Exhibit No.:	506NP
Witness:	Michael Gorman
Type of Exhibit:	Surrebuttal Testimony
Issues:	Rate of Return
Sponsoring Parties:	Enbridge Energy, LP Explorer Pipeline Company General Mills Praxair, Inc. Wal-Mart Stores, Inc.
Case No.:	ER-2008-0093

BEFORE THE PUBLIC SERVICE COMMISSION OF THE STATE OF MISSOURI

In the Matter of The Empire District Electric Company of Joplin, Missouri for Authority to File Tariffs Increasing Rates for Electric Service Provided to Customers in the Missouri Service Area of the Company	)	**Case No. ER-2008-0093**

Surrebuttal Testimony and Schedules of

Michael Gorman

On behalf of

Enbridge Energy, LP
Explorer Pipeline Company
General Mills
Praxair, Inc.
Wal-Mart Stores, Inc.

Industrial Intervenors Exhibit No. 506
Case No(s). ER-2008-0093
Date 5-12-08 Rptr KF

April 25, 2008

BRUBAKER & ASSOCIATES, INC.
ST. LOUIS, MO 63141-2000

NON-PROPRIETARY

Project 8875

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of The Empire District Electric Company of Joplin, Missouri for Authority to File Tariffs Increasing Rates for Electric Service Provided to Customers in the Missouri Service Area of the Company	)	Case No. ER-2008-0093

STATE OF MISSOURI)
) SS
COUNTY OF ST. LOUIS)

Affidavit of Michael Gorman

Michael Gorman, being first duly sworn, on his oath states:

1. My name is Michael Gorman. I am a consultant with Brubaker & Associates, Inc., having its principal place of business at 1215 Fern Ridge Parkway, Suite 208, St. Louis, Missouri 63141-2000. We have been retained by Enbridge Energy, LP; Explorer Pipeline Company; General Mills; Praxair, Inc. and Wal-Mart Stores, Inc. in this proceeding on their behalf.

2. Attached hereto and made a part hereof for all purposes are my surrebuttal testimony and schedules which were prepared in written form for introduction into evidence in Missouri Public Service Commission Case No. ER-2008-0093.

3. I hereby swear and affirm that the testimony and schedules are true and correct and that they show the matters and things that they purport to show.

Michael Gorman

Michael Gorman

Subscribed and sworn to before me this 25th day of April, 2008.

Maria E. Decker

Notary Public

MARIA E. DECKER
Notary Public, State of Missouri
St. Louis City
Commission # 05706793
My Commission Expires May 05, 2009

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of The Empire District Electric Company of Joplin, Missouri for Authority to File Tariffs Increasing Rates for Electric Service Provided to Customers in the Missouri Service Area of the Company	**)**	**Case No. ER-2008-0093**

<u>Surrebuttal Testimony of Michael Gorman</u>

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A My name is Michael Gorman and my business address is 1215 Fern Ridge Parkway, Suite 208, St. Louis, MO 63141-2000.

Q ARE YOU THE SAME MICHAEL GORMAN THAT FILED DIRECT AND REBUTTAL TESTIMONY IN THIS PROCEEDING?

A Yes.

Q WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY?

A I will respond to the rebuttal testimony of The Empire District Electric Company (Empire or Company) witnesses Dr. H. Edwin Overcast, Dr. James H. Vander Weide, and Robert W. Sager.

Response to Empire Witness Dr. H. Edwin Overcast

Q WHAT ISSUES IN DR. OVERCAST'S REBUTTAL TESTIMONY DO YOU WISH TO RESPOND?

A Dr. Overcast disputes my recommendation that a return on equity adjustment is necessary if the Commission approves a fuel adjustment clause in this proceeding. In support of this assertion, Dr. Overcast reviews the comparable group Staff witness Matthew J. Barnes and I relied on to support our return on equity recommendations. He finds that utility affiliates of most of those companies have fuel adjustment mechanisms. Therefore, he asserts that the return on equity he measured for Empire would be appropriate if a fuel adjustment clause is adopted because that is consistent with the same regulatory mechanisms that many of the companies in our proxy group have.

Q IS DR. OVERCAST'S ASSESSMENT OF A RETURN ON EQUITY ADJUSTMENT BASED ON A COMPLETE AND ACCURATE ANALYSIS?

A No. Dr. Overcast has not done a complete and accurate assessment of the operating risk of Empire relative to the operating risk of the companies included in my proxy group and the proxy group of Staff witness Mr. Barnes. Further, Dr. Overcast has not done any analysis of the <u>total</u> investment risk which includes a combination of <u>financial</u> and <u>operating</u> risk, in support of his testimony. Without a complete assessment of the total investment risks of Empire relative to those of the proxy group, Dr. Overcast's assessment of an appropriate return on equity is not reliable and is based only on his opinion and speculation.

Q WHAT WOULD BE THE CIRCUMSTANCE UNDER WHICH A RETURN ON EQUITY ADJUSTMENT WOULD BE APPROPRIATE IF CHANGES IN THE REGULATORY MECHANISMS UNDERLYING EMPIRE'S OPERATIONS ARE APPROVED?

A My proxy group and that of Staff witness Mr. Barnes were both selected based on a comparison of Empire's current total investment risks relative to those of the proxy group. Empire's current investment risk does <u>not</u> include the operating risk reduction created by implementing a fuel adjustment mechanism.

Regulatory mechanisms are an important assessment made by credit analysts in assigning the operating risk of a utility company, which goes into its overall credit rating. Specifically, Standard & Poor's (S&P) notes that the regulatory mechanisms are an important factor in determining the overall business risk assessment of a utility company.[1] In assigning a utility's business profile score, S&P reviews the utility's business risk using the following categories: management risk, regulatory risk, market risk, operations and competitive position risk. Regulatory risk includes responsiveness of the regulator to adjust rates to meet the utility's changed cost of service.

Empire's current regulatory mechanisms do not include a fuel adjustment clause; therefore, it is beyond dispute that its current total investment risk and bond rating does not reflect the risk reduction (or transfer to customers of risk) of fuel cost recovery. Importantly, if a fuel adjustment mechanism is implemented for Empire, its operating risk will be reduced, and a lower return on equity would be appropriate.

