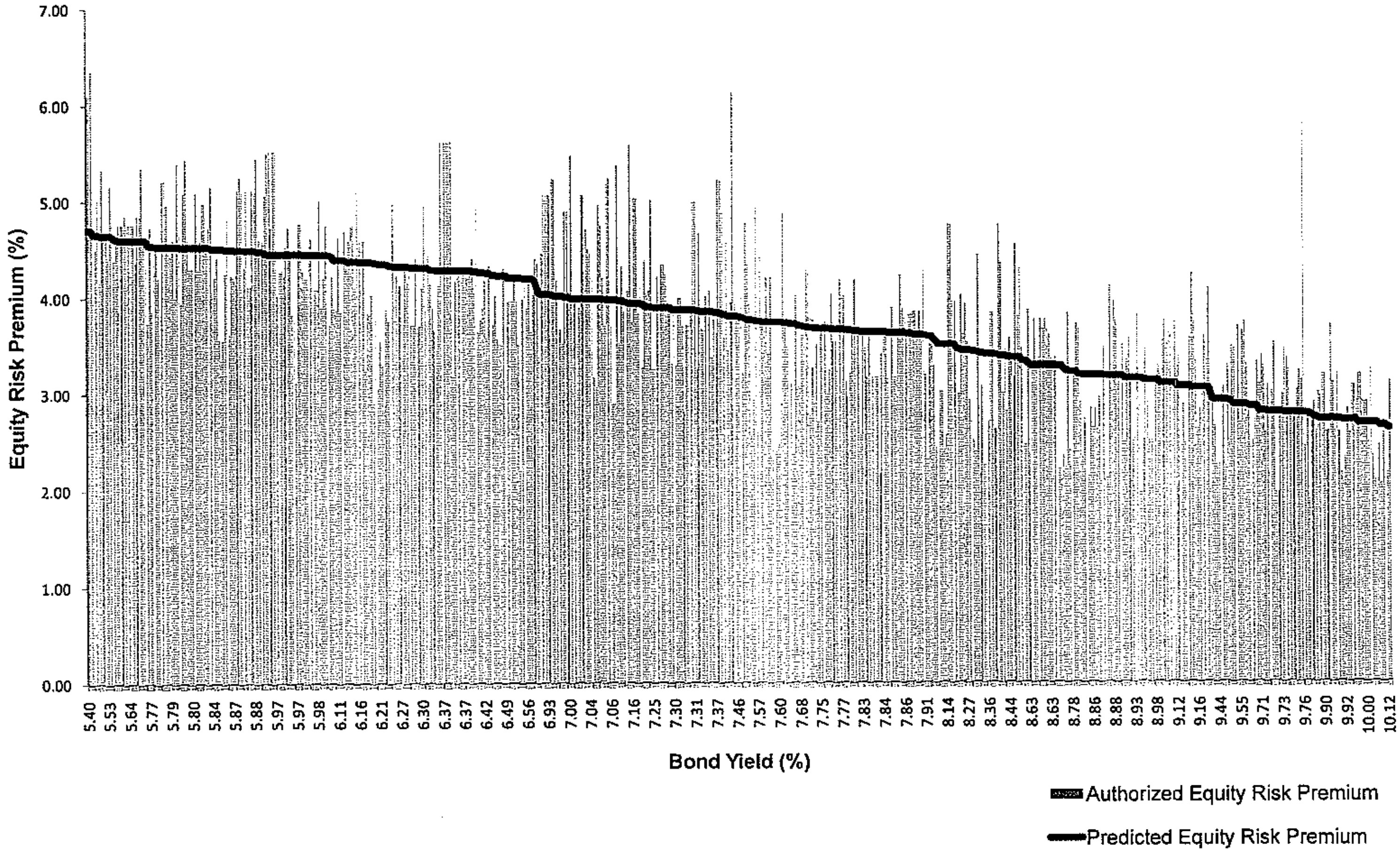
$$R_A = R_G + \frac{\sigma^2}{2}$$

$$5.18\% = 3.08\% + \frac{20.51\%^2}{2}$$

where:
R_A = the arithmetic average;
R_G = the geometric average;
σ = the standard deviation of equity returns.

Delmarva Power and Light Company
Esitmated Equity Risk Premia based upon Regression Analysis of
622 Fully-Litigated Gas and Electric Rate Orders
from January 1, 1989 through May 17, 2010

Prediction of Equity Risk Premium Relative to Moody's A Rated Public Utility Bond Yields



Source of Information:
Regulatory Research Associates (RRA)

Past Rate Cases

				Increase Authorized					
State	Company	Case Identification	Service	Date	Rate Increase ($M)	Return on Rate Base(%)	Return on Equity (%)	Moody's A Rated Utility Bonds	Implied Equity Risk Premium
Wisconsin	Wisconsin Power and Light Co	D-6680-UR-114 (elec)	Electric	7/19/2005	18.6	10.21	11.50	5.40	6.10
Wisconsin	Wisconsin Power and Light Co	D-6680-UR-114 (gas)	Natural Gas	7/19/2005	2.0	10.08	11.50	5.40	6.10
Texas	Cap Rock Energy Corp.	D-28813	Electric	8/5/2005	-1.3	6.17	11.75	5.40	6.35
Arkansas	CenterPoint Energy Resources	D-04-121-U	Natural Gas	9/19/2005	-11.3	5.31	9.45	5.50	3.95
Oregon	PacifiCorp	D-UE-170	Electric	9/28/2005	25.9	8.06	10.00	5.50	4.50
Illinois	Northern Illinois Gas Co.	D-04-0779	Natural Gas	9/30/2005	54.2	8.85	10.51	5.50	5.01
Arkansas	Arkansas Western Gas Co.	D-04-176-U	Natural Gas	11/2/2005	4.6	5.93	9.70	5.52	4.18
Minnesota	Northern States Power Co. - MN	D-E-002/GR-08-1065	Electric	10/23/2009	91.4	8.83	10.88	5.53	5.35
Nevada	Southwest Gas Corp.	D-09-04003 (Southern)	Natural Gas	10/28/2009	19.0	7.40	10.15	5.53	4.62
Nevada	Southwest Gas Corp.	D-09-04003 (Northern)	Natural Gas	10/28/2009	-0.2	8.30	10.15	5.53	4.62
Massachusetts	Bay State Gas Co.	DPU 09-30	Natural Gas	10/30/2009	19.1	8.18	9.95	5.53	4.42
Michigan	Consumers Energy Co.	C-U-15645	Electric	11/2/2009	139.4	6.98	10.70	5.53	5.17
Massachusetts	Massachusetts Electric Co.	DPU 09-39	Electric	11/30/2009	43.9	7.65	10.35	5.55	4.8
Vermont	Central Vermont Public Service	D-6946,6988	Electric	4/4/2005	-7.2	8.14	10.00	5.61	4.39
Arizona	Arizona Public Service Co.	D-U-1345A-03-0437	Electric	4/7/2005	75.5	7.80	10.25	5.61	4.64
Wisconsin	Wisconsin Electric Power Co.	D-5-UR-104 (WEP-EL)	Electric	12/18/2009	85.8	8.96	10.40	5.64	4.76
Wisconsin	Wisconsin Power and Light Co	6680 UR-117 (elec)	Electric	12/18/2009	58.6	8.81	10.40	5.64	4.76
Wisconsin	Wisconsin Electric Power Co.	D-5-UR-104 (WEP-GAS)	Natural Gas	12/18/2009	-2.0	8.65	10.40	5.64	4.76
Wisconsin	Wisconsin Gas LLC	D-5-UR-104 (WG)	Natural Gas	12/18/2009	5.7	9.09	10.50	5.64	4.86
Wisconsin	Wisconsin Power and Light Co	D-6680-UR-117 (gas)	Natural Gas	12/18/2009	5.6	8.84	10.40	5.64	4.76
Wisconsin	Madison Gas and Electric Co.	D-3270-UR-116 (elec)	Electric	12/22/2009	11.9	8.67	10.40	5.64	4.76
Wisconsin	Northern States Power Co - WI	D-4220-UR-116 (elec)	Electric	12/22/2009	8.4	8.93	10.40	5.64	4.76
Wisconsin	Madison Gas and Electric Co.	D-3270-UR-116 (gas)	Natural Gas	12/22/2009	-1.5	8.86	10.40	5.64	4.76
Maryland	Delmarva Power & Light Co.	C-9192	Electric	12/30/2009	7.5	7.96	10.00	5.64	4.36
Iowa	Interstate Power & Light Co.	D-RPU-2009-0002	Electric	1/4/2010	83.7	NA	10.50	5.64	4.86
Florida	Florida Power Corp.	D-090079-EI	Electric	1/11/2010	126.2	NA	10.50	5.64	4.86
Michigan	Detroit Edison Co.	C-U-15768	Electric	1/11/2010	217.4	7.02	11.00	5.64	5.36
Minnesota	CenterPoint Energy Resources	D-G-008/GR-08-1075	Natural Gas	1/11/2010	40.8	8.09	10.24	5.64	4.60
Florida	Florida Power & Light Co.	D-080677-EI	Electric	1/13/2010	75.5	6.65	10.00	5.64	4.36
Arizona	Southwest Gas Corp.	D-G-01551A-04-0876	Natural Gas	2/23/2006	49.3	8.40	9.50	5.75	3.75
Texas	CenterPoint Energy Resources	GUD 9902	Natural Gas	2/23/2010	5.1	8.65	10.50	5.77	4.73
District of Columbia	Potomac Electric Power Co.	F.C. 1076	Electric	3/2/2010	19.8	8.01	9.63	5.77	3.86
Washington	Puget Sound Energy Inc.	D-UE-04-0641	Electric	2/18/2005	56.6	8.40	10.30	5.78	4.52
Washington	Puget Sound Energy Inc.	D-UG-04-0640	Natural Gas	2/18/2005	26.3	8.40	10.30	5.78	4.52
Massachusetts	Bay State Gas Co.	DTE-05-27	Natural Gas	11/30/2005	11.1	8.22	10.00	5.79	4.21
Arkansas	Arkansas Oklahoma Gas Corp.	D-05-006-U	Natural Gas	12/9/2005	4.4	8.61	9.70	5.79	3.91
Wisconsin	Madison Gas and Electric Co.	D-3270-UR-114 (elec)	Electric	12/12/2005	35.9	9.37	11.00	5.79	5.21
Wisconsin	Madison Gas and Electric Co	D-3270-UR-114 (gas)	Natural Gas	12/12/2005	3.8	9.58	11.00	5.79	5.21
Oklahoma	Oklahoma Gas and Electric Co.	Ca-PUD-200500151	Electric	12/13/2005	42.3	8.66	10.75	5.79	4.96
Illinois	North Shore Gas Co.	D-09-0166	Natural Gas	1/21/2010	13.9	8.19	10.33	5.79	4.54
Illinois	Peoples Gas Light & Coke Co.	D-09-0167	Natural Gas	1/21/2010	69.8	8.05	10.23	5.79	4.44
Texas	Atmos Energy Corp.	GUD 9869	Natural Gas	1/26/2010	2.7	8.60	10.40	5.79	4.61
Rhode Island	Narragansett Electric Co.	D-4065	Electric	2/9/2010	23.5	7.20	9.80	5.79	4.01
Wisconsin	Wisconsin Electric Power Co.	D-05-UR-102 (WEP-GAS)	Natural Gas	1/25/2006	21.4	8.94	11.20	5.80	5.40
Wisconsin	Wisconsin Gas LLC	D-05-UR-102 (WG)	Natural Gas	1/25/2006	38.7	11.38	11.20	5.80	5.40
Connecticut	United Illuminating Co.	D-05-06-04	Electric	1/27/2006	14.3	6.88	9.75	5.80	3.95
Missouri	Empire District Electric Co.	C-ER-2006-0315	Electric	12/21/2006	29.4	9.10	10.90	5.80	5.10
Missouri	Kansas City Power & Light	C-ER-2006-0314	Electric	12/21/2006	50.6	8.89	11.25	5.80	5.45
Washington	Puget Sound Energy Inc.	D-UG-06-0267	Natural Gas	1/5/2007	29.5	8.40	10.40	5.80	4.60
Pennsylvania	Metropolitan Edison Co.C-R-	00061366	Electric	1/11/2007	58.7	7.52	10.10	5.80	4.30
Pennsylvania	Pennsylvania Electric Co.	C-R-00061367	Electric	1/11/2007	50.2	7.92	10.10	5.80	4.30
Wisconsin	Wisconsin Public Service Corp	D.6690-UR-118 (elec.)	Electric	1/11/2007	56.7	12.93	10.90	5.80	5.10
Wisconsin	Wisconsin Public Service Corp	D.6690-UR-118 (gas)	Natural Gas	1/11/2007	18.9	8.82	10.90	5.80	5.10
Oregon	Portland General Electric Co.	D-UE-180	Electric	1/12/2007	20.5	8.29	10.10	5.80	4.30
Washington	Puget Sound Energy Inc.	D-UE-06-0266	Electric	1/13/2007	-22.8	8.40	10.40	5.80	4.60
Wisconsin	Wisconsin Power and Light Co	D.6680-UR-115 (elec.)	Electric	1/19/2007	36.2	9.27	10.80	5.81	4.99
Wisconsin	Wisconsin Power and Light Co	D.6680-UR-115 (gas)	Natural Gas	1/19/2007	-1.9	9.15	10.80	5.81	4.99
Pennsylvania	UGI Central Penn Gas	C-R-00061398	Natural Gas	2/8/2007	8.1	8.44	10.40	5.81	4.59
Michigan	Consumers Energy Co.	C-U-15986	Natural Gas	5/17/2010	65.9	7.02	10.55	5.81	4.74
Michigan	Michigan Consolidated Gas Co.	C-U-13898	Natural Gas	4/28/2005	60.6	7.19	11.00	5.83	5.17
Illinois	Central Illinois Light Co.	D-09-0306	Electric	4/29/2010	2.2	8.05	9.90	5.84	4.06
Illinois	Central Illinois Public	D-09-0307	Electric	4/29/2010	17.5	8.02	10.06	5.84	4.22
Illinois	Illinois Power Co.	D-09-0308	Electric	4/29/2010	15.4	8.97	10.26	5.84	4.42
Illinois	Central Illinois Light Co.	D-09-0309	Natural Gas	4/29/2010	-7.4	7.83	9.40	5.84	3.56
Illinois	Central Illinois Public	D-09-0310	Natural Gas	4/29/2010	-1.7	7.59	9.19	5.84	3.35
Illinois	Illinois Power Co.	D-09-0311	Natural Gas	4/29/2010	-11.3	8.59	9.40	5.84	3.56
Illinois	MidAmerican Energy Co.	D-09-0312	Natural Gas	3/24/2010	2.7	7.60	10.13	5.87	4.26
Georgia	Atmos Energy Corp.	D-30442	Natural Gas	3/31/2010	2.9	8.61	10.70	5.87	4.83
Arizona	UNS Gas Inc.	D-G-04204A-08-0571	Natural Gas	4/1/2010	3.5	8.00	9.50	5.87	3.63
Washington	Puget Sound Energy Inc.	D-UE-090704	Electric	4/2/2010	74.1	8.10	10.10	5.87	4.23
Washington	Puget Sound Energy Inc.	D-UG-090705	Natural Gas	4/2/2010	10.1	8.10	10.10	5.87	4.23
Georgia	Atmos Energy Corp.	D-20298-U	Natural Gas	12/20/2005	0.4	7.57	10.13	5.88	4.25
Maryland	Baltimore Gas and Electric Co.	C-9036	Natural Gas	12/21/2005	35.6	8.49	11.00	5.88	5.12
Michigan	Consumers Energy Co.	C-U-14347	Electric	12/22/2005	177.4	6.78	11.15	5.88	5.27
Wisconsin	Wisconsin Public Service Corp	D-6690-UR-117 (elec.)	Electric	12/22/2005	79.9	12.06	11.00	5.88	5.12
Kentucky	Duke Energy Kentucky Inc.	C-2005-00042	Natural Gas	12/22/2005	8.1	7.63	10.20	5.88	4.32
Wisconsin	Wisconsin Public Service Corp	D-6690-UR-117 (gas)	Natural Gas	12/22/2005	7.2	8.85	11.00	5.88	5.12
Kansas	Kansas Gas and Electric Co.	D-05-WSEE-981-RTS (KG&E)	Electric	12/28/2005	-21.2	7.89	10.00	5.88	4.12
Kansas	Westar Energy Inc.	D-05-WSEE-981-RTS (WR)	Electric	12/28/2005	24.2	7.89	10.00	5.88	4.12
Wisconsin	Northern States Power Co-WI	D-4220-UR-114 (elec.)	Electric	1/5/2006	43.4	9.97	11.00	5.88	5.12
Wisconsin	Northern States Power Co-WI	D-4220-UR-114 (gas)	Natural Gas	1/5/2006	3.9	9.97	11.00	5.88	5.12
California	Pacific Gas and Electric Co.	AP-0512002 De-0703044 (gas)	Natural Gas	3/21/2007	20.5	8.79	11.35	5.90	5.45
Missouri	Southern Union Co.	C-GR-2006-0422	Natural Gas	3/22/2007	27.2	8.60	10.50	5.90	4.60
Texas	Atmos Energy Corp.	GUD-9670	Natural Gas	3/29/2007	4.8	7.90	10.00	5.90	4.10
Kansas	Mid-Kansas Electric Company	D-04-AQLE-1065-RTS	Electric	1/28/2005	7.4	8.73	10.50	5.92	4.58
Michigan	Detroit Edison Co.	C-U-13808	Electric	11/23/2004	373.7	7.24	11.00	5.94	5.06
Wisconsin	Wisconsin Public Service Corp	D-6690-UR-116 (elec)	Electric	12/21/2004	60.7	11.57	11.50	5.97	5.53
Wisconsin	Wisconsin Public Service Corp	D-6690-UR-116 (gas)	Natural Gas	12/21/2004	5.6	8.33	11.50	5.97	5.53
Pennsylvania	PPL Electric Utilities Corp.	C-R-00049255	Electric	12/22/2004	194.3	8.43	10.70	5.97	4.73
Wisconsin	Madison Gas and Electric Co.	D-3270-UR-113 (elec)	Electric	12/22/2004	27.4	9.92	11.50	5.97	5.53
Wisconsin	Madison Gas and Electric Co.	D-3270-UR-113 (gas)	Natural Gas	12/22/2004	-4.2	9.94	11.50	5.97	5.53
Virginia	Appalachian Power Co.	C-PUE-2006-00065	Electric	5/15/2007	24.0	7.36	10.00	5.97	4.03
Missouri	KCP&L Greater Missouri Op Co	C-ER-2007-0004 (L&P)	Electric	5/17/2007	13.6	8.93	10.25	5.97	4.28
Missouri	KCP&L Greater Missouri Op Co	C-ER-2007-0004 (MPS)	Electric	5/17/2007	45.2	8.39	10.25	5.97	4.28
Missouri	Union Electric Co.	C-ER-2007-0002	Electric	5/22/2007	41.8	7.94	10.20	5.97	4.23
West Virginia	Monongahela Power Co.	C-06-0960-E-42T	Electric	5/22/2007	-6.2	8.44	10.50	5.97	4.53
Nevada	Nevada Power Co.	D-06-11022	Electric	5/23/2007	120.5	9.06	10.70	5.97	4.73
Nebraska	NorthWestern Energy Division	D-NG-0048	Natural Gas	12/18/2007	1.5	NA	10.40	5.97	4.43
New York	Brooklyn Union Gas Co.	C-06-G-1185	Natural Gas	12/19/2007	46.9	NA	9.80	5.97	3.83
New York	KeySpan Gas East Corp.	C-06-G-1186	Natural Gas	12/18/2007	62.4	NA	9.80	5.97	3.83
New York	National Fuel Gas Dist Corp.	C-07-G-0141	Natural Gas	12/21/2007	1.6	7.61	9.10	5.97	3.13
Wisconsin	Northern States Power Co-WI	D-4220-UR-115 (elec)	Electric	1/8/2008	39.4	9.67	10.75	5.97	4.78
Wisconsin	Northern States Power Co-WI	D-4220-UR-115 (gas)	Natural Gas	1/8/2008	5.3	9.67	10.75	5.97	4.78
Texas	Oncor Electric Delivery Co.	D-35717	Electric	8/31/2009	115.1	8.28	10.25	5.97	4.28
Tennessee	Chattanooga Gas Company	D-04-00034	Natural Gas	10/20/2004	0.6	7.43	10.20	5.98	4.22
Washington	PacifiCorp	D-UE-05-0684	Electric	4/17/2006	0.0	8.10	10.20	5.98	4.22
Nevada	Sierra Pacific Power Co.	D-05-10003	Electric	4/26/2006	-14.0	8.96	10.60	5.98	4.62
Nevada	Sierra Pacific Power Co.	D-05-10005	Natural Gas	4/26/2006	4.9	7.98	10.60	5.98	4.62
Illinois	Central Illinois Light Co.	D-06-0070	Electric	11/21/2006	20.7	7.94	10.12	5.98	4.14
Illinois	Central Illinois Public	D-06-0071	Electric	11/21/2006	-8.0	8.06	10.08	5.98	4.10
Illinois	Illinois Power Co.	D-06-0072	Electric	11/21/2006	84.0	8.33	10.08	5.98	4.10
Michigan	Consumers Energy Co.	C-U-14547	Natural Gas	11/21/2006	80.8	8.69	11.00	5.98	5.02
Arkansas	Entergy Arkansas Inc.	D-06-101-U	Electric	6/15/2007	-5.1	5.58	9.90	5.99	3.91
Washington	PacifiCorp	D-UE-06-1546	Electric	6/21/2007	14.4	8.06	10.20	5.99	4.21

