NEW YORK PUBLIC SERVICE COMMISSION

ELECTRIC CASE 06-E-1433

ORANGE AND ROCKLAND UTILITIES, INC.

VOLUME 4

REBUTTAL TESTIMONY AND EXHIBITS

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Case No. 06-E-1433

ORANGE AND ROCKLAND UTILITIES, INC.
REBUTTAL TESTIMONY
L. MARIO DIVALENTINO

Q. Please state your name and business address.

A. My name is L. Mario DiValentino and my business address is 6 Moonstone Rd., New Paltz, NY 12561.

Q. By whom are you employed?

A. I am the President of Moonstone Consulting LLC.

Q. Please briefly describe your educational background.

A. I graduated from Pace College in 1972 with a Bachelor of Business Administration degree, having majored in Accounting.

Q. Please briefly describe your business experience.

A. After graduation from Pace, I joined Orange and Rockland Utilities, Inc. ("Orange and Rockland" or the "Company") a multi-jurisdictional combination utility in New York, and was with the Company for 22 years. In 1994, I became affiliated with the Industry Analysis Group of AUS Consultants. In 1995, I co-founded Strategic Energy Management, Inc. a predecessor of Strategic Power Management, Inc. In 2005, I founded Moonstone Consulting LLC. Since leaving Orange and Rockland, I have provided consulting services to commercial and industrial customers, governmental authorities, and building owners, as well as gas and electric utilities.

Q. Have you previously testified before regulatory commissions?

A. Yes, I have presented testimony before regulatory agencies in New York, New Jersey, Pennsylvania, and Hawaii as well as before the Federal Energy Regulatory Commission ("FERC"). The subjects of my testimony are shown in Attachment A.

Q. What is the purpose of your testimony?

A. I will present a framework by which Orange and Rockland can comply with the Public Service Commission's ("Commission") requirement, set forth in its Order Requiring Proposals for Revenue Decoupling Mechanisms ("Order"), issued April 20, 2007 in Case 03-E-0640, that utilities develop proposals for a revenue decoupling mechanism ("RDM").

Q. What did the Order require?

A. The Order required that all major utilities, including Orange and Rockland, develop proposals for an RDM for consideration in the context of their next base rate cases.

Q. This proceeding is not a base rate case. Why would Orange and Rockland submit an RDM proposal in this proceeding?

A. Staff, through the testimony of Staff witnesses Randt and Rieder (at 7-9), has proposed that the Company submit an RDM proposal for consideration by Staff and the other parties in a supplemental phase of this proceeding. Orange and Rockland shares the Commission's goals of encouraging cost effective energy

efficiency efforts and is willing to accelerate the consideration of an RDM for the Company. The ratemaking framework for the implementation of an RDM plainly is critical to its success. Since Orange and Rockland continues to support the adoption of a multi year rate plan in this proceeding, it wishes to expedite parties' exploration and consideration of an RDM in the current phase of this proceeding.

Q. Why initiate consideration now?

A. Orange and Rockland, Staff, and all other interested parties must understand the "rules of the road" under an RDM regime. An RDM is much more than simply a reconciliation of actual revenues to forecasted revenues. Energy efficiency programs and measurement metrics must be clearly defined, a multi year plan must be established, and cost recovery components must be determined. In addition, the annual true-up mechanism filing procedures must be established.

Q. What is the objective of the RDM that you are proposing for Orange and Rockland?

A. As noted in the Order, an RDM's critical objective is to eliminate a utility's disincentive to promote cost effective efficiency measures. In addition, an RDM allows for the establishment of meaningful performance based incentives so as to focus utility resources on achieving a Commission approved energy efficiency program. Such incentives also serve to align investor and consumer interests. Revenue reconciliation is combined with O&M expense and rate base attrition

adjustment procedures, establishing productivity gains and cost control as keys to profitability.

Q. Please describe the energy efficiency component of the proposed RDM.

A. The framework that the Company proposes for the energy efficiency component of its RDM proposal is as follows:

- Demand side management programs and other energy efficiency efforts must have defined measurement metrics;
- Incentive targets should be defined upfront;
- The program term should be a minimum of three years;
- Yearly targets should be established for each measure and the shortfall or excess over yearly targets can be carried forward into a subsequent year;
- Cumulative measures will be used for the total program period;
- The Company will be permitted to earn up to 100 basis points on equity or 20% of net resource savings if yearly targets are met and 30% of net resource savings to the extent yearly targets are exceeded;
- If the Company exceeds the cumulative three year targets it will be permitted to earn up to an additional 50 basis points, prorated for exceeding the three year target by up to 25% or more (e.g., 50 basis

points for exceeding the target by 25%, 20 basis points for exceeding the target by 10%); and

- Program achievement shall be reported to the Commission and other interested parties within 60 days of the end of the program year.

