BEFORE THE STATE OF NEW JERSEY

BOARD OF PUBLIC UTILITIES

OFFICE OF ADMINISTRATIVE LAW

I/M/O THE PETITION OF NEW JERSEY NATURAL GAS COMPANY FOR APPROVAL OF AN INCREASE IN ITS GAS RATES, DEPRECIATION RATES FOR GAS PROPERTY, AND FOR CHANGES IN THE TARIFF FOR GAS SERVICE, PURSUANT TO N.J.S.A. 48:2-18 AND 48:2-21	)))))))	**BPU DKT. NO. GR07110889** **OAL DKT. NO. PUCRL 12545-07**

TESTIMONY OF MATTHEW I. KAHAL
ON BEHALF OF THE
NEW JERSEY DEPARTMENT OF THE PUBLIC ADVOCATE,
DIVISION OF RATE COUNSEL

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I. <u>QUALIFICATIONS</u>

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Matthew I. Kahal. I am employed as an independent consultant retained in this matter by the Division of the Rate Counsel (Rate Counsel). My business address is 5565 Sterrett Place, Suite 310, Columbia, Maryland 21044.

Q. PLEASE STATE YOUR EDUCATIONAL BACKGROUND.

A. I hold B.A. and M.A. degrees in economics from the University of Maryland and have completed course work and examination requirements for the Ph.D. degree in economics. My areas of academic concentration included industrial organization, economic development and econometrics.

Q. WHAT IS YOUR PROFESSIONAL BACKGROUND?

A. I have been employed in the area of energy, utility and telecommunications consulting for the past 25 years working on a wide range of topics. Most of my work has focused on electric utility integrated planning, plant licensing, environmental issues, mergers and financial issues. I was a co-founder of Exeter Associates, and from 1981 to 2001 I was employed at Exeter Associates as a Senior Economist and Principal. During that time, I took the lead role at Exeter in performing cost of capital and financial studies. In recent years, the focus of much of my professional work has shifted to electric utility restructuring and competition.

Prior to entering consulting, I served on the Economics Department faculties at the University of Maryland (College Park) and Montgomery College teaching courses on economic principles, development economics and business.

A complete description of my professional background is provided in Appendix A.

Q. HAVE YOU PREVIOUSLY TESTIFIED AS AN EXPERT WITNESS BEFORE UTILITY REGULATORY COMMISSIONS?

A. Yes. I have testified before approximately two-dozen state and federal utility commissions in more than 300 separate regulatory cases. My testimony has addressed a variety of subjects including fair rate of return, resource planning, financial assessments, load forecasting, competitive restructuring, rate design, purchased power contracts, merger economics and other regulatory policy issues. These cases have involved electric, gas, water and telephone utilities. In 1989,1 testified before the U.S. House of Representatives, Committee on Ways and Means, on proposed federal tax legislation affecting utilities. A list of these cases may be found in Appendix A, with my statement of qualifications.

Q. WHAT PROFESSIONAL ACTIVITIES HAVE YOU ENGAGED IN SINCE LEAVING EXETER AS A PRINCIPAL IN 2001?

A. Since 2001,1 have worked on a variety of consulting assignments pertaining to electric restructuring, purchase power contracts, environmental controls, cost of capital and other regulatory issues. Current and recent clients include the U.S. Department of Justice, U.S. Air Force, U.S. Department of Energy, the Federal Energy Regulatory Commission, Connecticut Attorney General, Pennsylvania Office of Consumer Advocate, New Jersey Division of the Ratepayer Advocate, Rhode Island Division of Public Utilities, Louisiana Public Service Commission, Arkansas Public Service Commission, Maryland Department of Natural Resources and Energy Administration, and MCI.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE NEW JERSEY BOARD OF PUBLIC UTILITIES?

A. Yes. I have testified on cost of capital and other matters before the Board of Public Utilities (Board or BPU) in gas, water and electric cases during the past 20 years.

A listing of those cases is provided in my attached Statement of Qualifications. This includes the submission of testimony on rate of return issues in the most recent gas service rate case of Public Service Electric and Gas Company (BPU Docket No. GR05100845).

II. OVERVIEW

A. Summary of Recommendation

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. I have been asked by the New Jersey Department of the Public Advocate, Division of Rate Counsel ("Rate Counsel") to develop a recommendation concerning the fair rate of return on the gas utility distribution rate base of New Jersey Natural Gas Company ("NJNG" or "the Company"). This includes both a review of the Company's proposal concerning rate of return and the preparation of an independent study of the cost of common equity. I am providing my recommendation to Rate Counsel and its consultants for use in calculating the annual revenue requirement in this case.

Q. WHAT IS THE COMPANY'S RATE OF RETURN PROPOSAL IN THIS CASE?

A. As presented on Exhibit PRM-1, Schedule 1, page 1 of 30, the Company requests an authorized overall rate of return of 8.45 percent. The proposed capital structure is forecasted at April 30, 2008, the end of the test year, and includes 52.5 percent common equity, 0.5 percent customer deposits and 47 percent total debt. The Company has no preferred equity. For the claimed total debt amount, approximately 10 percent is short-term debt, based on a 13-month test-year average, with certain adjustments. The Company requests a return on the common equity component of 11.375 percent. The overall rate of return, capital structure and cost of equity recommendations are sponsored by the Company's witness, Mr. Paul M. Moul.

Q. DOES THE COMPANY'S FORECASTED CAPITAL STRUCTURE INCLUDE ESTIMATES OF ADDITIONAL FINANCINGS AT APRIL 30, 2008?

A. Yes. The common equity balance estimate includes the additional retained earnings (i.e., NJNG earnings minus dividend payments) through April 2008. Capital structure includes $125 million in new medium-term notes at an assumed cost rate of 6.0 percent, authorized by the Board in Docket No. GF07050343. Since short-term debt is based on a 13-month test year average, those balances are a combination of actual and estimated values. The filing assigns a cost rate to short-term debt of 4.8 percent, which was the Company's cost rate (i.e., commercial paper rate) as of early October 2007.

Q. WHAT IS THE COMPANY'S AUTHORIZED RETURN ON EQUITY AUTHORIZED IN ITS LAST BASE RATE CASE?

A. According to the response to RCR-ROR-1, the Company was granted a return of 11.5 percent in Docket No. GR93-04114, i.e., a 1993 rate case. In this case, the Company is proposing a nearly identical 11.375 percent return, despite the fact that the cost of capital has declined significantly since 1993. For example, as shown on Schedule MIK-4, page 1 of 4, the yield on Single A utility bonds was 8.7 percent in 1992 and 7.6 percent in 1993. As of early 2008, Single A yields have approximated 6 percent. Moreover, the Board has authorized a 10.5 percent return on equity for purposes of the earnings test for the Company's Conservation Incentive Program (CIP). (Reference: page 29 of the New Jersey Resources Corporation, SEC 10-Q for the quarter ending December 31, 2007)

Q. WHAT IS YOUR RECOMMENDATION AT THIS TIME ON RATE OF RETURN?

A. As summarized on Schedule MIK-1, I am recommending a return on NJNG's gas distribution rate base of 7.02 percent. This includes a return on common equity of 9.5 percent and a capital structure of 52 percent total debt (inclusive of short-term debt) and 48 percent common equity. On a provisional basis, I have accepted the Company's estimated debt cost rates, with the exception of short-term debt. Based on recent movements in commercial paper cost rates, I have lowered the 4.8 percent to 3.0 percent. The debt cost rates should be updated later in this proceeding to incorporate new information that becomes available.

In particular, NJNG has a substantial amount of variable rate debt with an assigned cost rate of 3.5 percent. While I am not altering that cost rate at this time, it should be revisited and, if appropriate, updated prior to the close of the record in this case.

Q. WHY DOES YOUR CAPITAL STRUCTURE DIFFER FROM THAT PROPOSED BY THE COMPANY?

A. The only difference at this time between our two capital structures pertains to the amount of short-term debt. While both Mr. Moul and I support including short-term debt in capital structure (as it is typically an important source of financing for gas utilities), our amounts differ. My 13-month average is $130 million compared to his adjusted value of $42 million. My figure is more recent than his (i.e., fewer estimated and more actual monthly balances), but in addition, Mr. Moul has subtracted the balance of construction work in progress (CWIP) and one-half the balance of unrecovered remediation costs from short-term debt to arrive at his final and adjusted balance of $42 million. This difference of nearly $90 million is rather important since short-term debt is the lowest cost source of investor-supplied funds.

Q. WHAT IS THE BASIS OF YOUR 9.5 PERCENT RECOMMENDATION FOR THE RETURN ON EQUITY?

A. I am relying primarily upon the standard discounted cash flow (DCF) model applied to a broad proxy group of gas distributions utility companies. This produces estimates in the 9.0 to 9.5 percent range. This is generally similar to the DCF results obtained by Mr.

Moul using a somewhat different proxy group of gas distribution utility companies. I have confirmed my DCF results and recommendation using the Capital Asset Pricing Model (CAPM) as a check. While the CAPM tends to produce a very wide range of cost of equity results, in my opinion, a reasonable application of this methodology provides estimates in approximately the 9 to 10 percent range for high quality gas utilities such as NJNG when using reasonable data inputs.

Q. DO YOU CONSIDER NJNG TO BE A LOW-RISK UTILITY COMPANY?

A. Yes, very much so. NJNG (or its parent company) is rated double A by credit rating agencies, an unusually strong credit rating, and "1" for Safety by the *Value Line Investment Survey*, which is that publication's highest rating for overall risk. While it appears to be lower in risk than the average gas utility company, I have made no risk adjustment to my DCF or CAPM results in obtaining my recommended cost of equity reflecting this favorable profile.

B. <u>Capital Cost Trends</u>

Q. HAVE YOU REVIEWED THE TRENDS IN MARKET CAPITAL COSTS OVER THE PAST DECADE?

A. Yes. My Schedule MIK-2 shows certain capital cost indicators on an annual average basis since 1992 and on a monthly basis during January 2002 – March 2008. The indicators include inflation (as measured by the annual change in the Consumer Price Index), yields on short-term Treasury Bills, yields on ten-year Treasury notes and single A-rated utility long-term bond yields (published by Moody's).

This schedule shows that despite year-to-year fluctuations there has been a general downward trend in capital costs over this time period, at least for long-term securities. Short-term interest rates tend to be governed by Federal Reserve Board (Fed) monetary policy, and up until about a year ago, the Fed had been tightening (i.e., raising short-term rates) in response to a strengthening economy. In response to a slowing U.S. economy, severe distress in the housing market and a variety of dislocations in financial markets, the Fed has reversed this trend and pursued a policy of monetary easing. In addition to lowering interest rates, it has taken a number of actions to make liquidity available to financial institutions to help ensure financial markets can function properly.

As measured by utility bond yields, it appears that capital costs "bottomed out" in mid-2005, with single-A utility bond yields reaching a low point in the mid 5 percent range. Long-term interest rates remained relatively low through most of 2006 (i.e., long-term utility bond yields at approximately 6 percent), and this has continued (with some fluctuations) since then. The trend has been relatively stable over that time, with single-A yields generally remaining in the 6.0 to 6.5 percent range. On the other hand, ten-year Treasury yields have trended sharply downward, in recent months reaching 3.5 percent. The Treasury yield downward trend relative to comparatively stable utility bond yields may reflect a "flight to quality" investor behavior that sometimes occurs during periods of economic and financial market distress.

Q. ACCORDING TO SCHEDULE MIK-2, THERE HAS BEEN A RECENT UPWARD MOVEMENT IN INFLATION DURING THE PAST YEAR. WHAT ACCOUNTS FOR THAT MOVEMENT?

A. The recent upward movement in inflation has been in response to price spikes for energy and, to some degree, increased food prices. However, the underlying "core" inflation (excluding the volatile fuel and food sectors) remains relatively stable. Importantly, the long-term "consensus" forecast for inflation, as measured by the GDP deflator, is 2.1 percent per year (*Blue Chip Economic Indicators*, March 2008). There are a number of important forces at work that tend to hold down inflation and inflationary expectations.

Q. YOUR SCHEDULE MIK-2 PROVIDES DATA ON LONG-TERM INTEREST RATES. IS THIS INDICATIVE OF COMMON EQUITY COST RATES?

A. At least in a general sense, I believe that it is. The forces over time that lead to lower yields on long-term debt are likely to also favorably affect the cost of equity, although I would acknowledge that debt and equity cost rates do not necessarily move together in lock step. The favorable cost trends discussed above likely affect NJNG's equity cost rate associated with providing gas distribution utility service.

There is another force at work favorably impacting the cost of equity – federal tax policy. In 2003, Congress enacted legislation granting very favorable income tax treatment for corporate dividend payments and capital gains. At least for taxable accounts, investors care very much about the tax treatment accorded to their returns. All else equal, lower taxes on returns to equity holders means that investors should be willing to accept lower return for holding common stocks (such as dividend-paying utility companies), particularly as compared to conventional utility bonds which do not enjoy such tax advantages.

Importantly, the DCF method, which uses relatively current market data, can capture reasonably the cost of equity implications of such tax advantages. Other methods, such as the historical risk premium (as used by Mr. Moul), cannot do so since these current tax treatments are not reflected in the long-term historical data series.

C. <u>Remainder of Testimony</u>

Q. PLEASE DESCRIBE THE ORGANIZATION OF THE REMAINDER OF YOUR DIRECT TESTIMONY.

A. Section III presents my proposed changes to NJNG's capital structure and cost of debt. Section IV presents my cost of equity analyses and recommendation. This includes both the DCF and CAPM studies, with the majority of emphasis on the former. Section V is a critique of the cost of equity studies of Mr. Moul on behalf of NJNG and his 11.375 percent recommendation. However, I address his DCF evidence in Section IV rather than in Section V.

III. CAPITAL STRUCTURE AND OVERALL RETURN

Q. HOW DID MR. MOUL DERIVE THE PROPOSED CAPITAL STRUCTURE IN THIS CASE?

A. Mr. Moul shows the derivation on page 9 of his Schedule 5 (Exhibit PRM-1), with supporting cost of debt data on his Schedule 6, pages 1 and 2. He begins with the Company's actual capitalization at July 31, 2007 and develops his projected capitalization at April 30, 2008, the end of the test year. He produces the projected April 30, 2008 capitalization with three important changes to the July 2007 actual values:

1. He adds $14 million in increased retained earnings between July 2007 and April 2008, an increase of 6.6 percent over the actual July 2007 retained earnings balance.

2. He includes the $125 million planned issuance in new medium term notes authorized by the Board.

3. He first computes a projected 13-month balance for short-term debt ($109 million), but then he reduces it to $41.5 million by subtracting out CWIP and one-half of the unrecovered Remediation Costs. These adjustments are largely unexplained in his testimony and data responses.

The proposed capital structure also includes the Meter Lease ($27.6 million) in long-term debt and $4.3 million of customer deposits. With these changes, his resulting capital structure is 47.09 percent total debt, 0.44 percent of customer deposits and 52.47 percent common equity.

Q. HOW DOES THIS 53/47 PERCENT PROPOSED CAPITAL STRUCTURE COMPARE TO THE COMPANY'S CAPITAL STRUCTURE OBJECTIVES?

A. It appears to be somewhat more equity heavy than the stated corporate objective. The response to S-RROR-3 states that the objective is a 50/50 capital structure, inclusive of short-term debt. The response further states that the intent is to maintain a capital structure consistent with Standard & Poors' (S&P) single-A criteria. According to Mr. Moul's Schedule 2, the Company's 2006 common equity ratio is 50.1 percent, and the five-year average is 46.4 percent, including short-term debt.

Q. DO CREDIT RATING AGENCIES, SUCH AS S&P INCLUDE SHORT-TERM DEBT WHEN EVALUATING A UTILITY'S CAPITAL STRUCTURE FOR PURPOSES OF ASSIGNING A CREDIT RATING?

A. Yes. As a general matter, credit rating agencies include short-term debt in capital structure. When defining the benchmarks, S&P utilizes the ratio of total debt to total capital.

Q. HOW DOES THE NJNG CAPITAL STRUCTURE COMPARE WITH THAT OF MR. MOUL'S PROXY GROUP?

A. NJNG has a stronger capital structure, on average, than his proxy group. Mr. Moul's Schedule 4 shows that his gas proxy group has a 45.8 percent common equity ratio for 2006 and a 46.0 percent common equity ratio for the historic five-year period. Again, these figures include short-term debt. My more recent equity ratio figures for year-end 2007, shown on my Schedule MIK-3, appear to be similar to Mr. Moul's calculations.

Q. ARE YOU PROPOSING CHANGES TO MR. MOUL'S CAPITAL STRUCTURE?

A. At this time, I am proposing one change to Mr. Moul's projected capital structure, the short-term debt balance. Mr. Moul first calculates a 13-month balance of short-term debt (five months actual and eight months estimates) of $109 million. He then subtracts the test-year average level of CWIP ($25.8 million) and one-half the 2007 balance of remediation costs ($41.8 million). This reduces this projected short-term debt balance from $109 million to $41.5 million. (Response to RCR-ROR-7) In my opinion, this balance of short-term understates the appropriate test-year amount.

As shown on page 2 of Schedule MIK-1, the updated 13-month average is $130 million. I have not adopted Mr. Moul's two offsets or reductions to short-term debt since they have not been supported and do not appear to be reasonable.

Q. IS THIS YOUR ONLY CHANGE TO THE PROPOSED CAPITAL STRUCTURE?

A. Yes. At this time, I am not contesting the $14 million estimated increase in common equity, nor am I contesting the proposed new issues of long-term debt. The Board recently reaffirmed NJNG's authority to issue $125 million of long-term debt on March 19, 2008 (Docket No. GF07050343). The Company's most recent quarterly report filing with the Securities and Exchange Commission (SEC) states that the medium term notes just approved by the Board "are anticipated to be issued during the second quarter of fiscal 2008." (page 24, SEC Form 10-Q for the quarter ending December 31, 2007, provided in response to S-RREV-10).

Q. DOES MR. MOUL EXPLAIN THE REASONS FOR REDUCING THE CALCULATED BALANCE FOR CWIP AND REMEDIATION COSTS?

A. Yes, he discusses these two adjustments very briefly in one paragraph in his testimony (pages 17-18) indicating that CWIP and remediation costs are not part of rate base and therefore should be deducted from short-term debt. He states that remediation costs are recovered through a separate rider, and CWIP accrues a separate return in the form of an Allowance for Funds Used during Construction (AFUDC).