State	Company	Case Identification	Service	Date	Rate Increase ($M)	Return on Rate Base(%)	Return on Equity (%)	Moody's A Rated Utility Bonds	Implied Equity Risk Premium
Arizona	Arizona Public Service Co.	D-E-01345A-05-0816	Electric	6/28/2007	321.7	8.32	10.75	5.99	4.76
New Mexico	Public Service Co. of NM	C-06-00210-UT	Natural Gas	6/29/2007	8.6	7.96	9.53	5.99	3.54
Minnesota	CenterPoint Energy Resources	D-G-008-GR-05-1380	Natural Gas	11/2/2006	21.0	7.54	9.71	6.00	3.71
Massachusetts	Fitchburg Gas & Electric Light	DPU-07-71	Electric	2/29/2008	2.1	8.38	10.25	6.02	4.23
Maryland	Washington Gas Light Co.	C-9104	Natural Gas	11/15/2007	20.6	8.20	10.00	6.11	3.89
Arizona	UNS Gas Inc.	D-G-04204A-06-0463	Natural Gas	11/27/2007	5.3	8.30	10.00	6.11	3.89
Missouri	Kansas City Power & Light	C-ER-2007-0291	Electric	12/6/2007	35.3	8.68	10.75	6.11	4.64
Texas	AEP Texas Central Co.	D-33309	Electric	12/13/2007	40.8	7.50	9.96	6.11	3.85
Wisconsin	Madison Gas and Electric Co.	D-3270-UR-115 (elec)	Electric	12/14/2007	16.2	9.06	10.80	6.11	4.69
Wisconsin	Madison Gas and Electric Co.	D-3270-UR-115 (gas)	Natural Gas	12/14/2007	7.8	9.09	10.80	6.11	4.69
Missouri	Southern Union Co.	C-GR-2004-0209	Natural Gas	9/21/2004	22.5	8.36	10.50	6.14	4.36
Wyoming	PacifiCorp	D-20000-ER-03-198	Electric	3/2/2004	22.9	8.42	10.75	6.15	4.60
California	Southwest Gas Corp.	AP-02-02-012 (So.Div)	Natural Gas	3/16/2004	3.6	9.17	10.90	6.15	4.75
California	Southwest Gas Corp.	AP-02-02-012 (No.Div)	Natural Gas	3/16/2004	3.8	9.17	10.90	6.15	4.75
Nevada	Nevada Power Co.	D-03-10001	Electric	3/26/2004	48.0	9.03	10.25	6.15	4.10
Minnesota	Interstate Power Co.	D-E-001/GR-03-767	Electric	4/5/2004	0.6	9.17	11.25	6.15	5.10
Wisconsin	Wisconsin Electric Power Co.	D-5-UR-103 (WEP-EL)	Electric	1/17/2008	148.4	9.26	10.75	6.16	4.59
Wisconsin	Wisconsin Electric Power Co.	D-5-UR-103 (WEP-GAS)	Natural Gas	1/17/2008	4.0	9.15	10.75	6.16	4.59
Wisconsin	Wisconsin Gas LLC	D-5-UR-103 (WG)	Natural Gas	1/17/2008	20.1	10.81	10.75	6.16	4.59
Connecticut	Connecticut Light & Power Co.	D-07-07-01	Electric	1/28/2008	98.0	7.72	9.40	6.16	3.24
District of Columbia	Potomac Electric Power Co.	FC-1053	Electric	1/30/2008	28.3	7.96	10.00	6.16	3.84
Illinois	North Shore Gas Co.	D-07-0241	Natural Gas	2/5/2008	-0.2	7.96	9.99	6.16	3.83
Illinois	Peoples Gas Light & Coke Co.	D-07-0242	Natural Gas	2/5/2008	71.2	7.76	10.19	6.16	4.03
New York	Orange & Rockland Utils Inc.	C-06-E-1433	Electric	10/17/2007	0.0	7.56	9.10	6.18	2.92
Texas	Electric Transmission Texas	D-33734	Electric	10/31/2007	12.0	7.88	9.96	6.18	3.78
Connecticut	Southern Connecticut Gas Co.	D-08-12-07	Natural Gas	7/17/2009	-12.5	8.05	9.26	6.20	3.06
New Jersey	Rockland Electric Company	D-ER-02100724	Electric	7/16/2003	-7.2	8.02	9.75	6.21	3.54
New Jersey	Jersey Cntrl Power & Light Co.	D-ER-02080506 PhaseI	Electric	7/25/2003	-222.7	8.38	9.50	6.21	3.29
New York	Consolidated Edison Co. of NY	C-07-E-0523	Electric	3/25/2008	425.3	7.34	9.10	6.21	2.89
New Mexico	Public Service Co. of NM	C-07-00077-UT	Electric	4/24/2008	34.4	8.24	10.10	6.21	3.89
Oklahoma	Public Service Co. of OK	Ca-PUD-200600285	Electric	10/9/2007	9.8	8.01	10.00	6.24	3.76
Minnesota	Northern States Power Co. - MN	D-G-002-GR-06-1429	Natural Gas	9/10/2007	14.4	8.37	9.71	6.25	3.46
Florida	Pivotal Utility Holdings Inc.	D-030569-GU	Natural Gas	2/9/2004	6.7	7.36	11.25	6.27	4.98
Nevada	Southwest Gas Corp	D-04-3011(Southern)	Natural Gas	8/26/2004	7.3	7.45	10.50	6.27	4.23
Nevada	Southwest Gas Corp.	D-04-3011(Northern)	Natural Gas	8/26/2004	6.4	8.56	10.50	6.27	4.23
Idaho	Avista Corp.	C-AVU-E-04-1	Electric	9/9/2004	24.7	9.25	10.40	6.27	4.13
Idaho	Avista Corp.	C-AVU-G-04-1	Natural Gas	9/9/2004	3.3	9.25	10.40	6.27	4.13
Texas	Atmos Energy Corp.	GUD-9762	Natural Gas	6/24/2008	19.7	7.98	10.00	6.27	3.73
Nevada	Sierra Pacific Power Co.	D-07-12001	Electric	6/27/2008	87.1	8.41	10.60	6.27	4.33
Minnesota	Otter Tail Corp.	D-E-017/GR-07-1178	Electric	7/10/2008	3.8	8.33	10.43	6.27	4.16
California	Southern California Edison Co.	Ap-04-12-014	Electric	5/17/2006	133.9	8.77	11.60	6.29	5.31
Delaware	Delmarva Power & Light Co.	D-05-304	Electric	6/6/2006	-11.1	7.17	10.00	6.29	3.71
Arizona	UNS Electric Inc.	D-E-04204A-06-0783	Electric	5/27/2008	4.0	9.02	10.00	6.29	3.71
Michigan	Consumers Energy Co.	C-U-15245	Electric	6/10/2008	221.0	6.93	10.70	6.29	4.41
Maryland	Delmarva Power & Light Co.	C-9093	Electric	7/19/2007	14.9	7.68	10.00	6.30	3.70
Maryland	Potomac Electric Power Co.	C-9092	Electric	7/19/2007	10.6	7.99	10.00	6.30	3.70
Nebraska	Black Hills Nebraska Gas	D-NG-0041	Natural Gas	7/24/2007	9.2	8.80	10.40	6.30	4.10
Florida	Tampa Electric Co.	D-080317-EI	Electric	3/17/2009	147.7	8.29	11.25	6.30	4.95
Illinois	Northern Illinois Gas Co.	D-08-0363	Natural Gas	3/25/2009	80.2	8.09	10.17	6.30	3.87
Minnesota	ALLETE (Minnesota Power)	D-E-015/GR-08-415	Electric	4/3/2009	20.4	8.45	10.74	6.30	4.44
Indiana	Duke Energy Indiana Inc.	Ca-42359	Electric	5/18/2004	107.3	7.30	10.50	6.35	4.15
Idaho	Idaho Power Co.	C-IPC-E-03-13	Electric	5/25/2004	39.5	7.85	10.25	6.35	3.90
Texas	Atmos Energy Corp.	GUD-9400	Natural Gas	5/25/2004	12.0	8.26	10.00	6.35	3.65
Connecticut	Connecticut Light & Power Co.	D-03-07-02	Electric	12/17/2003	70.5	8.19	9.85	6.37	3.48
Virginia	Washington Gas Light Co.	C-PUE-2002-00364	Natural Gas	12/18/2003	10.8	8.44	10.50	6.37	4.13
Wisconsin	Wisconsin Power and Light Co	D-6680-UR-113 (elec)	Electric	12/19/2003	14.5	10.23	12.00	6.37	5.63
Wisconsin	Wisconsin Public Service Corp	D-6690-UR-115 (elec)	Electric	12/19/2003	59.4	9.91	12.00	6.37	5.63
Wisconsin	Wisconsin Power and Light Co	D-6680-UR-113 (gas)	Natural Gas	12/19/2003	-0.4	10.15	12.00	6.37	5.63
Wisconsin	Wisconsin Public Service Corp	D-6690-UR-115 (gas)	Natural Gas	12/18/2003	8.9	9.28	12.00	6.37	5.63
Wisconsin	Madison Gas and Electric Co.	D-3270-UR-112 (elec)	Electric	1/13/2004	11.7	10.11	12.00	6.37	5.63
Wisconsin	Madison Gas and Electric Co.	D-3270-UR-112 (gas)	Natural Gas	1/13/2004	1.0	10.23	12.00	6.37	5.63
New York	NY State Electric & Gas Corp.	C-05-E-1222	Electric	8/23/2006	-36.3	7.18	9.55	6.37	3.18
Minnesota	Northern States Power Co - MN	D-E-002-GR-05-1428	Electric	9/1/2006	131.5	8.81	10.54	6.37	4.17
Georgia	Atmos Energy Corp.	D-27163-U	Natural Gas	9/17/2008	3.4	7.75	10.70	6.37	4.33
Illinois	Central Illinois Light Co.	D-07-0585	Electric	9/24/2008	-2.6	8.01	10.65	6.37	4.28
Illinois	Central Illinois Public	D-07-0586	Electric	9/24/2008	22.0	8.20	10.65	6.37	4.28
Illinois	Illinois Power Co.	D-07-0587	Electric	9/24/2008	103.9	8.68	10.65	6.37	4.28
Illinois	Central Illinois Light Co	D-07-0588	Natural Gas	9/24/2008	-9.2	8.03	10.68	6.37	4.31
Illinois	Central Illinois Public	D-07-0589	Natural Gas	9/24/2008	7.7	8.22	10.68	6.37	4.31
Illinois	Illinois Power Co.	D-07-0590	Natural Gas	9/24/2008	39.8	8.70	10.68	6.37	4.31
Missouri	Empire District Electric Co.	C-ER-2008-0093	Electric	7/30/2008	22.0	8.92	10.80	6.38	4.42
Indiana	Indiana Michigan Power Co.	Ca-43306	Electric	3/4/2009	19.1	7.82	10.50	6.39	4.11
California	Southern California Edison Co.	Ap-07-11-011	Electric	3/12/2009	308.1	8.75	11.50	6.39	5.11
Illinois	Commonwealth Edison Co.	D-05-0597	Electric	7/28/2006	82.6	8.01	10.05	6.40	3.65
New Mexico	Southwestern Public Service Co	C-07-00319-UT	Electric	8/26/2008	13.1	8.27	10.18	6.40	3.78
Illinois	Commonwealth Edison Co.	D-07-0566	Electric	9/10/2008	273.6	8.36	10.30	6.40	3.90
Utah	PacifiCorp	D-08-035-38	Electric	4/21/2009	45.0	8.36	10.61	6.42	4.19
New York	Consolidated Edison Co. of NY	C-08-E-0539	Electric	4/24/2009	523.4	7.79	10.00	6.42	3.58
Florida	Peoples Gas System	D-080318-GU	Natural Gas	5/5/2009	19.2	8.50	10.75	6.42	4.33
California	Southern California Edison Co.	AP-0205004 De-0407022	Electric	7/16/2004	73.0	9.39	11.60	6.46	5.14
Minnesota	Minnesota Energy Resources	D-G-007,011/GR-08-835	Natural Gas	5/21/2009	15.4	7.98	10.21	6.48	3.73
Idaho	Idaho Power Co.	C-IPC-E-09-07	Electric	5/29/2009	10.5	8.18	10.50	6.48	4.02
Texas	CenterPoint Energy Resources	GUD 9791	Natural Gas	10/20/2008	1.2	8.60	10.06	6.49	3.57
New York	Central Hudson Gas & Electric	C-08-G-0888	Natural Gas	6/18/2009	13.8	7.28	10.00	6.49	3.51
New York	Central Hudson Gas & Electric	C-08-E-0887	Electric	6/22/2009	39.6	7.28	10.00	6.49	3.51
Nevada	Nevada Power Co.	D-08-12002	Electric	6/24/2009	222.7	8.66	10.80	6.49	4.31
Connecticut	CT Natural Gas Corp.	D-08-12-06	Natural Gas	6/30/2009	-16.2	7.92	9.31	6.49	2.82
Ohio	Cleveland Elec Illuminating Co	C-07-0551-EL-AIR (CEI)	Electric	1/21/2009	28.2	8.48	10.50	6.54	3.96
Ohio	Ohio Edison Co.	C-07-0551-EL-AIR (OE)	Electric	1/21/2009	68.9	8.48	10.50	6.54	3.96
Ohio	Toledo Edison Co.	C-07-0551-EL-AIR (TE)	Electric	1/21/2009	38.5	8.48	10.50	6.54	3.96
Missouri	Union Electric Co.	C-ER-2008-0318	Electric	1/27/2009	161.7	8.34	10.76	6.54	4.22
Idaho	Idaho Power Co.	C-IPC-E-08-10	Electric	1/30/2009	27.0	8.18	10.50	6.54	3.96
Massachusetts	New England Gas Company	DPU 08-35	Natural Gas	2/2/2009	3.7	7.74	10.05	6.54	3.51
Connecticut	United Illuminating Co.	D-08-07-04	Electric	2/4/2009	6.1	7.59	8.75	6.54	2.21
Illinois	Central Illinois Light Co.	D-02-0837	Natural Gas	10/17/2003	9.1	8.16	10.54	6.56	3.98
Illinois	Central Illinois Public	D-03-0008	Natural Gas	10/22/2003	7.2	8.33	10.71	6.56	4.15
Illinois	Union Electric Co.	D-03-0009	Natural Gas	10/22/2003	1.9	8.24	10.46	6.56	3.90
Maryland	Washington Gas Light Co.	C-8959	Natural Gas	10/31/2003	2.9	8.61	10.75	6.56	4.19
Massachusetts	Boston Gas Co.	DTE-03-40	Natural Gas	10/31/2003	19.7	9.08	10.20	6.56	3.64
District of Columbia	Washington Gas Light Co.	FC-1016	Natural Gas	11/10/2003	5.4	8.42	10.60	6.56	4.04
Iowa	Interstate Power & Light Co.	D-RPU-02-7	Natural Gas	5/15/2003	13.3	9.03	11.05	6.64	4.41
Iowa	Interstate Power & Light Co.	D-RPU-02-3	Electric	4/15/2003	25.8	9.08	11.15	6.79	4.36
Connecticut	Connecticut Light & Power Co.	D-98-01-02	Electric	2/5/1999	-231.9	8.12	10.30	6.91	3.39
North Carolina	Public Service Co. of NC	D-G-5,SUB386	Natural Gas	10/30/1998	12.4	9.62	11.40	6.93	4.47
Wisconsin	Wisconsin Public Service Corp	D-6690-UR-114 (elec)	Electric	3/20/2003	21.4	9.61	12.00	6.93	5.07
Wisconsin	Wisconsin Public Service Corp	D-6690-UR-114 (gas)	Natural Gas	3/20/2003	-1.2	9.59	12.00	6.93	5.07
Wisconsin	Wisconsin Power and Light Co	D-6680-UR-112 (elec)	Electric	4/3/2003	77.1	10.22	12.00	6.93	5.07
Wisconsin	Wisconsin Power and Light Co	D-6680-UR-112 (gas)	Natural Gas	4/3/2003	3.6	10.20	12.00	6.93	5.07
Wisconsin	Madison Gas and Electric Co.	D-3270-UR-109 (elec.)	Electric	12/10/1998	8.4	11.24	12.20	6.96	5.24
Wisconsin	Madison Gas and Electric Co.	D-3270-UR-109 (gas)	Natural Gas	12/10/1998	0.7	11.01	12.20	6.96	5.24
Virginia	Columbia Gas of Virginia Inc	C-PUE-970455	Natural Gas	2/19/1999	4.6	8.96	11.15	6.97	4.18
Illinois	Central Illinois Public	D-98-0545	Natural Gas	3/1/1999	7.9	8.51	10.65	6.97	3.68
Illinois	Union Electric Co.	D-98-0546	Natural Gas	3/1/1999	1.6	8.99	10.65	6.97	3.68
Utah	PacifiCorp	D-97-035-01	Electric	3/4/1999	-97.8	8.84	10.50	6.97	3.53
Wisconsin	Northern States Power Co-WI	D-4220-UR-110 (elec.)	Electric	9/15/1998	7.3	10.25	11.90	7.00	4.90
Wisconsin	Northern States Power Co-WI	D-4220-UR-110 (gas)	Natural Gas	9/15/1998	-1.9	10.52	11.90	7.00	4.90
Tennessee	Chattanooga Gas Company	D-97-00982	Natural Gas	10/7/1998	-1.2	9.08	11.06	7.00	4.06
Delaware	Delmarva Power & Light Co.	D-91-24	Natural Gas	11/23/1993	4.1	8.85	12.50	7.03	5.47