Energy efficiency efforts under an RDM regime require predetermined measurable metrics that are agreed upon in advance of the RDM program year. The incentive component of the RDM also must be known so the Company understands the amount of additional earnings it can achieve. Certainty of measurement metrics and incentives are paramount in an RDM and must be known and understood by all parties for the implementation of successful pro-active energy efficiency efforts. The program period should be of sufficient length to provide for design, installation and customer education efforts.

Q. Please describe the cost recovery component of the Company's proposed RDM.

A. The cost attrition adjustments included in the proposed RDM are as follows:

- Market Supply Charge and Energy Cost Adjustment will continue;
- The Company will reconcile actual revenues to forecasted revenues by customer class, recognizing, however, that since warmer than normal weather causes incremental costs that are not captured by the RDM cost recovery components, the Company will be permitted to retain warmer than normal weather related sales;

- Wage increases on base rate payroll, net of productivity, will be reconciled to actual wage rates (union and management);
- Actual payroll tax expense will be reconciled to the amount allowed in rates:
- Property taxes will be reconciled;
- Medical, Property & Liability Insurance will be reconciled;
- Regulatory Fees (i.e., FERC and Commission) will be reconciled;
- Amortizations continue for:
  - R&D;
  - Pension;
  - OPEBS;
  - Environmental remediation (e.g., MGPs); and
  - Prior Period Amortizations.

Any expiring amortization during the RDM period will continue and be used to accelerate the write off of other prior period costs not fully amortized. Recognizing the Commission's concerns associated with growing deferral amounts and the Company's concern of the impact of deferrals on its cash position, if at the time of the annual RDM filing any deferral exceeds the base year amounts by more than 5%, the excess amount shall be recovered in rates via an amortization no longer than

three years. This will provide for rate stability and minimize rate volatility.

- All other O&M included in base rates shall be subject to an inflation adjustment;
- Deprecation expense will be updated;
- Rate Base will be updated (i.e., net utility plant in service net of deferred income taxes); and
- Capital structure and costs will be updated.

Q. How would any RDM adjustment be reflected in rates?

A. The Company proposes that within a specified time period (e.g., 60 days) after the conclusion of each rate year of a multi year rate plan, the Company will make a filing setting forth the results of the RDM program year. This would include the energy efficiency costs and incentives, plus the net of the cost recovery components described above. Billing to customers for the net adjustment would commence 30 days later. This procedure would be repeated annually.

Q. Has the Commission approved an RDM similar to the one you are proposing in your testimony?

A. Yes, in Case 89-E-175 the Commission approved an RDM for Orange and Rockland that is similar to my proposal.

Q. Do you believe that your proposed RDM is responsive to the Commission request?

A. Yes, defining an RDM framework is the first step towards the implementation of a successful RDM. The Company proposes to finalize the details of this RDM framework in conjunction with designing and implementing cost effective energy efficiency programs.

Q. Does that conclude your testimony?

A. Yes, it does.

L. Mario DiValentino
Testimony Presented Before Regulatory Agencies

New York Public Service Commission

Case Numbers Date Filed	28278/28279 July 1982	29046/29047 March 1985	88-G-011 January 1988	89-E-175 August 1989	91-G-0128 January 1991	92-G-0050 January 1992	93-E-0082 January 1993	00-E-127
Subject Matter of Testimony:								
Historical Financial Statements	√							
Executive Compensation Presentation			√		√	√	√	
Management Audit Recommendations					√			
Operating Expenses:								
Conservation Programs		√						
O&M Costs Subject to Inflation Updating			√	√		√	√	
Direct Labor					√	√		
Health & Life Insurance					√			
Rents						√		
Environmental Tax Increases							√	
Power Plant Maintenance Reserve Acctng				√			√	
Gas Turbine Maintenance Reserve Acctng				√			√	
Purchased Capacity Costs				√			√	
Purchased Gas Costs					√			
Property Taxes		√	√	√			√	
Rate Base Issues:								
Construction Expenditures						√		
Working Capital Requirements		√	√	√			√	
Lovett Coal Conversion		√						
Earnings Base/Capitalization Adjustment		√	√	√			√	
Staged Filing Proposals		√	√	√				
Electric RDM Proposal							√	
Gas RDM Proposal					√	√		
Performance Incentives						√	√	
Retail Access								√
Inter Departmental Cost Allocation								√
Cost Allocation								√