This is not to say that only downward return on equity adjustments are appropriate. If the Commission decided to make a change to another aspect of the

[1] Key Credit Factors: Assessing U.S. Vertically Integrated Utilities' Business Risk Drivers.

Company that caused a material increase in risk from the current status quo, then an upward adjustment to the recommended return on equity would be appropriate.

Q DID DR. OVERCAST ATTEMPT TO SUPPORT HIS CONCLUSION THAT EMPIRE'S OPERATING RISK WOULD NOT BE REDUCED WITH THE IMPLEMENTATION OF A FUEL ADJUSTMENT MECHANISM?

A No. In response to the Staff and Mr. Brubaker's proposed fuel adjustment mechanisms, Dr. Overcast simply asserts that a fuel adjustment clause can be used to ensure the utility recovers its prudent fuel costs. However, he ignores the fact that Empire does not need a single-issue ratemaking fuel adjustment mechanism to properly set rates. Empire can file a complete rate case where the Commission can fully evaluate all revenues and costs to ensure rates are no higher or lower than necessary to fully recover prudent costs. This full cost review is needed to determine whether or not Empire's rates are just and reasonable.

A fuel adjustment mechanism, in contrast, allows a utility to increase fuel prices to customers without a full review of all other revenues and operating expenses. Hence, a fuel adjustment clause may allow a utility to increase fuel prices when a price increase would not be justified if a full review of all revenues, expenses, and rate base items were examined. As such, a fuel adjustment mechanism can result in excessive charges.

Therefore, a single-issue fuel adjustment mechanism such as the one advocated by Dr. Overcast reduces a utility's operating risk because it provides a much lower threshold for increasing prices to customers relative to the traditional method of reviewing all revenues and expenses. As such, Dr. Overcast's support for a fuel adjustment mechanism does not result in an improvement in the development of just and reasonable rates. In fact, his proposal would produce just the opposite and potentially allow Empire to earn more than its authorized return on equity, by charging excessive rates.

Response to Empire Witness Dr. James H. Vander Weide

Q DID DR. VANDER WEIDE SPONSOR REBUTTAL TESTIMONY?

A Yes. Dr. Vander Weide offered testimony to respond to the return on equity recommendations made by Staff witness Matthew J. Barnes and me. Mr. Barnes recommended a return on equity of 10.28% and I recommended a return on equity of 10%. Dr. Vander Weide concludes that our recommended returns on equity understate Empire's current market cost of equity, and he continues to support his original recommended return on equity of 11.6%.

I. PROXY GROUP

Q IS THERE ANY MERIT TO DR. VANDER WEIDE'S ARGUMENT THAT THE PROXY GROUP YOU HAVE USED UNDERSTATED EMPIRE'S COST OF EQUITY?

A No. In my rebuttal testimony to Dr. Vander Weide, I applied my cost of equity models to his proxy group and produced results that are very similar to the results I produced when those models were applied to my proxy group. Hence, the difference between my proxy group and the proxy group used by Dr. Vander Weide is not a material issue in estimating Empire's cost of equity in today's marketplace. Rather, the difference is in the implementation of the DCF, risk premium and CAPM studies.

II. CONSTANT GROWTH DCF

Q PLEASE DESCRIBE THE ISSUES SURROUNDING THE RELIABILITY OF YOUR CONSTANT GROWTH DCF RESULT.

A My constant growth DCF analysis produced a return on equity estimate of 11.54%. That DCF return was based on a growth rate of 7.4%. In my direct testimony (pages 19 through 23), I explained in detail why that return on equity was not reliable or rational for estimating a DCF return. Hence, since this growth rate was too high to be a reasonable and rational estimate of long-term sustainable growth, I did not place any weight on this DCF return in forming my recommended return on equity. In response to that, Dr. Vander Weide disagreed with this conclusion stating the following:

1. Analyst growth rate projections do not need to be rational in order to reflect investors' expectations (at 26 and 27).
2. It was not appropriate to adjust a growth rate in the DCF model without also adjusting the stock price (at 27).

Q DOES DR. VANDER WEIDE PROVIDE ADEQUATE RESPONSE TO YOUR RATIONALE FOR NOT RELYING ON THE CONSTANT GROWTH DCF MODEL IN THIS CASE?

A No. Indeed, he provides very little response at all, much less a justification for relying on a DCF return estimate that is clearly out of line with today's low-cost capital market. First, there is academic and practical justification for rejecting growth rate estimates that do not reflect rational expectations. The DCF model itself is premised on an efficient market hypothesis. In an efficient market, investors would make rational investment decisions based on reasonable and rational estimates of investment performance, and stock value would be based on rational expectations.

Stocks would not be valued on the basis of irrational expectations as Dr. Vander Weide suggests.

Second, a stock price would reflect rational expectations of future growth. Stock price would not reflect a growth rate that is irrationally high, or irrationally low. Therefore, there is no need to adjust the stock price, in attempting to estimate what a rational investment market would use in valuing a utility stock. To the contrary, it would be inappropriate and erroneous to conclude that rational investors would rely on irrational long-term growth rate estimates in valuing a stock, as Dr. Vander Weide asserts.

Indeed, when a utility is not in a constant growth payment period because of declining ratios, or increasing capital expenditure programs, and issuing large amounts of common stock at prices above book value, a multi-stage growth DCF model is necessary in order to reasonably estimate the utility's cost of equity. This is advocated in many financial textbooks including one written by Dr. Roger Morin in which he states as follows:

> That investors, in fact, evaluate common stocks in the classical valuation framework, and trade securities <u>rationally at prices reflecting their perceptions of value</u>. Given the universality and pervasiveness of the classical valuation framework in investment education and in the professional investment community, this assumption is plausible.[2]
>
> * * *
>
> <u>If investors expect growth patterns to prevail in the future other than constant infinite growth, more complex DCF models are available</u>. For example, investors may expect dividends to grow at a relatively modest pace for the first 5 years and to resume a higher normal steady-state course thereafter, or conversely. The general valuation framework of Equation 8-5 can handle such situations. The "non-

[2] Roger A. Morin, Ph.D, *New Regulatory Finance* (Public Utilities Reports, Inc., June 2006), at 252, emphasis added.