Q. DOES HE PROVIDE ANY NEW JERSEY PRECEDENT OR AUTHORITY FOR THESE ADJUSTMENTS?

A. No. RCR-ROR-15 asked for Board orders or precedents supporting these exclusions. In the response, Mr. Moul states that he "is not aware of any Board orders in this regard." He then goes on to state that in a stipulation involving South Jersey Gas Company (BPU Docket No. GR00050295) certain amounts of short-term debt were excluded since they did not finance rate base. No other details were provided in the response.

Q. DO YOU AGREE WITH THESE EXCLUSIONS?

A. No, I do not. Mr. Moul's explanations are insufficient and appear to be arbitrary. In the case of CWIP it is sometimes argued that a utility's short-term debt is directly assigned to CWIP in determining the AFUDC return, and this must be taken into account when considering the capital structure treatment of short-term debt.

Whatever merit this argument may have had in the past or has for other utilities, it appears not to be applicable for NJNG. The New Jersey Resources most recent SEC Form 10-Q quarterly report states (page 26):

> Commencing October 1, 2007, in addition to cost of debt, AFUDC also includes the estimated cost of equity funds used to finance construction on its natural gas transmission and distribution system, which is currently established through allowed rates at 11.5 percent.

Thus, the Company acknowledges in its SEC filing that at this time, both debt <u>and</u> equity finance CWIP and are part of the AFUDC return. Thus, if Mr. Moul wishes to remove debt from capital structure, because CWIP is not in rate base, he also must remove a proportionate amount of equity used to calculate the AFUDC rate.

Q. IS IT PROPER TO SUBTRACT REMEDIATION COSTS FROM SHORT-TERM DEBT?

A. No convincing explanation is offered in testimony, nor is any precedent cited in discovery responses for this capital structure adjustment. His only explanation is that remediation costs are recovered through a rider, not through base rates. However, this does not justify removing short-term debt from capital structure.

Q. DOES MR. MOUL'S REMOVAL OF SHORT-TERM DEBT CONTRIBUTE TO THE PROPOSED RATE INCREASE?

A. Yes, it does. Mr. Moul recommends a return of 8.45 percent, or about 12.6 percent on a pre-tax basis. Had he used a capital structure with the updated and unadjusted test-year average balance of short-term debt, his pre-tax return (all else held equal) would be about 11.7 percent, or 0.9 percent lower. Given the proposed rate base of $950 million, the added cost of using $42 million of short-term debt instead of the more accurate $130 million is an increase in the annual revenue requirement of about $8 million. This is a significant portion of the $56 million rate request in this case.

Q. WHAT COST RATE IS MR. MOUL USING FOR SHORT-TERM DEBT?

A. Mr. Moul uses 4.8 percent which is the actual cost rate in October 2007, presumably at the time he prepared his testimony. This is based on the market cost rate for commercial payers.

Q. HAVE MARKET CONDITIONS CHANGED?

A. Yes. The current (late March/early April) cost rates for commercial paper have declined to the 2 to 3 percent range. (Reference: Federal Reserve weekly "Statistical Release") This is a sharp decline that is clearly attributable to Fed monetary easing, with short-term market rates declining dramatically. At this time and subject to updating, I am using 3.0 percent, which is a figure at the upper end of the range of recent commercial paper market rates.[1]

[1] The Company's "9+3" updated filing increases the cost rate for long-term debt to 5.48 percent and reduces the short-term debt cost rate to 2.35 percent (Schedule JSB-24). However, since no explanation or supporting detail was provide, I defer a full update to later in this case when more complete information is available.

Q. WITH YOUR INCLUSION OF $130 MILLION OF SHORT-TERM DEBT, WHAT IS YOUR RECOMMENDED RATEMAKING CAPITAL STRUCTURE?

A. This change reduces the proposed 53/47 capital structure to 48 percent equity and 52 percent debt. This is shown on page 1 of Schedule MIK-1. This capital structure is generally consistent with (or slightly stronger than) NJNG's historic five-year capital structure shown by Mr. Moul. It is also slightly stronger than the 2007 capital structures (inclusive of short-term debt) for the two proxy groups of natural gas companies used by Mr. Moul and me, as shown on page 1 of Schedule MIK-3. In my opinion, this is a reasonable capital structure for NJNG given the test-year data.

Q. MR. MOUL USES A 6.0 PERCENT COST RATE FOR NEW DEBT. IS THIS REASONABLE?

A. The Company has submitted financial data to the Board in its financing docket indicating that due to market disruptions market yield spreads have widened in recent months. For example, the yield spread over Treasury securities for 10 to 15-year term issuances is now a maximum of 200 basis points. At the same time, Treasury yields have fallen sharply compared to six months or a year ago, particularly for securities of ten-year terms or less.

My conclusion at this time is that the 6.0 percent assumed cost rate remains within the range of plausible cost rates for new medium-term debt note issuances. While the final cost rate could be more or less than that (depending on the term of the notes), I do not have a factual basis at this time to change the 6.0 percent assumption. The cost rate for this debt should be updated assuming the $125 million of new debt is issued prior to the close of this case.

IV. COST OF COMMON EQUITY

A. Using the DCF Model

Q. WHAT STANDARD ARE YOU USING TO DEVELOP YOUR RETURN ON EQUITY RECOMMENDATION?

A. As a general matter, the ratemaking process is designed to provide the utility an opportunity to recover its (prudently-incurred) costs of providing utility service to its customers, including the reasonable costs of financing its (used and useful) investment. Consistent with this "cost-based" approach, the fair and appropriate return on equity award for a utility is its cost of equity. The utility's cost of equity is the return required by investors (i.e., the "market return") to acquire or hold that Company's common stock. A return award greater than the market return would be excessive and would overcharge customers for utility service. Similarly, an insufficient return could unduly weaken the utility and impair incentives to invest.

Although the concept of the cost of equity may be precisely stated, its quantification poses challenges to regulators. The market cost of equity, unlike most other utility costs, cannot be directly observed (i.e., investors do not directly, unambiguously state their return requirements), and it therefore must be estimated using analytic techniques. The DCF model is one such technique familiar to analysts, this Board and other utility regulators.

Q. IS THE COST OF EQUITY A FAIR RETURN AWARD FOR THE UTILITY AND ITS CUSTOMERS?

A. Generally speaking, I believe it is. A return award commensurate with the cost of equity generally provides fair and reasonable compensation to utility investors and normally should allow efficient utility management to successfully finance its operations on reasonable terms. Certainly, this has been the case for New Jersey utilities based on the equity returns granted by the Board in recent years. Setting the return on equity equal to a reasonable estimate of the cost of equity also is fair to ratepayers.

I recognize that there can be exceptions to this general rule. For example, in some instances, utilities have sought rate of return adders as a reward for asserted good management performance. In this case, it does not appear that the Company is making an explicit request for an adder, and therefore the issue is one of <u>measuring</u> the cost of equity, not whether a properly measured cost of equity is fair return.[2]

Q. WHAT DETERMINES A COMPANY'S COST OF EQUITY?

A. It should be understood that the cost of equity is essentially a market price, and as such, it is ultimately determined by the forces of supply and demand operating in financial markets. In that regard, there are two key factors that determine this price. First, a company's cost of equity is determined by the fundamental conditions in capital markets (e.g., outlook for inflation, monetary policy, changes in investor behavior, investor asset preferences, etc.). The second factor (or set of factors) is the business and financial risks of the Company in question. For example, the fact that a utility company effectively operates as a regulated monopoly, dedicated to providing an essential service (in this case gas retail delivery), typically would imply very low business risk and therefore a relatively low cost of equity. NJNG's relatively strong balance sheet and very strong credit rating also contributes to its low cost of equity.

Q. DOES MR. MOUL INCORPORATE THESE PRINCIPLES?

A. In general, he attempts to incorporate these principles in conducting his DCF analysis. However, some of his non-DCF analyses do not adhere as closely to these principles. For example, risk premium and comparable earnings studies make excessive use of historical or non-market data to derive equity return results.

[2] Mr. Moul appears to indicate that the Company's service quality is at least a minor factor in his recommended 11.375 percent return on equity.

Q. WHAT METHODS ARE YOU USING IN THIS CASE?

A. I employ both the DCF and CAPM models, applied to a broad proxy group of gas distribution utility companies. However, for reasons discussed in my testimony, I emphasize the DCF model results in formulating my recommendation. It has been my experience that most utility regulatory commissions (federal and state) heavily emphasize the use of the DCF model to determine the cost of equity and setting the fair return. As a check (and partly to respond to Mr. Moul), I also perform a CAPM study which also is based on the gas distribution proxy group.

Q. PLEASE DESCRIBE THE DCF MODEL?

A. As mentioned, this model has been widely relied upon by the regulatory community, including by this Board. Its widespread acceptance is due to the fact that the model is market-based and is derived from standard economic/financial theory. The model is also transparent and understandable to regulators. I do not believe that an obscure or highly arcane model would receive the same degree of regulatory acceptance.

The theory begins by recognizing that any publicly-traded common stock (utility or otherwise) will sell at a price reflecting the discounted stream of cash flows <u>expected by investors</u>. The objective is to estimate that discount rate.

Using certain simplifying assumptions (that I believe are generally reasonable for utilities), the DCF model for dividend paying stocks can be distilled down as follows:

K_e = (Do/Po) (1 + 0.5g) + g, where:

K_e = cost of equity;

Do = the current annualized dividend;

Po = stock price at the current time; and

g = the long-term annualized dividend growth rate.

This is referred to as the constant growth DCF model, because for mathematical simplicity, it is assumed that the growth rate is constant for an indefinitely long time period. While this assumption may be unrealistic (or not fully realistic) in many cases, for traditional utilities (which tend to be more stable than most unregulated companies) the assumption generally is reasonable, particularly when applied to a group of companies.

Q. HOW HAVE YOU APPLIED THIS MODEL?

A. Strictly speaking, the model can be applied only to publicly-traded companies, i.e., companies whose market prices (and therefore market valuations) are transparently revealed. Consequently, the model cannot be applied to NJNG, which is a wholly-owned subsidiary of New Jersey Resources Corporation (NJR), and therefore, a market proxy is needed. In theory, NJR could serve as that market proxy, and, in fact, both Mr. Moul and I have incorporated NJR into our respective gas utility company proxy groups. I am reluctant, however, to rely upon a single-company DCF study (nor does Mr. Moul), although in theory that approach could be used.

In any case, I believe that an appropriately selected proxy group (preferably one reasonable in size) is likely to be more reliable than a single company study. This is because there is "noise" or fluctuations in stock price (or other) data that cannot always be readily accounted for in a simple DCF study. The use of an appropriate proxy group helps to allow such "data anomalies" to cancel out in the averaging process.

For the same reason, I prefer to use market data that are relatively current but averaged over a period of several months (i.e., six months) rather than purely relying upon "spot" market data. It is important to recall that this is not an academic exercise but involves the setting of "permanent" utility rates that are likely to be in effect for several years. The practice of averaging market data over a period of several months can add stability to the results.

B. <u>DCF Study Using the Proxy Group of Gas Distribution Utility Companies</u>

Q. HOW DID YOU SELECT YOUR PROXY GROUP IN THIS CASE?

A. I am basing my primary DCF study on the large group of publicly-traded companies classified by the *Value Line Investment Survey* as gas distribution utility companies. These companies generally are in the same line of business as NJNG's gas utility segment and therefore are a reasonable cost of equity proxy to be used in this case -- at least as a starting point. These eleven proxy companies are listed on Schedule MIK-3, page 1 of 2, along with several risk indicators. I have included all eleven companies even though it could be argued that not all companies are perfect proxies. For example, UGI has both electric and propane operations in addition to its gas distribution service.

It should be noted that although the proxy companies are primarily regulated utilities, some also have some non-regulated operations that may be perceived as riskier (e.g., energy marketing). I make no specific adjustment to the DCF cost of capital results or my final recommendation for those potentially riskier operations.

Q. HOW DOES THIS COMPARE TO THE PROXY GROUP OF GAS COMPANIES SELECTED BY MR. MOUL?

A. Mr. Moul's group of seven companies is a subset of my eleven. While I include all of his seven companies, he excludes LaClede, NICOR, Southwest Gas and UGI. While the two proxy groups are very similar, it appears that Mr. Moul's more restricted group is somewhat higher in investment quality. However, as explain later, I show data on my schedules for both groups and the two groups appear to have very similar capital cost attributes, as one would expect, with Mr. Moul's group having a slightly lower cost rate.

My conclusion is that the proxy group selection for gas utility proxy companies is not a significant issue in this case.

Q. HAVE EITHER YOU OR MR. MOUL PROPOSED A SPECIFIC RISK ADJUSTMENT TO THE COST OF EQUITY BETWEEN THE PROXY COMPANIES AND NJNG?

A. No, not as far as I can determine. Mr. Moul appears to propose "leverage adjustments" and "size adjustments" but this appears not to be related to the proxy groups, as far as I can determine. At page 50, Mr. Moul makes reference to an adjustment for "high quality of service and exemplary performance" in formulating his final recommendation, but he does not quantify that adjustment. I take no position on the Company's service quality.

Q. HOW HAVE YOU APPLIED THE DCF MODEL TO THIS GROUP?

A. I have elected to use a six-month time period to measure the dividend yield component (Do/Po) of the DCF formula. Using the Standard & Poor's Stock Guide, I compiled the month-ending dividend yields for the six months ending March 2008, the most recent data available to me as of this writing.[3] This covers the fourth quarter 2007 and first quarter 2008, a generally difficult market period with declining stock prices.

I show these dividend yield data on page 2 of Schedule MIK-4 for each month and each proxy company, October 2007 through March 2008. Over this six-month period the group average dividend yields were increasing somewhat, ranging from a low of 3.63 percent in October 2007 to 4.10 percent in February 2008, averaging 3.84 percent for the full six months. Please note that for Mr. Moul's group the six-month average yield was a nearly identical 3.88 percent.

[3] As of this writing, the April 2008 edition of the S&P *Stock Guide* has not yet been published. Consequently, I obtained the month-ending March 2008 dividend yields from the Yahoo Finance web site.

For DCF purposes and at this time, I am using a proxy group dividend yield of 3.84 percent.

Q. IS 3.84 PERCENT YOUR FINAL DIVIDEND YIELD?

A. Not quite. Strictly speaking, the dividend yield used in the model should be the value the investor expects over the next 12 months. Using the standard "half year" growth rate adjustment technique, the DCF adjusted yield becomes 4.0 percent. This is based on assuming that half of a year growth is 2.5 percent (i.e., a full year growth is 5.0 percent).

Q. DOES MR. MOUL EMPLOY THE SAME GROWTH RATE ADJUSTMENT?

A. While Mr. Moul (in his Appendix E) appears to discuss multiple methods, I read his testimony as also supporting the use of six months of dividend yields and the "0.5g" adjustment that I use. He derives an adjusted yield of 3.73 percent, which is lower than my 4.0 percent adjusted yield. This difference reflects primarily market timing (i.e., higher stock prices during Mr. Moul's measurement period), not differences in methodology.

Q. HOW HAVE YOU DEVELOPED YOUR GROWTH RATE COMPONENT?

A. Unlike the dividend yield, the investor growth rate cannot be directly observed but instead must be inferred through a review of available evidence. The growth rate in question is the <u>long-run</u> dividend per share growth rate, but analysts frequently use earnings growth as a proxy for (long-term) dividend growth. This is because in the long-run earnings are the ultimate source of dividend payments to shareholders, and this is likely to be particularly true for a large group of utility companies.

One possible approach is to examine historical growth as a guide to investor expected future growth, for example the recent five-year or ten-year growth in earnings, dividends and book value per share. However, my experience with utilities in recent years is that these historic measures have been very volatile and are not reliable as prospective measures. This is due in part to extensive corporate or financial restructuring, particularly in the electric industry. I note that Mr. Moul also chooses not to rely on historic growth measures for DCF purposes. The DCF growth rate should be prospective, and one useful source of information on prospective growth is the projections of earnings per share (typically five years) prepared by securities analysts. It appears that Mr. Moul places substantial though not exclusive weight on this information, and I agree that it warrants substantial emphasis.

Q. PLEASE DESCRIBE THIS EVIDENCE.

A. Schedule MIK-4, page 3 presents four well-known sources of projected earnings growth rates. Three of these four sources -- First Call, Zacks and CNNfn -- provide averages from securities analyst surveys conducted by or for these organizations (typically the median value). The fourth, Value Line, is that organization's own estimates. Value Line publishes its own projections using annual average earnings for a base period of 2005-2007 compared to a forecast period of 2011-2013.

As this schedule shows, the growth rates for individual companies vary somewhat among the four sources, but the group growth averages are similar. These are 5.3 percent for CNNfn, 5.20 percent for First Call, 5.51 percent for Zacks and 5.36 percent for Value Line. All four sources appear to be generally similar, although CNN is missing two observations. In this case, I have selected the average of these four sources, or 5.24 percent, as the best midpoint measure of expected growth, and a range of 5.0 to 5.5 percent.

Please note that the projected earnings growth rates for Mr. Moul's proxy group are very similar to my proxy group, though slightly lower. Mr. Moul himself adopts a DCF growth rate of 5.0 percent.

Q. IS THERE ANY OTHER EVIDENCE THAT SHOULD BE CONSIDERED?

A. Yes. There are a number of reasons why investor expectations of long-run growth could differ from the limited, five-year earnings projections from securities analysts. Consequently, while securities analyst estimates should be considered and given substantial weight, these growth rates should be subject to a reasonableness test and corroboration, to the extent feasible.

On Schedule MIK-4, page 4 of 4, I have compiled three other measures of growth published by Value Line, i.e., growth rates of dividends and book value per share and long-run retained earnings growth. (Retained earnings growth reflects the growth over time one would expect from the reinvestment of retained earnings, i.e., earnings not paid out as dividends.) As shown on this schedule, these growth measures tend to be similar to or less than analyst growth projections. Dividend growth averages 4.04 percent, book value growth averages 4.68 percent and earnings retention growth averages 5.59 percent. Again, the results for my proxy group are very similar to Mr. Moul's group averages.