State	Company	Case Identification	Service	Date	Rate Increase ($M)	Return on Rate Base(%)	Return on Equity (%)	Moody's A Rated Utility Bonds	Implied Equity Risk Premium
Colorado	Public Service Co. of CO	D-93S-001E	Electric	11/26/1993	-13.1	9.40	11.00	7.03	3.97
Colorado	Public Service Co. of CO	D-93S-001G	Natural Gas	11/26/1993	7.1	9.40	11.00	7.03	3.97
Maine	Central Maine Power Co.	D-92-345	Electric	12/14/1993	26.0	8.52	10.55	7.03	3.52
Missouri	Southern Union Co.	C-GR-96-140	Natural Gas	8/26/1996	13.3	9.40	10.93	7.03	3.90
Wisconsin	Wisconsin Public Service Corp	D-6690-UR-111 (elec)	Electric	12/17/1998	26.9	10.79	12.10	7.03	5.07
Wisconsin	Wisconsin Public Service Corp	D-6690-UR-111 (gas)	Natural Gas	12/17/1998	10.3	10.62	12.10	7.03	5.07
Virginia	Columbia Gas of Virginia Inc	C-PUE-920037	Natural Gas	10/15/1993	5.6	9.73	11.75	7.04	4.71
Nevada	Southwest Gas Corp.	D-93-3004(Southern)	Natural Gas	10/25/1993	-0.6	8.89	11.55	7.04	4.51
Michigan	Michigan Consolidated Gas Co.	C-U-10150	Natural Gas	10/28/1993	15.7	8.04	11.50	7.04	4.46
Massachusetts	Boston Gas Co.	DPU-93-60	Natural Gas	10/29/1993	37.7	9.91	11.25	7.04	4.21
West Virginia	Hope Gas Inc	C-92-1068-G-P	Natural Gas	10/29/1993	1.8	8.76	10.20	7.04	3.16
West Virginia	Equitable Gas Company	C-93-005-G-42T	Natural Gas	10/29/1993	3.4	9.62	10.10	7.04	3.06
Indiana	Indiana Michigan Power Co.	Ca-39314	Electric	11/12/1993	34.7	8.78	12.00	7.04	4.96
Wisconsin	Wisconsin Gas LLC	D-6650-GR-111	Natural Gas	11/12/1993	12.3	10.48	11.80	7.04	4.76
Vermont	Green Mountain Power Corp.	D-5983	Electric	3/2/1998	5.6	9.21	11.25	7.05	4.20
Missouri	KCP&L Greater Missouri Op Co	C-ER-97-394	Electric	3/6/1998	-16.9	9.10	10.75	7.05	3.70
Wisconsin	Madison Gas and Electric Co.	D-3270-UR-111 (elec)	Electric	2/28/2003	20.3	10.17	12.30	7.06	5.24
Wisconsin	Madison Gas and Electric Co.	D-3270-UR-111 (gas)	Natural Gas	2/28/2003	6.8	10.32	12.30	7.06	5.24
Wyoming	PacifiCorp	D-20000-ER-02-184	Electric	3/6/2003	8.7	8.45	10.75	7.06	3.69
New York	Rochester Gas & Electric Corp.	C-02-E-0198	Electric	3/7/2003	-15.6	8.11	9.96	7.06	2.90
New York	Rochester Gas & Electric Corp.	C-02-G-0199	Natural Gas	3/7/2003	5.5	8.11	9.96	7.06	2.90
South Carolina	South Carolina Electric & Gas	D-2002-223-E	Electric	1/31/2003	70.7	9.84	12.45	7.07	5.38
District of Columbia	Washington Gas Light Co.	FC-989	Natural Gas	10/30/2002	-7.5	8.83	10.60	7.08	3.52
Michigan	Consumers Energy Co.	C-U-13000	Natural Gas	11/7/2002	55.7	7.45	11.40	7.08	4.32
Hawaii	Maui Electric Company Ltd	D-97-0346	Electric	4/6/1999	11.3	8.83	10.94	7.09	3.85
Louisiana	Entergy Louisiana Holdings	D-U-20925-E	Electric	3/20/1998	-8.1	NA	10.50	7.12	3.38
Utah	Questar Gas Co.	D-02-057-02	Natural Gas	12/30/2002	11.2	9.64	11.20	7.14	4.06
Maine	Bangor Hydro-Electric Co.	D-97-116	Electric	2/2/1998	13.2	9.65	12.75	7.16	5.59
Virginia	Virginia Natural Gas Inc.	C-PUE-960227	Natural Gas	4/28/1998	7.2	9.24	10.90	7.16	3.74
Wisconsin	Wisconsin Electric Power Co.	D-6630-UR-110 (elec.)	Electric	4/30/1998	160.2	10.48	12.20	7.16	5.04
Wisconsin	Wisconsin Electric Power Co.	D-6630-UR-110 (gas)	Natural Gas	4/30/1998	18.5	10.32	12.20	7.16	5.04
Georgia	Atlanta Gas Light Co.	D-8390-U	Natural Gas	6/30/1998	-7.4	9.11	11.00	7.16	3.84
Texas	Entergy Texas Inc.	D-16705	Electric	7/10/1998	-122.0	9.76	11.40	7.16	4.24
Connecticut	United Illuminating Co.	D-01-10-10	Electric	9/26/2002	-30.9	8.41	10.45	7.17	3.28
Michigan	Consumers Energy Co.	C-U-10755	Natural Gas	3/11/1996	-11.7	7.83	11.60	7.22	4.38
Colorado	Public Service Co. of CO	D-98S-518G	Natural Gas	6/8/1999	14.8	9.43	11.25	7.22	4.03
Virginia	Virginia Natural Gas Inc.	C-PUE-940054	Natural Gas	1/31/1998	6.1	9.64	11.30	7.23	4.07
Michigan	Consumers Energy Co.	C-U-10685	Electric	2/5/1996	46.5	8.06	12.25	7.23	5.02
Washington	Puget Sound Energy Inc.	D-UE-92-1262	Electric	9/21/1993	-64.0	8.94	10.50	7.25	3.25
Washington	Puget Sound Energy Inc.	D-UG-92-084	Natural Gas	9/27/1993	-16.9	9.15	10.50	7.25	3.25
Minnesota	Northern States Power Co. - MN	D-E-002-GR-92-1185	Electric	9/29/1993	72.2	9.31	11.47	7.25	4.22
Georgia	Atlanta Gas Light Co.	D-4451-U	Natural Gas	9/29/1993	11.2	9.32	11.00	7.25	3.75
Wisconsin	Wisconsin Power and Light Co	D-6680-UR-108 (elec)	Electric	9/30/1993	15.6	9.56	11.60	7.25	4.35
Wisconsin	Wisconsin Power and Light Co	D-6680-UR-108 (gas)	Natural Gas	9/30/1993	1.8	NA	11.60	7.25	4.35
District of Columbia	Washington Gas Light Co.	FC-922	Natural Gas	10/8/1993	4.7	9.86	11.50	7.25	4.25
Rhode Island	Narragansett Electric Co.	D-2082	Natural Gas	10/14/1993	0.7	9.32	11.20	7.25	3.95
Hawaii	Maui Electric Company Ltd	D-96-0040	Electric	12/23/1997	0.0	9.13	11.12	7.25	3.87
New York	Central Hudson Gas & Electric	C-92-E-1055	Electric	12/16/1993	5.1	8.58	10.60	7.30	3.30
Connecticut	CT Natural Gas Corp.	D-93-02-04	Natural Gas	12/16/1993	7.6	9.65	11.20	7.30	3.90
New York	Central Hudson Gas & Electric	C-92-G-1056	Natural Gas	12/16/1993	0.0	8.58	10.60	7.30	3.30
Wisconsin	Wisconsin Public Service Corp	D-6690-UR-108 (elec)	Electric	12/21/1993	-17.4	10.72	11.30	7.30	4.00
Wisconsin	Wisconsin Public Service Corp	D-6690-UR-108 (gas)	Natural Gas	12/21/1993	1.0	10.82	11.30	7.30	4.00
California	Southern California Gas Co.	AP-9211017 De-9312043	Natural Gas	12/22/1993	-132.0	9.22	11.00	7.30	3.70
New York	Long Island Lighting Co	C-93-G-0002	Natural Gas	12/23/1993	25.6	9.39	10.10	7.30	2.80
Utah	Questar Gas Co.	D-93-057-01	Natural Gas	1/10/1994	-1.8	10.08	11.00	7.30	3.70
Arizona	Tucson Electric Power Co.	D-U-1933-93-006	Electric	1/13/1994	21.6	8.51	11.00	7.30	3.70
Illinois	MidAmerican Energy Co.	D-01-0696	Natural Gas	9/11/2002	0.0	8.85	11.20	7.31	3.89
Wisconsin	Wisconsin Power and Light Co	D-6680-UR-111 (elec.)	Electric	9/12/2002	60.1	10.02	12.30	7.31	4.99
Wisconsin	Wisconsin Power and Light Co	D-6680-UR-111 (gas)	Natural Gas	9/12/2002	21.5	9.93	12.30	7.31	4.99
Maine	Bangor Hydro-Electric Co.	D-93-062	Electric	2/17/1994	11.0	9.25	10.60	7.33	3.27
Oklahoma	Oklahoma Gas and Electric Co.	Ca-PUD-90000898-etal	Electric	2/25/1994	-18.9	9.99	12.00	7.33	4.67
District of Columbia	Potomac Electric Power Co.	FC-929	Electric	3/4/1994	25.4	9.05	11.00	7.33	3.67
Michigan	Detroit Edison Co.	C-U-10102	Electric	1/21/1994	-76.0	7.66	11.00	7.34	3.66
Texas	Oncor Electric Delivery Co.	D-11735	Electric	1/28/1994	435.4	9.98	11.35	7.34	4.01
New York	Niagara Mohawk Power Corp.	C-93-G-0162	Natural Gas	2/2/1994	10.1	9.17	10.40	7.34	3.06
Virginia	Virginia Electric & Power Co.	C-PUE-920041	Electric	2/3/1994	241.9	9.19	11.40	7.34	4.06
Arkansas	CenterPoint Energy Resources	D-93-081-U	Natural Gas	2/8/1994	5.5	8.56	10.70	7.34	3.36
Illinois	Northern Illinois Gas Co.	D-95-0219	Natural Gas	4/3/1996	33.4	9.67	11.13	7.37	3.76
Minnesota	Interstate Power Co.	D-E-001-GR-95-601	Electric	4/8/1996	2.3	8.92	11.00	7.37	3.63
Ohio	Cleveland Elec Illuminating Co	C-95-300-EL-AIR	Electric	4/11/1996	83.9	10.06	12.59	7.37	5.22
Ohio	Toledo Edison Co.	C-95-299-EL-AIR	Electric	4/11/1996	35.2	10.06	12.59	7.37	5.22
Wisconsin	Wisconsin Public Service Corp	D-6690-UR-113 (gas)	Natural Gas	6/20/2002	10.6	10.24	12.30	7.42	4.88
Vermont	Frontier Communications Corp.	D-6596	Electric	7/15/2002	4.8	8.43	11.00	7.42	3.58
South Carolina	South Carolina Electric & Gas	D-95-1000-E	Electric	12/27/1995	67.5	9.60	12.00	7.43	4.57
Rhode Island	Narragansett Electric Co.	D-2286	Natural Gas	11/17/1995	4.0	9.21	10.90	7.46	3.44
Maryland	Baltimore Gas and Electric Co.	C-8697	Natural Gas	11/20/1995	16.9	9.04	11.40	7.46	3.94
Alabama	Mobile Gas Service Corp	D-24794	Natural Gas	11/27/1995	6.9	11.08	13.60	7.46	6.14
Hawaii	Hawaiian Electric Co.	D-7766	Electric	12/11/1995	9.1	9.16	11.40	7.46	3.94
Wisconsin	Northern States Power Co-WI	D-4220-UR-108 (gas)	Natural Gas	12/14/1995	2.5	10.72	11.30	7.46	3.84
Illinois	Illinois Power Co.	D-93-0183	Natural Gas	4/6/1994	18.9	9.29	11.24	7.47	3.77
Tennessee	Piedmont Natural Gas Co.	D-96-00977	Natural Gas	12/17/1996	4.4	9.65	11.50	7.49	4.01
Arizona	UNS Electric Inc.	D-E-1032-95-433	Electric	1/3/1997	0.5	8.68	10.70	7.49	3.21
Wisconsin	Wisconsin Public Service Corp	D-6690-UR-113 (elec.)	Electric	6/20/2002	58.6	10.23	12.30	7.52	4.78
Wisconsin	Wisconsin Natural Gas Co	D-6670-GR-108	Natural Gas	8/31/1993	9.2	9.71	11.90	7.54	4.36
Minnesota	Northern States Power Co. - MN	D-G-002-GR-92-1186	Natural Gas	9/1/1993	8.3	9.31	11.47	7.54	3.93
Nevada	Nevada Power Co.	D-01-10001	Electric	3/27/2002	-40.2	8.37	10.10	7.54	2.56
Rhode Island	Narragansett Electric Co.	D-3943	Natural Gas	11/24/2008	13.7	NA	10.50	7.56	2.94
Georgia	Georgia Power Co.	D-14000-U	Electric	12/20/2001	-117.7	9.71	12.50	7.57	4.93
Nevada	Sierra Pacific Power Co.	D-01-11030	Electric	5/28/2002	-13.7	8.61	10.17	7.57	2.60
Florida	Gulf Power Co.	D-010949-EI	Electric	6/10/2002	53.2	7.92	12.00	7.57	4.43
Missouri	Southern Union Co.	C-GR-96-285	Natural Gas	1/22/1997	7.5	9.46	11.30	7.59	3.71
Colorado	Public Service Co. of CO	D-96S-290G	Natural Gas	1/31/1997	18.6	9.48	11.25	7.59	3.66
Wisconsin	Wisconsin Electric Power Co.	D-6630-UR-109 (elec)	Electric	2/13/1997	-7.4	10.61	11.80	7.59	4.21
New Mexico	Public Service Co. of NM	C-2662	Natural Gas	2/13/1997	-7.0	9.18	11.00	7.59	3.41
Wisconsin	Wisconsin Natural Gas Co	D-6630-UR-109 (gas)	Natural Gas	2/13/1997	-6.5	10.29	11.80	7.59	4.21
Missouri	Empire District Electric Co.	C-ER-2001-299	Electric	9/20/2001	17.1	8.75	10.00	7.59	2.41
Michigan	Detroit Edison Co.	C-U-15244	Electric	12/23/2008	83.6	7.16	11.00	7.60	3.40
Arizona	Southwest Gas Corp.	D-G-01551A-07-0504	Natural Gas	12/24/2008	33.5	8.86	10.00	7.60	2.40
Oregon	Portland General Electric Co.	D-UE-197	Electric	12/29/2008	121.0	8.33	10.10	7.60	2.50
Oklahoma	Public Service Co. of OK	Ca-PUD-200800144	Electric	1/14/2009	59.3	8.31	10.50	7.60	2.90
South Carolina	Piedmont Natural Gas Co.	D-95-715-G	Natural Gas	11/7/1995	7.8	10.77	12.50	7.62	4.88
Illinois	North Shore Gas Co.	D-95-0031	Natural Gas	11/8/1995	5.6	9.75	11.30	7.62	3.68
Illinois	Peoples Gas Light & Coke Co.	D-95-0032	Natural Gas	11/8/1995	30.6	9.19	11.10	7.62	3.48
Mississippi	Mississippi Power Co.	D-01-UN-0548	Electric	12/3/2001	39.0	9.90	12.88	7.63	5.25
Michigan	Michigan Gas Utilities Corp	C-U-10960	Natural Gas	3/27/1997	1.7	8.42	10.75	7.64	3.11
Texas	AEP Texas Central Co.	D-14965	Electric	3/31/1997	-32.3	8.73	10.02	7.64	2.38
Hawaii	Hawaii Electric Light Co Inc	D-94-0140	Electric	4/2/1997	6.8	9.34	11.65	7.64	4.01
Montana	NorthWestern Energy Division	D-D2000.8.113 (elec)	Electric	5/8/2001	16.0	8.46	10.75	7.68	3.07
Montana	NorthWestern Energy Division	D-D2000.8.113 (gas)	Natural Gas	5/8/2001	4.3	8.62	10.75	7.68	3.07
Wisconsin	Wisconsin Electric Power Co.	D-6630-UR-108	Electric	8/11/1995	-33.8	10.29	11.30	7.70	3.60
Wisconsin	Wisconsin Natural Gas Co	D-6670-GR-109	Natural Gas	8/11/1995	-8.3	10.18	11.30	7.70	3.60
Wisconsin	Madison Gas and Electric Co.	D-3270-UR-108 (elec)	Electric	7/17/1997	4.9	11.06	12.00	7.72	4.28
Wisconsin	Madison Gas and Electric Co.	D-3270-UR-108 (gas)	Natural Gas	7/17/1997	3.5	11.35	12.00	7.72	4.28
Kansas	Westar Energy Inc.	D-193,305-U	Natural Gas	4/15/1998	34.4	8.95	10.50	7.73	2.77
Minnesota	CenterPoint Energy Resources	D-G-008-GR-95-700	Natural Gas	5/10/1996	12.9	9.76	11.00	7.73	3.27
Idaho	Avista Corp.	C-WWP-E-98-11	Electric	7/29/1999	9.3	8.98	10.75	7.74	3.01
Colorado	Public Service Co. of CO	D-00S-422G	Natural Gas	3/15/2001	14.2	9.33	11.25	7.74	3.51
Arizona	UNS Electric Inc.	D-E-1032-92-073	Electric	7/20/1993	2.8	9.20	10.46	7.75	2.71