> constant growth" model presented later in the chapter is a popular version of the DCF model.[3]
>
> * * *
>
> Dividends need not be, and probably are not, constant from period to period. Moreover, there are circumstances where the standard DCF model cannot be used to assess investor return requirements. For example, if a utility company is in the process of altering its dividend payout policy and <u>dividends are not expected to grow at the same rate as earnings during the transition period, the standard DCF model is inapplicable</u>. This is because the expected growth in stock price has to be different from that of dividends, earnings, and book value if the market price is to converge toward book value.[4]

Hence, there is academic and practical support and justification for not relying on a constant growth DCF model if the proxy group's dividend payout ratios are declining, the group's capital expenditures are increasing, and the companies are issuing common stock above book value to fund capital improvements. All of this is the case in this proceeding. This indicates that the three- to five-year growth rates are abnormally high during this time period, but will eventually decline to more reasonable sustainable level. Therefore, a multi-growth DCF model is needed to accurately estimate Empire's cost of equity.

<u>III. MULTI-STAGE DCF</u>

Q PLEASE DESCRIBE THE ISSUES DR. VANDER WEIDE RAISED WITH RESPECT TO YOUR TWO-STAGE DCF MODEL.

A He asserts that I did not provide any evidence to support my assumption that the long-term sustainable growth rate would be proxied by the GDP growth. However, he does not take issue with my general conclusion that it is rational to expect that a company's stock price, earnings and dividends cannot grow, indefinitely, at a growth

---

[3] *Id.* at 256, emphasis added.
[4] *Id.* at 264, emphasis added.

rate greater than the growth rate of the U.S. economy. Nevertheless, he takes issue with the use of a two-stage growth DCF model that incorporates this assumption.

Q DO YOU DISPUTE DR. VANDER WEIDE'S CLAIM THAT THE STOCK MARKET GENERALLY RELIES ON ANALYST GROWTH FORECASTS IN VALUING STOCK PRICES?

A No. Indeed, I recognize that most of the financial literature suggests that analyst growth forecasts have a lot of influence on utility stock price valuations. Because I agree with this suggestion, I did not reject analyst growth forecasts in either my constant growth or two-stage growth DCF models. Rather, I relied on them. However, there are periods where analyst three- to five-year growth projections simply reflect abnormally high growth periods for utility companies. This is particularly the case when utilities are in a high capital expenditure period and rate base is growing significantly, which will create strong earnings and dividend growth over the next three to five years.

During those times, analysts' growth rate projections are reasonable estimates for the short-term. However, they are not reasonable estimates for long-term sustainable growth. Given that DCF analyses are long term, even perpetual in derivation, the use of such abnormal short-term growth estimates in a long-term model produces unreliable and flawed estimates. Relying on three- to five-year growth rate projections as long-term sustainable growth would be irrational and indicate that the utility stock market is not capable of making intelligent, informed assessments of the utility's earnings outlooks, and stock price values. I reject that premise because the market in general makes rational investment decisions. In any event, if you cannot accept the premise that the market is generally efficient, then the DCF and CAPM models simply cannot produce reliable results.

Q DR. VANDER WEIDE ALSO PROVIDED A STATISTICAL TEST THAT HE CLAIMS TO SHOW THAT I/B/E/S GROWTH RATES PROVIDE A BETTER PRESENTATION OF INVESTOR VALUE THAN YOUR TWO-STAGE DCF MODEL. PLEASE RESPOND.

A Dr. Vander Weide attempted to demonstrate that a two-stage growth DCF model growth rate does not explain as much of changes to price-to-earnings (P/E) ratios and dividend payout ratios as does his constant growth DCF model. He asserts that he performed this study using the data in my two-stage DCF model. Dr. Vander Weide's model should be rejected for several reasons, including the following.

First, the R^2 factor in both of these models is very low, indicating that there is a very weak relationship between the growth rates in the constant growth and two-stage growth DCF models and the P/E ratios. This corroborates my finding that three- to five-year growth forecasts are not a very good indicator of long-term sustainable growth for these companies. Nevertheless, the coefficient for the two-stage growth rate estimates implies a stronger correlation with P/E than the I/B/E/S growth rates. Again, this supports the use of a two-stage growth model.

But more importantly, Dr. Vander Weide did not perform the analysis he claimed he did. This analysis was not performed on my two-stage DCF analysis. In my proxy group, I included 16 companies. In Dr. Vander Weide's study, he included over 37 companies. Hence, his study was not performed on my proxy group and cannot be used in the manner he suggests.

IV. RISK PREMIUM

Q WHAT ISSUES DID DR. VANDER WEIDE TAKE WITH YOUR RISK PREMIUM STUDY?

A Dr. Vander Weide takes primarily two issues with my risk premium study. First, he asserts that the equity returns are not based on independent evaluations since they are derived from commission authorized returns on equity for utility companies nationwide.

Second, he asserts that I should have reflected an inverse relationship between the equity risk premium and interest rates in developing my return on equity for Empire.

Q IS DR. VANDER WEIDE'S CORRECT THAT THE COMMISSION AUTHORIZED RETURNS ON EQUITY DO NOT REFLECT AN INDEPENDENT ASSESSMENT OF THE MARKET COST OF EQUITY?

A It is not an independent assessment to the extent that it is not based on current market information such as a DCF, two-stage DCF, or CAPM study. However, it is an independent assessment of the historical relationship commissions have found between the current market cost of common equity and contemporary utility bond yields. Since the cost of common equity cannot be observed it must be approximated, and there is significant controversy in estimating the current market cost of equity. Commission-authorized returns on equity are one proxy for the contemporary market required return on common equity and a reasonable approach for estimating contemporary market risk premiums.

As such, it is a valid and appropriate methodology for estimating how cost of equity changes in relationship to cost of debt. Therefore, this study does provide an unbiased assessment of historical equity risk premiums and thus provides meaningful information in estimating Empire's current cost of equity in this proceeding.

Q IS IT APPROPRIATE TO REFLECT AN INVERSE RELATIONSHIP BETWEEN THE EQUITY RISK PREMIUM AND INTEREST RATES WHEN USING YOUR RISK PREMIUM DATA AS DR. VANDER WEIDE IMPLIES?