Q. WHAT IS YOUR DCF CONCLUSION?

A. I summarize my DCF analysis on page 1 of Schedule MIK-4. The adjusted dividend yield for the six months ending March 2008 is 4.0 percent for this group. Available evidence would support a long-run growth rate in the range of 5.0 to 5.5 percent, as explained above. Summing the adjusted yield and growth rates produces a total return of 9.0 percent 9.5 percent, and a midpoint result of 9.25 percent.

Q. HOW DOES YOUR DCF COST OF EQUITY COMPARE TO MR. MOUL'S GAS UTILITY DCF COST OF EQUITY?

A. As shown on page 35 of his testimony, he arrives at a final DCF result of 9.40 percent, which is roughly consistent with my 9.0 to 9.5 percent range. However, he includes 0.49 percent for leverage, an adjustment which is improper, and 0.18 percent for flotation expense. This latter adjustment may be theoretically appropriate, assuming that such expenses are actually incurred by NJNG and properly documented.

Q. DO YOU INCLUDE AN ADJUSTMENT FOR FLOTATION EXPENSE?

A. A company can incur flotation expenses when engaging in a public issuance of common stock to support its growth in investment. It might choose to do so and incur this cost if retained earnings growth (and other capital sources such as dividend reinvestment programs) are insufficient to provide the needed equity capitalization. A public issuance typically involves significant underwriting fees and other administrative expenses, which the utility may seek to recover as a cost of equity adder. As mentioned, Mr. Moul includes 0.2 percent to his cost of equity estimate for that purpose.

In this case, I see no evidence that NJNG has in the recent past incurred flotation expenses, nor is there any evidence that NJNG (or its parent on behalf of NJNG) will incur such costs for the foreseeable future. No public issuances of common stock by NJR have been identified in this case. The response to RCR-ROR-9 states that no such issuance has occurred within the last three years, and the response to RCR-ROR-10 indicates that no such issuance is expected during the next three years. Hence, there are no NJNG flotation expenses to recover in customer rates.

Q. WHAT IS YOUR RECOMMENDATION AT THIS TIME?

A. I am recommending the upper end of my 9.0 to 9.5 DCF range, i.e., 9.5 percent. I am doing so for two reasons. First, there has been instability and arguably an upward trend in dividend yields during the present calendar quarter as compared to earlier in the fourth quarter 2007. Second, other evidence such as the CAPM at least potentially could support a cost of capital result somewhat higher than my DCF range, although some of my CAPM calculations actually produce a lower result than my DCF range, as shown below. However, I must reiterate my position that my DCF range for the proxy gas utility distribution group is far and away the best available cost of equity evidence. Mr. Moul's own DCF analysis of the cost of equity also supports my 9.5 percent recommendation.

C. The CAPM Analysis

Q. PLEASE DESCRIBE THE CAPM MODEL.

A. The CAPM is a form of the "risk premium" approach and is based on modern portfolio theory. Based on my experience, the CAPM is the cost of equity method most often used in rate cases after the DCF method, and it is one of Mr. Moul's three cost of equity methods.

According to this model, the cost of equity (K_e) is equal to the yield on a risk-free asset plus an equity risk premium multiplied by a firm's "beta" statistic. "Beta" is a firm-specific risk measure which is computed as the movements in a company's stock price (or market return) relative to contemporaneous movements in the broadly defined stock market (e.g., the S&P 500 or the New York Stock Exchange Composite). This measures the investment risk that cannot be reduced or eliminated through asset diversification (i.e., holding a broad portfolio of assets). The overall market, by definition, has a beta of 1.0, and a company with lower than average investment risk (e.g., a utility company) would have a beta below 1.0. The "risk premium" is defined as the expected return on the overall stock market minus the yield or return on a risk-free asset.

The CAPM formula is:

K_e = $R_f + \beta (R_m - R_f)$, where:

K_e = the firm's cost of equity

R_m = the expected return on the overall market

R_f = the yield on the risk free asset

β = the firm (or group of firms) risk measure.

Two of the three principal variables in the model are directly observable -- the yield on a risk-free asset (e.g., a Treasury security yield) and the beta. For example, Value Line publishes estimated betas for each of the companies that it covers and Mr. Moul uses those betas to the exclusion of all other sources. The greatest difficulty, however, is in the measurement of the expected stock market return (and therefore the risk premium), since that variable cannot be directly observed.

While the beta itself also is "observable," different investor services provide differing estimates betas depending on the calculation methods that they use. These differences can have large impacts on the CAPM results. In this case, both Mr. Moul and I use Value Line published betas, but I note that other sources have very different gas utility betas, which would yield lower results. For that reason, I have incorporated other published sources, along with Value Line, to obtain a reasonable range of betas. This is analogous to the procedure followed by Mr. Moul and me to use several sources for DCF earnings growth rates rather than relying on just one source.

Q. HOW HAVE YOU APPLIED THIS MODEL?

A. For purposes of my CAPM analysis, I have used a long-term (i.e., 20-year) Treasury yield as the risk-free-return along with the average beta for the eleven proxy group companies. (See Schedule MIK-5, page 2 of 2, for the gas utility company-by-company betas.) I also show the average betas for Mr. Moul's proxy group, which are slightly lower. In recent months, long-term Treasury yields have averaged approximately 4.5 percent, and the recent Value Line beta for my proxy group averages 0.87. However, the Value Line betas are the <u>highest</u> of the available published betas, and the proxy group average for the three public sources that I have identified (Value Line, Yahoo Finance and MSN Money) averages to 0.75. I note that Mr. Moul has elected to use a beta of

0.80. Finally, and as explained below, I am using a stock market return estimate of 10 to 12 percent, although I see less support for the upper end of that range.

Using these data inputs, the CAPM calculation results are shown on page 1 of Schedule MIK-5. My low-end cost of equity estimate uses a risk-free rate of 4.5 percent, a proxy group beta of 0.75 and a stock market return of 10.0 percent:

$$K_e = 4.5\% + 0.75\ (10.0 - 4.5) = 8.62\%$$

The upper end estimate uses a risk-free rate of 4.5 percent, a group beta of 0.85 and a stock market return of 12.0 percent.

$$K_e = 4.5 + 0.85\ (12.0 - 4.5) = 10.88\%$$

Thus, with these inputs the CAPM provides a cost of equity range of 8.6 to 10.9 percent, with a midpoint of 9.7 percent. The CAPM analysis produces a midpoint result somewhat higher than the range of results from my DCF analysis, and I have factored this into my return on equity recommendation in this case. However, the CAPM range of 8.6 to 10.9 percent brackets my 9.5 percent recommendation. The midpoint result of 9.7 percent is very close to my recommendation, and there is more support for results in the lower end than the higher end of my range.

Q. IT APPEARS THAT A KEY ELEMENT IN YOUR CAPM STUDY IS YOUR MARKET RETURN RANGE OF 10 TO 12 PERCENT. HOW DID YOU DERIVE THAT RANGE?

A. There is a great deal of disagreement among analysts regarding the reasonably expected market return on the stock market as a whole and therefore the risk premium. In my opinion, a reasonable risk premium to use would be about 6 percent, which today would imply a stock market return of 10.5 percent (i.e., 6.0 + 4.5 = 10.5 percent). Due to uncertainty concerning the true market return value, I am employing a broad range of 10 to 12 percent.

Q. PLEASE DESCRIBE THESE MEASURES.

A. In general, two analytic approaches have been used to obtain either the risk premium or the market return required by the CAPM. The first method is to perform a DCF calculation on the overall stock market, and the second approach makes use of historical after-the-fact returns data measured over a long time period. Mr. Moul makes use of both methods, although I believe his estimates of the market return or risk premium are overstated. (As discussed below, a non-analytic method, investor or expert opinion surveys, also are sometimes considered.)

Q. HAVE YOU REVIEWED STOCK MARKET TOTAL RETURNS DATA?

A. I have done so but in a somewhat different manner than Mr. Moul. I note that Value Line publishes projections for its "Industrial Composite" twice each year, and that information can be used to perform a DCF total return calculation. The Industrial Composite is a very broad measure of the overall stock market, excluding only utilities, the financial services industry and non-North American companies. As of November 2007, Value Line was projecting five-year earnings and dividend growth of 9.0 percent per year and five-year book value growth of 7.5 percent per year. Combining the 9.0 percent earnings growth rate with the Value Line-reported dividend yield of 1.6 percent produces a total return for the Industrial Composite of 10.6 percent.[4] It should also be noted that Value Line forecasts a five-year total annualized return outlook for the Industrial Composite of 3 to 12 percent. Obviously, a range of market returns that wide is not very useful for cost of equity purposes.

I also have consulted the "consensus" forecast of corporate profits published by *Blue Chip Economic Indicators*, a compilation of forecasts from major economic forecasting organizations. As of March 10, 2008, the Blue Chip "consensus" called for

[4] It should be noted that Value Line also shows a value for percent retained to earnings of 14.5 percent, but that would be an implausible value for total return purposes.

a ten-year growth rate of 5.1 to 5.3 percent in U. S. pre-tax corporate profits (nominal dollars). Mr. Moul also cites to the *Blue Chip* forecast, and at footnote 4, page 25, he states that historical earnings growth for U. S. corporations has been "two percentage points faster than GDP since 1934." All of this evidence would support expectations of a stock market rate of return no greater than about 10 to 11 percent.

Q. WHAT ARE THE HISTORICAL RISK PREMIUM VALUES?

A. Cost of equity analysts frequently cite to historic returns data compiled by Ibbotson Associates, and I have used that source as well. Based on historic (1926-2006), after-the-fact returns published by the Morningstar (i.e., the new publisher of the Ibbotson data) in 2007, the stock market risk premium relative to long-term Treasury bonds averages 6.5 percent. (See Mr. Moul's Schedule 13, page 6 of 6.) Combining that 6.5 percent value with recent long-term Treasury yields of about 4.5 percent provides a market rate of return of 11.0 percent. This is the midpoint of my 10 to 12 percent range.

There are reasons, however, for believing that even the 6.5 percent historical premium is too high. A recent research study by Ibbotson and Chen, estimates a long-term (arithmetic) historic risk premium of 5.9 percent. The authors estimate this figure using a supply-side model removing the effects of a rising P/E ratio over the historical period. This analysis acknowledges that the historical trend of rising P/Es served to inflate the achieved historical returns and such an increase would not be expected to continue indefinitely into the future. Combining the Ibbotson/Chen 5.9 percent risk premium with a current long-term Treasury yield of 4.5 percent produces an overall stock market return of 10.4 percent.[5] I would note that the Ibbotson/Chen paper also reports a geometric historic average risk premium of about 4 percent.

[5] Roger G. Ibbotson and Peng Chen, "Stock Market Returns in the Long Run: Participating in the Real Economy," Financial Analyst Journal, 2003.

Q. ARE YOU AWARE OF ANY OTHER EVIDENCE THAT WOULD PROVIDE INSIGHT INTO A REALISTIC MARKET RISK PREMIUM?

A. Yes. The prominent finance textbook by Brealey, Myers and Allen (*Principles of Corporate Finance*, 8th edition, page 152) cites to opinion surveys taken on the market risk premium. A 2001 Yale University survey study of financial economists finds a 5.5 percent risk premium, and a 2003 Duke University Study of Corporate Chief Financial Officers ("CFOs") obtains a 3.8 percent risk premium. While survey estimates are not precise measures and can always be questioned, they can serve as a "reality check" on the type of data presented by Mr. Moul on the risk premium. The survey data suggest that my 6 percent risk premium may be a conservatively high figure.

V. MR. MOUL'S COST OF EQUITY METHODS

A. Overview of Mr. Moul's Methods

Q. HOW HAS MR. MOUL DEVELOPED HIS RETURN ON COMMON EQUITY RECOMMENDATION IN THIS CASE?

A. Mr. Moul employs four methods with three of the methods being "market model approaches to estimating the cost of equity." (Testimony, page 5) The fourth method, "comparable earnings," is neither market-based nor is it a method that estimates NJNG's cost of capital. For that reason, this fourth method is given no weight in Mr. Moul's recommendation in this case. Since comparable earnings have little practical importance in this case, I do not devote much time to discussing that method.

The three market-based methods produce the following results: (1) DCF -- 9.40 percent; (2) Comparables Earnings -- 11.68 percent; and (3) CAPM -- 12.65 percent. Mr. Moul takes the simple average of these three studies (i.e., implicitly assigning equal weight to each) and obtains 11.24 percent. He concludes that a reasonable range would be 11.0 to 11.5 percent, and he recommends a figure for NJNG that is close to the upper end of that range, 11.375 percent. He justifies a return exceeding the midpoint of his "reasonable range" based on Mr. Downes' testimony asserting superior "customer service and management efficiency."

Q. DOES MR. MOUL PROVIDE A QUANTIFICATION FOR THIS SERVICE QUALITY/MANAGEMENT EFFICIENCY BONUS?

A. No, but it appears to be equivalent to bonus of 0.125 percent return on equity. Given the Company's proposed rate base of roughly $950 million, this would translate into annual earnings of $0.6 million and additional annual customer revenues of about $1.0 million. There is no clear explanation concerning why this bonus was requested or how it was quantified.

Q. ARE YOU CONTESTING MR. MOUL'S DCF ANALYSIS?

A. I am not contesting his application of the DCF model to his proxy group or his 9.4 percent end result. It appears that both Mr. Moul and I are applying that model in a very similar manner, although he employed data from 2007 when stock prices were somewhat higher than at present. I am contesting two adjustments or "adders" that he included in his DCF cost of equity results. I already have discussed one of his adders -- 0.2 percent for possible flotation expense. This adjustment (or some reasonable amount) could be justified if there is actual evidence of such costs or expectations that such costs will be incurred in the near future. In this case, that evidence is lacking, as previously discussed.

A second and much more controversial adjustment is Mr. Moul's decision to include 0.49 percentage points (49 basis points) for a "leverage" adjustment. The leverage adjustment adder has nothing to do with the DCF model or even the market-derived cost of equity, as explained below.

B. <u>The Merits of the "Leverage" Adjustment</u>

Q. MR. MOUL INCLUDES AN ADDER TO HIS DCF ESTIMATE FOR "LEVERAGE." WHAT EXPLANATION DOES HE PROVIDE?

A. This is discussed at pages 30-35 of his testimony. Quite simply, Mr. Moul's "leverage" adjustment provides <u>additional</u> return compensation to investors to recognize the fact that standard utility ratemaking employs a utility's book value capital structure instead of a market value capital structure. A company's market value capital structure has a thicker equity ratio than a book value capital structure if that company has a market-to-book ratio greater than 1.0. That is, in fact, the case with most utilities today including Mr. Moul's gas proxy group. According to Mr. Moul, that group has (on average) a 54 percent book equity ratio and a 68 percent market equity ratio. (For some reason, these ratios exclude short-term debt.) Using these data, he calculates the 49 basis adjustment, as shown in his Appendix E.

Q. IS THERE A DIFFERENCE BETWEEN NJNG'S MARKET VERSUS BOOK CAPITAL STRUCTURE?

A. No, NJNG does not have a market-based capital structure because its stock is not publicly traded. It is wholly-owned by NJR and only has a book capital structure. It has been standard practice in New Jersey and other states to employ book capital structures (assuming such capital structures are reasonable) for utility ratemaking, just as regulators also use book value rather than market value rate base. No additional shareholder compensation is required simply because either utilities or utility holding companies have market-to-book ratios greater than 1.0. Similarly, if the market-to-book ratio was less than 1.0 (for example, a distressed utility), it would not be proper to decrement the DCF result, thereby reducing shareholder compensation below the DCF return.

Q. IS MR. MOUL'S ADJUSTMENT PART OF THE DCF COST OF EQUITY?

A. No, it is an adder to the DCF cost of equity, unless Mr. Moul is willing to argue that NJNG has a <u>higher</u> cost of equity than his proxy group. DCF theory is very clear that the cost of equity can be calculated as "yield plus growth," and this fully accounts for all investment risk including leverage. For example, assume the DCF analysis for the proxy group produces a 9.0 percent result based on a dividend yield of 4.0 percent and a consensus long-run growth rate of 5.0 percent. This result states that investors expect and therefore require (on average) a 9.0 percent long-run annualized return to hold these stocks. In expressing this return requirement, investors are fully aware of the market capital structures of these companies, the book values of these companies <u>and</u> the fact that state regulators set rates based on book value capital structure. This knowledge is fully reflected in the stock prices and dividend yields. By their own market behavior, investors are not requiring the leverage adjustment that Mr. Moul proposes, although I am sure that they would not mind receiving the additional earnings that his adjustment provides.

Mr. Moul's adjustment is totally contrary to accepted DCF theory.

Q. IS MR. MOUL'S ADJUSTMENT ACCEPTED IN THE REGULATORY COMMUNITY?

A. Mr. Moul asserts that it has been accepted in Pennsylvania, a state commission that relies very heavily on the DCF methodology. He mentions no other jurisdiction adopting this kind of market-to-book adjustment, nor am I aware of any.

Q. IS IT YOUR POSITION THAT A LEVERAGE ADJUSTMENT COULD NEVER BE JUSTIFIED?

A. No, all else equal, debt leverage could be a factor (though not the only factor) in determining a company's cost of equity, and in that context such an adder could be considered (along with other risk attributes). For example, if NJNG has a more leverage capital structure than the gas proxy group, then potentially, a leverage adjustment could be proposed, consistent with financial theory. The argument here would be that NJNG is riskier than the proxy group (due to its greater leverage), and therefore the 9.0 percent DCF result -- while accurate for the proxy group -- is too low a cost rate for NJNG. In this case, however, NJNG is simply not more leveraged than the proxy group, and therefore no adjustment is needed.

Moreover, Mr. Moul is not claiming that NJNG is either more leveraged or more risky than his gas proxy group. He makes it clear that the issue is one of providing additional compensation to NJNG investors because the Board uses a book value capital structure in setting rates. To be clear, Mr. Moul's disagreement is with the practice of cost-based ratemaking and whether that paradigm provides adequate investor compensation.

Q. DOES MR. MOUL CITE ANY EXPERT AUTHORITY FOR A MARKET-TO-BOOK ADJUSTMENT IN THE DCF STUDY?

A. No. Standard financial theory is very clear that, assuming the data inputs are accurate, the DCF model calculates the cost of equity. No further adjustment is needed unless the DCF proxy company group differs in risk from the subject utility -- which is not the case here.