State	Company	Case Identification	Service	Date	Rate Increase ($M)	Return on Rate Base(%)	Return on Equity (%)	Moody's A Rated Utility Bonds	Implied Equity Risk Premium
Illinois	MidAmerican Energy Co.	D-92-0357(elec)	Electric	7/21/1993	9.6	9.61	11.38	7.75	3.63
Illinois	MidAmerican Energy Co.	D-92-0357(gas)	Natural Gas	7/21/1993	2.0	9.80	11.78	7.75	4.03
Kentucky	Duke Energy Kentucky Inc.	C-92-346	Natural Gas	7/23/1993	3.9	9.96	11.50	7.75	3.75
Arizona	Southwest Gas Corp.	D-U-1551-92-253	Natural Gas	8/12/1993	6.5	9.13	10.75	7.75	3.00
Arizona	Southwest Gas Corp.	D-G-01551A-00-0309	Natural Gas	10/24/2001	21.6	9.19	11.00	7.75	3.25
North Dakota	MDU Resources Group Inc.	C-PU-399-01-186	Electric	4/22/2002	-4.3	10.24	11.80	7.76	4.04
Wisconsin	Northern States Power Co-WI	D-4220-UR-109 (elec)	Electric	11/26/1996	0.0	10.10	11.30	7.77	3.53
Wisconsin	Northern States Power Co-WI	D-4220-UR-109 (gas)	Natural Gas	11/26/1996	0.0	10.83	11.30	7.77	3.53
Massachusetts	Boston Gas Co.	DPU-96-50	Natural Gas	11/29/1996	6.3	9.38	11.00	7.77	3.23
Ohio	Duke Energy Ohio Inc.	C-95-656-GA-AIR	Natural Gas	12/12/1996	8.3	9.67	11.96	7.77	4.19
Wisconsin	Wisconsin Public Service Corp	D-6690-UR-110 (elec)	Electric	2/20/1997	-35.5	10.72	11.80	7.77	4.03
Wisconsin	Wisconsin Public Service Corp	D-6690-UR-110 (gas)	Natural Gas	2/20/1997	5.7	10.84	11.80	7.77	4.03
Kansas	Mid-Kansas Electric Company	D-01-WPEE-473-RTS	Electric	8/15/2001	3.9	9.21	10.91	7.78	3.13
Oregon	PacifiCorp	D-UE-116	Electric	9/7/2001	64.4	8.61	10.75	7.78	2.97
Utah	PacifiCorp	D-01-035-01	Electric	9/10/2001	40.5	8.87	11.00	7.78	3.22
South Carolina	South Carolina Electric & Gas	D-92-619-E	Electric	5/25/1993	60.4	9.60	11.50	7.81	3.69
Wisconsin	Madison Gas and Electric Co.	D-3270-UR-106 (elec)	Electric	6/3/1993	-4.4	10.92	12.00	7.81	4.19
Wisconsin	Madison Gas and Electric Co.	D-3270-UR-106 (gas)	Natural Gas	6/3/1993	-1.4	11.31	12.00	7.81	4.19
Nevada	Sierra Pacific Power Co.	D-92-12021	Natural Gas	6/7/1993	1.8	8.70	11.50	7.81	3.69
New York	National Fuel Gas Dist Corp.	C-94-G-0604	Natural Gas	9/15/1995	14.2	9.10	10.40	7.83	2.57
Pennsylvania	PPL Electric Utilities Corp.	C-R-00943217	Electric	9/27/1995	85.2	9.54	11.50	7.03	3.07
Wisconsin	Northern States Power Co-WI	D-4220-UR-108 (elec)	Electric	9/27/1995	-4.8	10.16	11.30	7.83	3.47
Massachusetts	Massachusetts Electric Co.	DPU-95-40	Electric	9/29/1995	30.9	9.24	11.00	7.83	3.17
Virginia	Washington Gas Light Co.	C-PUE-940031	Natural Gas	9/29/1995	6.8	9.72	11.50	7.83	3.67
Connecticut	CT Natural Gas Corp.	D-95-02-07	Natural Gas	10/13/1995	8.9	9.56	10.76	7.83	2.93
Connecticut	Yankee Gas Services Co.	D-01-05-19	Natural Gas	1/30/2002	-4.0	8.91	11.00	7.83	3.17
Kentucky	Duke Energy Kentucky Inc.	C-2001-00092	Natural Gas	1/31/2002	2.7	8.74	11.00	7.83	3.17
Indiana	Duke Energy Indiana Inc.	Ca-40003	Electric	9/27/1996	73.9	8.21	11.00	7.84	3.16
New York	Central Hudson Gas & Electric	C-95-G-1034	Natural Gas	10/3/1996	0.0	8.45	10.00	7.84	2.16
Vermont	Green Mountain Power Corp.	D-6107	Electric	1/23/2001	20.0	NA	11.25	7.84	3.41
Florida	Pivotal Utility Holdings Inc.	D-000768-GU	Natural Gas	2/5/2001	5.1	7.89	11.50	7.84	3.66
Hawaii	Hawaii Electric Light Co Inc	D-99-0207	Electric	2/8/2001	8.4	9.14	11.50	7.84	3.66
Montana	NorthWestern Energy Division	D-D93.6.24 (elec)	Electric	4/25/1994	7.6	9.09	11.00	7.85	3.15
Montana	NorthWestern Energy Division	D-D93.6.24 (gas)	Natural Gas	4/25/1994	5.8	9.49	11.00	7.85	3.15
Michigan	Consumers Energy Co.	C-U-10335	Electric	5/10/1994	57.6	7.43	11.75	7.85	3.90
Kansas	Kansas Gas and Electric Co.	D-01-WSRE-436-RTS (KG&E)	Electric	7/25/2001	-41.0	9.08	11.02	7.85	3.17
Kansas	Westar Energy Inc.	D-01-WSRE-436-RTS (WR)	Electric	7/25/2001	25.4	9.08	11.02	7.85	3.17
Connecticut	Connecticut Light & Power Co.	D-92-11-11	Electric	6/16/1993	141.3	8.84	11.50	7.86	3.64
North Carolina	Nantahala Power & Light Compan	D-E-13,SUB157	Electric	6/18/1993	4.3	10.32	12.10	7.86	4.24
Virginia	Virginia Natural Gas Inc.	C-PUE-920031	Natural Gas	6/22/1993	10.4	9.97	11.75	7.86	3.89
Missouri	KCP&L Greater Missouri Op Co	C-ER-93-42	Electric	6/25/1993	-0.9	10.34	11.67	7.86	3.81
Hawaii	Maui Electric Company Ltd	D-94-0345	Electric	4/28/1997	3.9	9.27	11.50	7.87	3.63
Wisconsin	Wisconsin Power and Light Co	D-6680-UR-110 (elec)	Electric	4/29/1997	-10.6	9.46	11.70	7.87	3.83
Wisconsin	Wisconsin Power and Light Co	D-6680-UR-110 (gas)	Natural Gas	4/29/1997	-1.2	9.38	11.70	7.87	3.83
Maryland	Baltimore Gas and Electric Co.	C-8487(elec)	Electric	4/23/1993	84.9	9.40	11.75	7.90	3.85
Maryland	Baltimore Gas and Electric Co.	C-8487(gas)	Natural Gas	4/23/1993	1.6	9.40	11.75	7.90	3.65
Minnesota	CenterPoint Energy Resources	D-G-008-GR-92-400	Natural Gas	5/3/1993	11.5	10.41	11.50	7.90	3.60
Michigan	Upper Peninsula Power Co.	C-U-10094	Electric	5/11/1993	3.6	8.93	11.75	7.90	3.85
Pennsylvania	West Penn Power Co.	C-R-922378	Electric	5/14/1993	53.6	9.45	11.50	7.90	3.60
Indiana	Southern Indiana Gas & Elec Co	Ca-39871	Electric	6/21/1995	4.6	7.94	12.25	7.91	4.34
District of Columbia	Potomac Electric Power Co.	FC-939	Electric	6/30/1995	27.9	9.09	11.10	7.91	3.19
Oregon	Northwest Natural Gas Co.	D-UG-132	Natural Gas	11/12/1999	0.2	8.91	10.25	7.93	2.32
Kentucky	Kentucky Utilities Co.	C-98-474	Electric	1/7/2000	-30.4	8.85	11.50	7.94	3.56
Kentucky	Louisville Gas & Electric Co.	C-98-426	Electric	1/7/2000	-28.3	8.00	11.50	7.94	3.56
Florida	Pivotal Utility Holdings Inc.	D-960502-GU	Natural Gas	10/29/1996	3.8	7.87	11.30	8.01	3.29
Missouri	Laclede Gas Co.	C-GR-99-315	Natural Gas	12/14/1999	11.2	8.90	10.50	8.06	2.44
Kentucky	Louisville Gas & Electric Co.	C-2000-080	Natural Gas	9/27/2000	20.2	7.66	11.25	8.13	3.12
Washington	Avista Corp.	D-UE-99-1606	Electric	9/29/2000	-2.8	9.03	11.16	8.13	3.03
Washington	Avista Corp.	D-UE-99-1607	Natural Gas	9/29/2000	1.8	9.03	11.16	8.13	3.03
Kansas	Mid-Kansas Electric Company	D-99-WPEE-818-RTS	Electric	1/19/2000	-8.3	8.90	10.55	8.14	2.41
Connecticut	Southern Connecticut Gas Co.	D-99-04-18	Natural Gas	1/28/2000	0.5	9.97	10.71	8.14	2.57
Wisconsin	Madison Gas and Electric Co.	D-3270-UR-110 (elec.)	Electric	11/28/2000	7.5	10.65	12.90	8.14	4.76
Wisconsin	Madison Gas and Electric Co.	D-3270-UR-110 (gas)	Natural Gas	11/28/2000	3.4	11.01	12.90	8.14	4.76
Wisconsin	Wisconsin Public Service Corp	D-6690-UR-112 (elec.)	Electric	11/30/2000	27.2	10.28	12.10	8.14	3.96
Wisconsin	Wisconsin Public Service Corp	D-6690-UR-112 (gas)	Natural Gas	11/30/2000	4.3	10.28	12.10	8.14	3.96
Iowa	Interstate Power & Light Co.	D-RPU-93-6	Electric	6/3/1994	7.4	9.11	11.00	8.22	2.78
Wyoming	PacifiCorp	D-20000-ER-99-145	Electric	3/28/2000	10.6	8.65	11.25	8.25	3.00
Wisconsin	Wisconsin Electric Power Co.	D-6630-UR-106	Electric	2/15/1993	26.7	11.52	12.30	8.27	4.03
Maryland	Potomac Edison Co.	C-8849	Electric	2/24/1993	15.2	9.68	11.90	8.27	3.63
New Jersey	Jersey Cntrl Power & Light Co.	D-ER-91121820J	Electric	2/26/1993	123.8	10.28	12.20	8.27	3.93
North Carolina	Virginia Electric & Power Co.	D-E-22,SUB333	Electric	2/26/1993	10.6	9.48	11.80	8.27	3.53
Louisiana	Entergy Louisiana Holdings	D-U-20925	Electric	5/25/1995	-40.9	9.99	11.20	8.27	2.93
Utah	PacifiCorp	D-99-035-10	Electric	5/24/2000	17.0	9.02	11.00	8.29	2.71
Connecticut	CT Natural Gas Corp.	D-99-09-03	Natural Gas	5/25/2000	-0.1	9.30	10.80	8.29	2.51
New York	National Fuel Gas Dist Corp.	C-93-G-0756	Natural Gas	7/19/1994	11.1	9.17	10.70	8.31	2.39
Hawaii	Maui Electric Company Ltd	D-7000	Electric	8/5/1994	8.1	10.19	12.75	8.31	4.44
Arizona	UNS Gas Inc.	D-G-1032-93-111	Natural Gas	6/16/1994	2.5	9.23	10.50	8.33	2.17
Virginia	Appalachian Power Co.	C-PUE-920081	Electric	6/27/1994	17.9	9.55	11.40	8.33	3.07
California	Pacific Gas and Electric Co.	AP-9712020 De-0002046 (elec.)	Electric	2/17/2000	163.0	8.75	10.60	8.35	2.25
California	Pacific Gas and Electric Co.	AP-9712020 De-0002046 (gas)	Natural Gas	2/17/2000	93.0	8.75	10.60	8.35	2.25
Illinois	MidAmerican Energy Co.	D-99-0534	Natural Gas	7/17/2000	2.1	9.12	11.06	8.36	2.70
Wisconsin	Wisconsin Electric Power Co.	D-6630-UR-111 (elec.)	Electric	7/18/2000	64.0	10.52	12.20	8.36	3.84
Wisconsin	Wisconsin Electric Power Co.	D-6630-UR-111 (gas)	Natural Gas	7/20/2000	8.0	10.28	12.20	8.36	3.84
New York	Niagara Mohawk Power Corp.	C-94-E-0098,9	Electric	4/19/1995	36.6	9.26	11.00	8.37	2.63
New York	Niagara Mohawk Power Corp.	C-94-G-0100	Natural Gas	4/19/1995	4.9	9.26	11.00	8.37	2.63
Texas	Texas-New Mexico Power Co.	D-10200	Electric	10/16/1992	25.8	10.53	13.16	8.40	4.76
Wisconsin	Wisconsin Gas LLC	D-6650-GR-110	Natural Gas	10/29/1992	8.4	12.92	12.75	8.40	4.35
Massachusetts	Bay State Gas Co.	DPU-92-11	Natural Gas	10/30/1992	11.5	10.35	11.40	8.40	3.00
North Carolina	Public Service Co. of NC	D-G-5,SUB327	Natural Gas	10/7/1994	10.8	10.51	11.87	8.41	3.46
Pennsylvania	Metropolitan Edison Co.	C-R-922314	Electric	1/21/1993	11.1	9.59	11.25	8.43	2.82
Florida	Florida Power Corp.	D-910890-EI	Electric	8/22/1992	65.8	8.37	12.00	8.44	3.56
Massachusetts	Massachusetts Electric Co.	DPU-92-78	Electric	8/30/1992	45.6	9.90	11.75	8.44	3.31
Georgia	Atlanta Gas Light Co.	D-4177-U	Natural Gas	9/30/1992	13.0	9.93	11.60	8.44	3.16
Hawaii	Hawaii Electric Light Co Inc	D-6999	Electric	10/2/1992	3.9	10.40	13.00	8.44	4.56
Illinois	Peoples Gas Light & Coke Co.	D-91-0568	Natural Gas	10/6/1992	30.6	10.40	12.25	8.44	3.81
Wisconsin	Wisconsin Natural Gas Co	D-6670-GR-107	Natural Gas	10/13/1992	4.0	11.01	12.75	8.44	4.31
Texas	Entergy Texas Inc.	D-12852	Electric	3/20/1995	-52.9	10.05	12.00	8.52	3.48
New York	Long Island Lighting Co	C-93-E-1123	Electric	4/7/1995	0.0	9.45	11.00	8.52	2.48
New York	Long Island Lighting Co	C-91-G-1328	Natural Gas	11/25/1992	46.6	9.87	11.00	8.54	2.46
Connecticut	Yankee Gas Services Co.	D-92-02-19	Natural Gas	8/26/1992	12.8	10.55	12.43	8.57	3.86
North Dakota	Northern States Power Co. - MN	C-PU-400-92-399	Electric	12/15/1992	2.8	9.30	11.00	8.63	2.37
California	Pacific Gas and Electric Co.	AP-9111036 De-9212057 (elec)	Electric	12/16/1992	254.4	10.13	11.90	8.63	3.27
Connecticut	United Illuminating Co.	D-92-06-05	Electric	12/16/1992	33.1	10.60	12.40	8.63	3.77
California	Pacific Gas and Electric Co.	AP-9111036 De-9212057 (gas)	Natural Gas	12/16/1992	68.3	10.13	11.90	8.63	3.27
Florida	Tampa Electric Co.	D-920324-EI	Electric	12/17/1992	29.6	8.34	12.00	8.63	3.37
Wisconsin	Wisconsin Power and Light Co	D-6680-UR-107 (elec)	Electric	12/22/1992	-0.6	9.68	12.40	8.63	3.77
Wisconsin	Wisconsin Public Service Corp	D-6690-UR-107 (elec)	Electric	12/22/1992	8.7	11.54	12.30	8.63	3.67
Wisconsin	Wisconsin Power and Light Co	D-6680-UR-107 (gas)	Natural Gas	12/22/1992	-0.3	9.68	12.40	8.63	3.77
Wisconsin	Wisconsin Public Service Corp	D-6690-UR-107 (gas)	Natural Gas	12/22/1992	3.8	11.48	12.30	8.63	3.67
Virginia	Virginia Electric & Power Co	C-PUE-910047	Electric	12/29/1992	45.2	9.92	12.25	8.63	3.62
Wisconsin	Northern States Power Co-WI	D-4220-UR-106 (elec)	Electric	1/12/1993	8.0	10.92	12.00	8.63	3.37
Kansas	Atmos Energy Corp.	D-181,940-U	Natural Gas	1/12/1993	0.9	10.64	12.00	8.63	3.37
Wisconsin	Northern States Power Co-WI	D-4220-UR-106 (gas)	Natural Gas	1/12/1993	1.1	11.00	12.00	8.63	3.37
Vermont	Central Vermont Public Service	D-5701,5724	Electric	10/31/1994	8.6	8.68	10.00	8.64	1.36
West Virginia	Monongahela Power Co.	C-94-0035-E-42T	Electric	11/9/1994	23.5	9.02	10.85	8.64	2.21
West Virginia	Potomac Edison Co.	C-940027-E-42T	Electric	11/9/1994	1.5	9.40	10.85	8.64	2.21
Maryland	Baltimore Gas and Electric Co.	C-8829	Natural Gas	6/19/2000	6.4	8.61	11.05	8.70	2.35
Idaho	Idaho Power Co.	C-IPC-E-94-5	Electric	1/31/1995	17.2	9.20	11.00	8.76	2.24