A No. Dr. Vander Weide's belief that there is a simplistic inverse relationship between equity risk premiums and interest rates is not supported by academic research. While academic studies have shown that, in the past, there has been an inverse relationship with these variables, researchers have found that the relationship changes over time and is influenced by changes in perception of the risk of bond investments relative to equity investments, and not simply changes to interest rates.[5]

In the 1980s, equity risk premiums were inversely related to interest rates but that was likely attributable to the interest rate volatility that existed at that time. Interest rate volatility currently is much lower than it was in the 1980s.[6] As such, when interest rates were more volatile, the relative perception of bond investment risk increased relative to the investment risk of equities. This changing investment risk perception caused changes in equity risk premiums.

In today's marketplace, interest rate variability is not as extreme as it was during the 1980s. Nevertheless, changes in the perceived risk of bond investments relative to equity investments still drive changes in equity premiums. However, a relative investment risk differential cannot be measured simply by observing nominal

[5] "The Market Risk Premium: Expectational Estimates Using Analysts' Forecasts," Robert S. Harris and Felicia C. Marston, *Journal of Applied Finance*, Volume 11, No. 1, 2001 and "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.

[6] *SBBI 2007 Yearbook* (Morningstar, Inc.) at 112.

interest rates. Changes in nominal interest rates are highly influenced by changes to inflation outlooks, which also change equity return expectations. As such, the relevant factor needed to explain changes in equity risk premiums is the relative changes to the risk of equity versus debt securities investments, not simply changes to interest rates.

Importantly, Dr. Vander Weide's analysis ignores investment risk differentials. He bases his adjustment to the equity risk premium exclusively on changes in nominal interest rates. This is a flawed methodology and does not produce accurate or reliable risk premium estimates. His results should be rejected.

Q DOES DR. VANDER WEIDE'S REGRESSION STUDY OF THE DATA USED IN YOUR RISK PREMIUM STUDY INDICATE THAT THERE IS AN INVERSE RELATIONSHIP BETWEEN EQUITY RISK PREMIUMS AND INTEREST RATES?

A Statistically it does; however, a common sense approach to this data indicates Dr. Vander Weide's analysis is providing a false conclusion. Specifically, Commission-authorized returns have been declining over the years, in some cases while interest rates have been relatively flat. In reality, Commissions have reduced authorized returns on equity slower than the market has reduced bond interest rates. This gives the impression of an inverse relationship, but the reality is that it is simply reflecting Commissions' conservative nature in authorizing returns on equity in setting rates.

V. CAPITAL ASSET PRICING MODEL (CAPM)

Q WHAT ISSUES DOES DR. VANDER WEIDE TAKE WITH YOUR CAPM ANALYSIS?

A Dr. Vander Weide's primary argument with my CAPM analysis is he believes I have understated the market risk premium. He believes that using Morningstar data, the market risk premium should be 7.1%, and not the 6.5% I developed.

The differences between the two market risk premiums are as follows. The Morningstar estimate for the market risk premium of 7.1% as proposed by Dr. Vander Weide is based on the difference between the <u>total</u> market return on common stocks (price appreciation, reinvestment return and coupon yields), less the <u>income</u> return on Treasury bond investments (coupon yield only). In comparison, my 6.5% market risk premium is based on the difference between the <u>total</u> return on common stock, less the <u>total</u> return on Treasury bonds (coupon yield, reinvestment return, and price appreciation).

My market risk premium reflects the actual real experienced risk return premium investors would have experienced by investing in common stock relative to Treasury bonds. In contrast, Dr. Vander Weide's proposed 7.1% market risk premium reflects a contrived estimate of the market risk premium over a nonexistent risk-free rate estimate. Hence, the primary difference reflects the reality that a risk-free rate does not exist, and the determination of the risk premium actually earned over the proxy for the risk-free rate over historical time periods. As such, my return reflects real market experiences, and Dr. Vander Weide's proposed premium does not.

Q DO YOU BELIEVE YOU HAVE UNDERSTATED THE MARKET RISK PREMIUM AS ASSERTED BY DR. VANDER WEIDE?

A No. Even using Morningstar data, there are two market risk premiums that this publication recommends. First, it recommends a 7.1% market risk premium based on the S&P 500 and Treasury bond income returns as identified by Dr. Vander Weide. However, Morningstar also identifies market risk premiums of 6.83% and 6.35% using the New York Stock Exchange as market indexes rather than the S&P 500.[7] As such, Morningstar found that the market risk premium can change based on the stock market index.

Further, Morningstar acknowledges that the price-to-earnings ratios in the S&P 500 have exhibited abnormal growth during the 1980 to 2001 period, which impacted its market risk premium estimate. Morningstar offered an alternative market risk premium of 6.2%[8] based on a correction to the abnormal P/E ratio growth. Hence, Morningstar's studies indicate a range of market risk premium of 6.2% to 7.1%. Dr. Vander Weide is only recognizing Morningstar's business risk premium estimates.

Q HOW WOULD YOUR CAPM RETURN ESTIMATE CHANGE IF THE RANGE IN MORNINGSTAR'S ESTIMATED MARKET RISK PREMIUM WERE USED IN YOUR CAPM ANALYSIS RATHER THAN THE HIGHEST ESTIMATE MADE BY MORNINGSTAR AS RELIED ON BY DR. VANDER WEIDE?

A Adjusting my CAPM study to reflect a market risk premium in the range of 6.2% to 7.1% would produce an indicated CAPM return of 10.1% to 10.8% with a midpoint of

---

[7] *Ibbotson SBBI 2008 Valuation Yearbook* (Morningstar, Inc.) at 72.
[8] *Id.* at 92-98.

10.5%. I would note that this result is the same CAPM result I offered in my rebuttal testimony, 10.46%.

Q DO YOU BELIEVE IT IS APPROPRIATE TO INCLUDE A SMALL CAPITALIZATION RETURN ON EQUITY ADJUSTMENT TO YOUR CAPM RETURN ESTIMATE AS PROPOSED BY DR. VANDER WEIDE?

A No. Small company risk is part of a company's <u>total</u> investment risk. By selecting companies with similar risk to Empire, the proxy group can be used to estimate a fair return to compensate investors for Empire's total investment risk, including those risks related to its size.

Q HOW WOULD A COMPANY'S SIZE IMPACT ITS RISK?

A A company's size would impact its operating risk in the following ways:

1. Small companies typically have less ability to attract qualified management.
2. Small companies usually do not have the economies of scale to minimize operating expenses by spreading expertise over a larger customer base and buying materials and supplies in larger quantities.
3. Small companies do not have the geographic diversification to mitigate sales variations caused by weather and local economic cycles.