Mr. Moul attempts to cite in connection with his adjustment the work of Miller/Modigliani (of more than 30 years ago) that recognized that a company's leverage could affect its cost of equity. The discussion in my testimony fully recognizes that. However, Mr. Moul, in my opinion takes Miller/Modigliani out of context. Their published work does not address public utility ratemaking practices, including the appropriateness regulators setting rates based on book value capital structure as opposed to market value. To my knowledge, they have expressed no opinion on whether an "adder" to the DCF result is needed due to the practice of using book value capital structure to further compensate investors.

It is important to note that Mr. Moul characterizes their work as stating, "as the borrowing of a firm increases, the expected return on stockholders' equity also increases." (Testimony, page 34) To the extent this is true, this is fully captured in a properly performed DCF analysis -- without the need for an extraneous leverage adjustment. That is, investors recognize whatever leverage is present and incorporate it into the "yield plus growth" DCF return result.

Q. DOES MR. MOUL UTILIZE THE LEVERAGE ADJUSTMENT IN ANY OTHER COST OF EQUITY STUDY?

A. Yes. He also includes it in his CAPM study, but he does not appear to use it in his Risk Premium study. Rather than including it as an "adder," his CAPM study uses leverage as a means of increasing the published proxy group beta from its actual value of 0.80 to 0.94. Since his assumed equity risk premium is 6.9 percent, this means that the leverage adjustment has the effect of adding about 1.0 percentage point to CAPM end result ((0.94-0.80) x 6.9% = 0.97 percent). This is roughly double the adder that he used in his DCF study.

C. <u>Risk Premium</u>

Q. HOW DID MR. MOUL CALCULATE HIS RISK PREMIUM COST OF EQUITY?

A. Mr. Moul calculated the long-term historical returns on the Standard & Poors (S&P) utility index going back to 1928 and compares that to the long-term return on utility bonds over that same time. He calculates average returns over historical subperiods and calculates "average" historical returns using at least three different methods. Combining certain results, he finds what he calls a "reasonable" risk premium of 5.72 percentage points. However, he concludes that the S&P utility group is riskier than NJNG, so he selects a lower risk premium of 5.25 for the Company (i.e., a 47 basis point reduction). Finally, he selects 6.25 percent as a representative current yield on single A bonds. The sum of the 6.25 percent bond yield, a 5.25 percent risk premium and 0.18 percent for flotation expense produces his risk premium return estimate of 11.68 percent.

Q. HOW DID MR. MOUL CALCULATE THE 47 BASIS POINT DIFFERENCE BETWEEN THE NJNG AND S&P INDEX RISK PREMIUM?

A. This is not clear because no calculation is shown for this adjustment. Mr. Moul shows a listing of the S&P utilities on page 3 of his Schedule 4. None of the companies in this group is primarily a gas distribution utility (although some do have gas operations). The vast majority are electric companies, including electrics with extensive unregulated generation operations, such as Constellation, Public Service Enterprise, PPL Corp., Allegheny Energy, Sempra Energy, Exelon Corp., Entergy Corp., TXU Corp., etc. While some of the members of this group are mainly utilities, the group as a whole is not a very good proxy for NJNG's gas distribution operations.

I would note that the average "beta" for this group is 0.95, as shown on Mr. Moul's page 3, Schedule 4, compared to 0.80 for his gas proxy group. While betas are not necessarily precise risk measures, this difference in beta, this measure implies a cost of equity difference of about 1.0 percent, if Mr. Moul's 6.9 percent CAPM risk premium is used, or 0.9 percent if my 6.0 percent figure is used.

Q. IS MR. MOUL'S S&P UTILITY INDEX HISTORICAL ANALYSIS AN ACCEPTED METHOD OF ESTIMATING THE COST OF CAPITAL?

A. No, I do not believe this is an accepted method, even for the electric utility/merchant generators that comprise this group. At best, this shows the long-term historical investment experience for this Index, but Mr. Moul does not explain why or how this reliably estimates today's cost of equity.

It is true that financial analysts sometimes use historical stock market data as a benchmark measure of the risk premium, but the reliability of historical returns as being prospective measures is controversial. However, when such historical returns averages are used by analysts it is almost always for the stock market as a whole (such as the S&P 500), not for an individual company or industry. For example, it clearly is not common practice to use historical returns data for individual industries such as the chemical industry, banking, automobiles, etc. to measure the cost of capital (or risk premia) for those industries. It is unclear why Mr. Moul believes this is a reliable method for utilities or NJNG.

Q. DO YOU HAVE OTHER CONCERNS WITH MR. MOUL'S ANALYSIS?

A. Yes. Mr. Moul's Schedule 12, page 2 of 2, presents numerous results, but his most comprehensive results are for the lengthy time period 1928-2006 and using the arithmetic returns calculation method which he (and some other analysts) seems to prefer. This produces an average stock return of 11.14 percent, an average bond return of 5.73 percent, and a risk premium of 5.41 percent

The difficulty here is with his historic utility bond return of 5.7 percent. For a nearly identical time period (1926-2006), the Morningstar/Ibbotson data series shows a return on long-term Treasury bonds of a slightly higher figure of 5.8 percent. (Reference Schedule 13, page 6 of 6) This is very hard to explain in any rational manner since utility bonds typically yield significantly more than Treasury bonds, not less. It appears that Mr. Moul's S&P Utility risk premium is overstated because his historic utility bond return figure is unrealistically low.

Q. WHAT WOULD THE S&P UTILITY INDEX BE IF TREASURY BOND RETURNS HAD BEEN USED INSTEAD OF UTILITY BONDS?

A. In that case, the risk premium would be slightly lower, about 5.3 percent (i.e., 11.14 - 5.8 = 5.3%). Long-term Treasury yields in recent months have been about 4.5 percent, and using this current yield results in a risk premium cost of equity of about 9.8 percent (4.5% + 5.3%). This risk premium result is before considering <u>any</u> risk decrement for the difference between the S&P Utility Index and NJNG, which Mr. Moul assumes to be about 0.5 percent. This implies a final estimate of about 9.0 to 10.0 percent, depending on whether a risk adjustment for NJNG is factored in.

Q. ARE YOU SUGGESTING THE BOARD SHOULD ADOPT A RANGE OF 9.0 TO 10.0 PERCENT BASED ON RISK PREMIUM EVIDENCE?

A. No, not at all. The historic, industry-specific risk premium is neither an accepted nor reliable cost of equity method. My discussion points out that the results will differ rather drastically depending on the definition of "debt" that is selected in the study. Using utility debt, the historic average debt return of 5.7 percent is anomalously and unrealistically low, which leads to an overstated equity risk premium. By comparison, it is far more common to use the long-run average return on long-term government bonds in a risk premium study. It is notable that the use of historic returns on government bonds (per Morningstar/Ibbotson) produces a risk premium cost of equity that is much closer to the more reliable DCF evidence.

D. <u>CAPM Study</u>

Q. HOW DID MR. MOUL DERIVE HIS CAPM ESTIMATE?

A. Mr. Moul begins with the standard CAPM model adopting a proxy group beta of 0.80 (obtained from Value Line), a prospective cost of long-term debt of 5.0 percent and a stock market risk premium of 6.9 percent). In addition, he adds three discrete adjustments, all of which inflate his CAPM final result:

- 0.18 percent for flotation expense;
- a leverage adjustment that increases the proxy group beta (published by Value Line) from 0.80 to 0.94 (adding nearly a full percentage point to the final result); and
- a "size" adjustment that adds 0.97 percent (97 basis points) to the final result.

These inputs and adjustments produce:

$$K_e = 5.0\% + 0.94\ (6.9) + 0.97\% + 0.18\% = \underline{12.65\text{ percent}}.$$

The 12.65 percent CAPM estimate is 35 percent greater than his DCF study estimate (i.e., 9.4 percent) using the very same gas distribution proxy group. This is a troubling inconsistency that must be explained.

Q. WHAT WOULD HIS RESULT BE WITHOUT THESE THREE ADJUSTMENTS?

A. If the three adjustments were removed, his cost of equity estimate would be:

$$K_e = 5.0\% + 0.80\ (6.9) = \underline{10.52\text{ percent.}}$$

Q. IS THIS CAPM CALCULATION MORE REASONABLE?

A. Yes, though it remains somewhat high. In particular, long-term Treasury yields in recent months have declined to 4.5 percent, and in my opinion, a more realistic stock market risk premium would be 6.0 percent. If the Treasury bond yield is updated to 4.5 percent, the CAPM return shown above falls from 10.5 percent shown above to 10.0 percent. Further, substituting a 6.0 percent risk premium for Mr. Moul's 6.9 percent results in the following CAPM estimate:

$$R_m = 4.5\% + 0.8\ (6.0) = \underline{9.3\text{ percent}}.$$

This updated and revised 9.3 percent CAPM estimate is roughly consistent with the DCF estimates that both Mr. Moul and I obtained.

Q. IS THERE ANY MERIT TO MR. MOUL'S CAPM "ADDERS?"

A. Let's set aside the 0.18 percent for flotation expense, since that adjustment could have merit if there was evidence such expenses would be incurred. I already explained why the leverage adjustment is improper in connection with the DCF study. This adder has nothing whatsoever to do with the cost of equity but instead is intended as additional shareholder income to compensate for the alleged inadequacies of cost-based ratemaking (i.e., using a book value capital structure instead of the more lucrative market value).

In the CAPM study, Mr. Moul now adds on 97 basis points for size, i.e., NJNG (or the proxy gas companies) are smaller than the companies comprising the stock market as a whole. He therefore assumes they must be riskier. Moreover, Mr. Moul claims to be "conservative" and that he really should have used 176 basis points instead of 97 basis points. (Testimony, page 46) In other words, absent his "conservatism," his CAPM estimate would be 13.44 percent, or 43 percent higher than his DCF result.

Q. YOU HAVE INDICATED THAT YOU QUESTION MR. MOUL'S STOCK MARKET RISK PREMIUM OF 6.9 PERCENT. PLEASE EXPLAIN WHY.

A. I believe that 6.0 percent is a more realistic value for the stock market risk premium, and Mr. Moul's 6.9 percent is at the upper end of the plausible range. It appears that Mr. Moul relied on two sources of information, the Morningstar/Ibbotson historical risk premium of 6.5 percent and a "forecast" risk premium of 7.34 percent. The average of these two sources is the 6.9 percent that he employed in his CAPM analysis. This is intended to be the overall stock market risk premium relative to the yield on long-term Treasury bonds.

As discussed earlier in the CAPM portion of my testimony, the simple or unadjusted historical risk premium estimate tends to be somewhat overstated for cost of equity purposes. As noted by Ibbotson and Chen (see footnote 5), the historical (arithmetic) risk premium should be reduced to remove the effects of an increasing price/earnings (P/E) ratio from the historical data. It would be inconsistent with accepted financial theory to assume that the historically rising P/E ratios persist indefinitely into the future. As a result, their corrected historical risk premium is 5.9 percent (or 4.0 percent using the geometric historical risk premium).

Q. WHAT IS YOUR OBJECTION TO THE "FORECAST" METHOD OF DERIVING THE RISK PREMIUM?

A. Mr. Moul employed two "forecasted" measures of stock market returns. The first is Value Line's median "Appreciation Potential" for the approximately 1,700 stocks that the publication follows (i.e., a median 45 percent stock price increase over the next three to five years). This method produces a 11.53 percent return. The second method is a forecast of the rate of return on the S&P 500, based on a published forecast of earnings per share growth (published by First Call of 11.23 percent). This produces a stock market return of 13.15 percent. (See Mr. Moul's Appendix I-4.)

Neither of these estimates is very reliable. Mr. Moul's S&P 500 estimate depends on long-run earnings growth of over 11 percent, which is not plausible. As Mr. Moul notes at page 25 of his testimony, the Blue Chip long-term consensus forecast of pre-tax corporate profits for the U.S. economy does not exceed 5.5 percent, and even the historical corporate profits growth rate has been about two percentage points above the rate of U.S. economic growth. Value Line has a similar outlook for the growth rate in U.S. corporate profits. Since the S&P 500 is a very broad measure of the U.S. corporate sector and the U.S. stock market, it is difficult to see how on a long-term basis its earnings can grow twice as rapidly as the consensus outlook for overall U.S. corporate profits. The 13.15 percent "forecasted" annual return is overstated.

In the case of the Value Line, the problem is more with the method than the result. Certainly, his 11.5 percent estimate using the Value Line projections is more plausible than the 13.15 percent he obtained for the S&P 500. The problem here is that the median Value Line stock is simply not the same thing as a broad measure of the overall market, such as the Value Line Industrial Composite or the S&P 500, where large stocks (such as General Electric or AT&T) are given more weight than smaller companies. After all, the Value Line population is a mixture of large cap, mid cap and small stocks, and to obtain the "median" value for 1,700 all companies, each company is given equal weight regardless of size. This is contrary to standard stock market measure.[6]

It is also quite apparent that Value Line does not view these "price appreciation" measures as being realistic estimates of the long-run returns on the overall stock market.

[6] This probably imparts an upward bias to the return results since smaller stocks tend to have more rapid growth characteristics than larger, more mature companies.

I applied Mr. Moul's method using Value Line data from two points in time, one year apart: March 30, 2007 and March 28, 2008. At March 30, 2007, Value Line identified median price appreciation potential of 40 percent and a median dividend yield of 1.7 percent (for dividend paying stocks). This produces a rate of return for the medium stock of about 10.5 percent. However, on March 28, 2008, after sharp declines it the stock market, the Value Line median stock price appreciation potential had increased to 75 percent, with a median dividend yield of 2.1 percent. This translates into an annualized return of 17.1 percent. No one would possibly argue that within that one year time period (March 2007 to March 2008) the stock market cost of equity had risen from 10.5 to 17.1 percent. This is simply not a credible method for estimating the overall stock market return.

Q. IS MR. MOUL'S CAPM 12.65 A REASONABLE ESTIMATE OF NJNG'S COST OF EQUITY PERCENT CAPM RESULT?

A. No, it is not. Let's begin with what we know to be undeniably true. Mr. Moul and I both applied the standard DCF model in the conventional manner using somewhat different market data time periods and gas utility proxy groups. Both of us obtained estimates in the 9.0 to 9.5 percent range. It is also undeniable that by every measure NJNG is a high quality, low-risk utility company. It has a strong single-A, low double-A credit rating, Value Line's highest Safety Rating and a favorable beta statistic (well below 1.0) from several published sources. Even Mr. Moul acknowledges that NJNG has a significantly lower cost of equity than the S&P Utility Index.

Now consider his CAPM results of 12.65 percent, or even his 13.44 percent without his "conservatism." Something here is terribly wrong. Mr. Moul has produced a cost of equity analysis, using his CAPM adders, indicating that NJNG has a <u>higher</u> cost of equity than the stock market as a whole (e.g., the S&P 500).

Q. PLEASE EXPLAIN THE BASIS FOR YOUR STATEMENT.

A. A CAPM study for the S&P 500 (or a company equal in risk to the S&P 500) would have a beta of 1.0, with none of the adders:

$$K_e = 5.0\% + 1.0\ (6.9) = \underline{11.9\ \text{percent}}.$$

This leads to the counter-intuitive conclusion that NJNG has a significantly higher cost of equity than the overall stock market.

I already have discussed the leverage adjustment issue, and that does not need repeating. The so-called size adjustment also should be rejected for several reasons. First, while there may be a risk premium for certain small stocks (in particular, start-ups and rapidly growing companies whose prospects may be volatile and hard to reliably predict), that profile simply does not apply to NJNG (or the parent NJR) which is a very stable, mature company. Second, if NJNG (i.e., NJR) is “risky” due to its small size, we would probably detect that using standard measures such as the beta, Value Line Safety Rating, credit ratings, etc. There is simply no corroborating evidence from financial markets that NJNG is anything but a low-risk company. Third, Mr. Moul has no evidence that is remotely persuasive that there is such a thing as a small company risk premium <u>for utility companies</u>. The evidence he cites (e.g., a brief 1995 article) is primarily or entirely based on non utilities. In any event, NJR is hardly a small company, with a market cap of $1.3 billion.

If the CAPM is to be given any weight at all in this proceeding, both the leverage and size adjustments (nearly 2 full percentage points) should be rejected as being completely improper.

E. <u>Comparable Earnings</u>

Q. HOW DID MR. MOUL CONDUCT HIS COMPARABLE EARNINGS STUDY?

A. Mr. Moul selected a group of unregulated companies that appear to have relatively stable operating profiles. He compiled both their historical earned returns on equity and their projected equity returns. On a historical basis, their earned returns average 19.8 percent and on a projected basis they average 17.4 percent.

Q. IS THIS A COST OF EQUITY METHOD?

A. No, it is not. These are pure accounting results and no market data is employed in the analysis. As a result Mr. Moul disregards this information in deriving his 11.375 percent return on equity.

Q. DO THESE ACCOUNTING FIGURES TELL US ANYTHING ABOUT INVESTOR RETURN REQUIREMENTS?

A. No. The main problem is that these stocks normally sell at large premiums to their book values. While a given non-regulated company might have an accounting return on equity of 20 percent, if its shares are selling at two to three times book value per share, investors purchasing the stock at that price very likely expect to realizes (and therefore require) market returns much lower than that 20 percent.

Mr. Moul's comparables earning study is not helpful in gaining insight into the cost of equity for NJNG. He quite properly excluded these results in developing his return on equity range.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does, at this time. On April 16, 2008, NJNG provided a provisional cost of capital update that I am presently reviewing. I therefore reserve the right to update my testimony at the appropriate time in supplemental and/or surrebuttal testimony.

APPENDIX A

QUALIFICATIONS OF
MATTHEW I. KAHAL

MATTHEW I. KAHAL

Mr. Kahal is currently an independent consulting economist, specializing in energy economics, public utility regulation and financial analysis. Over the past two decades, his work has encompassed electric utility integrated resource planning (IRP), power plant licensing and a wide range of utility financial issues. In the financial area he has conducted numerous cost of capital studies and addressed other financial issues for electric, gas, telephone and water utilities. Mr. Kahal's work in recent years has shifted to electric utility restructuring, mergers and competition.

Mr. Kahal has provided expert testimony on more than 300 occasions before state and federal regulatory commissions and the U.S. Congress. His testimony has covered need for power, integrated resource planning, cost of capital, purchased power practices and contracts, merger economics, industry restructuring and various other regulatory policy issues.

Education:

B.A. (Economics) - University of Maryland, 1971.

M.A. (Economics) - University of Maryland, 1974.