L. Mario DiValentino
Testimony Presented Before Regulatory Agencies

New Jersey Board of Public Utilities

Case Numbers Date Filed	827-612 July 1982	839-790 Sept. 1983	ER85-032890 March 1985	ER86-09973 Sept. 1986	ER87-101189 February 1988	ER91-030356 March 1991
Subject Matter of Testimony						
Historical Financial Statements	√	√				
Operating Expenses:						
Conservation Programs		√				
Property Taxes			√			√
Rate Case Costs			√			√
Purchased Capacity Costs						√
Service Reliability						√
Rents						√
Interest on Customer Deposits						√
Stony Point/Transco Surcharges			√			
Consolidated Tax Benefits			√			
Rate Base Issues:						
Lovett Coal Conversion/Rio Penstock				√		
Staged Filing Proposals			√			√
Tax Reform Act of 1986 Issues				√	√	
SFAS 87 Rate Impacts				√		
Return on Common Equity				√		

Federal Energy Regulatory Commission

Case Numbers Date Filed	ER82-565/566 1982	EL87-53 1987	ER89-73/74 1989	ER93-328/329 January 1993
Subject Matter of Testimony:				
Historical Financial Statements	√		√	
Present and Proposed Power Supply Agreements	√		√	
FERC Return on Equity		√		√
Tax Reform Act of 1986 Issues			√	

L. Mario DiValentino
Testimony Presented Before Regulatory Agencies

Pennsylvania Public Utility Commission

Case Numbers Date Filed	R-821856/7 January 1982	R-832325 March 1983	R-870772 August 1987	R-891530/1 November 1989	R-922516/8 November 1992
Subject Matter of Testimony:					
Historical Financial Statements	√	√		√	√
Cost of Service Exhibit	√	√	√	√	√
Rate Base Exhibit	√		√	√	√
Unbilled Revenue	√				
Operating Expenses:					
Conservation Programs				√	
Wages	√	√	√	√	√
SFAS 106 (OPEB)					√
Tree Trimming Expenses		√			
Delaware River Flood	√				
Postage	√				
Health & Life Insurance		√	√	√	√
Purchased Power and Gas Costs	√		√	√	√
Rate Case Costs		√	√		
Rents				√	√
Federal Income Taxes				√	√
Payroll Taxes	√	√	√	√	√
Capital Stock Tax			√	√	√
Rate Base Issues:					
Lovett Coal Conversion/Rio Penstock			√		
FERC Return on Common Equity		√			
Tax Reform Act of 1986 Issues			√		

Public Service Commission of Hawaii

Rate Moderation Plan	Docket 94-0307

BINDING PRODUCTS

ORANGE AND ROCKLAND UTILITIES, INC.
REBUTTAL TESTIMONY OF
RICHARD A. KANE

NYPSC CASE No. 06-E-1433

Q. Please state your name and business address.

A. Richard A. Kane, 4 Irving Place, New York, New York 10003.

Q. Have you previously testified in this proceeding?

A. Yes, I previously submitted direct and supplemental testimony in this proceeding on behalf of Orange and Rockland Utilities, Inc. ("Orange and Rockland," "O&R," or "the Company").

Q What is the purpose of your rebuttal testimony?

A. I will respond to certain adjustments and proposals presented in the direct testimony of several Department of Public Service Staff witnesses:

a) With regard to the testimony of Staff witness Robert Burke I will address adjustments he has proposed to the Company cost of service calculation in the following areas:

a. Other Operating Revenues ;

b.1% Productivity Adjustment;

c. Employee and Other Insurance Costs;

d.Netti ng of Deferred Assets & Liabilities;

e. Interest for deferred 263A tax benefits; and

f. The earnings threshold during the temporary rate period.

b) With regards to the testimony of Staff witness Martin Insogna I will address the following areas:

a. Proposed increases in low income subsidies; and

b.Pr oposed increases to customer service performance penalties.

c) In my discussion of customer service performance penalties I will also address the proposed increases in penalties for SAIFI and CAIDI submitted by Staff witness Jason Pause.

Other Operating Revenues

Q. On page 31, lines 8-13 of his direct testimony, Staff witness Burke indicated that he utilized the Company's forecast of Joint Use Rents in his revenue requirement calculation. How did the Company develop its forecast for these revenues?

A. The Company calculated its forecast of Joint Use Rents to be billed to its utility affiliates Rockland Electric Company and Pike County Light & Power Company based on current actual data. The cost of capital from the Company's expired rate plan (Case 03-E-0797) was applied to the average net plant balance. To the extent that Staff witness Henry is now recommending an allowed return on equity of 8.95%, it is necessary to revise this calculation to reflect the amounts to be billed under permanent rates. An adjustment would also be required for the power supply billing included in the filing.

Q. Have you quantified the impact of adjusting the Joint Use Rents and Power Supply Billing for the return on equity recommend by Staff witness Henry?