Q CAN ONE SELECT A COMPARABLE GROUP THAT ENCAPSULATED EMPIRE'S SMALL COMPANY RISK IN ESTIMATING A FAIR RETURN FOR EMPIRE IN THIS CASE?

A Yes. These small company risk factors certainly are considered by credit rating analysts and security analysts in assessing a utility's investment risk and valuation. Hence, when selecting a group of comparable risk companies, if one relies on a group of companies with risk characteristics that are comparable to the proxy company, then the proxy group itself would reflect these risk factors.

As such, it is unreasonable and would be redundant to add a size premium to a proxy group return if that proxy group already reasonably captures Empire's total investment risk. For example, Empire's small company risk can be offset by differences in other risk elements. As such, focusing on a single aspect of investment risk, rather than reviewing proxy groups on the basis of total investment risk, is inappropriate and produces unreasonable results.

Since the overall risk profiles of my proxy group and Dr. Vander Weide's proxy group are reasonably comparable to Empire, the proxy group reasonably captures Empire's small size risk and all other risk factors. As such, there is no need to add a size premium to the return on equity estimated from this proxy group.

Q **DID DR. VANDER WEIDE OFFER ANY CRITICISMS OF YOUR RETURN ON EQUITY ADJUSTMENT TO REFLECT A FUEL ADJUSTMENT MECHANISM THAT YOU HAVE NOT ALREADY RESPONDED TO WITH RESPECT TO EMPIRE WITNESS OVERCAST?**

A No. Dr. Vander Weide's arguments are nearly identical to those of Dr. Overcast. Dr. Vander Weide's arguments are flawed for the same reasons. Therefore, my criticisms of Dr. Overcast equally apply to the flawed arguments offered by Dr. Vander Weide.

Response to Empire Witness Robert W. Sager

Q WHAT ARE THE ISSUES WITH MR. SAGER'S REBUTTAL TESTIMONY TO WHICH YOU WILL RESPOND?

A I will respond to Mr. Sager's proposed regulatory plan amortization (RPA) expense of $19.8 million as he offers in his rebuttal testimony. That regulatory amortization expense was based on an analysis agreed to in principle by Staff, OPC and the Company.

Q DO YOU GENERALLY AGREE WITH THE SPREADSHEET UNDERLYING THIS RPA DEVELOPMENT SETTLEMENT?

A Generally, yes. However, there are adjustments I propose in order to accurately estimate the amount of regulatory amortization expense that is necessary.

Q PLEASE EXPLAIN YOUR PROPOSED ADJUSTMENT TO MR. SAGER'S ESTIMATED REGULATORY AMORTIZATION SCHEDULES.

A First, I provided the Company with the S&P document which outlines S&P's methodology for including imputed purchased power adjustment (PPA) debt amortization expense in its credit metric calculations. As I understand it, this was provided to the Company, and I am not sure why Mr. Sager did not receive this workpaper. Nevertheless, it was provided to the Company and the PPA debt amortization should be reflected in the regulatory amortization calculation.

Second, the amount of imputed debt associated with PPA obligations is overstated for test year conditions. Specifically, the Company included an imputed debt equivalent for purchased power obligations of **________**. This overstates the amount of purchased power obligation expenses the Company has incurred in 2007 and 2008. Excluding the purchased power obligation which the Company would put into effect in 2009, one year after the rate effective year in this proceeding, would reduce the off-balance-sheet PPA debt to **_________**, the 2008 balance. I recommend that the development of the regulatory amortization expense should be based on jurisdictional cost of service as the Regulatory Plan prescribes. Going beyond the rate effective year to increase the off-balance-sheet debt equivalent distorts the regulatory balance objective of the Regulatory Plan. The 2008 PPA debt equivalent is developed on Schedule MPG-1HC.

Third, S&P's methodology prescribes that the imputed interest expense on the off-balance-sheet debt and lease obligations should be set at the same interest rate as the discount rate. As such, on lines 39 and 40 of Mr. Sager's schedule, RWS-1, the interest adjustment for off-balance-sheet obligations should be based on an interest rate of 6.8% and not 10%. S&P prescribes the use of a discount rate as the interest expense in these calculations, as set forth on my Schedule MPG-2.

Finally, I developed an imputed amortization expense associated with PPA based on the Company's workpapers used to develop the test year off-balance-sheet debt equivalents for PPAs. Based on S&P's methodology and the Company's test year PPA obligations, an imputed amortization expense of **______** Total Company is appropriate. Development of this off-balance-sheet PPA debt equivalent is set forth on my Schedule MPG-1HC.

NON-PROPRIETARY

Next, I estimated the amount of regulatory amortization expense based on Staff's filing in this case and not the Company's. Importantly, this spreadsheet should be updated based on the Commission's authorized return on equity, and other regulatory findings in this case, at the conclusion of this proceeding.

Q **WHAT REGULATORY AMORTIZATION EXPENSE WOULD BE APPROPRIATE BASED ON YOUR ADJUSTMENTS TO THE COMPANY'S RECOMMENDATION?**

A As shown on my Schedule MPG-3HC, reflecting all the adjustments to Mr. Sager's rebuttal Schedule RWS-1 described above, the appropriate amount of regulatory amortization expense for the Company would be $2,910,076.

Q **DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?**

A Yes.

\\Huey\Shares\PLDocs\SDW\8875\Testimony - BAI\133936.doc

NON-PROPRIETARY

The Empire District Electric Company

Purchased Power Debt Equivalent

Line	Year	NPV (1)	30% Imputed Debt (2)	Annual Payment: Westar (3)	Annual Payment: Wind (4)	Annual Payment: Total (5)	Risk Factor 30% x Col. 5 (6)	Interest 6.8% x Col. 2 (7)	Depreciation Col. 6 - Col. 7 (8)
1	2008			Highly Confidential					

Source:
Empire's Response to Praxair/Explorer DR 113.