State	Company	Case Identification	Service	Date	Rate Increase ($M)	Return on Rate Base(%)	Return on Equity (%)	Moody's A Rated Utility Bonds	Implied Equity Risk Premium
Hawaii	Hawaii Electric Light Co Inc	D-7764	Electric	2/10/1995	15.5	9.87	12.60	8.76	3.84
New York	NY State Electric & Gas Corp.	C-91-E-0863,4	Electric	7/22/1992	48.0	9.74	11.20	8.78	2.42
New York	NY State Electric & Gas Corp.	C-91-G-0865	Natural Gas	7/22/1992	10.4	9.74	11.20	8.78	2.42
Iowa	Interstate Power & Light Co.	D-RPU-91-9	Electric	8/3/1992	7.9	9.99	12.00	8.78	3.22
Nevada	Nevada Power Co.	D-92-1067	Electric	8/6/1992	22.2	10.02	12.50	8.78	3.72
Delaware	Delmarva Power & Light Co.	D-91-20	Electric	2/25/1992	18.5	9.85	12.50	8.84	3.66
Arizona	Southwest Gas Corp.	D-U-1551-90-322	Natural Gas	2/27/1992	8.3	10.31	11.75	8.84	2.91
Virginia	Potomac Edison Co.	C-PUE-830033	Electric	11/18/1994	4.5	9.51	11.20	8.86	2.34
Minnesota	ALLETE (Minnesota Power)	D-E-015-GR-94-1	Electric	11/22/1994	19.0	9.33	11.60	8.86	2.74
Oklahoma	Oklahoma Natural Gas Co	Ca-PUD-91001190	Natural Gas	11/22/1994	23.7	10.32	12.12	8.86	3.26
Pennsylvania	National Fuel Gas Dist Corp.	C-R-942991	Natural Gas	12/1/1994	4.8	9.39	11.00	8.86	2.14
Wisconsin	Madison Gas and Electric Co.	D-3270-UR-107 (elec)	Electric	12/8/1994	-4.2	10.99	11.70	8.86	2.84
Wisconsin	Wisconsin Power and Light Co	D-6680-UR-109 (elec)	Electric	12/8/1994	-12.3	9.41	11.50	8.86	2.64
Wisconsin	Madison Gas and Electric Co.	D-3270-UR-107 (gas)	Natural Gas	12/8/1994	0.0	11.31	11.70	8.86	2.84
Wisconsin	Wisconsin Power and Light Co	D-6680-UR-109 (gas)	Natural Gas	12/8/1994	0.7	9.28	11.50	8.86	2.64
Illinois	Central Illinois Light Co.	D-94-0040	Natural Gas	12/12/1994	10.6	9.24	11.82	8.86	2.96
Louisiana	Entergy Gulf States LA LLC	D-U-19904	Electric	12/14/1994	-4.4	9.58	10.95	8.86	2.09
District of Columbia	Potomac Electric Power Co.	FC-912	Electric	6/26/1992	30.4	9.96	12.35	8.87	3.48
New York	Rochester Gas & Electric Corp.	C-91-E-765,6	Electric	6/29/1992	32.2	9.31	11.00	8.87	2.13
New York	Rochester Gas & Electric Corp.	C-91-G-767	Natural Gas	6/29/1992	12.3	9.31	11.00	8.87	2.13
Hawaii	Hawaiian Electric Co.	D-6998	Electric	6/30/1992	124.3	10.06	13.00	8.87	4.13
Iowa	Interstate Power & Light Co.	D-RPU-91-7	Electric	7/13/1992	10.4	9.50	11.90	8.87	3.03
Missouri	Southern Union Co.	C-GR-91-291	Natural Gas	1/22/1992	7.3	10.54	12.84	8.88	3.96
Maryland	Conowingo Power Co.	C-8352	Electric	1/27/1992	15.7	11.00	12.65	8.88	3.77
Nevada	Sierra Pacific Power Co.	D-91-7079	Electric	1/31/1992	4.9	10.00	12.00	8.88	3.12
Nevada	Sierra Pacific Power Co.	D-91-7080	Natural Gas	1/31/1992	1.4	8.36	12.00	8.88	3.12
Illinois	Illinois Power Co.	D-91-0147	Electric	2/11/1992	100.2	10.21	12.40	8.88	3.52
Rhode Island	Narragansett Electric Co.	D-2016	Electric	3/16/1992	3.0	10.26	11.43	8.93	2.50
Illinois	Central Illinois Public	D-91-0193 (elec)	Electric	3/18/1992	3.4	9.77	12.28	8.93	3.35
Illinois	Central Illinois Public	D-91-0193 (gas)	Natural Gas	3/18/1992	8.2	9.88	12.50	8.93	3.57
Vermont	Green Mountain Power Corp.	D-5532	Electric	4/2/1992	7.0	10.64	12.10	8.93	3.17
New York	Central Hudson Gas & Electric	C-91-E-0506	Electric	4/9/1992	18.3	9.06	11.45	8.93	2.52
Rhode Island	Narragansett Electric Co.	D-2019	Electric	4/10/1992	3.5	9.94	11.50	8.93	2.57
Iowa	MidAmerican Energy Co.	D-RPU-91-5	Natural Gas	5/15/1992	5.0	10.12	12.75	8.93	3.82
Iowa	MidAmerican Energy Co.	D-RPU-91-6	Electric	6/1/1992	-4.0	9.93	12.30	8.93	3.37
Minnesota	Interstate Power Co.	D-E-001-GR-91-605	Electric	6/12/1992	4.9	9.20	10.90	8.93	1.97
Kentucky	Duke Energy Kentucky Inc.	C-91-370	Electric	5/5/1992	22.3	9.60	11.50	8.97	2.53
Ohio	Columbus Southern Power Co.	C-91-418-EL-AIR	Electric	5/12/1992	123.0	10.33	12.46	8.97	3.49
Ohio	Duke Energy Ohio Inc.	C-91-410-EL-AIR	Electric	5/12/1992	114.6	10.42	11.87	8.97	2.90
Pennsylvania	West Penn Power Co.	C-R-942986	Electric	12/15/1994	57.3	9.15	11.50	8.98	2.52
Wisconsin	Wisconsin Public Service Corp	D-6690-UR-109 (elec)	Electric	12/19/1994	-10.9	10.91	11.50	8.98	2.52
Wisconsin	Wisconsin Public Service Corp	D-6690-UR-109 (gas)	Natural Gas	12/19/1994	0.0	11.04	11.50	8.98	2.52
Hawaii	Hawaiian Electric Co.	D-7700	Electric	12/28/1994	40.5	9.38	12.15	8.98	3.17
Illinois	Commonwealth Edison Co.	D-94-0065	Electric	1/9/1995	303.2	9.87	12.28	8.98	3.30
Maine	Bangor Hydro-Electric Co.	D-91-010	Electric	12/18/1991	12.2	10.83	12.25	9.05	3.20
Wisconsin	Northern States Power Co-WI	D-4220-UR-105 (elec)	Electric	12/19/1991	7.1	11.59	12.60	9.05	3.55
Wisconsin	Wisconsin Public Service Corp	D-6690-UR-106 (elec)	Electric	12/19/1991	5.7	11.48	12.80	9.05	3.75
Wisconsin	Northern States Power Co-WI	D-4220-UR-105 (gas)	Natural Gas	12/19/1991	1.4	11.65	12.60	9.05	3.55
Wisconsin	Wisconsin Public Service Corp	D-6690-UR-106 (gas)	Natural Gas	12/19/1991	0.0	11.40	12.80	9.05	3.75
California	Southern California Edison Co.	AP-9012018 De-9112076	Electric	12/20/1991	42.0	10.59	12.65	9.05	3.60
Kansas	Westar Energy Inc.	D-176,716-U	Natural Gas	12/30/1991	39.3	8.54	12.10	9.05	3.05
Wisconsin	Wisconsin Electric Power Co.	D-6630-UR-105	Electric	1/9/1992	56.4	11.76	12.80	9.05	3.75
Maryland	Potomac Edison Co.	C-8341	Electric	11/25/1991	11.1	9.98	12.40	9.12	3.28
Nevada	Nevada Power Co.	D-91-5055	Electric	11/26/1991	12.2	9.72	12.50	9.12	3.38
New York	Long Island Lighting Co	C-90-E-1185	Electric	11/26/1991	73.4	10.59	11.60	9.12	2.48
Georgia	Atlanta Gas Light Co.	D-4011-U	Natural Gas	11/26/1991	4.9	10.30	12.00	9.12	2.88
New York	Long Island Lighting Co	C-91-G-0112	Natural Gas	11/26/1991	18.8	10.59	11.60	9.12	2.48
Minnesota	Northern States Power Co. - MN	D-E-002-GR-91-1	Electric	11/27/1991	53.5	10.05	12.10	9.12	2.98
North Carolina	NC Natural Gas Corp.	D-G-21,SUB295	Natural Gas	12/6/1991	2.6	11.16	12.70	9.12	3.58
Wisconsin	Wisconsin Gas LLC	D-6650-GR-109	Natural Gas	10/15/1991	3.8	13.07	13.40	9.16	4.24
Hawaii	Hawaiian Electric Co.	D-6531	Electric	10/17/1991	52.0	8.99	13.00	9.16	3.84
District of Columbia	Potomac Electric Power Co.	FC-905	Electric	10/23/1991	19.7	9.93	12.50	9.16	3.34
North Dakota	Northern States Power Co. - MN	C-PU-400-91-112	Electric	10/31/1991	3.7	9.90	11.80	9.16	2.64
West Virginia	Appalachian Power Co.	C-91-026E-42T	Electric	11/1/1991	-1.1	10.14	12.00	9.16	2.84
South Carolina	Duke Energy Carolinas LLC	D-91-216E	Electric	11/5/1991	30.3	10.35	12.25	9.16	3.09
Illinois	North Shore Gas Co.	D-91-0010	Natural Gas	11/8/1991	5.3	11.39	12.75	9.16	3.59
North Carolina	Duke Energy Carolinas LLC	D-E-7,SUB487	Electric	11/12/1991	100.1	10.44	12.50	9.16	3.34
Texas	El Paso Electric Co.	D-9945	Electric	11/12/1991	37.9	10.69	13.25	9.16	4.09
New York	Consolidated Edison Co. of NY	C-90-G-1001	Natural Gas	10/3/1991	21.4	9.33	11.30	9.29	2.01
New Jersey	Pivotal Utility Holdings Inc.	D-GR-88121321	Natural Gas	1/18/1990	3.5	11.69	12.50	9.44	3.06
New York	Long Island Lighting Co	C-89-G-030	Natural Gas	1/26/1990	5.5	11.32	12.10	9.44	2.66
New York	Rochester Gas & Electric Corp.	C-90-E-847,8	Electric	6/25/1991	33.1	9.66	11.70	9.44	2.26
New York	Rochester Gas & Electric Corp.	C-90-G-849	Natural Gas	6/25/1991	1.2	9.66	11.70	9.44	2.26
New York	Niagara Mohawk Power Corp.	C-89-E-152,3	Electric	6/28/1991	293.9	NA	12.50	9.44	3.06
New York	Niagara Mohawk Power Corp.	C-89-G-154	Natural Gas	6/28/1991	32.7	NA	12.50	9.44	3.06
New York	Central Hudson Gas & Electric	C-90-G-0673	Natural Gas	7/1/1991	4.9	9.45	11.70	9.44	2.26
Maryland	Potomac Electric Power Co.	C-8315	Electric	5/30/1991	19.7	9.98	12.75	9.46	3.29
West Virginia	Monongahela Power Co.	C-90-504-E-42T	Electric	8/12/1991	19.4	9.69	12.00	9.46	2.54
California	Southern California Gas Co.	AP-8812047 De-900116	Natural Gas	1/9/1990	121.4	10.75	13.00	9.51	3.49
Virginia	Virginia Electric & Power Co.	C-PUE-900023	Electric	4/22/1991	78.6	10.33	13.00	9.55	3.45
Michigan	Consumers Energy Co.	C-U-9346	Electric	5/7/1991	-44.6	8.99	13.50	9.55	3.95
Virginia	Appalachian Power Co.	C-PUE-900026	Electric	5/13/1991	25.5	10.77	13.25	9.55	3.70
Virginia	Virginia Natural Gas Inc.	C-PUE-900028	Natural Gas	8/15/1991	4.7	10.82	12.25	9.55	2.70
Texas	Oncor Electric Delivery Co.	D-9300	Electric	8/16/1991	442.4	11.05	13.20	9.55	3.65
Wisconsin	Wisconsin Natural Gas Co	D-6870-GR-106	Natural Gas	8/29/1991	3.4	11.27	13.30	9.55	3.75
Texas	Texas-New Mexico Power Co.	D-8928	Electric	2/24/1990	8.6	11.30	12.86	9.56	3.30
Arizona	Tucson Electric Power Co.	D-U-1933-88-280	Electric	10/24/1989	43.2	9.17	12.50	9.58	2.92
Montana	NorthWestern Energy Division	D-D90.6.39 (elec)	Electric	7/19/1991	39.8	10.24	12.10	9.59	2.51
Montana	NorthWestern Energy Division	D-D90.6.39 (gas)	Natural Gas	7/19/1991	6.2	10.41	12.10	9.59	2.51
New York	National Fuel Gas Dist Corp.	C-90-G-0734	Natural Gas	7/19/1991	16.7	10.48	12.30	9.59	2.71
Connecticut	Connecticut Light & Power Co.	D-90-12-03	Electric	8/1/1991	77.2	10.16	12.90	9.59	3.31
Rhode Island	Narragansett Electric Co.	D-1971	Natural Gas	2/15/1991	9.2	11.03	12.80	9.71	3.09
Hawaii	Hawaii Electric Light Co Inc	D-6432	Electric	3/6/1991	5.7	10.46	13.10	9.71	3.39
Illinois	Commonwealth Edison Co.	D-90-0169	Electric	3/8/1991	750.2	11.15	13.00	9.71	3.29
Maine	Central Maine Power Co.	D-90-076	Electric	3/8/1991	34.2	10.52	12.30	9.71	2.59
Washington	Puget Sound Energy Inc.	Ca-U-89-2688	Electric	1/17/1990	29.7	10.22	12.80	9.73	3.07
Utah	PacifiCorp	D-89-035-10	Electric	2/9/1990	-38.8	10.21	12.10	9.73	2.37
Wisconsin	Northern States Power Co-WI	D-4220-UR-104	Electric	1/15/1991	7.3	11.74	12.75	9.73	3.02
Illinois	Central Illinois Light Co.	D-90-0127	Natural Gas	1/16/1991	12.9	10.35	13.25	9.73	3.52
New York	NY State Electric & Gas Corp.	C-90-E-0138,9	Electric	1/25/1991	50.3	10.17	11.70	9.73	1.97
New York	NY State Electric & Gas Corp.	C-90-G-0140	Natural Gas	1/25/1991	4.5	10.17	11.70	9.73	1.97
Texas	Texas-New Mexico Power Co.	D-9491	Electric	2/7/1991	36.7	10.71	12.50	9.73	2.77
North Carolina	Virginia Electric & Power Co.	D-E-22,SUB314	Electric	2/14/1991	13.9	10.27	12.72	9.73	2.99
Ohio	Ohio Edison Co.	C-89-1001-EL-AIR	Electric	8/16/1990	142.4	11.20	13.21	9.75	3.46
Texas	El Paso Electric Co.	D-9165	Electric	8/22/1990	13.1	10.99	13.10	9.75	3.35
Indiana	Indiana Michigan Power Co.	Ca-38728	Electric	8/24/1990	14.3	8.79	13.00	9.75	3.25
Arizona	Southwest Gas Corp.	D-U-1551-89-103	Natural Gas	8/31/1990	0.4	11.60	12.50	9.75	2.75
Arizona	Southwest Gas Corp.	D-U-1551-89-102	Natural Gas	8/31/1990	7.4	11.12	12.50	9.75	2.75
Kentucky	Atmos Energy Corp.	C-90-013	Natural Gas	9/13/1990	3.6	11.20	12.50	9.75	2.75
New Jersey	New Jersey Natural Gas Co.	D-GR-89030335J	Natural Gas	3/21/1990	17.3	11.16	12.80	9.76	3.04
Connecticut	Southern Connecticut Gas Co.	D-89-09-06	Natural Gas	3/28/1990	8.4	11.27	13.00	9.76	3.24
Massachusetts	Massachusetts Electric Co.	DPU-88-194	Electric	3/30/1990	40.9	9.73	12.90	9.76	3.14
Indiana	Duke Energy Indiana Inc.	Ca-37809	Electric	4/4/1990	-37.3	9.97	15.76	9.76	6.00
Ohio	Columbia Gas of Ohio Inc	C-89-616,620-GA-AIR	Natural Gas	4/5/1990	11.4	10.55	12.20	9.76	2.44
New Mexico	Public Service Co. of NM	C-2262	Electric	4/12/1990	-2.9	8.95	12.52	9.76	2.76
New York	National Fuel Gas Dist Corp.	C-89-G-179	Natural Gas	7/19/1990	12.0	10.62	11.70	9.80	1.90
Florida	Gulf Power Co.	D-891345-EI	Electric	8/10/1990	14.1	8.10	12.55	9.80	2.75
Pennsylvania	PECO Energy Co.	C-R-891364	Electric	4/19/1990	242.3	11.23	12.75	9.65	2.90