Ph.D. candidate - University of Maryland, completed all course work and qualifying examinations.

Previous Employment:

1981-2001 - Exeter Associates, Inc. (founding Principal).

1980-1981 - Member of the Economic Evaluation Directorate, The Aerospace Corporation, Washington, D.C. office.

1977-1980 - Economist, Washington, D.C. consulting firm.

1972-1977 - Research/Teaching Assistant and Instructor, Department of Economics, University of Maryland (College Park).

1975-1977 - Lecturer in Business/Economics, Montgomery College.

Professional Work Experience:

Mr. Kahal has more than twenty years experience managing and conducting consulting assignments relating to public utility economics and regulation. In 1981, he and five colleagues founded the firm of Exeter Associates, Inc. and for the next 20 years he served as a Principal and corporate officer in the firm. During that time, he supervised multi-million dollar support contracts with the State of Maryland and directed the technical work conducted both by Exeter professional staff and numerous subcontractors. Additionally, Mr. Kahal took the lead role at Exeter in consulting to the firm's other governmental and private clients in the areas of financial analysis, utility mergers, electric restructuring and utility purchase power contracts.

At the Aerospace Corporation, Mr. Kahal served as an economic consultant to the Strategic Petroleum Reserve (SPR). In that capacity he participated in a detailed financial assessment of the SPR, and developed an econometric forecasting model of U.S. petroleum industry inventories. That study has been used to determine the extent to which private sector petroleum stocks can be expected to protect the U.S. from the impacts of oil import interruptions.

Before entering consulting, Mr. Kahal held faculty positions with the Department of Economics at the University of Maryland and with Montgomery College teaching courses on economic principles, business and economic development.

Publications and Consulting Reports:

Projected Electric Power Demands of the Baltimore Gas and Electric Company, Maryland Power Plant Siting Program, 1979.

Projected Electric Power Demands of the Allegheny Power System, Maryland Power Plant Siting Program, January 1980.

An Econometric Forecast of Electric Energy and Peak Demand on the Delmarva Peninsula, Maryland Power Plant Siting Program, March 1980 (with Ralph E. Miller).

A Benefit/Cost Methodology of the Marginal Cost Pricing of Tennessee Valley Authority Electricity, prepared for the Board of Directors of the Tennessee Valley Authority, April 1980.

An Evaluation of the Delmarva Power and Light Company Generating Capacity Profile and Expansion Plan, (Interim Report), prepared for the Delaware Office of the Public Advocate, July 1980, (with Sharon L. Mason).

Rhode Island-DOE Electric Utilities Demonstration Project, Third Interim Report on Preliminary Analysis of the Experimental Results, prepared for the Economic Regulatory Administration, U.S. Department of Energy, July 1980.

Petroleum Inventories and the Strategic Petroleum Reserve, The Aerospace Corporation, prepared for the Strategic Petroleum Reserve Office, U.S. Department of Energy, December 1980.

Alternatives to Central Station Coal and Nuclear Power Generation, prepared for Argonne National Laboratory and the Office of Utility Systems, U.S. Department of Energy, August 1981.

"An Econometric Methodology for Forecasting Power Demands," Conducting Need-for-Power Review for Nuclear Power Plants (D.A. Nash, ed.), U.S. Nuclear Regulatory Commission, NUREG-0942, December 1982.

State Regulatory Attitudes Toward Fuel Expense Issues, prepared for the Electric Power Research Institute, July 1983, (with Dale E. Swan).

"Problems in the Use of Econometric Methods in Load Forecasting," Adjusting to Regulatory, Pricing and Marketing Realities (Harry Trebing, ed.), Institute of Public Utilities, Michigan State University, 1983.

Proceedings of the Maryland Conference on Electric Load Forecasting, (editor and contributing author), Maryland Power Plant Siting Program, PPES-83-4, October 1983.

"The Impacts of Utility-Sponsored Weatherization Programs: The Case of Maryland Utilities," (with others), in Government and Energy Policy (Richard L. Itteilag, ed.), 1983.

Power Plant Cumulative Environmental Impact Report, contributing author, (Paul E. Miller, ed.) Maryland Department of Natural Resources, January 1984.

Projected Electric Power Demands for the Potomac Electric Power Company, three volumes with Steven L. Estomin), prepared for the Maryland Power Plant Siting Program, March 1984.

"An Assessment of the State-of-the-Art of Gas Utility Load Forecasting," (with Thomas Bacon, Jr. and Steven L. Estomin), published in the Proceedings of the Fourth NARUC Biennial Regulatory Information Conference, 1984.

"Nuclear Power and Investor Perceptions of Risk," (with Ralph E. Miller), published in The Energy Industries in Transition: 1985-2000 (John P. Weyant and Dorothy Sheffield, eds.), 1984.

The Financial Impact of Potential Department of Energy Rate Recommendations on the Commonwealth Edison Company, prepared for the U.S. Department of Energy, October 1984.

"Discussion Comments," published in Impact of Deregulation and Market Forces on Public Utilities: The Future of Regulation (Harry Trebing, ed.), Institute of Public Utilities, Michigan State University, 1985.

An Econometric Forecast of the Electric Power Loads of Baltimore Gas and Electric Company, two volumes (with others), prepared for the Maryland Power Plant Siting Program, 1985.

A Survey and Evaluation of Demand Forecast Methods in the Gas Utility Industry, prepared for the Public Utilities Commission of Ohio, Forecasting Division, November 1985, (with Terence Manuel).

A Review and Evaluation of the Load Forecasts of Houston Lighting & Power Company and Central Power & Light Company -- Past and Present, prepared for the Texas Public Utility Commission, December 1985, (with Marvin H. Kahn).

Power Plant Cumulative Environmental Impact Report for Maryland, principal author of three of the eight chapters in the report (Paul E. Miller, ed.), PPSP-CEIR-5, March 1986.

"Potential Emissions Reduction from Conservation, Load Management, and Alternative Power," published in Acid Deposition in Maryland: A Report to the Governor and General Assembly, Maryland Power Plant Research Program, AD-87-1, January 1987.

Determination of Retrofit Costs at the Oyster Creek Nuclear Generating Station, March 1988, prepared for Versar, Inc., New Jersey Department of Environmental Protection.

Excess Deferred Taxes and the Telephone Utility Industry, April 1988, prepared on behalf of the National Association of State Utility Consumer Advocates.

Toward a Proposed Federal Policy for Independent Power Producers, comments prepared on behalf of the Indiana Consumer Counselor, FERC Docket EL87-67-000, November 1987.

Review and Discussion of Regulations Governing Bidding Programs, prepared for the Pennsylvania Office of Consumer Advocate, June 1988.

A Review of the Proposed Revisions to the FERC Administrative Rules on Avoided Costs and Related Issues, prepared for the Pennsylvania Office of Consumer Advocate, April 1988.

Review and Comments on the FERC NOPR Concerning Independent Power Producers, prepared for the Pennsylvania Office of Consumer Advocate, June 1988.

The Costs to Maryland Utilities and Ratepayers of an Acid Rain Control Strategy -- An Updated Analysis, prepared for the Maryland Power Plant Research Program, October 1987, AD-88-4.

"Comments," in New Regulatory and Management Strategies in a Changing Market Environment (Harry M. Trebing and Patrick C. Mann, editors), Proceedings of the Institute of Public Utilities Eighteenth Annual Conference, 1987.

Electric Power Resource Planning for the Potomac Electric Power Company, prepared for the Maryland Power Plant Research Program, July 1988.

Power Plant Cumulative Environmental Impact Report for Maryland (Thomas E. Magette, ed.) authored two chapters, November 1988, PPRP-CEIR-6.

Resource Planning and Competitive Bidding for Delmarva Power & Light Company, October 1990, prepared for the Maryland Department of Natural Resources (with M. Fullenbaum).

Electric Power Rate Increases and the Cleveland Area Economy, prepared for the Northeast Ohio Areawide Coordinating Agency, October 1988.

An Economic and Need for Power Evaluation of Baltimore Gas & Electric Company's Perryman Plant, May 1991, prepared for the Maryland Department of Natural Resources (with M. Fullenbaum).

The Cost of Equity Capital for the Bell Local Exchange Companies in a New Era of Regulation, October 1991, presented at the Atlantic Economic Society 32nd Conference, Washington, D.C.

A Need for Power Review of Delmarva Power & Light Company's Dorchester Unit 1 Power Plant, March 1993, prepared for the Maryland Department of National Resources (with M. Fullenbaum)

The AES Warrior Run Project: Impact on Western Maryland Economic Activity and Electric Rates, February 1993, prepared for the Maryland Power Plant Research Program (with Peter Hall).

An Economic Perspective on Competition and the Electric Utility Industry, November 1994. Prepared for the Electric Consumers' Alliance.

PEPCO's Clean Air Act Compliance Plan: Status Report, prepared for the Maryland Power Plant Research Plan, January 1995 (w/Diane Mountain, Environmental Resources Management, Inc.).

The FERC Open Access Rulemaking: A Review of the Issues, prepared for the Indiana Office of Utility Consumer Counselor and the Pennsylvania Office of Consumer Advocate, June 1995.

A Status Report on Electric Utility Restructuring: Issues for Maryland, prepared for the Maryland Power Plant Research Program, November 1995 (with Daphne Psacharopoulos).

Modeling the Financial Impacts on the Bell Regional Holding Companies from Changes in Access Rates, prepared for MCI Corporation, May 1996.

The CSEF Electric Deregulation Study: Economic Miracle or the Economists' Cold Fusion?, prepared for the Electric Consumers' Alliance, Indianapolis, Indiana, October 1996.

Reducing Rates for Interstate Access Service: Financial Impacts on the Bell Regional Holding Companies, prepared for MCI Corporation, May 1997.

The New Hampshire Retail Competition Pilot Program: A Preliminary Evaluation, July 1997, prepared for the Electric Consumers' Alliance (with Jerome D. Mierzwa).

Electric Restructuring and the Environment: Issue Identification for Maryland, March 1997, prepared for the Maryland Power Plant Research Program (with Environmental Resource Management, Inc.)

An Analysis of Electric Utility Embedded Power Supply Costs, prepared for Power-Gen International Conference, Dallas, Texas, December 1997.

Market Power Outlook for Generation Supply in Louisiana, December 2000, prepared for the Louisiana Public Service Commission (with others).

A Review of Issues Concerning Electric Power Capacity Markets, prepared for the Maryland Power Plant Research Program, December 2001 (with B. Hobbs and J. Inon).

The Economic Feasibility of Air Emissions Controls at the Brandon Shores and Morgantown Coal-fired Power Plants, February 2005, (prepared for the Chesapeake Bay Foundation).

The Economic Feasibility of Power Plant Retirements on the Entergy System, September 2005 with Phil Hayet (prepared for the Louisiana Public Service Commission).

Expert Report on Capital Structure, Equity and Debt Costs, prepared for the Edmonton Regional Water Customers Group, August 30, 2006.

Maryland's Options to Reduce and Stabilize Electric Power Prices Following Restructuring, with Steven L. Estomin, prepared for the Power Plant Research Program, Maryland Department of Natural Resources, September 2006.

Conference and Workshop Presentations:

Workshop on State Load Forecasting Programs, sponsored by the Nuclear Regulatory Commission and Oak Ridge National Laboratory, February 1982 (presentation on forecasting methodology).

Fourteenth Annual Conference of the Michigan State University Institute for Public Utilities, December 1982 (presentation on problems in forecasting).

Conference on Conservation and Load Management, sponsored by the Massachusetts Energy Facilities Siting Council, May 1983 (presentation on cost-benefit criteria).

Maryland Conference on Load Forecasting, sponsored by the Maryland Power Plant Siting Program and the Maryland Public Service Commission, June 1983 (presentation on overforecasting power demands).

The 5th Annual Meetings of the International Association of Energy Economists, June 1983 (presentation on evaluating weatherization programs).

The NARUC Advanced Regulatory Studies Program (presented lectures on capacity planning for electric utilities), February 1984.

The 16th Annual Conference of the Institute of Public Utilities, Michigan State University (discussant on phase-in and excess capacity), December 1984.

U.S. Department of Energy Utilities Conference, Las Vegas, Nevada (presentation of current and future regulatory issues), May 1985.

The 18th Annual Conference of the Institute of Public Utilities, Michigan State University, Williamsburg, Virginia, December 1986 (discussant on cogeneration).

The NRECA Conference on Load Forecasting, sponsored by the National Rural Electric Cooperative Association, New Orleans, Louisiana, December 1987 (presentation on load forecast accuracy).

The Second Rutgers/New Jersey Department of Commerce Annual Conference on Energy Policy in the Middle Atlantic States, Rutgers University, April 1988 (presentation on spot pricing of electricity).

The NASUCA 1988 Mid-Year Meeting, Annapolis, Maryland, June 1988, sponsored by the National Association of State Utility Consumer Advocates (presentation on the FERC electricity avoided cost NOPRs).

The Thirty Second Atlantic Economic Society Conference, Washington, D.C., October 1991 (presentation of a paper on cost of capital issues for the Bell Operating Companies).

The NASUCA 1993 Mid-Year Meeting, St. Louis, Missouri, sponsored by the National Association of State Utility Consumer Advocates, June 1993 (presentation on regulatory issues concerning electric utility mergers).

The NASUCA and NARUC annual meetings in New York City, November 1993 (presentations and panel discussions on the emerging FERC policies on transmission pricing).

The NASUCA annual meetings in Reno, Nevada, November 1994 (presentation concerning the FERC NOPR on stranded cost recovery).

U.S. Department of Energy Utilities/Energy Management Workshop, March 1995 (presentation concerning electric utility competition).

The 1995 NASUCA Mid-Year Meeting, Breckenridge, Colorado, June 1995, (presentation concerning the FERC rulemaking on electric transmission open access).

The 1996 NASUCA Mid-Year Meeting, Chicago, Illinois, June 1996 (presentation concerning electric utility merger issues).

Conference on "Restructuring the Electric Industry," sponsored by the National Consumers League and Electric Consumers Alliance, Washington, D.C., May 1997 (presentation on retail access pilot programs).

The 1997 Mid-Atlantic Conference of Regulatory Utilities Commissioners (MARUC), Hot Springs, Virginia, July 1997 (presentation concerning electric deregulation issues).

Power-Gen '97 International Conference, Dallas, Texas, December 1997 (presentation concerning utility embedded costs of generation supply).

Consumer Summit on Electric Competition, sponsored by the National Consumers League and Electric Consumers' Alliance, Washington, D.C., March 2001 (presentation concerning generation supply and reliability).

National Association of State Utility Consumer Advocates, Mid-Year Meetings, Austin, Texas, June 16-17, 2002 (presenter and panelist on RTO/Standard Market Design issues).

Louisiana State Bar Association, Public Utility Section, October 2, 2002. (Presentation on Performance-Based Ratemaking and panelist on RTO issues). Baton Rouge, Louisiana.

Virginia State Corporation Commission/Virginia State Bar, Twenty Second National Regulatory Conference, May 10, 2004. (Presentation on Electric Transmission System Planning.) Williamsburg, Virginia.

Expert Testimony
of Matthew I. Kahal

	Docket Number	Utility	Jurisdiction	Client	Subject
1.	27374 & 27375 October 1978	Long Island Lighting Company	New York Counties	Nassau & Suffolk	Economic Impacts of Proposed Rate Increase
2.	6807 January 1978	Generic	Maryland	MD Power Plant Siting Program	Load Forecasting
3.	78-676-EL-AIR February 1978	Ohio Power Company	Ohio	Ohio Consumers' Counsel	Test Year Sales and Revenues
4.	17667 May 1979	Alabama Power Company	Alabama	Attorney General	Test Year Sales, Revenues, Costs and Load Forecasts
5.	None April 1980	Tennessee Valley Authority	TVA Board	League of Women Voters	Time-of-Use Pricing
6.	R-80021082	West Penn Power Company	Pennsylvania	Office of Consumer Advocate	Load Forecasting, Marginal Cost pricing
7.	7259 (Phase I) October 1980	Potomac Edison Company	Maryland	MD Power Plant Siting Program	Load Forecasting
8.	7222 December 1980	Delmarva Power & Light Company	Maryland	MD Power Plant Siting Program	Need for Plant, Load Forecasting
9.	7441 June 1981	Potomac Electric Power Company	Maryland	Commission Staff	PURPA Standards
10.	7159 May 1980	Baltimore Gas & Electric	Maryland	Commission Staff	Time-of-Use Pricing
11.	81-044-E-42T	Monongahela Power	West Virginia	Commission Staff	Time-of-Use Rates
12.	7259 (Phase II) November 1981	Potomac Edison Company	Maryland	MD Power Plant Siting Program	Load Forecasting, Load Management
13.	1606 September 1981	Blackstone Valley Electric and Narragansett	Rhode Island	Division of Public Utilities	PURPA Standards
14.	RID 1819 April 1982	Pennsylvania Bell	Pennsylvania	Office of Consumer Advocate	Rate of Return
15.	82-0152 July 1982	Illinois Power Company	Illinois	U.S. Department of Defense	Rate of Return, CWIP
16.	7559 September 1982	Potomac Edison Company	Maryland	Commission Staff	Cogeneration

Expert Testimony
of Matthew I. Kahal

	Docket Number	Utility	Jurisdiction	Client	Subject
17.	820150-EU September 1982	Gulf Power Company	Florida	Federal Executive Agencies	Rate of Return, CWIP
18.	82-057-15 January 1983	Mountain Fuel Supply Company	Utah	Federal Executive Agencies	Rate of Return, Capital Structure
19.	5200 August 1983	Texas Electric Service Company	Texas	Federal Executive Agencies	Cost of Equity
20.	28069 August 1983	Oklahoma Natural Gas	Oklahoma	Federal Executive Agencies	Rate of Return, deferred taxes, capital structure, attrition
21.	83-0537 February 1984	Commonwealth Edison Company	Illinois	U.S. Department of Energy	Rate of Return, capital structure, financial capability
22.	84-035-01 June 1984	Utah Power & Light Company	Utah	Federal Executive Agencies	Rate of Return
23.	U-1009-137 July 1984	Utah Power & Light Company	Idaho	U.S. Department of Energy	Rate of Return, financial condition
24.	R-842590 August 1984	Philadelphia Electric Company	Pennsylvania	Office of Consumer Advocate	Rate of Return
25.	840086-EI August 1984	Gulf Power Company	Florida	Federal Executive Agencies	Rate of Return, CWIP
26.	84-122-E August 1984	Carolina Power & Light Company	South Carolina	South Carolina Consumer Advocate	Rate of Return, CWIP, load forecasting
27.	CGC-83-G & CGC-84-G October 1984	Columbia Gas of Ohio	Ohio	Ohio Division of Energy	Load forecasting
28.	R-842621 October 1984	Western Pennsylvania Water Company	Pennsylvania	Office of Consumer Advocate	Test year sales
29.	R-842710 January 1985	ALLTEL Pennsylvania Inc.	Pennsylvania	Office of Consumer Advocate	Rate of Return
30.	ER-504 February 1985	Allegheny Generating Company	FERC	Office of Consumer Advocate	Rate of Return
31.	R-842632 March 1985	West Penn Power Company	Pennsylvania	Office of Consumer Advocate	Rate of Return, conservation, time-of-use rates
32.	83-0537 & 84-0555 April 1985	Commonwealth Edison Company	Illinois	U.S. Department of Energy	Rate of Return, incentive rates, rate base