NON-PROPRIETARY

Ratings

Standard & Poor?s Methodology For Imputing Debt For U.S. Utilities? Power Purchase Agreements

Back

Publication Date: May 07, 2007 12:38 EDT

Standard & Poor's Methodology For Imputing Debt For U.S. Utilities' Power Purchase Agreements

Primary Credit Analyst:
David Bodek, New York (1) 212-438-7969;
david_bodek@standardandpoors.com
Secondary Credit Analysts:
Richard W Cortright, Jr., New York (1) 212-438-7665;
richard_cortright@standardandpoors.com
Solomon B Samson, New York (1) 212-438-7653;
sol_samson@standardandpoors.com
Additional Contacts:
Arthur F Simonson, New York (1) 212-438-2094;
arthur_simonson@standardandpoors.com
Arleen Spangler, New York (1) 212-438-2098;
arleen_spangler@standardandpoors.com
Scott Taylor, New York (1) 212-438-2057;
scott_taylor@standardandpoors.com
John W Whitlock, New York (1) 212-438-7678;
john_whitlock@standardandpoors.com

Publication date: 07-May-07, 12:38:56 EST
Reprinted from RatingsDirect

For many years, Standard & Poor's Ratings Services has viewed power supply agreements (PPA) in the U.S. utility sector as creating fixed, debt-like, financial obligations that represent substitutes for debt-financed capital investments in generation capacity. In a sense, a utility that has entered into a PPA has contracted with a supplier to make the financial investment on its behalf. Consequently, PPA fixed obligations, in the form of capacity payments, merit inclusion in a utility's financial metrics as though they are part of a utility's permanent capital structure and are incorporated in our assessment of a utility's creditworthiness.

We adjust utilities' financial metrics, incorporating PPA fixed obligations, so that we can compare companies that finance and build generation capacity and those that purchase capacity to satisfy customer needs. The analytical goal of our financial adjustments for PPAs is to reflect fixed obligations in a way that depicts the credit exposure that is added by PPAs. That said, PPAs also benefit utilities that enter into contracts with suppliers because PPAs will typically shift various risks to the suppliers, such as construction risk and most of the operating risk. PPAs can also provide utilities with asset diversity that might not have been achievable through self-build. The principal risk borne by a utility that relies on PPAs is the recovery of the financial obligation in rates.

The Mechanics Of PPA Debt Imputation

A starting point for calculating the debt to be imputed for PPA-related fixed obligations can be found among the "commitments and contingencies" in the notes to a utility's financial statements. We calculate a net present value (NPV) of the stream of the outstanding contracts' capacity payments reported in the financial statements as the foundation of our financial adjustments.

The notes to the financial statements enumerate capacity payments for the five years succeeding the annual report and a "thereafter" period. While we have access to proprietary forecasts that show the detail underlying the costs that are amalgamated beyond the five-year horizon, others, for purposes of calculating an NPV, can divide the amount reported as "thereafter" by the average of the capacity payments in the preceding five years to derive an approximate tenor of the amounts combined as the sum of the obligations beyond the fifth year.

In calculating debt equivalents, we also include new contracts that will commence during the forecast period. Such contracts aren't reflected in the notes to the financial statements, but relevant information regarding these contracts are provided to us on a confidential basis. If a contract has been executed but the energy will not flow until some later period, we won't impute debt for that contract until the year that energy deliveries begin under the contract if the contract represents incremental capacity. However, to the extent that the contract will simply replace an expiring contract, we will impute debt as though the future contract is a continuation of the existing contract.

We calculate the NPV of capacity payments using a discount rate equivalent to the company's average cost of debt, net of securitization debt. Once we arrive at the NPV, we apply a risk factor, as is discussed below, to reflect the benefits of regulatory or legislative cost recovery mechanisms.

Balance sheet debt is increased by the risk-factor-adjusted NPV of the stream of capacity payments. We derive an adjusted debt-to-capitalization ratio by adding the adjusted NPV to both the numerator and the denominator of that ratio.

We calculate an implied interest expense for the imputed debt by multiplying the same utility average cost of debt used as the discount rate in the NPV calculation by the amount of imputed debt. The adjusted FFO-to-interest expense ratio is calculated by adding the implied interest expense to both the numerator and denominator of the equation. We also add implied depreciation to the equation's numerator. We calculate the adjusted FFO-to-total-debt ratio by adding imputed debt to the equation's denominator and an implied depreciation expense to its numerator.

Our adjusted cash flow credit metrics include a depreciation expense adjustment to FFO. This adjustment represents a vehicle for capturing the ownership-like attributes of the contracted asset and tempers the effects of imputation on the cash flow ratios. We derive the depreciation expense adjustment by multiplying the relevant year's capacity payment obligation by the risk factor and then subtracting the implied PPA-related interest expense for that year from the product of the risk factor times the scheduled capacity payment.

↑ back to top

Risk Factors

The NPVs that Standard & Poor's calculates to adjust reported financial metrics to capture PPA capacity payments are multiplied by risk factors. These risk factors typically range between 0% to 50%, but can be as high as 100%. Risk factors are inversely related to the strength and availability of regulatory or legislative vehicles for the recovery of the capacity costs associated with power supply arrangements. The strongest recovery mechanisms translate into the smallest risk factors. A 100% risk factor would signify that all risk related to contractual obligations rests on the company with no mitigating regulatory or legislative support.

For example, an unregulated energy company that has entered into a tolling arrangement with a third-party supplier would be assigned a 100% risk factor. Conversely, a 0% risk factor indicates that the burden of the contractual payments rests solely with ratepayers. This type of arrangement is frequently found among regulated utilities that act as conduits for the delivery of a third party's electricity and essentially deliver power, collect charges, and remit revenues to the suppliers. These utilities have typically been directed to sell all their generation assets, are barred from developing new generation assets, and the power supplied to their customers is sourced through a state auction or third parties, leaving the utilities to act as intermediaries between retail customers and the electricity suppliers.

Intermediate degrees of recovery risk are presented by a number of regulatory and legislative mechanisms. For example, some regulators use a utility's rate case to establish base rates that provide for the recovery of the fixed costs created by PPAs. Although we see this type of mechanism as generally supportive of credit quality, the fact remains that the utility will need to litigate the right to recover costs and the prudence of PPA capacity payments in successive rate cases to ensure ongoing recovery of its fixed costs. For such a PPA, we employ a 50% risk factor. In cases where a regulator has established a power cost adjustment mechanism that recovers all prudent PPA costs, we employ a risk factor of 25% because the recovery hurdle is lower than it is for a utility that must litigate time and again its right to recover costs.