A. Yes. Exhibit __ (E-18) shows the revenue impact of changing the return on equity reflected in the current joint operating rents and power supply billing to the return on equity recommended by Staff witness Henry of 8.95%.

1% Productivity Adjustment

Q. Staff witness Burke states (page 13, lines 8-19) in his direct testimony, that it is the "Commission's usual practice is to apply a 1% productivity adjustment to a broader base than that used by the Company (i.e., 1% of labor costs, fringe benefits and payroll taxes)." Are you aware of any Public Service Commission ("Commission") Policy, Directive or Order regarding either the imputation of a 1% productivity adjustment or the manner in which the adjustment would be calculated?

A. No. I am not aware of any formal Policy, Directive or Order issued by the Commission (or any statute or regulation) that requires a 1% productivity adjustment be imputed in every base rate filing or describes the method for calculating such an adjustment. I would agree that in my experience over the last 30 years, most rate cases in New York have included a 1% productivity adjustment as a means of capturing potential increases in operating efficiencies due to the implementation of new technology, changes in work practices, or by other means. This method is flawed, however, because it does not allow utilities to recover all of the prudent normal recurring operating expenses incurred to provide service. Productivity adjustments foster an environment where utilities may seek to reduce spending on programs that, while not essential to the rendition of service, may still impact the quality of service that a customer may receive. Examples might take the form of reduced spending for pubic outreach or other public programs when necessary funding is not available due to reductions imputed by Staff. As Staff witness Insogna points

out in his direct testimony (page 6, lines 4 - 6), customer service staffing levels for many utilities in the State have been reduced over the last several years. This is exactly the type of result that may happen when utilities are required to reduce their actual payroll cost in an effort to impute arbitrary "productivity savings" targets. I would add that I have not seen a formal methodology adopted by the Commission to calculate the productivity adjustment. I strongly disagree with Mr. Burke's premise that the 1% productivity adjustment must be expanded to include fringe benefits in the calculation of this adjustment. First, unless Mr. Burke is advocating that the Company reduce its staffing levels, employee health insurance and pension costs will not diminish as a result of a reduction in payroll expense. Health insurance is dependent on the number of employees and pension costs are dependent on employees' base payroll. The productivity reductions, if possible, generally would be accomplished through reductions in overtime due to changes in work practices, through the reduced use of outside contractors, through the implementation of new technology, or by other means.

Q. Do you have other concerns regarding the imputation of the 1% productivity adjustment?

A. The Company's workload has been increasing significantly over the last several years with continued load growth. Despite this situation, the Company has held the line on staffing. The Commission has increased its oversight and is proposing numerous new regulations and standards that the Company must comply with. The cost of this additional regulatory oversight has increased the

Company's annual regulatory assessments by approximately 50% in just the last three years going from roughly $900,000 in calendar year 2004 to approximately $1.35 million this year. It is completely inconsistent that Staff is advocating payroll and other workforce reductions (i.e., through the use of the productivity adjustment and the elimination of payroll for new linemen already hired and trained by the Company), while adding additional regulatory oversight as well as proposing increasingly tougher performance goals along with significantly higher penalties on the Company.

Employee and Other Insurance Costs

Q. In his direct testimony (page 15, lines 1-9), Staff witness Burke discusses the elimination of workers compensation expense of former electric production employees in the amount of $215,000 (i.e., workers compensation expense of $324,000 less capitalized and recovered costs of $109,000), stating that this amount should be offset against the reserve which was established for the sale of electric generation. Do you agree with the adjustment proposed by Mr. Burke? If not, please explain why.

A. I do not agree with Mr. Burke's recommended adjustment for two reasons. First, the amounts paid for asbestos claims of former electric production employees has exceeded the amounts set aside as part of the divestiture by approximately $450,000 as of December 31, 2006. Second, the ongoing payments applicable to New York operations over the last five years have averaged approximately $400,000 per year and should be reflected in rates.

Q. How would you recommend the Company recover the shortfall in funding and ongoing asbestos claim expense for this item going forward?

A. The rate allowance should reflect the recovery of the December 31, 2006 deficit of $450,000 either by offsetting this balance against available credits or by providing for an amortization of these costs in base rates. Going forward the rate allowance should include an additional $265,000 to cover the cost of former generation employees (workers compensation expense of $400,000 less capitalized and recovered costs of $135,000).

Netting of Deferred Assets & Liabilities

Q. In his direct testimony (page 29, lines 9-15), Staff witness Burke discusses the netting of $16.198 million of available credits against deferred costs and leaving a residual balance of $14.691 million to mitigate remaining deferred charges in the future. Do you agree with this approach?