State	Company	Case Identification	Service	Date	Rate Increase ($M)	Return on Rate Base(%)	Return on Equity (%)	Moody's A Rated Utility Bonds	Implied Equity Risk Premium
Iowa	Interstate Power & Light Co.	D-RPU-89-3	Natural Gas	4/30/1990	3.6	10.34	12.45	9.85	2.60
Wisconsin	Wisconsin Electric Power Co.	D-6630-UR-103	Electric	1/11/1990	-29.7	11.47	12.90	9.90	3.00
Maryland	Baltimore Gas and Electric Co.	C-8278	Electric	12/17/1990	77.0	9.84	12.87	9.90	2.97
Wisconsin	Wisconsin Public Service Corp	D-6690-UR-105 (elec)	Electric	12/18/1990	10.9	11.40	13.10	9.90	3.20
Wisconsin	Wisconsin Public Service Corp	D-6690-UR-105 (gas)	Natural Gas	12/18/1990	2.0	11.52	13.10	9.90	3.20
Pennsylvania	National Fuel Gas Dist Corp.	C-R-901670	Natural Gas	12/20/1990	4.5	10.86	12.50	9.90	2.60
Kentucky	Louisville Gas & Electric Co.	C-90-158 (elec)	Electric	12/21/1990	6.2	9.52	12.50	9.90	2.60
Alabama	Mobile Gas Service Corp	D-21530	Natural Gas	12/21/1990	4.3	9.90	13.60	9.90	3.70
Florida	Pivotal Utility Holdings Inc.	D-891175-GU	Natural Gas	12/21/1990	3.1	9.47	13.00	9.90	3.10
Kentucky	Louisville Gas & Electric Co.	C-90-158 (gas)	Natural Gas	12/21/1990	0.7	9.52	12.50	9.90	2.60
Wisconsin	Wisconsin Electric Power Co.	D-6630-UR-104	Electric	1/2/1991	35.4	11.62	13.10	9.90	3.20
Vermont	Green Mountain Power Corp.	D-5428	Electric	1/4/1991	7.3	10.96	12.50	9.90	2.60
New York	Central Hudson Gas & Electric	C-89-E-107	Electric	5/21/1990	13.8	10.15	12.10	9.92	2.18
Vermont	Central Vermont Public Service	D-5372	Electric	5/31/1990	14.0	10.77	12.00	9.92	2.08
Illinois	Illinois Power Co.	D-89-0276	Electric	6/6/1990	74.8	10.11	12.25	9.92	2.33
Georgia	Atlanta Gas Light Co.	D-3923-U	Natural Gas	9/18/1990	19.8	11.32	12.75	9.92	2.83
Pennsylvania	Columbia Gas of Pennsylvania	C-R-891469	Natural Gas	8/20/1990	13.4	10.83	12.50	9.92	2.58
Kentucky	Duke Energy Kentucky Inc.	C-90-041 (elec)	Electric	10/2/1990	6.4	11.17	13.00	9.92	3.08
Kentucky	Duke Energy Kentucky Inc.	C-90-041 (gas)	Natural Gas	10/2/1990	5.8	11.17	13.00	9.92	3.08
Missouri	KCP&L Greater Missouri Op Co	C-ER-90-101	Electric	10/5/1990	12.4	11.00	12.84	9.92	2.92
Wisconsin	Madison Gas and Electric Co.	D-3270-UR-104 (elec)	Electric	6/15/1990	3.1	11.34	13.20	10.00	3.20
Wisconsin	Madison Gas and Electric Co.	D-3270-UR-104 (gas)	Natural Gas	6/15/1990	-0.9	11.42	13.20	10.00	3.20
Texas	CenterPoint Energy Houston	D-8425	Electric	6/20/1990	227.0	10.61	12.92	10.00	2.92
Wisconsin	Wisconsin Power and Light Co	D-6680-UR-105 (elec)	Electric	6/27/1990	-7.3	10.27	12.90	10.00	2.90
Wisconsin	Wisconsin Power and Light Co	D-6680-UR-105 (gas)	Natural Gas	6/27/1990	-3.1	10.27	12.90	10.00	2.90
Massachusetts	Western Massachusetts Electric	DPU-89-255	Electric	6/29/1990	20.0	10.22	12.50	10.00	2.50
Michigan	SEMCO Energy Inc.	C-U-9323	Natural Gas	6/29/1990	3.2	10.16	13.25	10.00	3.25
District of Columbia	Potomac Electric Power Co.	FC-889	Electric	7/6/1990	9.5	9.78	12.35	10.00	2.35
New York	Rochester Gas & Electric Corp.	C-89-E-166,67	Electric	7/6/1990	36.1	9.91	12.10	10.00	2.10
New York	Rochester Gas & Electric Corp.	C-89-G-168	Natural Gas	7/6/1990	4.3	9.91	12.10	10.00	2.10
Pennsylvania	Equitable Gas Company	C-R-901595	Natural Gas	11/21/1990	18.8	10.99	12.50	10.05	2.45
Utah	Questar Gas Co.	D-89-057-15	Natural Gas	11/21/1990	0.1	11.03	12.10	10.05	2.05
Illinois	Central Illinois Public	D-90-0072	Natural Gas	11/28/1990	8.5	10.13	12.75	10.05	2.70
Pennsylvania	West Penn Power Co.	C-R-901609	Electric	12/13/1990	36.2	9.77	12.30	10.05	2.25
Iowa	Interstate Power & Light Co.	D-RPU-89-9	Electric	10/25/1990	24.1	10.25	12.30	10.12	2.18
Illinois	Peoples Gas Light & Coke Co.	D-90-0007	Natural Gas	11/6/1990	27.5	10.56	13.25	10.12	3.13

Pacific Gas and Electric Company

Decoupling in California: More Than Two Decades of Broad Support and Success

Workshop on Aligning Regulatory Incentives with Demand-Side Resources

San Francisco
August 2, 2006

Roland Risser. Director
Customer Energy Efficiency
Pacific Gas and Electric Company

Decoupling at PG&E – A Long History

Pacific Gas and Electric Company

- Decoupling of revenues/sales for non-fuel costs began in 1978 for natural gas; 1982 for electric:

  "...the adoption of an ERAM [Electric Revenue Adjustment Mechanism] ... will eliminate any disincentives PG&E may have to promote vigorous conservation measures and also be fair to ratepayers in assuring that PG&E receives no more or no less than the level of revenues intended to be earned."

  California Public Utilities Commission
  Decision 93887, **12/30/1981**

- Key goal: encourage conservation

- Broad stakeholder support at time: PUC staff, Energy Commission, environmentalists, PG&E, other utilities

Decoupling – Current View

Pacific Gas and Electric Company

- Electric decoupling required by Public Utilities Code:

  "The Commission shall ensure that errors in estimates of demand elasticity or sales to not result in material over or undercollections of the electrical corporations."

  Section 739.10, April 2001

- Nearly all PG&E revenues now decoupled:
  - Electric revenues: about 6% at risk
  - Natural gas revenues: about 4.2% at risk
- California PUC considering further decoupling of natural gas revenues in Gas OIR proceeding
- Continuing widespread support for decoupling (with forward-looking revenue/rate setting) from broad stakeholder group throughout state

STANDARD & POOR'S

Global Credit Portal
RatingsDirect®

September 29, 2010

Summary:
Pacific Gas & Electric Co.