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33.	Rulemaking Docket No. 11, May 1985	Generic	Delaware	Delaware Commission Staff	Interest rates on refunds
34.	29450 July 1985	Oklahoma Gas & Electric Company	Oklahoma	Oklahoma Attorney General	Rate of Return, CWIP in rate base
35.	1811 August 1985	Bristol County Water Company	Rhode Island	Division of Public Utilities	Rate of Return, capital Structure
36.	R-850044 & R-850045 August 1985	Quaker State & Continental Telephone Companies	Pennsylvania	Office of Consumer Advocate	Rate of Return
37.	R-850174 November 1985	Philadelphia Suburban Water Company	Pennsylvania	Office of Consumer Advocate	Rate of Return, financial conditions
38.	U-1006-265 March 1986	Idaho Power Company	Idaho	U.S. Department of Energy	Power supply costs and models
39.	EL-86-37 & EL-86-38 September 1986	Allegheny Generating Company	FERC	PA Office of Consumer Advocate	Rate of Return
40.	R-850287 June 1986	National Fuel Gas Distribution Corp.	Pennsylvania	Office of Consumer Advocate	Rate of Return
41.	1849 August 1986	Blackstone Valley Electric	Rhode Island	Division of Public Utilities	Rate of Return, financial condition
42.	86-297-GA-AIR November 1986	East Ohio Gas Company	Ohio	Ohio Consumers' Counsel	Rate of Return
43.	U-16945 December 1986	Louisiana Power & Light Company	Louisiana	Public Service Commission	Rate of Return, rate phase-in plan
44.	Case No. 7972 February 1987	Potomac Electric Power Company	Maryland	Commission Staff	Generation capacity planning, purchased power contract
45.	EL-86-58 & EL-86-59 March 1987	System Energy Resources and Middle South Services	FERC	Louisiana PSC	Rate of Return
46.	ER-87-72-001 April 1987	Orange & Rockland	FERC	PA Office of Consumer Advocate	Rate of Return
47.	U-16945 April 1987	Louisiana Power & Light Company	Louisiana	Commission Staff	Revenue requirement update phase-in plan
48.	P-870196 May 1987	Pennsylvania Electric Company	Pennsylvania	Office of Consumer Advocate	Cogeneration contract

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49.	86-2025-EL-AIR June 1987	Cleveland Electric Illuminating Company	Ohio	Ohio Consumers' Counsel	Rate of Return
50.	86-2026-EL-AIR June 1987	Toledo Edison Company	Ohio	Ohio Consumers' Counsel	Rate of Return
51.	87-4 June 1987	Delmarva Power & Light Company	Delaware	Commission Staff	Cogeneration/small power
52.	1872 July 1987	Newport Electric Company	Rhode Island	Commission Staff	Rate of Return
53.	WO 8606654 July 1987	Atlantic City Sewerage Company	New Jersey	Resorts International	Financial condition
54.	7510 August 1987	West Texas Utilities Company	Texas	Federal Executive Agencies	Rate of Return, phase-in
55.	8063 Phase I October 1987	Potomac Electric Power Company	Maryland	Power Plant Research Program	Economics of power plant site selection
56.	00439 November 1987	Oklahoma Gas & Electric Company	Oklahoma	Smith Cogeneration	Cogeneration economics
57.	RP-87-103 February 1988	Panhandle Eastern Pipe Line Company	FERC	Indiana Utility Consumer Counselor	Rate of Return
58.	EC-88-2-000 February 1988	Utah Power & Light Co. PacifiCorp	FERC	Nucor Steel	Merger economics
59.	87-0427 February 1988	Commonwealth Edison Company	Illinois	Federal Executive Agencies	Financial projections
60.	870840 February 1988	Philadelphia Suburban Water Company	Pennsylvania	Office of Consumer Advocate	Rate of Return
61.	870832 March 1988	Columbia Gas of Pennsylvania	Pennsylvania	Office of Consumer Advocate	Rate of Return
62.	8063 Phase II July 1988	Potomac Electric Power Company	Maryland	Power Plant Research Program	Power supply study
63.	8102 July 1988	Southern Maryland Electric Cooperative	Maryland	Power Plant Research Program	Power supply study
64.	10105 August 1988	South Central Bell Telephone Co.	Kentucky	Attorney General	Rate of Return, incentive regulation

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65.	00345 August 1988	Oklahoma Gas & Electric Company	Oklahoma	Smith Cogeneration	Need for power
66.	U-17906 September 1988	Louisiana Power & Light Company	Louisiana	Commission Staff	Rate of Return, nuclear power costs Industrial contracts
67.	88-170-EL-AIR October 1988	Cleveland Electric Illuminating Co.	Ohio	Northeast-Ohio Areawide Coordinating Agency	Economic impact study
68.	1914 December 1988	Providence Gas Company	Rhode Island	Commission Staff	Rate of Return
69.	U-12636 & U-17649 February 1989	Louisiana Power & Light Company	Louisiana	Commission Staff	Disposition of litigation proceeds
70.	00345 February 1989	Oklahoma Gas & Electric Company	Oklahoma	Smith Cogeneration	Load forecasting
71.	RP88-209 March 1989	Natural Gas Pipeline of America	FERC	Indiana Utility Consumer Counselor	Rate of Return
72.	8425 March 1989	Houston Lighting & Power Company	Texas	U.S. Department of Energy	Rate of Return
73.	EL89-30-000 April 1989	Central Illinois Public Service Company	FERC	Soyland Power Coop, Inc.	Rate of Return
74.	R-891208 May 1989	Pennsylvania American Water Company	Pennsylvania	Office of Consumer Advocate	Rate of Return
75.	89-0033 May 1989	Illinois Bell Telephone Company	Illinois	Citizens Utility Board	Rate of Return
76.	881167-EI May 1989	Gulf Power Company	Florida	Federal Executive Agencies	Rate of Return
77.	R-891218 July 1989	National Fuel Gas Distribution Company	Pennsylvania	Office of Consumer Advocate	Sales forecasting
78.	8063, Phase III Sept. 1989	Potomac Electric Power Company	Maryland	Depart. Natural Resources	Emissions Controls
79.	37414-S2 October 1989	Public Service Company of Indiana	Indiana	Utility Consumer Counselor	Rate of Return, DSM, off-system sales, incentive regulation

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80.	October 1989	Generic	U.S. House of Reps. Comm. on Ways & Means	NA	Excess deferred income tax
81.	38728 November 1989	Indiana Michigan Power Company	Indiana	Utility Consumer Counselor	Rate of Return
82.	RP89-49-000 December 1989	National Fuel Gas Supply Corporation	FERC	PA Office of Consumer Advocate	Rate of Return
83.	R-891364 December 1989	Philadelphia Electric Company	Pennsylvania	PA Office of Consumer Advocate	Financial impacts (surrebuttal only)
84.	RP89-160-000 January 1990	Trunkline Gas Company	FERC	Indiana Utility Consumer Counselor	Rate of Return
85.	EL90-16-000 November 1990	System Energy Resources, Inc.	FERC	Louisiana Public Service Commission	Rate of Return
86.	89-624 March 1990	Bell Atlantic	FCC	PA Office of Consumer Advocate	Rate of Return
87.	8245 March 1990	Potomac Edison Company	Maryland	Depart. Natural Resources	Avoided Cost
88.	000586 March 1990	Public Service Company of Oklahoma	Oklahoma	Smith Cogeneration Mgmt.	Need for Power
89.	38868 March 1990	Indianapolis Water Company	Indiana	Utility Consumer Counselor	Rate of Return
90.	1946 March 1990	Blackstone Valley Electric Company	Rhode Island	Division of Public Utilities	Rate of Return
91.	000776 April 1990	Oklahoma Gas & Electric Company	Oklahoma	Smith Cogeneration Mgmt.	Need for Power
92.	890366 May 1990, December 1990	Metropolitan Edison Company	Pennsylvania	Office of Consumer Advocate	Competitive Bidding Program Avoided Costs
93.	EC-90-10-000 May 1990	Northeast Utilities	FERC	Maine PUC, et. al.	Merger, Market Power, Transmission Access
94.	ER-891109125 July 1990	Jersey Central Power & Light	New Jersey	Rate Counsel	Rate of Return
95.	R-901670 July 1990	National Fuel Gas Distribution Corp.	Pennsylvania	Office of Consumer Advocate	Rate of Return Test year sales

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96.	8201 October 1990	Delmarva Power & Light Company	Maryland	Depart. Natural Resources	Competitive Bidding, Resource Planning
97.	EL90-45-000 April 1991	Entergy Services, Inc.	FERC	Louisiana PSC	Rate of Return
98.	GR90080786J January 1991	New Jersey Natural Gas	New Jersey	Rate Counsel	Rate of Return
99.	90-256 January 1991	South Central Bell Telephone Company	Kentucky	Attorney General	Rate of Return
100.	U-17949A February 1991	South Central Bell Telephone Company	Louisiana	Louisiana PSC	Rate of Return
101.	ER90091090J April 1991	Atlantic City Electric Company	New Jersey	Rate Counsel	Rate of Return
102.	8241, Phase I April 1991	Baltimore Gas & Electric Company	Maryland	Dept. of Natural Resources	Environmental controls
103.	8241, Phase II May 1991	Baltimore Gas & Electric Company	Maryland	Dept. of Natural Resources	Need for Power, Resource Planning
104.	39128 May 1991	Indianapolis Water Company	Indiana	Utility Consumer Counselor	Rate of Return, rate base, financial planning
105.	P-900485 May 1991	Duquesne Light Company	Pennsylvania	Office of Consumer Advocate	Purchased power contract and related ratemaking
106.	G900240 P910502 May 1991	Metropolitan Edison Company Pennsylvania Electric Company	Pennsylvania	Office of Consumer Advocate	Purchased power contract and related ratemaking
107.	GR901213915 May 1991	Elizabethtown Gas Company	New Jersey	Rate Counsel	Rate of Return
108.	91-5032 August 1991	Nevada Power Company	Nevada	U.S. Dept. of Energy	Rate of Return
109.	EL90-48-000 November 1991	Entergy Services	FERC	Louisiana PSC	Capacity transfer
110.	000662 September 1991	Southwestern Bell Telephone	Oklahoma	Attorney General	Rate of Return
111.	U-19236 October 1991	Arkansas Louisiana Gas Company	Louisiana	Louisiana PSC Staff	Rate of Return

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112.	U-19237 December 1991	Louisiana Gas Service Company	Louisiana	Louisiana PSC Staff	Rate of Return
113.	ER91030356J October 1991	Rockland Electric Company	New Jersey	Rate Counsel	Rate of Return
114.	GR91071243J February 1992	South Jersey Gas Company	New Jersey	Rate Counsel	Rate of Return
115.	GR91081393J March 1992	New Jersey Natural Gas Company	New Jersey	Rate Counsel	Rate of Return
116.	P-870235 et al. March 1992	Pennsylvania Electric Company	Pennsylvania	Office of Consumer Advocate	Cogeneration contracts
117.	8413 March 1992	Potomac Electric Power Company	Maryland	Dept. of Natural Resources	IPP purchased power contracts
118.	39236 March 1992	Indianapolis Power & Light Company	Indiana	Utility Consumer Counselor	Least-cost planning Need for power
119.	R-912164 April 1992	Equitable Gas Company	Pennsylvania	Office of Consumer Advocate	Rate of Return
120.	ER-91111698J May 1992	Public Service Electric & Gas Company	New Jersey	Rate Counsel	Rate of Return
121.	U-19631 June 1992	Trans Louisiana Gas Company	Louisiana	PSC Staff	Rate of Return
122.	ER-91121820J July 1992	Jersey Central Power & Light Company	New Jersey	Rate Counsel	Rate of Return
123.	R-00922314 August 1992	Metropolitan Edison Company	Pennsylvania	Office of Consumer Advocate	Rate of Return
124.	92-049-05 September 1992	US West Communications	Utah	Committee of Consumer Services	Rate of Return
125.	92PUE0037 September 1992	Commonwealth Gas Company	Virginia	Attorney General	Rate of Return
126.	EC92-21-000 September 1992	Entergy Services, Inc.	FERC	Louisiana PSC	Merger Impacts (Affidavit)
127.	ER92-341-000 December 1992	System Energy Resources	FERC	Louisiana PSC	Rate of Return

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128.	U-19904 November 1992	Louisiana Power & Light Company	Louisiana	Staff	Merger analysis, competition competition issues
129.	8473 November 1992	Baltimore Gas & Electric Company	Maryland	Dept. of Natural Resources	QF contract evaluation
130.	IPC-E-92-25 January 1993	Idaho Power Company	Idaho	Federal Executive Agencies	Power Supply Clause
131.	E002/GR-92-1185 February 1993	Northern States Power Company	Minnesota	Attorney General	Rate of Return
132.	92-102, Phase II March 1992	Central Maine Power Company	Maine	Staff	QF contracts prudence and procurements practices
133.	EC92-21-000 March 1993	Entergy Corporation	FERC	Louisiana PSC	Merger Issues
134.	8489 March 1993	Delmarva Power & Light Company	Maryland	Dept. of Natural Resources	Power Plant Certification
135.	11735 April 1993	Texas Electric Utilities Company	Texas	Federal Executives Agencies	Rate of Return
136.	2082 May 1993	Providence Gas Company	Rhode Island	Division of Public Utilities	Rate of Return
137.	P-00930715 December 1993	Bell Telephone Company of Pennsylvania	Pennsylvania	Office of Consumer Advocate	Rate of Return, Financial Projections, Bell/TCI merger
138.	R-00932670 February 1994	Pennsylvania-American Water Company	Pennsylvania	Office of Consumer Advocate	Rate of Return
139.	8583 February 1994	Conowingo Power Company	Maryland	Dept. of Natural Resources	Competitive Bidding for Power Supplies
140.	E-015/GR-94-001 April 1994	Minnesota Power & Light Company	Minnesota	Attorney General	Rate of Return
141.	CC Docket No. 94-1 May 1994	Generic Telephone	FCC	MCI Comm. Corp.	Rate of Return
142.	92-345, Phase II June 1994	Central Maine Power Company	Maine	Advocacy Staff	Price Cap Regulation Fuel Costs
143.	93-11065 April 1994	Nevada Power Company	Nevada	Federal Executive Agencies	Rate of Return

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144.	94-0065 May 1994	Commonwealth Edison Company	Illinois	Federal Executive Agencies	Rate of Return
145.	GR94010002J June 1994	South Jersey Gas Company	New Jersey	Rate Counsel	Rate of Return
146.	WR94030059 July 1994	New Jersey-American Water Company	New Jersey	Rate Counsel	Rate of Return
147.	RP91-203-000 June 1994	Tennessee Gas Pipeline Company	FERC	Customer Group	Environmental Externalities (oral testimony only)
148.	ER94-998-000 July 1994	Ocean State Power	FERC	Boston Edison Company	Rate of Return
149.	R-00942986 July 1994	West Penn Power Company	Pennsylvania	Office of Consumer Advocate	Rate of Return, Emission Allowances
150.	94-121 August 1994	South Central Bell Telephone Company	Kentucky	Attorney General	Rate of Return
151.	35854-S2 November 1994	PSI Energy, Inc.	Indiana	Utility Consumer Counsel	Merger Savings and Allocations
152.	IPC-E-94-5 November 1994	Idaho Power Company	Idaho	Federal Executive Agencies	Rate of Return
153.	November 1994	Edmonton Water	Alberta, Canada	Regional Customer Group	Rate of Return (Rebuttal Only)
154.	90-256 December 1994	South Central Bell Telephone Company	Kentucky	Attorney General	Incentive Plan True-Ups
155.	U-20925 February 1995	Louisiana Power & Light Company	Louisiana	PSC Staff	Rate of Return Industrial Contracts Trust Fund Earnings
156.	R-00943231 February 1995	Pennsylvania-American Water Company	Pennsylvania	Consumer Advocate	Rate of Return
157.	8678 March 1995	Generic	Maryland	Dept. Natural Resources	Electric Competition Incentive Regulation (oral only)
158.	R-000943271 April 1995	Pennsylvania Power & Light Company	Pennsylvania	Consumer Advocate	Rate of Return Nuclear decommissioning Capacity Issues

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159.	U-20925 May 1995	Louisiana Power & Light Company	Louisiana	Commission Staff	Class Cost of Service Issues
160.	2290 June 1995	Narragansett Electric Company	Rhode Island	Division Staff	Rate of Return
161.	U-17949E June 1995	South Central Bell Telephone Company	Louisiana	Commission Staff	Rate of Return
162.	2304 July 1995	Providence Water Supply Board	Rhode Island	Division Staff	Cost recovery of Capital Spending Program
163.	ER95-625-000 et al. August 1995	PSI Energy, Inc.	FERC	Office of Utility Consumer Counselor	Rate of Return
164.	P-00950915 et al. September 1995	Paxton Creek Cogeneration Assoc.	Pennsylvania	Office of Consumer Advocate	Cogeneration Contract Amendment
165.	8702 September 1995	Potomac Edison Company	Maryland	Dept. of Natural Resources	Allocation of DSM Costs (oral only)
166.	ER95-533-001 September 1995	Ocean State Power	FERC	Boston Edison Co.	Cost of Equity
167.	40003 November 1995	PSI Energy, Inc.	Indiana	Utility Consumer Counselor	Rate of Return Retail wheeling
168.	P-55, SUB 1013 January 1996	BellSouth	North Carolina	AT&T	Rate of Return
169.	P-7, SUB 825 January 1996	Carolina Tel.	North Carolina	AT&T	Rate of Return
170.	February 1996	Generic Telephone	FCC	MCI	Cost of capital
171.	95A-531EG April 1996	Public Service Company of Colorado	Colorado	Federal Executive Agencies	Merger issues
172.	ER96-399-000 May 1996	Northern Indiana Public Service Company	FERC	Indiana Office of Utility Consumer Counselor	Cost of capital
173.	8716 June 1996	Delmarva Power & Light Company	Maryland	Dept. of Natural Resources	DSM programs
174.	8725 July 1996	BGE/PEPCO	Maryland	Md. Energy Admin.	Merger Issues
175.	U-20925	Entergy Louisiana, Inc.	Louisiana	PSC Staff	Rate of Return