A. To a limited degree. Mr. Burke's direct testimony (page 29, line 1-9) states that he reduced one fifth of certain deferrals without any explanation for his reason to eliminate only this amount. The Company's approach in its initial and supplemental filings was to utilize all available credits to offset all deferrals to the extent practical. There is no basis for only eliminating a percentage of certain deferrals if credits are available. The Company believes that all credits available as of December 31, 2006 should have been applied. Mr. Burke's proposal would leave an unapplied credit balance of $14.691 million ($30.282 million less $15.591 million) as discussed on page 29, lines 13 - 15, of his testimony.

Interest for Deferred 263A Tax Benefits

Q. In his direct testimony (page 25, line 19), Mr. Burke indicates that the Company should not be entitled to be reimbursed for interest paid to the Treasury Department related to the Company's Section 263A tax deduction. He expresses the view that since the Company retained the full benefit of this tax deduction it should therefore be solely responsible to pay for the interest. Do you agree that the Company retained all benefits related to the 263A tax deduction?

A. No. The annual earnings tests filed by the Company with the Commission demonstrate that customers have received benefits from the 263A tax deduction. These filings show the 263A tax benefits reflected as a rate base reduction. Exhibit __ (E-19) is a copy of the cumulative earnings test filed by the Company for the rate years ending June 30, 2004, June 30, 2005 and June 30, 2006. The rate base reductions resulting from 263A tax benefits, as shown on page 3 of 7 of this Exhibit, were $11,460,000, $14,629,000 and $13,981,000 respectively for each of the rate years. The earnings associated with these rate base reductions amounted to $1,852,000, of which customers' share was $926,000. I would further note that there is also an associated reduction in state income taxes related to the 263A deduction that was also passed back to customers.

Q. In his direct testimony (page 26, lines 7-14), Staff witness Burke acknowledges that the treatment of 263A Overheads was not specifically addressed in the Joint Proposal in Case 03-E-0797. He goes on to indicate that

since the Company can not document that this benefit is included it should therefore be assumed that customers never received any benefit from the 263A tax deduction in the Rate Plan. Do you agree with this position?

A. No. As I indicated previously this benefit was reflected in the Company's annual earnings tests. With regards to the Joint Proposal, this agreement was the result of a settlement reached by the Company, Staff, and other parties. It constitutes a "black box" settlement (i.e., specific revenue, plant and expense adjustments were not shown or displayed in the final document). Black box settlements are subject to interpretation by the respective parties as to whether specific adjustments are included and as to what return on equity and capital structure is reflected in the final settlement. It is therefore impossible to state definitively, without agreement of all parties, whether specific adjustments have been reflected or not. I would note however, that the Company first deducted 263A Overheads on its 2002 tax return. To the extent cash was actually received, it would have been included either in the earnings base capitalization adjustment or as part of deferred income taxes in the calculation underlying the revenue requirement used in the development of this agreement.

Temporary Rate Period - Earnings Threshold

Q. In your supplemental direct testimony (page 11, line 11), you discussed the need to add 100 basis points to the earnings threshold that is to be established for the period of time that temporary rates are in effect in order to compensate the Company for the risks of operating under the uncertainty of temporary rates. Did Staff witness Burke address this proposal?

A. The response put forth by Staff witness Burke in his direct testimony (page 37, lines 2-4) on this matter is unclear. He states the following: "I note that the actual income will fully quantify those risks (i.e., the risk of operating under temporary rates), for the four months that temporary rates are effective." Mr. Burke does not explain how actual income quantifies the risks for establishing a forward looking earnings threshold target. Furthermore, it is unclear whether he recommends that all of the Company's earnings achieved above Mr. Henry's recommended return on equity of 8.95% be deferred solely for customers or shared (and if so, on what basis). The Company has submitted a data request to Staff witness Burke asking him to clarify whether he would recommend that any earnings above their recommended return on equity be retained solely by customers or shared with the Company during the temporary rate period. Due to time limitations, Staff's response was not received in time to be included in this testimony.

Q. Does Orange and Rockland face additional risk beyond the risks it otherwise faces as a result of operating in the period during which temporary rates are in effect?

A. Yes, in several respects. To begin with, the Commission's scope of review in this proceeding, as I understand it, is of all electric revenues realized by the Company in the period in which temporary rates are in effect. This means the Company is not afforded in this period the important investor protection against retroactive ratemaking that is uniform throughout the utility industry in America for utilities operating under permanent rates. The consequence of

operating under temporary rates is that the Commission has the ability to retroactively review the Company's business decisions during the period. In short, without protection against retroactive ratemaking investors have no certainty of earnings and are subject to retrospective hindsight-laden reviews regarding operating decisions.