Primary Credit Analyst:
Anne Selting, San Francisco (1) 415-371-5009; anne_selting@standardandpoors.com

Table Of Contents

Summary:
Pacific Gas & Electric Co.

Credit Rating: BBB+/Watch Neg/A-2

Rationale

On Sept. 10, 2010, Standard & Poor's Ratings Services placed the corporate credit ratings of the Pacific Gas and Electric Co. (PG&E; BBB+/--/A-2) and its parent, PG&E Corp. (BBB+/--/--)on CreditWatch with negative implications.

The watch listing followed a PG&E gas pipeline explosion that claimed eight lives as of yesterday, seriously injured six, and destroyed or significantly damaged an estimated 55 homes on Sept. 9 in San Bruno, a suburb outside San Francisco, Calif. Our action was driven by uncertainty regarding the ultimate costs of the San Bruno blast, the potential reputational damage to the utility, and the possibility that the incident may weaken the utility's constructive regulatory support, which is the a critical underpinning for the ratings. We expect to resolve the watch listing after analyzing all the direct and indirect costs stemming from the explosion, including liability for the accident, higher levels of maintenance capital spending that the company may encounter, responses from regulatory and legislative bodies and their impact on PG&E, as well as PG&E's plan to fortify its reputation and advance constructive solutions that address any fundamental operational and infrastructure gaps that are found in its system.

The 'BBB+' corporate credit rating (CCR) assigned to PG&E Corp. and its subsidiary PG&E reflects consolidated operations that consist of the regulated utility operations of PG&E, with parent activities limited to routine corporate functions. The parent and PG&E have unsecured debt ratings of 'BBB' and 'BBB+', respectively.

The parent and subsidiary both have an "excellent" business profile and "significant" financial profile. The company's consolidated business risk reflects the regulated, diversified nature of the utility's franchise, which serves 5.1 million retail electric customers and 4.3 million natural gas distribution customers throughout Northern and Central California. The financial profile is principally supported by what we consider to be a reasonable capital structure for the utility, which the California Public Utilities Commission (CPUC) limits to no more than 46% long-term debt, and the utility's modest use of parent leverage. Also supporting the "significant" financial profile is the company's strategy of pursuing shareholder growth through the utility rather than through unregulated energy businesses.

Investigations into the root causes of the explosion of a 30" steel pipe on PG&E's line 132 has been initiated by both the National Transportation Safety Board (NTSB) and the California Public Utilities Commission (CPUC). The NTSB is expected to assess all physical evidence from the blast, as well as examine the integrity of the system, the quality of PG&E's repair program, and its emergency response to make both a determination as to the cause of the explosion and recommendations for improvements.

The CPUC's response to the explosion has been swift, balanced, and focused firmly on fact finding, in our view. Last week, the CPUC announced that it will establish an independent panel of three to five experts to review the facts surrounding the accident and to make recommendations to improve the safety of PG&E's natural gas transmission lines. Still, we believe that the constructive regulatory support from the CPUC could erode if PG&E is found negligent. And because the legislature has a long history of drafting laws governing utility operations, we expect that, as a result of this accident, new statutes could be introduced, which may have uncertain consequences for California utilities, including PG&E. We note that the tragedy occurred in the midst of an election season, and the newly elected governor could appoint as many as four commissioners in 2011 due to retirements and appointment confirmations. As a result, it may be that the investigation's findings will be acted upon by a newly constituted group of commissioners.

PG&E currently has two important gas-related cases before the CPUC. It is not clear if the blast will have any impact on the schedule or outcome of either. First, as part of its three-year general rate case cycle, the company has requested a $1.1 billion increase in its revenue requirement beginning in 2011-2013, representing an increase of approximately 6.4%. The company also has reached a settlement that is currently before the CPUC in its 2011 gas transmission and storage rate case for an estimated 11% increase relative to the current revenue requirement. The settlement provides for an increase of $529 million in 2011, with further upward adjustments in 2012-2014. On Sept. 15, 2010, the administrative law judge assigned to the case asked parties to comment on whether the proposed settlement is adequate in light of the San Bruno accident. PG&E has proposed that any additional requirements the CPUC mandates should be addressed in a separate proceeding and has asked the CPUC to rule on the settlement by the end of the 2010.

Managing the many challenges the accident has created may pose a major distraction from the existing hurdles that faced PG&E prior to the blast. Chief among these challenges is executing its massive capital investment program. At this point, it is impossible to determine if PG&E will be required to spend incremental capital as a result of the investigation, but we do believe that the utility was already at or near its capacity to implement the capital plans it had prior to the blast. PG&E has indicated that its capital investment will range from $4 billion to $4.6 billion in 2010 and $3.2 billion to $5.3 billion in 2011. Through June 30, it has spent $1.8 billion.

Given the various mandates facing the California utilities, as well as the programs PG&E is itself pursuing, there is scant evidence that 2010 and 2011 represent a temporary blip in capital projects. Indeed, PG&E management, state policymakers, and regulators appear united in their objectives to strengthen the state's energy infrastructure, ensure California's role as a leader in renewable energy, and leverage the electric utility's growth plans as a way to bolster a state economy severely affected by the recession. Prior to the accident, we viewed the virtual tsunami of energy programs and initiatives, along with the associated capital PG&E is planning, to be happening too quickly to ensure credit quality is maintained over the long run. We specifically note the impact PG&E's plans will have on retail electric rates and the company's ability to maintain its financial profile, which has always been above average for its rating and, thus, has been an important source of support for the rating. The accident, in our view, will add to the stress already facing the company.

To prepare customers for needed rate increases to support large infrastructure investments, PG&E has been honing its image as a progressive electric and gas utility devoted to reducing its carbon footprint. But negative sentiment toward the utility has been strong in recent months. In our view, the pipeline explosion mars a company reputation already suffering from smart meter implementation problems and the political fallout over the company's $45 million sponsorship of the failed Proposition 16 this spring. (Proposition 16 was a June state ballot initiative that would have required a two-thirds vote for cities and counties to enter the retail power business. Voters defeated the measure.) A critical component of the firm's constructive regulatory relationship is customer confidence in PG&E's ability to provide safe and reliable service at an affordable price. Our review will assess management's ability to manage additional capital programs that may be ordered, its ongoing response to the accident, the transparency of its outreach, and whether we believe it has a credible plan that will restore public confidence in the utility.

Liquidity

We view parent and utility liquidity on a consolidated basis. Consolidated liquidity is "adequate" under Standard & Poor's corporate liquidity methodology, which categorizes liquidity in five standard descriptors (exceptional, strong, adequate, less than adequate, and weak). This assessment considers consolidated projected sources of liquidity and considers the company's operating cash flow and available bank lines against expected projected uses, necessary capital expenditures, debt maturities, and common dividends. On a consolidated basis, sources of cash divided by uses of cash is nearly 1.3x.

The company's liquidity could deteriorate to "less than adequate" if the costs associated with the San Bruno accident are not covered by PG&E's liability policy. The company has disclosed that it carries liability insurance for damages caused by fire of $992 million, with a $10 million deductible. In addition to the direct costs of the accident, PG&E may also incur costs to rectify any operational or system deficiencies that are brought to light as part of ongoing investigations or legislative actions. It is unclear what the costs of any ordered changes may be, nor how much of the expense would be recovered from ratepayers versus absorbed by the company. As a result, we believe it is too early to conclude with certainty that the company's liability insurance policy, while ample, will meet all of its obligations.

As of June 30, 2010 consolidated cash and cash equivalents totaled $60 million while total availability under three credit lines totaled $1,564 million. The parent, PG&E Corp., maintains a $187 million revolving credit facility, of which $157 million was available as of June 30, 2010. The utility has a $1,940 million facility, of which $657 million was available as of the same date. We would note that PG&E's commercial paper balances have been at this high level all year, and are occurring largely to support the capital investment needs of the utility.

In June, PG&E added an additional credit facility in the amount of $750 million that extends through Feb. 26, 2010. There were no borrowings under the facility as of the same date. Under the new facility, the utility has the right to increase its capacity by $250 million under certain conditions We do not consider this amount in our liquidity calculations. Covenants are similar to those in place for PG&E's utility's $1.9 billion revolving line.

All three facilities expire in February 2012 and, as a result, are included in our assessment of consolidated liquidity (e.g., as of June 30, 2010 the expiration of the credit line was at least a year away.)

CreditWatch

Details of the accident are unfolding daily, and investigations into the root cause have only just begun. We expect greater clarity around the facts of the tragedy to emerge in the coming months, which also will afford us more opportunity to gauge the response of both regulators and the company in repairing the public's trust in the safety of PG&E's gas transmission system. We also expect needed improvements in PG&E's gas infrastructure or operating procedures, if any, will be at least preliminarily identified, allowing us to assess the cost and capital investment implications of any recommendations. As a result, we anticipate assessing whether it is appropriate to resolve the CreditWatch placement no sooner than in the fourth quarter of this year.

SNL

SNLFinancial

Rate Case History

Pending Rate Cases

State	Company	Case Identification	Service	Filing Date	Rate Increase ($M)	Rate Change/Revenue (%)	Return on Rate Base (%)	Return on Equity (%)	Common Equity /Total Cap (%)	Test Year End	Rate Base ($M)	Rate Base Valuation Method	Action Likely By
California	Pacific Gas and Electric Co.	AP-09-12-020 (elec)	Electric	12/21/2009	856.0	NA	8.79	11.35	52.00	12/2011	14,783.0	Average	12/31/2010
California	Pacific Gas and Electric Co.	AP-09-12-020 (gas)	Natural Gas	12/21/2009	208.7	NA	8.79	11.35	52.00	12/2011	2,458.6	Average	12/31/2010
California	Southern California Edison Co.	SCE-GRC-TY2012-NOI	Electric	NA	903.0	7.90	8.75	11.50	48.00	12/2012	NA	NA	12/31/2011
California	Southern California Gas Co.	SCG-GRC-TY2012-NOI	Natural Gas	NA	282.0	NA	8.68	10.82	48.00	12/2012	NA	NA	12/31/2011

Past Rate Cases

				Increase Requested						Increase Authorized								
State	Company	Case Identification	Service	Date	Rate Increase ($M)	Return on Rate Base (%)	Return on Equity (%)	Common Equity /Total Cap (%)	Rate Base ($M)	Date	Rate Increase ($M)	Return on Rate Base (%)	Return on Equity (%)	Common Equity /Total Cap (%)	Test Year End	Rate Base ($M)	Rate Base Valuation Method	Lag (months)
California	Pacific Gas and Electric Co.	AP-0512002 De-0703044 (elec)	Electric	12/2/2005	359.1	8.79	11.35	52.00	10,548.6	3/21/2007	192.2	8.79	11.35	52.00	12/2007	10,354.3	Average	15
California	Pacific Gas and Electric Co.	AP-0512002 De-0703044 (gas)	Natural Gas	12/2/2005	35.5	8.79	11.35	52.00	2,197.4	3/21/2007	20.5	8.79	11.35	52.00	12/2007	2,195.8	Average	15
California	San Diego Gas & Electric Co.	Ap-06-12-009 (elec.)	Electric	12/8/2006	197.9	8.23	10.70	49.00	2,989.3	7/31/2008	131.0	8.23	10.70	49.00	12/2008	2,938.2	Average	20
California	San Diego Gas & Electric Co.	AP-06-12-009 (gas)	Natural Gas	12/8/2006	33.8	8.23	10.70	49.00	429.2	7/31/2008	7.0	8.23	10.70	49.00	12/2008	409.4	Average	20
California	Sierra Pacific Power Co.	AP-08-08-004	Electric	8/1/2008	8.9	8.81	11.40	43.71	146.5	11/3/2009	5.5	8.51	10.70	43.71	12/2009	141.5	Average	15
California	Southern California Edison Co.	Ap-07-11-011	Electric	11/19/2007	738.7	8.75	11.50	48.00	13,242.0	3/12/2009	308.1	8.75	11.50	48.00	12/2009	12,766.5	Average	15
California	Southern California Gas Co.	AP-06-12-010	Natural Gas	12/8/2006	139.3	8.68	10.82	48.00	2,887.1	7/31/2008	59.0	8.68	10.82	48.00	12/2008	2,800.9	Average	20
California	Southwest Gas Corp.	A-07-12-022 (SoCalDiv)	Natural Gas	12/21/2007	7.1	8.49	11.50	47.00	155.2	11/21/2008	2.4	7.87	10.50	47.00	12/2009	143.9	Average	11
California	Southwest Gas Corp.	A-07-12-022 (NoCalDiv)	Natural Gas	12/21/2007	-0.1	9.50	11.50	47.00	54.5	11/21/2008	-1.0	8.99	10.50	47.00	12/2009	52.3	Average	11
California	Southwest Gas Corp.	A-07-12-022 (LkTah)	Natural Gas	12/21/2007	2.1	9.50	11.50	47.00	12.4	11/21/2008	1.8	8.99	10.50	47.00	12/2009	11.8	Average	11

SNL Financial LC, One SNL Plaza, PO Box 2124, Charlottesville, Virginia 22902 USA, (434) 977-1600

Schedule FJH R-9

Delmarva Power and Light Company
Regression Analysis of Total Net Gas Revenues and Heating Degree Days
from April 2006 through June 2010

	Total Net Gas Revenues (1)	Heating Degree Days
Apr-06	4,665,820	485.38
May-06	2,825,402	197.25
Jun-06	2,329,973	70.88
Jul-06	2,122,964	2.38
Aug-06	2,034,670	0.00
Sep-06	2,133,080	18.38
Oct-06	2,476,466	169.50
Nov-06	4,177,442	402.75
Dec-06	5,714,859	610.63
Jan-07	6,743,151	703.50
Feb-07	9,139,902	1033.75
Mar-07	8,905,715	824.00
Apr-07	6,014,379	567.63
May-07	4,000,332	236.25
Jun-07	2,731,632	39.13
Jul-07	2,527,553	1.00
Aug-07	2,469,301	0.88
Sep-07	2,551,142	9.50
Oct-07	2,569,884	69.63
Nov-07	4,290,011	359.88
Dec-07	7,393,718	726.38
Jan-08	8,902,920	831.75
Feb-08	9,177,562	882.50
Mar-08	8,125,983	734.38
Apr-08	5,655,397	507.88
May-08	3,572,185	212.50
Jun-08	2,910,659	86.00
Jul-08	2,443,194	0.75
Aug-08	2,431,476	0.00
Sep-08	2,425,349	5.00
Oct-08	2,803,512	122.63
Nov-08	4,542,453	433.63
Dec-08	7,939,033	759.88
Jan-09	9,539,529	959.38
Feb-09	9,781,889	992.75
Mar-09	8,137,759	756.88
Apr-09	5,656,417	542.13
May-09	3,380,747	207.75
Jun-09	2,879,640	58.25
Jul-09	2,467,184	6.25
Aug-09	2,352,042	0.00
Sep-09	2,391,421	11.50
Oct-09	2,883,298	162.00
Nov-09	4,168,239	384.13
Dec-09	6,355,803	644.13
Jan-10	10,333,038	1017.13
Feb-10	9,281,816	1001.63
Mar-10	8,358,068	721.38
Apr-10	4,653,025	363.63
May-10	3,334,829	214.75
Jun-10	2,580,417	38.75

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.983108931
R Square	0.96650317
Adjusted R Square	0.965819561
Standard Error	492308.6443
Observations	51

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	3.42666E+14	3.42666E+14	1413.824988	8.40081E-38
Residual	49	1.1876E+13	2.42368E+11		
Total	50	3.54542E+14			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	2041615.362	101614.6498	20.09174235	2.63899E-25	1837413.078	2245817.646	1837413.078	2245817.646
X Variable 1	7460.956311	198.4251285	37.60086419	8.40081E-38	7062.206086	7859.706536	7062.206086	7859.706536

Notes:
(1) Represents monthly distribution revenues net of taxes, surcharges and the commodity cost of gas.

Source of Information: Company-Provided.