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	August 1996				Allocations Fuel Clause
176.	EC96-10-000 September 1996	BGE/PEPCO	FERC	Md. Energy Admin.	Merger issues competition
177.	EL95-53-000 November 1996	Entergy Services, Inc.	FERC	Louisiana PSC	Nuclear Decommissioning
178.	WR96100768 March 1997	Consumers NJ Water Company	New Jersey	Ratepayer Advocate	Cost of Capital
179.	WR96110818 April 1997	Middlesex Water Co.	New Jersey	Ratepayer Advocate	Cost of Capital
180.	U-11366 April 1997	Ameritech Michigan	Michigan	MCI	Access charge reform/financial condition
181.	97-074 May 1997	BellSouth	Kentucky	MCI	Rate Rebalancing financial condition
182.	2540 June 1997	New England Power	Rhode Island	PUC Staff	Divestiture Plan
183.	96-336-TP-CSS June 1997	Ameritech Ohio	Ohio	MCI	Access Charge reform Economic impacts
184.	WR97010052 July 1997	Maxim Sewerage Corp.	New Jersey	Ratepayer Advocate	Rate of Return
185.	97-300 August 1997	LG&E/KU	Kentucky	Attorney General	Merger Plan
186.	Case No. 8738 August 1997	Generic (oral testimony only)	Maryland	Dept. of Natural Resources	Electric Restructuring Policy
187.	Docket No. 2592 September 1997	Eastern Utilities	Rhode Island	PUC Staff	Generation Divestiture
188.	Case No.97-247 September 1997	Cincinnati Bell Telephone	Kentucky	MCI	Financial Condition
189.	Docket No. U-20925 November 1997	Entergy Louisiana	Louisiana	PSC Staff	Rate of Return
190.	Docket No. D97.7.90 November 1997	Montana Power Co.	Montana	Montana Consumers Counsel	Stranded Cost
191.	Docket No. EO97070459	Jersey Central Power & Light Co.	New Jersey	Ratepayer Advocate	Stranded Cost

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	November 1997				
192.	Docket No. R-00974104 November 1997	Duquesne Light Co.	Pennsylvania	Office of Consumer Advocate	Stranded Cost
193.	Docket No. R-00973981 November 1997	West Penn Power Co.	Pennsylvania	Office of Consumer Advocate	Stranded Cost
194.	Docket No. A-1101150F0015 November 1997	Allegheny Power System DQE, Inc.	Pennsylvania	Office of Consumer Advocate	Merger Issues
195.	Docket No. WR97080615 January 1998	Consumers NJ Water Company	New Jersey	Ratepayer Advocate	Rate of Return
196.	Docket No. R-00974149 January 1998	Pennsylvania Power Company	Pennsylvania	Office of Consumer Advocate	Stranded Cost
197.	Case No. 8774 January 1998	Allegheny Power System DQE, Inc.	Maryland	Dept. of Natural Resources MD Energy Administration	Merger Issues
198.	Docket No. U-20925 (SC) March 1998	Entergy Louisiana, Inc.	Louisiana	Commission Staff	Restructuring, Stranded Costs, Market Prices
199.	Docket No. U-22092 (SC) March 1998	Entergy Gulf States, Inc.	Louisiana	Commission Staff	Restructuring, Stranded Costs, Market Prices
200.	Docket Nos. U-22092 (SC) and U-20925(SC) May 1998	Entergy Gulf States and Entergy Louisiana	Louisiana	Commission Staff	Standby Rates
201.	Docket No. WR98010015 May 1998	NJ American Water Co.	New Jersey	Ratepayer Advocate	Rate of Return
202.	Case No. 8794 December 1998	Baltimore Gas & Electric Co.	Maryland	MD Energy Admin./Dept. Of Natural Resources	Stranded Cost/ Transition Plan
203.	Case No. 8795 December 1998	Delmarva Power & Light Co.	Maryland	MD Energy Admin./Dept. Of Natural Resources	Stranded Cost/ Transition Plan
204.	Case No. 8797 January 1998	Potomac Edison Co.	Maryland	MD Energy Admin./Dept. Of Natural Resources	Stranded Cost/ Transition Plan
205.	Docket No. WR98090795 March 1999	Middlesex Water Co.	New Jersey	Ratepayer Advocate	Rate of Return
206.	Docket No. 99-02-05 April 1999	Connecticut Light & Power	Connecticut	Attorney General	Stranded Costs

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207.	Docket No. 99-03-04 May 1999	United Illuminating Company	Connecticut	Attorney General	Stranded Costs
208.	Docket No. U-20925 (FRP) June 1999	Entergy Louisiana, Inc.	Louisiana	Staff	Capital Structure
209.	Docket No. EC-98-40-000, et al. May 1999	American Electric Power/ Central & Southwest	FERC	Arkansas PSC	Market Power Mitigation
210.	Docket No. 99-03-35 July 1999	United Illuminating Company	Connecticut	Attorney General	Restructuring
211.	Docket No. 99-03-36 July 1999	Connecticut Light & Power Co.	Connecticut	Attorney General	Restructuring
212.	WR99040249 Oct. 1999	Environmental Disposal Corp.	New Jersey	Ratepayer Advocate	Rate of Return
213.	2930 Nov. 1999	NEES/EUA	Rhode Island	Division Staff	Merger/Cost of Capital
214.	DE99-099 Nov. 1999	Public Service New Hampshire	New Hampshire	Consumer Advocate	Cost of Capital Issues
215.	00-01-11 Feb. 2000	Con Ed/NU	Connecticut	Attorney General	Merger Issues
216.	Case No. 8821 May 2000	Reliant/ODEC	Maryland	Dept. of Natural Resources	Need for Power/Plant Operations
217.	Case No. 8738 July 2000	Generic	Maryland	Dept. of Natural Resources	DSM Funding
218.	Case No. U-23356 June 2000	Entergy Louisiana, Inc.	Louisiana	PSC Staff	Fuel Prudence Issues Purchased Power
219.	Case No. 21453, et al July 2000	SWEPCO	Louisiana	PSC Staff	Stranded Costs
220.	Case No. 20925 (B) July 2000	Entergy Louisiana	Louisiana	PSC Staff	Purchase Power Contracts
221.	Case No. 24889 August 2000	Entergy Louisiana	Louisiana	PSC Staff	Purchase Power Contracts
222.	Case No. 21453, et al. February 2001	CLECO	Louisiana	PSC Staff	Stranded Costs

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223.	P-00001860 and P-0000181 March 2001	GPU Companies	Pennsylvania	Office of Consumer Advocate	Rate of Return
224.	CVOL-0505662-S March 2001	ConEd/NU	Connecticut Superior Court	Attorney General	Merger (Affidavit)
225.	U-20925 (SC) March 2001	Entergy Louisiana	Louisiana	PSC Staff	Stranded Costs
226.	U-22092 (SC) March 2001	Entergy Gulf States	Louisiana	PSC Staff	Stranded Costs
227.	U-25533 May 2001	Entergy Louisiana/ Gulf States	Louisiana Interruptible Service	PSC Staff	Purchase Power
228.	P-00011872 May 2001	Pike County Pike	Pennsylvania	Office of Consumer Advocate	Rate of Return
229.	8893 July 2001	Baltimore Gas & Electric Co.	Maryland	MD Energy Administration	Corporate Restructuring
230.	8890 September 2001	Potomac Electric/Connectivity	Maryland	MD Energy Administration	Merger Issues
231.	U-25533 August 2001	Entergy Louisiana / Gulf States	Louisiana	Staff	Purchase Power Contracts
232.	U-25965 November 2001	Generic	Louisiana	Staff	RTO Issues
233.	3401 March 2002	New England Gas Co.	Rhode Island	Division of Public Utilities	Rate of Return
234.	99-833-MJR April 2002	Illinois Power Co.	U.S. District Court	U.S. Department of Justice	New Source Review
235.	U-25533 March 2002	Entergy Louisiana/ Gulf States	Louisiana	PSC Staff	Nuclear Uprates Purchase Power
236.	P-00011872 May 2002	Pike County Power & Light	Pennsylvania	Consumer Advocate	POLR Service Costs
237.	U-26361, Phase I May 2002	Entergy Louisiana/ Gulf States	Louisiana	PSC Staff	Purchase Power Cost Allocations
238.	R-00016849C001 et al. June 2002	Generic	Pennsylvania	Pennsylvania OCA	Rate of Return

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239.	U-26361, Phase II July 2002	Entergy Louisiana/ Entergy Gulf States	Louisiana	PSC Staff	Purchase Power Contracts
240.	U-20925(B) August 2002	Entergy Louisiana	Louisiana	PSC Staff	Tax Issues
241.	U-26531 October 2002	SWEPCO	Louisiana	PSC Staff	Purchase Power Contract
242.	8936 October 2002	Delmarva Power & Light	Maryland	Energy Administration Dept. Natural Resources	Standard Offer Service
243.	U-25965 November 2002	SWEPCO/AEP	Louisiana	PSC Staff	RTO Cost/Benefit
244.	8908 Phase I November 2002	Generic	Maryland	Energy Administration Dept. Natural Resources	Standard Offer Service
245.	02S-315EG November 2002	Public Service Company of Colorado	Colorado	Fed. Executive Agencies	Rate of Return
246.	EL02-111-000 December 2002	PJM/MISO	FERC	MD PSC	Transmission Ratemaking
247.	02-0479 February 2003	Commonwealth Edison	Illinois	Dept. of Energy	POLR Service
248.	PL03-1-000 March 2003	Generic	FERC	NASUCA	Transmission Pricing (Affidavit)
249.	U-27136 April 2003	Entergy Louisiana	Louisiana	Staff	Purchase Power Contracts
250.	8908 Phase II July 2003	Generic	Maryland	Energy Administration Dept. of Natural Resources	Standard Offer Service
251.	U-27192 June 2003	Entergy Louisiana and Gulf States	Louisiana	LPSC Staff	Purchase Power Contract Cost Recovery
252.	C2-99-1181 October 2003	Ohio Edison Company	U.S. District Court	U.S. Department of Justice, et al.	Clean Air Act Compliance Economic Impact (Report)
253.	RP03-398-000 December 2003	Northern Natural Gas Co.	FERC	Municipal Distributors Group/Gas Task Force	Rate of Return
254.	8738 December 2003	Generic	Maryland	Energy Admin Department of Natural Resources	Environmental Disclosure (oral only)

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255.	U-27136 December 2003	Entergy Louisiana, Inc.	Louisiana	PSC Staff	Purchase Power Contracts
256.	U-27192, Phase II October/December 2003	Entergy Louisiana & Entergy Gulf States	Louisiana	PSC Staff	Purchase Power Contracts
257.	WC Docket 03-173 December 2003	Generic	FCC	MCI	Cost of Capital (TELRIC)
258.	ER 030 20110 January 2004	Atlantic City Electric	New Jersey	Ratepayer Advocate	Rate of Return
259.	E-01345A-03-0437 January 2004	Arizona Public Service Company	Arizona	Federal Executive Agencies	Rate of Return
260.	03-10001 January 2004	Nevada Power Company	Nevada	U.S. Dept. of Energy	Rate of Return
261.	R-00049255 June 2004	PPL Elec. Utility	Pennsylvania	Office of Consumer Advocate	Rate of Return
262.	U-20925 July 2004	Entergy Louisiana, Inc.	Louisiana	PSC Staff	Rate of Return Capacity Resources
263.	U-27866 September 2004	Southwest Electric Power Co.	Louisiana	PSC Staff	Purchase Power Contract
264.	U-27980 September 2004	Cleco Power	Louisiana	PSC Staff	Purchase Power Contract
265.	U-27865 October 2004	Entergy Louisiana, Inc. Entergy Gulf States	Louisiana	PSC Staff	Purchase Power Contract
266.	RP04-155 December 2004	Northern Natural Gas Company	FERC	Municipal Distributors Group/Gas Task Force	Rate of Return
267.	U-27836 January 2005	Entergy Louisiana/ Gulf States	Louisiana	PSC Staff	Power plant Purchase and Cost Recovery
268.	U-199040 et al. February 2005	Entergy Gulf States/ Louisiana	Louisiana	PSC Staff	Global Settlement, Multiple rate proceedings
269.	EF03070532 March 2005	Public Service Electric & Gas	New Jersey	Ratepayers Advocate	Securitization of Deferred Costs
270.	05-0159 June 2005	Commonwealth Edison	Illinois	Department of Energy	POLR Service

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of Matthew I. Kahal

	Docket Number	Utility	Jurisdiction	Client	Subject
271.	U-28804 June 2005	Entergy Louisiana	Louisiana	LPSC Staff	QF Contract
272.	U-28805 June 2005	Entergy Gulf States	Louisiana	LPSC Staff	QF Contract
273.	05-0045-EI June 2005	Florida Power & Lt.	Florida	Federal Executive Agencies	Rate of Return
274.	9037 July 2005	Generic	Maryland	MD. Energy Administration	POLR Service
275.	U-28155 August 2005	Entergy Louisiana Entergy Gulf States	Louisiana	LPSC Staff	Independent Coordinator of Transmission Plan
276.	U-27866-A September 2005	Southwestern Electric Power Company	Louisiana	LPSC Staff	Purchase Power Contract
277.	U-28765 October 2005	Cleco Power LLC	Louisiana	LPSC Staff	Purchase Power Contract
278.	U-27469 October 2005	Entergy Louisiana Entergy Gulf States	Louisiana	LPSC Staff	Avoided Cost Methodology
279.	A-313200F007 October 2005	Sprint (United of PA)	Pennsylvania	Office of Consumer Advocate	Corporate Restructuring
280.	EM05020106 November 2005	Public Service Electric & Gas Company	New Jersey	Ratepayer Advocate	Merger Issues
281.	U-28765 December 2005	Cleco Power LLC	Louisiana	LPSC Staff	Plant Certification, Financing, Rate Plan
282.	U-29157 February 2006	Cleco Power LLC	Louisiana	LPSC Staff	Storm Damage Financing
283.	U-29204 March 2006	Entergy Louisiana Entergy Gulf States	Louisiana	LPSC Staff	Purchase power contracts
284.	A-310325F006 March 2006	Alltel	Pennsylvania	Office of Consumer Advocate	Merger, Corporate Restructuring
285.	9056 March 2006	Generic	Maryland	Maryland Energy Administration	Standard Offer Service Structure
286.	C2-99-1182 April 2006	American Electric Power Utilities	U. S. District Court Southern District, Ohio	U. S. Department of Justice	New Source Review Enforcement (expert report)

	Docket Number	Utility	Jurisdiction	Client	Subject
287.	EM05121058 April 2006	Atlantic City Electric	New Jersey	Ratepayer Advocate	Power plant Sale
288.	ER05121018 June 2006	Jersey Central Power & Light Company	New Jersey	Ratepayer Advocate	NUG Contracts Cost Recovery
289.	U-21496, Subdocket C June 2006	Cleco Power LLC	Louisiana	Commission Staff	Rate Stabilization Plan
290.	GR0510085 June 2006	Public Service Electric & Gas Company	New Jersey	Ratepayer Advocate	Rate of Return (gas services)
291.	R-000061366 July 2006	Metropolitan Ed. Company Penn. Electric Company	Pennsylvania	Office of Consumer Advocate	Rate of Return
292.	9064 September 2006	Generic	Maryland	Energy Administration	Standard Offer Service
293.	U-29599 September 2006	Cleco Power LLC	Louisiana	Commission Staff	Purchase Power Contracts
294.	WR06030257 September 2006	New Jersey American Water Company	New Jersey	Rate Counsel	Rate of Return
295.	U-27866/U-29702 October 2006	Southwestern Electric Power Company	Louisiana	Commission Staff	Purchase Power/Power Plant Certification
296.	9063 October 2006	Generic	Maryland	Energy Administration Department of Natural Resources	Generation Supply Policies
297.	EM06090638 November 2006	Atlantic City Electric	New Jersey	Rate Counsel	Power Plant Sale
298.	C-2000065942 November 2006	Pike County Light & Power	Pennsylvania	Consumer Advocate	Generation Supply Service
299.	ER06060483 November 2006	Rockland Electric Company	New Jersey	Rate Counsel	Rate of Return
300.	A-110150F0035 December 2006	Duquesne Light Company	Pennsylvania	Consumer Advocate	Merger Issues
301.	U-29203, Phase II January 2007	Entergy Gulf States Entergy Louisiana	Louisiana	Commission Staff	Storm Damage Cost Allocation
302.	06-11022 February 2007	Nevada Power Company	Nevada	U.S. Dept. of Energy	Rate of Return