Q. What are you recommending?

A. I believe the Commission's determination of the cost of equity covering the period in which temporary rates are in effect ought to be different than the Commission's cost of equity determination for the period in which permanent rates are to be in effect. I believe the cost of equity for the period in which temporary rates are in effect ought to be at least 100 basis points higher.

Q. Please continue.

A. I want to point out another substantial risk to Orange and Rockland in the temporary phase of this proceeding, a risk that is implicit in the testimony of Staff in this proceeding. The Staff testimony identifies a barebones cost of common equity and implicitly assumes that the barebones level ought to be a "cap" on the Company's earnings in the temporary rate period. This is wholly contrary to the precept of incentive ratemaking in that the Company has, by all accounts, continued to operate its business efficiently during the temporary rate period in the good faith expectation that it would be treated fairly by the Commission. Yet the Staff testimony gives no recognition to any "earnings deadband" that the Company ought to be allowed to retain above the "barebones" cost of equity, nor does the Staff testimony indicate a willingness

to consider any semblance of reward to the Company for having conducted its business efficiently and responsibly in this difficult period.

Q. What remedy would you recommend to address this deficiency?

A. At a minimum, the Commission should authorize a "deadband" above the barebones cost of equity that it determines before requiring the Company to allocate amounts to customer accounts above a specific earnings level. A deadband of 100 basis points above the barebones cost plus a 50-50 sharing of the next 100 basis points would recognize the unusual position in which the Commission has placed the Company and would be more in line with what I believe would be reasonable incentive rate of return regulation.

Low Income Program

Q. In his direct testimony (page 9, line 23) Staff witness Insogna indicates that the credit low income heating customers receive should be increased from $5 to $10 per month. Additionally he indicates that non-heating HEAP eligible customers should receive a $5 bill credit every month rather than just during the months of May through September. Does he provide any basis for this change?

A. While Mr. Insogna generally refers to escalating fuel costs as apparent support for his low income proposal, in fact, he has provided no analysis of the impact of the Company's rates on its low income customers or specific support for the level of the increase that he is recommending in low income credits.

Q. Do you agree with this proposal?

A. No. Since the Company will not be increasing its rates in this proceeding, it is inappropriate to increase the level of low income funding.

Q. How is the Company's current low income program funded?

A. The Company's current low income bill credits for electric customers of approximately $200,000 per year were funded by divestiture proceeds and other customer credits. Since these proceeds and credits have been exhausted, pursuant to the terms of the Joint Proposal adopted by the Commission in Case 03-E-0797, the Company is currently deferring the costs of the low income program.

Q. Please go on.

A. Since as noted above, the funding sources for the current low income program have been depleted, the costs of the current program need to be reflected in the revenue requirement calculation. Similarly, deferred amounts relating to the low income program need to be addressed. Mr. Insogna's proposal would require an increase in base rates of $430,000. If the Commission decides to adopt Mr. Insogna's proposal, the Company's revenue requirement will need to be increased accordingly.

Q. Do you have any other comments regarding Mr. Insogna's low income proposal?

A. Yes. Mr. Insogna's proposal suggests that the low income program be funded solely by non-participating customers. This would be impractical and administratively burdensome since the populations of participants and non-participants are constantly changing. I recommend that the program be funded

by all O&R electric customers. This is consistent with the current program funding through customer credits that are applicable to all O&R customers.

Penalties

Q. When discussing in his direct testimony the Company's current customer service performance incentive ("CSPI"), which utilizes "basis points' to measure the value of potential penalties, Mr. Insogna (page 5, lines 20-23) states that "establishing a firm dollar value for the revenue adjustment removes any potential penalty uncertainty regarding either the amount at risk or its independence for calculations of earnings." Do you agree with this characterization of the current measurement procedures?

A. No. While I am not opposed to stating a fixed dollar amount for a penalty, the use of basis points does not result in any uncertainty as to the amount at risk. Company earnings have very little impact on the level of the penalty at risk. In fact, the amount at risk using the basis point method will result in higher penalties over time as rate base grows. Mr. Insogna's testimony seems to imply that the amount at risk will vary based on the Company's earnings. The calculation using basis points is a function of the Company's capital structure relative to its plant investment, not its earnings.

Q. In his direct testimony (page 6, lines 4-6), Mr. Insogna indicates that "as many utilities have restructured, staffing levels have already been reduced, including reductions in customer service areas." This is his purported basis for increasing the potential customer penalties by almost 150% above their current levels. Do you agree with this observation?

A. No. While I am not aware of staffing reductions that may have occurred in the customer service departments of other utilities, such staffing reductions have not occurred at Orange and Rockland.

Q. Mr. Pause proposes an increase for SAIFI and CAIDI penalties recommending that they increase from a total of twenty to forty basis points, a 100% increase in the penalty. Do you agree with this position?