We recognize that there are certain jurisdictions that have true-up mechanisms that are more favorable and frequent than the review of base rates, but still don't amount to pure pass-through mechanisms. Some of these mechanisms are triggered when certain financial thresholds are met or after prescribed periods of time have passed. In these instances, in calculating adjusted ratios, we will employ a risk factor between the revised 25% risk factors for utilities with power cost adjustment mechanisms and 50%.

Finally, we view legislatively created cost recovery mechanisms as longer lasting and more resilient to change than regulatory cost recovery vehicles. Consequently, such mechanisms lead to risk factors between 0% and 15%, depending on the legislative provisions for cost recovery and the supply function borne by the utility. Legislative guarantees of complete and timely recovery of costs are particularly important to achieving the lowest risk factors.

↑back to top

Illustration Of The PPA Adjustment Methodology

The calculations of the debt equivalents, implied interest expense, depreciation expense, and adjusted financial metrics, using risk factors, are illustrated in the following example:

Example Of Power-Purchase Agreement Adjustment

($000s)	Assumption	Year 1	Year 2	Year 3	Year 4	Year 5	Thereafter
Cash from operations	2,000,000						
Funds from operations	1,500,000						
Interest expense	444,000						
Directly issued debt							
Short-term debt	600,000						
Long-term due within one year	300,000						
Long-term debt	6,500,000						
Shareholder's Equity	6,000,000						
Fixed capacity commitments	600,000	600,000	600,000	600,000	600,000	600,000	4,200,000*
NPV of fixed capacity commitments							
Using a 6.0% discount rate	5,030,306						
Application of an assumed 25% risk factor	1,257,577						
Implied interest expense¶	75,455						
Implied depreciation expense	74,545						
Unadjusted ratios							
FFO to interest (x)	4.4						
FFO to total Debt (%)	20.0						
Debt to capitalization (%)	55.0						

Ratios adjusted for debt imputation	
FFO to interest (x)§	4.0
FFO to total debt (%)**	18.0
Debt to capitalization (%)¶¶	59.0

*Thereafter approximate years: 7. ¶The current year's implied interest is subtracted from the product of the risk factor multiplied by the current year's capacity payment. §Adds implied interest to the numerator and denominator and adds implied depreciation to FFO. **Adds implied depreciation expense to FFO and implied debt to reported debt. ¶¶Adds implied debt to both the numerator and the denominator. FFO--Funds from operations. NPV--Net present value.

↑back to top

Short-Term Contracts

Standard & Poor's has abandoned its historical practice of not imputing debt for contracts with terms of three years or less. However, we understand that there are some utilities that use short-term PPAs of approximately one year or less as gap fillers pending the construction of new capacity. To the extent that such short-term supply arrangements represent a nominal percentage of demand and serve the purposes described above, we will neither impute debt for such contracts nor provide evergreen treatment to such contracts.

↑back to top

Evergreen Treatment

The NPV of the fixed obligations associated with a portfolio of short-term or intermediate-term contracts can lead to distortions in a utility's financial profile relative to the NPV of the fixed obligations of a utility with a portfolio of PPAs that is made up of longer-term commitments. Where there is the potential for such distortions, rating committees will consider evergreen treatment of existing PPA obligations as a scenario for inclusion in the rating analysis. Evergreen treatment extends the tenor of short- and intermediate-term contracts to reflect the long-term obligation of electric utilities to meet their customers' demand for electricity.

While we have concluded that there is a limited pool of utilities whose portfolios of existing and projected PPAs don't meaningfully correspond to long-term load serving obligations, we will nevertheless apply evergreen treatment in those cases where the portfolio of existing and projected PPAs is inconsistent with long-term load-serving obligations. A blanket application of evergreen treatment is not warranted.

To provide evergreen treatment, Standard & Poor's starts by looking at the tenor of outstanding PPAs. Others can look to the "commitments and contingencies" in the notes to a utility's financial statements to derive an approximate tenor of the contracts. If we conclude that the duration of PPAs is short relative to our targeted tenor, we would then add capacity payments until the targeted tenor is achieved. Based on our analysis of several companies, we have determined that the evergreen extension of the tenor of existing contracts and anticipated contracts should extend contracts to a common length of about 12 years.

The price for the capacity that we add will be derived from new peaker entry economics. We use empirical data to establish the cost of developing new peaking capacity and reflect regional differences in our analysis. The cost of new capacity is translated into a dollars per kilowatt-year (kW-year) figure using a weighted average cost of capital for the utility and a proxy capital recovery period.

↑back to top

Analytical Treatment Of Contracts With All-In Energy Prices

The pricing for some PPA contracts is stated as a single, all-in energy price. Standard & Poor's considers an implied capacity price that funds the recovery of the supplier's capital investment to be subsumed within the all-in energy price. Consequently, we use a proxy capacity charge, stated in \$/kW, to calculate an implied capacity payment associated with the PPA. The \$/kW figure is multiplied by the number of kilowatts under contract. In cases of resources such as wind power that exhibit very low capacity factors, we will adjust the kilowatts under contract to reflect the anticipated capacity factor that the resource is expected to achieve.

We derive the proxy cost of capacity using empirical data evidencing the cost of developing new peaking capacity. We will reflect regional differences in our analysis. The cost of new capacity is translated into a \$/kW figure using a weighted average cost of capital and a proxy capital recovery period. This number will be updated from time to time to reflect prevailing costs for the development and financing of the marginal unit, a combustion turbine.

↑back to top

Transmission Arrangements

In recent years, some utilities have entered into long-term transmission contracts in lieu of building generation. In some cases, these contracts provide access to specific power plants, while other transmission arrangements provide access to competitive wholesale electricity markets. We have concluded that these types of transmission arrangements represent extensions of the power plants to which they are connected or the markets that they serve. Irrespective of whether these transmission lines are integral to the delivery of power from a specific plant or are conduits to wholesale markets, we view these arrangements as exhibiting very strong parallels to PPAs as a substitute for investment in power plants. Consequently, we will impute debt for the fixed costs associated with long-term transmission contracts.