	Docket Number	Utility	Jurisdiction	Client	Subject
303.	U-29526 March 2007	Cleco Power	Louisiana	Commission Staff	Affiliate Transactions
304.	P-00072245 March 2007	Pike County Light & Power	Pennsylvania	Consumer Advocate	Provider of Last Resort Service
305.	P-00072247 March 2007	Duquesne Light Company	Pennsylvania	Consumer Advocate	Provider of Last Resort Service
306.	EM07010026 May 2007	Jersey Central Power & Light Company	New Jersey	Rate Counsel	Power Plant Sale
307.	U-30050 June 2007	Entergy Louisiana Entergy Gulf States	Louisiana	Commission Staff	Purchase Power Contract
308.	U-29956 June 2007	Entergy Louisiana	Louisiana	Commission Staff	Black Start Unit
309.	U-29702 June 2007	Southwestern Electric Power Company	Louisiana	Commission Staff	Power Plant Certification
310.	U-29955 July 2007	Entergy Louisiana Entergy Gulf States	Louisiana	Commission Staff	Purchase Power Contracts
311.	2007-67 July 2007	FairPoint Communications	Maine	Office of Public Advocate	Merger Financial Issues
312.	P-00072259 July 2007	Metropolitan Edison Co.	Pennsylvania	Office of Consumer Advocate	Purchase Power Contract Restructuring
313.	EO07040278 September 2007	Public Service Electric & Gas	New Jersey	Rate Counsel	Solar Energy Program Financial Issues
314.	U-30192 September 2007	Entergy Louisiana	Louisiana	Commission Staff	Power Plant Certification Ratemaking, Financing
315.	9117 (Phase II) October 2007	Generic (Electric)	Maryland	Energy Administration	Standard Offer Service Reliability
316.	IPC-E-07-8 December 2007	Idaho Power Co.	Idaho	U.S. Department of Energy	Cost of Capital
317.	U-30422 (Phase I) January 2008	Entergy Gulf States	Louisiana	Commission Staff	Purchase Power Contract
318.	U-29702 (Phase II) February, 2008	Southwestern Electric Power Co.	Louisiana	Commission Staff	Power Plant Certification

	Docket Number	Utility	Jurisdiction	Client	Subject
319.	March 2008	Delmarva Power & Light	Delaware State Senate	Senate Committee	Wind Energy Economics
320.	U-30192 (Phase II) March 2008	Entergy Louisiana	Louisiana	Commission Staff	Cash CWIP Policy, Credit Ratings
321.	U-30422 (Phase II) April 2008	Entergy Gulf States - LA	Louisiana	Commission Staff	Power Plant Acquisition
322.	U-29955 (Phase II) April 2008	Entergy Gulf States - LA Entergy Louisiana	Louisiana	Commission Staff	Purchase Power Contract
323.	R-070110889 April 2008	New Jersey Natural Gas Co.	New Jersey	Rate Counsel	Cost of Capital

BEFORE THE STATE OF NEW JERSEY
OFFICE OF ADMINISTRATIVE LAW
BOARD OF PUBLIC UTILITIES

I/M/O THE PETITION OF NEW JERSEY NATURAL GAS COMPANY FOR APPROVAL OF AN INCREASE IN GAS RATES, DEPRECIATION RATES FOR GAS PROPERTY, AND FOR CHANGES IN THE TARIFF FOR GAS SERVICE, B.P.U. N.J., NO. 13 GAS PURSUANT TO N.J.S.A. 48:2-18, 48:2-21 AND 48:2-21.1	)))))))	**BPU DKT. NO. GR070110889** **OAL DKT. NO. PUC-12545-07**

SCHEDULES
ACCOMPANYING THE
TESTIMONY OF MATTHEW I. KAHAL

ON BEHALF OF THE

NEW JERSEY DEPARTMENT OF THE PUBLIC ADVOCATE
DIVISION OF RATE COUNSEL

RONALD K. CHEN
PUBLIC ADVOCATE OF NEW JERSEY

STEPHANIE A. BRAND, ESQ.
DIRECTOR, DIVISION OF RATE COUNSEL

31 Clinton Street, Eleventh Floor
P. O. Box 46005
Newark, New Jersey 07101

Filed: April 18, 2008

NEW JERSEY NATURAL GAS COMPANY

Rate of Return Summary
Estimated at April 30, 2008
(Provisional)

Capital Type	Balance (Thousands $)	% of Total	Cost Rate	Weighted Cost
Long-Term Debt[1]	$ 407,432	39.09%	5.26%	2.06%
Customer Deposits[1]	4,254	0.41	4.58	0.02
Short-Term Debt[2]	130,323	12.50	3.00	0.38
Common Equity[1]	500,300	48.00	9.50[3]	4.56
Total	$1,042,309	100.0%	--	7.02%

(1) Source: Exhibit PRM-1, Schedule 5, pages 9-11.
Long-term debt includes the meter lease, which reduces the embedded cost rate slightly from 5.30 to 5.26 percent.

(2) Based on the 12-months ending of actual and short-term debt in the response to RCR-ROR-8. The 3.0 percent cost rate approximates the upper end of the range in commercial paper rates as published by the Federal Reserve. See page 2 of this schedule.

(3) See Schedule MIK-4, page 1 of 4.

NEW JERSEY NATURAL GAS COMPANY

Updated Short-Term Debt Balances
April 2007 - April 2008
(Thousands $)

April 2007	$ 56,000
May	87,800
June	111,600
July	153,100
August	153,500
September	175,700
October	196,000
November	195,700
December	190,100
January	176,900
February	131,662
March	66,133
April	0
Average	$130,323

Source: RCR-ROR-8. February-April figures are company estimates.

NEW JERSEY NATURAL GAS COMPANY

U.S. Historic Trends in Capital Costs

	Annualized Inflation (CPI)	10-Year Treasury Yield	3-Month Treasury Yield	Single A Utility Yield
1992	3.0%	7.0%	3.5%	8.7%
1993	3.0	5.9	3.0	7.6
1994	2.6	7.1	4.3	8.3
1995	2.8	6.6	5.5	7.9
1996	3.0	6.4	5.0	7.8
1997	2.3	6.4	5.1	7.6
1998	1.6	5.3	4.8	7.0
1999	2.2	5.7	4.7	7.6
2000	3.4	6.0	5.9	8.2
2001	2.9	5.0	3.5	7.8
2002	1.6	4.6	1.6	7.4
2003	1.9	4.1	1.0	6.6
2004	2.7	4.3	1.4	6.2
2005	3.4	4.3	3.0	5.6
2006	2.5	4.8	4.8	6.1
2007	2.8	4.6	4.5	6.3

NEW JERSEY NATURAL GAS COMPANY

U.S. Historic Trends in Capital Costs (Continued)

	Annualized Inflation (CPI)	10-Year Treasury Yield	3-Month Treasury Yield	Single A Utility Yield
2002				
January	1.1%	5.0%	1.7%	7.7%
February	1.1	4.9	1.7	7.5
March	1.5	5.3	1.8	7.8
April	1.6	5.2	1.7	7.6
May	1.2	5.2	1.7	7.5
June	1.1	4.9	1.7	7.4
July	1.5	4.7	1.7	7.3
August	1.8	4.3	1.6	7.2
September	1.5	3.9	1.6	7.1
October	2.0	3.9	1.6	7.2
November	2.2	4.1	1.3	7.1
December	2.4	4.0	1.2	7.1
2003				
January	2.6%	4.1%	1.2%	7.1%
February	3.0	3.9	1.2	6.9
March	3.0	3.8	1.1	6.8
April	2.1	4.0	1.1	6.6
May	2.1	3.6	1.1	6.4
June	2.1	3.7	0.9	6.2
July	2.1	4.0	0.9	6.6
August	2.2	4.5	1.0	6.8
September	2.3	4.3	1.0	6.6
October	2.0	4.3	0.9	6.4
November	1.8	4.3	1.0	6.4
December	1.8	4.3	0.9	6.3
2004				
January	1.9%	4.2%	0.9%	6.2%
February	1.7	4.1	0.9	6.2
March	1.7	3.8	0.9	6.0
April	2.3	4.4	0.9	6.4
May	3.1	4.7	1.0	6.6
June	3.3	4.7	1.3	6.5
July	3.0	4.5	1.4	6.3
August	2.7	4.3	1.5	6.1
September	2.5	4.1	1.6	6.0
October	3.2	4.1	1.8	5.9
November	3.5	4.2	2.1	6.0
December	3.3	4.2	2.2	5.9

NEW JERSEY NATURAL GAS COMPANY

U.S. Historic Trends in Capital Costs (Continued)

	Annualized Inflation (CPI)	10-Year Treasury Yield	3-Month Treasury Yield	Single A Utility Yield
2005				
January	3.0%	4.2%	2.4%	5.8%
February	3.0	4.2	2.6	5.6
March	3.1	4.5	2.8	5.8
April	3.5	4.3	2.8	5.6
May	2.8	4.1	2.9	5.5
June	2.5	4.0	3.0	5.4
July	3.2	4.2	3.3	5.5
August	3.6	4.3	3.5	5.5
September.	4.7	4.2	3.5	5.5
October	4.3	4.5	3.8	5.8
November	3.5	4.5	4.0	5.9
December	3.4	4.5	4.0	5.8
2006				
January	4.0%	4.4%	4.3%	5.8%
February	3.6	4.6	4.5	5.8
March	3.4	4.7	4.6	6.0
April	3.5	5.0	4.7	6.3
May	4.2	5.1	4.8	6.4
June	4.3	5.1	4.9	6.4
July	4.1	5.1	5.1	6.4
August	3.8	4.9	5.1	6.2
September	2.1	4.7	4.9	6.0
October	3.5	4.7	5.1	6.0
November	2.5	4.6	5.1	5.8
December	2.5	4.6	5.0	5.8

NEW JERSEY NATURAL GAS COMPANY

U.S. Historic Trends in Capital Costs (Continued)

	Annualized Inflation (CPI)	10-Year Treasury Yield	3-Month Treasury Yield	Single A Utility Yield
2007				
January	2.1%	4.8%	5.1%	6.0%
February	2.4	4.7	5.2	5.9
March	2.8	4.6	5.1	5.9
April	2.6	4.7	5.0	6.0
May	2.7	4.8	5.0	6.0
June	2.7	5.1	5.0	6.3
July	2.4	5.0	5.0	6.3
August	2.0	4.7	4.3	6.2
September	2.8	4.5	4.0	6.2
October	3.5	4.5	4.0	6.1
November	4.3	4.2	3.4	6.0
December	4.1	4.1	3.1	6.2
2008				
January	4.3%	3.7%	2.8%	6.0%
February	4.0	3.7	2.2	6.2
March	4.0	3.5	1.3	--

Source: *Economic Report of the President, Mergent's Bond Record, Federal Reserve Statistical Release, Consumer Price Index Summary*

NEW JERSEY NATURAL GAS COMPANY

Listing of the Comparable Gas Utility Companies

	Company	Safety Rating	Financial Strength	Beta	2007 Common Equity Ratio*
(1)	AGL Resources	2	B++	0.85	49.8%
(2)	Atmos Energy	2	B+	0.85	48.0
(3)	LaClede Group	2	B+	0.90	54.6
(4)	New Jersey Resources	1	A	0.85	62.7
(5)	Nicor, Inc.	3	A	1.00	70.0
(6)	NW Natural Gas	1	A	0.80	53.7
(7)	Piedmont Natural	2	B++	0.85	51.6
(8)	South Jersey Ind.	2	B++	0.80	57.3
(9)	Southwest Gas	3	B	0.90	41.9
(10)	UGI Corp.	2	B+	0.90	39.3
(11)	WGL Corp.	1	A	0.85	60.3
	Average	**1.9**	**--**	**0.87**	**53.6%**
	Average of Mr. Moul's Group	**1.6**	**--**	**0.84**	**54.8%**

* The common equity ratio excludes short-term debt (and current maturities of long-term debt). Inclusive of total debt, the common equity ratio averages 45.3 percent, and for Mr. Moul's group, it averages 47.3 percent.

Source: *Value Line Investment Survey*, March 14, 2008

NEW JERSEY NATURAL GAS COMPANY

Calculations of 2007 Capital Structure
for the Proxy Gas Distribution Companies
Using Value Line Data
(millions $)

Company	Total Debt	Preferred Stock	Common Equity	Total Capital	Common Equity Ratio
AGL Resources	$2,254	$ --	$1,661	$3,915	42.4%
Atmos	2,331	--	1,966	4,297	45.8
LaClede	650	1	428	1,079	39.7
New Jersey	683	--	645	1,328	48.6
NICOR	867	1	922	1,790	51.5
Northwest	660	--	595	1,255	47.4
Piedmont	1,020	--	878	1,898	46.3
South Jersey	476	--	481	957	50.3
Southwest Gas	1,413	--	983	2,396	41.0
UGI	2,401	--	1,322	3,723	35.5
WGI	941	28	981	1,950	50.3
Average					45.3%
Average for Moul's Group					47.3%

Source: *Value Line Investment* Survey, March 14, 2008.

NEW JERSEY NATURAL GAS COMPANY

DCF Summary for
Gas Distribution Proxy Group

(1)	Dividend yield (October 2007 - March 2008)	3.84%[(1)]
(2)	Adjusted yield ((1) x 1.025)	4.0%
(3)	Long-term Growth Rate	5.0-5.5[(2)]
(4)	Total Return ((2) + (3))	9.0 - 9.5%
(5)	Flotation Adjustment	0.00%
(6)	Cost of equity ((4) + (5))	9.25%
Recommendation		**9.5%**

[(1)]Schedule MIK-4, page 2 of 4

[(2)]Schedule MIK-4, page 3 of 4

NEW JERSEY NATURAL GAS COMPANY

Dividend Yields for Gas Distribution Proxy Group
(October 2007 – March 2008)

	Company	October	November	December	January	February	March	Average
(1)	AGL Resources	4.1%	4.4%	4.4%	4.3%	4.8%	4.9%	4.48%
(2)	Atmos	4.6	5.0	4.6	4.5	5.0	5.1	4.80
(3)	LaClede	4.2	4.4	4.4	4.4	4.4	4.2	4.33
(4)	NICOR	4.3	4.4	4.4	4.5	5.5	5.7	4.80
(5)	New Jersey Res.	3.1	3.2	3.2	3.6	3.7	3.7	3.42
(6)	Northwest Nat.	3.1	3.1	3.1	3.2	3.6	3.5	3.27
(7)	Piedmont	3.9	3.8	3.8	4.0	4.1	4.0	3.93
(8)	South Jersey	2.9	2.9	3.0	3.1	3.2	3.1	3.03
(9)	Southwest Gas	2.9	3.0	2.9	3.0	3.5	3.3	3.10
(10)	UGI	2.8	2.8	2.7	2.8	2.9	3.0	2.83
(11)	WGL	4.0	4.1	4.2	4.2	4.4	4.5	4.23
	Average	**3.63%**	**3.74%**	**3.70%**	**3.78%**	**4.10%**	**4.09%**	**3.84%**
	Moul Subgroup Average	**3.67%**	**3.79%**	**3.76%**	**3.84%**	**4.11%**	**4.11%**	**3.88%**

Source: S&P *Stock Guide*, November 2007 – March 2008 issues. March yields are based on month-ending dividend yields as published on yahoofinance.com web site.

NEW JERSEY NATURAL GAS COMPANY

Projection of Earnings Per Share
Five-Year Growth Rates for the
Gas Distribution Proxy Group

Company	Value Line	First Call	Zacks	CNN	Average
AGL Resources	3.5%	5.25	4.8%	5%	4.64%
Atmos	4.5	4.62	4.6	5	4.68
LaClede	3.5	3.5	--	--	3.5
New Jersey	6.0	5.5	5.5	5	5.5
NICOR	4.0	4.0	4.0	--	4.0
Northwest	7.0	4.9	5.3	5	5.55
Piedmont	5.0	5.18	5.4	5	5.14
SJI	7.5	6.63	7.5	7	7.16
Southwest	7.5	5.67	6.0	6	6.29
UGI	7.0	8.0	8.0	6	7.25
WGL	3.5	4.0	4.0	4	3.88
Average	**5.36%**	**5.20%**	**5.51%**	**5.3%**	**5.24%**
Moul Subgroup	**5.24%**	**5.15%**	**5.30%**	**5.1%**	**5.22%**

Sources: Value Line Investment Survey, March 14, 2008. First Call is from Yahoo Finance website (March 2008) and Zacks is from MSN Money website (March 2008). In addition, the CNN figures are from the CNNfn web site (March 2008).

NEW JERSEY NATURAL GAS COMPANY

Other Value Line Measure of
Growth for the Gas Distribution
Proxy Group

Company	Dividend Per Share	Book Value Per Share	Earnings Retention
AGL Resources	4.0%	1.5%	6.5%
Atmos	2.0	3.5	4.0
LaClede	2.5	5.0	4.5
New Jersey	6.0	9.0	5.0
NICOR	0.5	4.0	5.5
Northwest	5.5	3.5	5.0
Piedmont	4.0	3.5	4.0
SJI	5.5	5.0	8.5
Southwest	4.0	3.5	6.0
UGI	8.0	11.0	8.5
WGL	2.5	5.0	4.0
Average	**4.04%**	**4.68%**	**5.59%**
Moul Subgroup	**4.21%**	**4.43%**	**5.29%**

Source: Value Line Investment Survey, March 14, 2008. The earnings retention figures are projections for 2011-2013.

NEW JERSEY NATURAL GAS COMPANY

Capital Asset Pricing Model Study
Illustrative Calculations

A. Model Specification

$K_e = R_F + \beta\ (R_m - R_F)$, where

K_e = cost of equity

R_F = return on risk free asset

Rm = expected stock market return

B. Data Inputs

R_F = 4.5% (20-year Treasury bond yield for the most recent six months)

Rm = 10-12% (equates to equity risk premium of 5.5-7.5%)

Beta = 0.75-0.85 (Source: page 2 of this schedule)

C. Model Calculations

Low end: K_e = 4.5% + 0.75 (10.0 - 4.5) = 8.62%

Midpoint: K_e = 4.5% + 0.80 (11.0-4.5) = 9.70%

Upper end: K_e = 4.5% + 0.85 (12.0-4.5) = 10.88%

NEW JERSEY NATURAL GAS COMPANY

Beta Statistics for the
Gas Distribution Proxy Group

Company	Value Line	Yahoo Finance	MSN Money	Average
AGL Resources	0.85	0.45	0.47	0.59%
Atmos	0.85	0.73	0.75	0.78
LaClede	0.90	0.83	0.74	0.82
New Jersey Res.	0.85	0.62	0.59	0.69
NICOR	1.00	0.9	0.90	0.94
Northwest Natural	0.85	0.89	0.74	0.81
Piedmont	0.85	0.58	0.54	0.66
SJI	0.80	0.65	0.70	0.72
Southwest	0.90	0.75	0.49	0.71
UGI	0.90	0.69	0.71	0.77
WGL	0.85	0.9	0.68	0.81
Average	**0.87**	**0.73**	**0.66**	**0.75**
Moul Subgroup	**0.84**	**0.69**	**0.64**	**0.72**

Source: *Value Line Investment Survey*, March 14, 2008, YahooFinance.com and MSNMoney.com, March 2008.