A. No. As noted by Company witness Regan, this increase is inappropriate.

Q. What factors need to be addressed in determining the appropriate level of penalties to be imposed?

A. Assuming the targets are reasonable and achievable, one should first look at a Company's historical performance over time to see whether the Company has met its goals. It should only be necessary to review the level of penalties when a company is consistently not achieving its targets. At that point a determination should be made as to whether the penalties were adequate to incent the Company to meet its target or if there was some other reason. Secondly, it is necessary to look at the fairness of the penalties in relation to the earning impact of the proposed penalties and other financial risks borne by the Company (i.e., allowed return on equity). Companies with authorized returns that are very low in relation to other similar utilities have less available resources (i.e., greater risk) in being able to meet ongoing operating requirements and performance targets as well as, severely limited in their ability to raise capital to meet construction needs. Small companies like O&R with limited financial resources will have greater difficulties when confronted

by unusual events such as major storms, terrorist acts, changes in laws, new regulatory requirements, etc. and are disadvantaged. It is inappropriate to set penalties that severely impact their operating results when at the same time Staff is recommending an allowed return on equity that is totally inadequate and inappropriate as discussed by Company witness Morin. The proposed increases in penalties are significant because the one sided nature of these penalties poses additional risk to the Company that has not been reflected in either Staff witness Henry's cost of equity recommendation or Company witness Morin's calculations.

Q. Please explain.

A. The Staff cost of equity presentation relies on the Generic Financing Methodology. It is my understanding that at the time that methodology was formulated it took into consideration the state of the ratemaking model used by the Commission at that time. A review of the service quality and customer service penalties / incentives shows that the amounts in effect for that time were far less than the amount proposed by Staff witnesses Insogna and Pause in this current proceeding. The ratemaking model has evolved since 1994. The increase of one sided penalties provides additional regulatory risk that is not reflected in the cost of equity. To impute higher penalties for failure to meet targets while at the same time provide an allowed return on equity that is wholly inadequate is completely inappropriate. Neither witness Insogna nor Pause has recommended any positive incentives for the Company's ability to achieve desired goals, which is also very disconcerting.

Q. What would you recommend?

A. There are several ways to re-establish the balance that existed in 1994. First, provide that the Company be rewarded if it exceeds service quality and customer service targets. This would permit the Company to retain additional earnings equal to the penalty amounts proposed by Staff. Second, would be to leave the penalties at their current levels. Third, would be to provide for an adder to the cost of equity recommendation equal to penalty amounts proposed by Staff.

Q. Are there other considerations that you considered in making your recommendation?

A. Yes, the service restoration (i.e., SAFI and CAIDI) and CSPI targets continue to include risk for events that are outside of the Company's direct control. This risk is not factored into cost of equity capital or reflected in the higher penalties proposed by Mr. Insogna or Mr. Pause. It would be appropriate to increase the allowed return to reflect the impact of the additional risk.

Q. How would you determine the equity adder?

A. I would take the full amount of proposed penalties and divide it by the portion of rate base supported by equity (approximately 48%). The result would be added to the return on equity to be granted. In this case, the total penalties recommended by Mr. Insogna and Mr. Pause amount to approximately $2.5 million (i.e., CSPI penalties of $1.1 million and SAIFI/CAIDI penalties of 40 basis points or $1.4 million). These two adjustments are equivalent to approximately 70 basis points. If this amount were added to the ROE

supported by Company witness Morin of 11.2% than the appropriate ROE should be 11.9% (11.2% plus 0.7%). Without reflecting this change to the ROE supported by Mr. Morin, it would be totally inappropriate to increase the current penalties to the levels recommend by Mr. Insogna and Mr. Pause.

Q. Does this conclude your testimony?

A. Yes, it does.

Orange and Rockland Utilities, Inc.
Impact of Adjusting ROE in JOA & PSA Agreements

Return on Equity	Joint Operating Agreement	Power Supply Agreement	Net Adjustment
8.95%	$ (218,100)	$ (137,500)	$ (355,600)
9.25%	(194,300)	(125,000)	(319,300)
9.50%	(174,500)	(112,500)	(287,000)
9.75%	(154,700)	(100,000)	(254,700)
10.00%	(134,900)	(87,500)	(222,400)
10.25%	(115,100)	(75,000)	(190,100)
10.50%	(95,300)	(62,500)	(157,800)
10.75%	(75,500)	(50,000)	(125,500)
11.00%	(55,700)	(37,500)	(93,200)
11.25%	(35,900)	(25,000)	(60,900)
11.50%	(16,100)	(12,500)	(28,600)
11.70% (a)	-	-	-
12.00%	19,800	12,500	32,300