↑back to top

PPAs Treated As Leases

Several utilities have reported that their accountants dictate that certain PPAs need to be treated as leases for accounting purposes due to the tenor of the PPA or the residual value of the asset upon the PPA's expiration. We have consistently taken the position that companies should identify those capacity charges that are subject to operating lease treatment in the financial statements so that we can accord PPA treatment to those obligations, in lieu of lease treatment. That is, PPAs that receive operating lease treatment for accounting purposes won't be subject to a 100% risk factor for analytical purposes as though they were leases. Rather, the NPV of the stream of capacity payments associated with these PPAs will be reduced by the risk factor that is applied to the utility's other PPA commitments. PPAs that are treated as capital leases for accounting purposes will not receive PPA treatment because capital lease treatment indicates that the plant under contract economically "belongs" to the utility.

↑back to top

Evaluating The Effect Of PPAs

Though history is on the side of full cost recovery, PPAs nevertheless add financial obligations that heighten financial risk. Yet, we apply risk factors that reduce debt imputation to recognize that utilities that rely on PPAs transfer significant risks to ratepayers and suppliers.

↑back to top

NON-PROPRIETARY

The Empire District Electric Company

Line	Item	Source	Total Company	Juris Alloc
1	**Calculation of Amortization to meet Financial Ratio Targets**			
2		**Case No. ER-2008-0093**		
3			Total	Juris
4			Company	Alloc
5	Additional Net Balance Sheet Investment	(numeric value for this case only)		94,500,000
6	Rate Base	Staff Acct. Schedule 2 *		679,960,138
7	Jurisdictional Allocation for Capital			0.837404
8				
9	Total Capital	L5+L6		774,460,138
10	Equity	Barnes Workpapers	0.5082	393,580,642
11	Trust Preferred	Barnes Workpapers	0.0458	35,470,274
12	Long-term Debt	Barnes Workpapers	0.4461	345,486,668
13	Cost of Debt	Barnes Workpapers		6.80%
14	Interest Expense	L12 * L13 (+$2,125,000 (TOPRs))		25,618,093
15				
16	Electric Sales Revenue	Staff Acct. Schedule 9, L.1-2, + Rate Increase		358,933,949
17	Other Electric Operating Revenue	Staff Acct. Schedule 9, L.3		3,010,138
18	Water Revenue			
19	Operating Revenue	L16 + L17		361,944,087
20				
21	Operating and Maintenance Expense	Staff Acct. Schedule 9, L.94 (less cust. deposits)		218,313,347
22	Depreciation	Staff Acct. Schedule 9, L.97		34,764,791
23	Amortization	Staff Acct. Schedule 9, L.99-100		13,909,452
24	Interest on Customer Deposits	Staff Acct. Schedule 10, Adj. S-62.1		527,165
25	Taxes Other than Income Taxes	Staff Acct. Schedule 9, L.101		12,481,678
26	Federal and State Income Taxes	Staff Acct. Schedule 9, L.112 (plus rate incr. impact)		23,131,102
27	Gains on Disposition of Plant			
28	Total Water Operating Expenses			
29	Total Electric/Water Operating Exp	Sum of L. 21-28		303,127,535
30				
31	Operating Income - Electric	L19 - L29		58,816,552
32	Operating Income - Water			
33	less: Interest Expense	L14		-25,618,093
34	Depreciation	L22		34,764,791
35	Amortization			13,909,452
36	Deferred Taxes	Staff Acct. Schedule 9, L111		-2,884,453
37	Funds from Operations (FFO)	Sum of L31-36		78,988,249
38				
39				
40				
41				
42				
43		**Additional Financial Information Needed for Calculation of Ratios**		
44	Capitalized Lease Obligations	EDE Accounts 227 + 243		
45	Short-term Debt Balance	EDE Form 10-Q, p. 8		
46	Short-term Debt Interest	EDE Accounts 417.891 + 431.400		
47	Cash Interest Paid	Information Supplied by EDE		
48	AFUDC Debt (capitalized interest)	EDE Form 10-Q, p. 4		
49	Imputed PPA Debt Amortization			
50		**Adjustments Made by Rating Agencies for Off-Balance Sheet Obligations**		
51	Debt Adj for Off-Balance Sheet Obligs			
52	Operating Lease Debt Equivalent	Information Supplied by EDE		
53	Purchase Power Debt Equivalent	Information Supplied by EDE		
54	Total OSB Debt Adjustment	L52 + l53		
55				
56	Operating Lease Deprec Adjustment	Information Supplied by EDE		
57				
58	Interest Adjustments for Off-Balance Sheet Obligations			
59	Present Value of Operating Leases	L52 * 6.8%		
60	Purchase Power Debt Equivalent	L53 * 6.8%		
61	Total OSB Interest Adjustment	L59 + L60		
62				
63	**Ratio Calculations**			
64	Adjusted Interest Expense	L14 + L46 + L61		
65	Adjusted Total Debt 12/31/07	(L11/2) + L12 + L44 + L45 +L54		
66	Adjusted Total Debt 12/31/06	Same as L65, but for prior year		
67	Adjusted Total Capital	L9 + L44 + L45 + L54		
68				
69	Adj. FFO Interest Coverage	(L37 + L56 + L64+L49)/L64		
70	Adj. FFO as a % of Average Total Debt	(L37 + L56+L49)/L65		
71	Adj. Total Debt to Total Capital	L65/L67		
72				
73		**Changes Required to Meet Ratio Targets**		
74	Adj. FFO Interest Coverage Target			
75	FFO Adjustment to Meet Target	(L74 - L69) * L64		
76	Interest Adjustment to Meet Target	L37 * (1/L74 - 1) - 1/L69 - 1)		
77				
78	Adj. FFO as a % of Average Total Debt			
79	FFO Adjustment to Meet Target	(L78 - L70) * L65		
80	Debt Adjustment to Meet Target	L37 * (1/L78 - 1/L70)		
81				
82	Adj. Total Debt to Total Capital Target			
83	Debt Adjustment to Meet Target	(L82 - L71) * L67		
84	Total Capital Adjustment to Meet Target	L65/L82 - L67		
85				
86		Amortization and Revenue Needed to Meet Targeted Ratios		
87	FFO Adj Needed to Meet Target Ratios	Maximum of L75, L79 or zero		
88	Effective Income Tax Rate			
89	Deferred Income Taxes	L87 * L88/(1 - L88)		
90	Total Amortization Req for FFO Adj	L87 - L89		2,910,078
91				
92	* All references to Staff Acct. Schedules tie to schedules supporting amounts reflected in the			
93	Accounting Schedules distributed 4/4/08			

NON-PROPRIETARY