Delmarva Power and Light Company
Reductions in ROE due to Decoupling
in Fully-Litigated Gas Distribution Cases since 2007

Date	Jurisdiction	Company	Docket / Case No.	ROE Reduction
12/21/2007	New York	National Fuel Gas Distribution	07-G-0141	10 basis points
3/25/2009	Illinois	NICOR Gas	08-0363	6.5 basis points
6/22/2009	New York	Central Hudson Gas & Electric	08-G-0888	10 basis points
9/30/2009	Massachusetts	Bay State Gas Company	DPU-09-30	Not Specified
10/28/2009	Nevada	Southwest Gas Corporation	09-04003	25 basis points
1/11/2010	Minnesota	Centerpoint Energy Resources	GR-08-1075	0 basis points
1/21/2010	Illinois	North Shore Gas Company	09-0166	10 basis points
1/21/2010	Illinois	Peoples Gas	09-0167	10 basis points
2/10/2010	Missouri	Missouri Gas Energy	GR-2009-0355	0 basis points
5/17/2010	Michigan	Consumers Energy Co.	U-15986	0 basis points
5/24/2010	Tennessee	Chattanooga Gas Company	09-00354	25 basis points
6/3/2010	Michigan	Michigan Consolidated Gas Company	U-15985	0 basis points
10/21/2010	Kentucky	Delta Natural Gas Company	C-2010-00116	0 basis points
11/2/2010	Massachusetts	Boston Gas Company	D.P.U 10-55 (BG)	Not Specified
11/2/2010	Massachusetts	Colonial Gas Company	D.P.U 10-55 (CG)	Not Specified
			Average	8 basis points

Source of Information:

Commission Orders

FIFTH EDITION

PRINCIPLES OF CORPORATE FINANCE

RICHARD A. BREALEY
Tokai Bank Professor of Finance
London Business School

STEWART C. MYERS
Gordon Y Billard Professor of Finance
Sloan School of Management
Massachusetts Institute of Technology

The McGraw-Hill Companies, Inc.
New York St. Louis San Francisco Auckland Bogotá Caracas Lisbon London Madrid Mexico City Milan Montreal New Delhi San Juan Singapore Sydney Tokyo Toronto

McGraw-Hill
A Division of the McGraw-Hill Companies

Principles of Corporate Finance

This book is printed on acid-free paper.

234567890 DOC DOC 90987

ISBN 0-07-007417-8

This book was set in Janson by York Graphic Services, Inc.
The editors were Michelle E. Cox and Elaine Rosenberg; the production supervisor was Kathryn Porzio.
The design manager was Charles Carson.
The text was designed by Blake Logan.
The cover was designed by Danielle Conlon.
New drawings were done by Dartmouth Publishing, Inc.
R. R. Donnelley & Sons Company was printer and binder.

Cover photograph by Joshua Sheldon.
Library of Congress Cataloging-in-Publication Data is available:
LC Card # 96-76441.

INTERNATIONAL EDITION

When ordering this title, use ISBN 0-07-114053-0.

9

Capital Budgeting and Risk

Long before the development of modern theories linking risk and expected return, smart financial managers adjusted for risk in capital budgeting. They realized intuitively that, other things being equal, risky projects are less desirable than safe ones. Therefore financial managers demanded a higher rate of return from risky projects, or they based their decisions on conservative estimates of the cash flows.

Various rules of thumb are often used to make these risk adjustments. For example, many companies estimate the rate of return required by investors in their securities and use the **company cost of capital** to discount the cash flows on all new projects. Since investors require a higher rate of return from a very risky company, such a firm will have a higher company cost of capital and will set a higher discount rate for its new investment opportunities. For example, in Table 8-1 we estimated that investors expected a rate of return of .163 or about 16.5 percent from Microsoft common stock. Therefore, according to the company cost of capital rule, Microsoft should have been using a 16.5 percent discount rate to compute project net present values.[1]

This is a step in the right direction. Even though we can't measure risk or the expected return on risky securities with absolute precision, it is still reasonable to assert that Microsoft faced more risk than the average firm and, therefore, should have demanded a higher rate of return from its capital investments.

But the company cost of capital rule can also get a firm into trouble if the new projects are more or less risky than its existing business. Each project should be evaluated at its *own* opportunity cost of capital. This is a clear implication of the value-additivity principle introduced in Chapter 7. For a firm composed of assets A and B, the firm value is

$$\text{Firm value} = \text{PV(AB)} = \text{PV(A)} + \text{PV(B)} = \text{sum of separate asset values}$$

Here PV(A) and PV(B) are valued just as if they were mini-firms in which stockholders could invest directly. Investors would value A by discounting its forecasted cash flows at a rate reflecting the risk of A. They would value B by discounting at a rate reflecting the risk of B. The two discount rates will, in general, be different.

[1]Microsoft did not use any significant amount of debt financing. Thus its cost of capital is the rate of return investors expect on its common stock. The complications caused by debt are discussed later in this chapter.

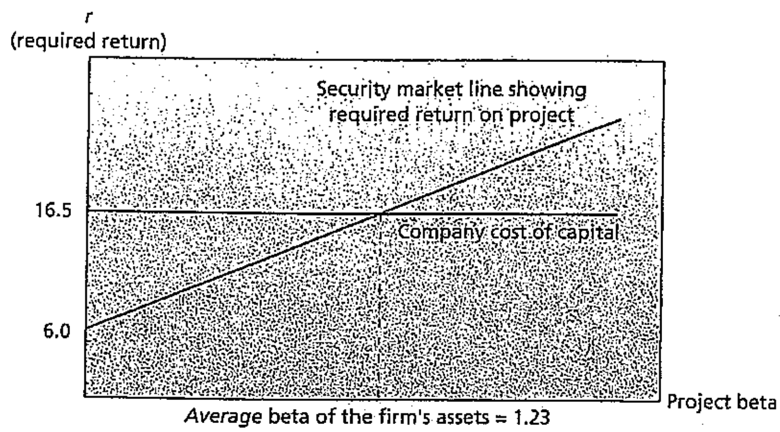


Figure 9-1 A comparison between the company cost of capital rule and the required return under the capital asset pricing model. Microsoft's company cost of capital is about 16.5 percent. This is the correct discount rate only if the project beta is 1.23. In general, the correct discount rate increases as project beta increases. Microsoft should accept projects with rates of return above the security market line relating required return to beta.

If the firm considers investing in a third project C, it should also value C as if C were a mini-firm. That is, the firm should discount the cash flows of C at the expected rate of return that investors would demand to make a separate investment in C. *The true cost of capital depends on the use to which the capital is put.*

This means that Microsoft should accept any project that more than compensates for the *project's beta*. In other words, Microsoft should accept any project lying above the upward-sloping line that links expected return to risk in Figure 9-1. If the project has a high risk, Microsoft needs a higher prospective return than if the project has a low risk. Now contrast this with the company cost of capital rule, which is to accept any project *regardless of its risk* as long as it offers a higher return than the *company's* cost of capital. In terms of Figure 9-1, the rule tells Microsoft to accept any project above the horizontal cost-of-capital line, i.e., any project offering a return of more than 16.5 percent.

It is clearly silly to suggest that Microsoft should demand the same rate of return from a very safe project as from a very risky one. If Microsoft used the company cost of capital rule, it would reject many good low-risk projects and accept many poor high-risk projects. It is also silly to suggest that just because Duke Power has a low company cost of capital, it is justified in accepting projects that Microsoft would reject. If you followed such a rule to its seemingly logical conclusion, you would think it possible to enlarge the company's investment opportunities by investing a large sum in Treasury bills. That would make the common stock safe and create a low company cost of capital.[2]

The notion that each company has some individual discount rate or cost of capital is widespread, but far from universal. Many firms require different returns from different categories of investment. For example, discount rates might be set as follows:

[2] If the present value of an asset depended on the identity of the company that bought it, present values would not add up. Remember, a good project is a good project is a good project.

Category	Discount Rate
Speculative ventures	30%
New products	20%
Expansion of existing business	15% (company cost of capital)
Cost improvement, known technology	10%

The capital asset pricing model is widely used by large corporations to estimate the discount rate. It states

$$\text{Expected project return} = r = r_f + (\text{project beta})(r_m - r_f)$$

To calculate this, you have to figure out the project beta. Before thinking about the betas of individual projects, we will look at some problems you would encounter in using beta to estimate a company's cost of capital. It turns out that beta is difficult to measure accurately for an individual firm: Much greater accuracy can be achieved by looking at an average of similar companies. But then we have to define *similar*. Among other things, we will find that a firm's borrowing policy affects its stock beta. It would be misleading, e.g., to average the betas of Chrysler, which has been a heavy borrower, and General Motors, which has generally borrowed less.

The company cost of capital is the correct discount rate for projects that have the same risk as the company's existing business but *not* for those projects that are safer or riskier than the company's average. The problem is to judge the relative risks of the projects available to the firm. To handle that problem, we will need to dig a little deeper and look at what features make some investments riskier than others. After you know *why* AT&T stock has less market risk than, say, Ford Motor, you will be in a better position to judge the relative risks of capital investment opportunities.

There is still another complication: Project betas can shift over time. Some projects are safer in youth than in old age; others are riskier. In this case, what do we mean by *the* project beta? There may be a separate beta for each year of the project's life. To put it another way, can we jump from the capital asset pricing model, which looks out one period into the future, to the discounted-cash-flow formula that we developed in Chapters 2 and 6 for valuing long-lived assets? Most of the time it is safe to do so, but you should be able to recognize and deal with the exceptions.

We will use the capital asset pricing model, or CAPM, throughout this chapter. But don't infer that the CAPM is the last word on risk and return. The principles and procedures covered in this chapter work just as well with other models such as arbitrage pricing theory (APT). For example, we could have started with an APT estimate of the expected rate of return on Microsoft stock; the discussion of company and project costs of capital would have followed exactly.

9-1 MEASURING BETAS

Suppose that you were considering an across-the-board expansion by your firm. Such an investment would have about the same degree of risk as the existing business. Therefore you should discount the projected flows at the company cost of capital. To estimate that, you could begin by estimating the beta of the company's stock.

An obvious way to measure the beta of the stock is to look at how its price has responded in the past to market movements. For example, in Figure 9-2*a* and *b* we have plotted monthly rates of return from AT&T and Hewlett-Packard against mar-

Ibbotson® SBBI®
2010 Valuation Yearbook

Market Results for
Stocks, Bonds, Bills, and Inflation
1926–2009

MORNINGSTAR®

whether caused by a shift to a different decile portfolio, bankruptcy, or other such reason. On the other hand, the S&P 500 does not make this adjustment. Once a company is no longer included among the S&P 500, its return is dropped from the index. However, this effect may be lessened by the advance announcement of companies being dropped from or added to the S&P 500. In many instances throughout this publication we will present equity risk premia using both the S&P 500 and the NYSE "Deciles 1–2" portfolio to provide a comparison between these large-capitalization benchmarks.

The Market Benchmark and Firm Size

Although not restricted to include only the 500 largest companies, the S&P 500 is considered a large company index. The returns of the S&P 500 are capitalization weighted, which means that the weight of each stock in the index, for a given month, is proportionate to its market capitalization (price times number of shares outstanding) at the beginning of that month. The larger companies in the index therefore receive the majority of the weight. The use of the NYSE "Deciles 1–2" series results in an even purer large company index. Yet many valuation professionals are faced with valuing small companies, which historically have had different risk and return characteristics than large companies. If using a large stock index to calculate the equity risk premium, an adjustment is usually needed to account for the different risk and return characteristics of small stocks. This will be discussed further in Chapter 7 on the size premium.

The Risk-Free Asset

The equity risk premium can be calculated for a variety of time horizons when given the choice of risk-free asset to be used in the calculation. The *2010 Ibbotson® Stocks, Bonds, Bills, and Inflation® Classic Yearbook* provides equity risk premia calculations for short-, intermediate-, and long-term horizons. The short-, intermediate-, and long-horizon equity risk premia are calculated using the income return from a 30-day Treasury bill, a 5-year Treasury bond, and a 20-year Treasury bond, respectively.

Although the equity risk premia of several horizons are available, the long-horizon equity risk premium is preferable for use in most business-valuation settings, even if an investor has a shorter time horizon. Companies are entities that generally have no defined life span; when determining a company's value, it is important to use a long-term discount rate because the life of the company is assumed to be infinite. For this reason, it is appropriate in most cases to use the long-horizon equity risk premium for business valuation.

20-Year versus 30-Year Treasuries

Our methodology for estimating the long-horizon equity risk premium makes use of the income return on a 20-year Treasury bond; however, the Treasury currently does not issue a 20-year bond. The 30-year bond that the Treasury recently began issuing again is theoretically more correct due to the long-term nature of business valuation, yet Ibbotson Associates instead creates a series of returns using bonds on the market with approximately 20 years to maturity. The reason for the use of a 20-year maturity bond is that 30-year Treasury securities have only been issued over the relatively recent past, starting in February of 1977, and were not issued at all through the early 2000s.

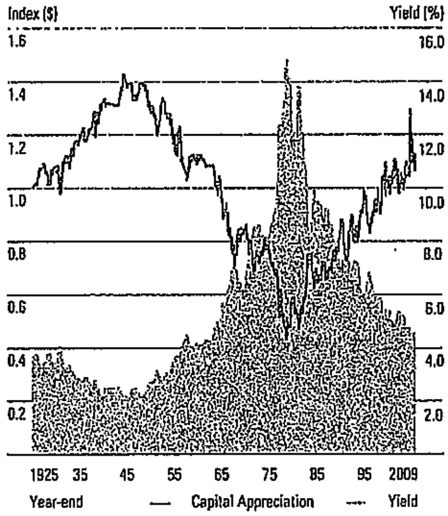
The same reason exists for why we do not use the 10-year Treasury bond—a long history of market data is not available for 10-year bonds. We have persisted in using a 20-year bond to keep the basis of the time series consistent.

Income Return

Another point to keep in mind when calculating the equity risk premium is that the income return on the appropriate-horizon Treasury security, rather than the total return, is used in the calculation. The total return is comprised of three return components: the income return, the capital appreciation return, and the reinvestment return. The income return is defined as the portion of the total return that results from a periodic cash flow or, in this case, the bond coupon payment. The capital appreciation return results from the price change of a bond over a specific period. Bond prices generally change in reaction to unexpected fluctuations in yields. Reinvestment return is the return on a given month's investment income when reinvested into the same asset class in the subsequent months of the year. The income return is thus used in the estimation of the equity risk premium because it represents the truly riskless portion of the return.[2]

Yields have generally risen on the long-term bond over the 1926–2009 period, so it has experienced negative capital appreciation over much of this time. This trend has turned around since the 1980s, however. Graph 5-1 illustrates the yields on the long-term government bond series compared to an index of the long-term government bond capital appreciation. In general, as yields rose, the capital appreciation index fell, and vice versa. Had an investor held the long-term bond to maturity, he would have realized the yield on the bond as the total return. However, in a constant maturity portfolio, such as those used to measure bond returns in this publication, bonds are sold before maturity (at a capital loss if the market yield has risen since the time of purchase). This negative return is associated with the risk of unanticipated yield changes.

Graph 5-1: Long-term Government Bond Yields versus Capital Appreciation Index



Data from 1925–2009.

For example, if bond yields rise unexpectedly, investors can receive a higher coupon payment from a newly issued bond than from the purchase of an outstanding bond with the former lower-coupon payment. The outstanding lower-coupon bond will thus fail to attract buyers, and its price will decrease, causing its yield to increase correspondingly, as its coupon payment remains the same. The newly priced outstanding bond will subsequently attract purchasers who will benefit from the shift in price and yield; however, those investors who already held the bond will suffer a capital loss due to the fall in price.

Anticipated changes in yields are assessed by the market and figured into the price of a bond. Future changes in yields that are not anticipated will cause the price of the bond to adjust accordingly. Price changes in bonds due to unanticipated changes in yields introduce price risk into the total return. Therefore, the total return on the bond series does not represent the riskless rate of return.The income return better represents the unbiased estimate of the purely riskless rate of return, since an investor can hold a bond to maturity and be entitled to the income return with no capital loss.

Arithmetic versus Geometric Means

The equity risk premium data presented in this book are arithmetic average risk premia as opposed to geometric average risk premia. The arithmetic average equity risk premium can be demonstrated to be most appropriate when discounting future cash flows. For use as the expected equity risk premium in either the CAPM or the building block approach, the arithmetic mean or the simple difference of the arithmetic means of stock market returns and riskless rates is the relevant number. This is because both the CAPM and the building block approach are additive models, in which the cost of capital is the sum of its parts. The geometric average is more appropriate for reporting past performance, since it represents the compound average return.

The argument for using the arithmetic average is quite straightforward. In looking at projected cash flows, the equity risk premium that should be employed is the equity risk premium that is expected to actually be incurred over the future time periods. Graph 5-2 shows the realized equity risk premium for each year based on the returns of the S&P 500 and the income return on long-term government bonds. (The actual, observed difference between the return on the stock market and the riskless rate is known as the realized equity risk premium.) There is considerable volatility in the year-by-year statistics. At times the realized equity risk premium is even negative.