(a) The return on equity embedded in JOA & PSA billings between O&R and affiliates

Comparison to JOA Billings with Different ROE's

Billing from O&R to RECO & PIKE	Billing Based on Current ROE	Billing Based on 8.95% ROE	Variation
Electric Transmission	$ 206,591	$ 189,761	$ (16,830)
A&G - Allocated to Transmission (11.1%)	92,184	84,873	(7,311)
Transmission Total	298,775	274,634	(24,141)
Electric Distribution	1,031,407	958,145	(73,262)
Customer Accounts	1,234,062	1,171,930	(62,132)
A&G - Allocated to Transmission (88.9%)	738,302	679,750	(58,552)
Distribution Total	**3,003,771**	**2,809,825**	**(193,946)**
Total T&D Billing	$ 3,302,546	$ 3,084,459	$ (218,087)

ORANGE AND ROCKLAND UTILITIES, INC
CALCULATION OF ELECTRIC RETURN ON COMMON EQUITY
PER ELECTRIC SETTLEMENT AGREEMENT (03-E-0797)
(THOUSANDS OF DOLLARS)

	12 Months Ended June 30, 2004	12 Months Ended June 30, 2005	12 Months Ended June 30, 2006	3 Year Total
OPERATING INCOME (ADJUSTED)	$ 35,020	$ 39,257	$ 40,869	$ 115,146
AVERAGE RATE BASE	$ 355,355	$ 356,860	$ 369,437	$ 1,081,653
RATE OF RETURN ON RATE BASE	9.85%	11.00%	11.06%	10.65%
RATE OF RETURN ON COMMON EQUITY	13.38%	15.85%	16.17%	15.15%
RATE OF RETURN - SHARING THRESHOLD BASE SHARING THRESHOLD	12.75%	12.75%	12.75%	12.75%
EXCESS IN RATE OF RETURN ON COMMON EQUITY	0.63%	3.10%	3.42%	2.40%
EQUITY EARNINGS BASE ($ 369,437 x 48.00%)	$ 170,570	$ 171,293	$ 177,330	$ 519,193
EQUITY EARNINGS OVER TARGET ($ 177,330 x 3.42%)	$ 1,075	$ 5,310	$ 6,065	$ 12,450
EXCESS IN REVENUE EQUIVALENT ($ 6,065 / 60.125%)	$ 1,788	$ 8,832	$ 10,087	$ 20,707
CUSTOMER SHARE @ 50.00%	$ 894	$ 4,416	$ 5,044	$ 10,354

ORANGE AND ROCKLAND UTILITIES, INC.
ELECTRIC OPERATING INCOME
(THOUSANDS OF DOLLARS)

PER BOOKS	12 Months Ended June 30, 2004	12 Months Ended June 30, 2005	12 Months Ended June 30, 2006	3 Year Total
OPERATING REVENUES				
SALES TO PUBLIC	$ 349,629	$ 347,705	$ 417,374	$ 1,114,708
SALES FOR RESALE	29,672	24,726	32,402	86,800
OTHER OPERATING REVENUES (A)	25,802	(3,189)	1,876	24,489
TOTAL OPERATING REVENUES	405,103	369,242	451,652	1,225,997
OPERATING EXPENSES				
OTHER POWER SUPPLY EXPENSES	192,790	181,568	256,581	630,939
OTHER O&M	109,137	93,812	94,208	297,157
TOTAL OPERATING EXPENSES	301,927	275,380	350,789	928,096
DEPRECIATION AND AMORTIZATION	21,565	21,773	22,045	65,383
GAIN / LOSS ON DISPOSITION OF UTILITY PLANTS	202	-	-	202
TAXES OTHER THAN INCOME TAXES	28,096	27,573	27,331	83,000
TOTAL OPERATING REVENUE DEDUCTIONS	351,790	324,726	400,165	1,076,681
OPERATING INCOME BEFORE INCOME TAXES	53,313	44,516	51,487	149,316
STATE INCOME TAX (A)	5,135	(5,329)	2,956	2,762
FEDERAL INCOME TAX	11,668	12,463	10,267	34,398
OPERATING INCOME AFTER INCOME TAXES	36,510	37,382	38,264	112,156
OVEREARNINGS ACCRUAL ADJUSTMENT	-	2,312	3,844	6,156
INTEREST SYNCHRONIZATION ADJUSTMENT	268	139	(760)	(353)
OPERATING INCOME ADJUSTED FOR INTEREST SYNCHRONIZATION	36,778	39,833	41,348	117,959
NORMALIZING ADJUSTMENTS TO INCOME (NET OF INCOME TAX):				
- PSA EQUALIZATION ADJUSTMENT	(72)	(73)	(75)	(220)
- MERGER SAVINGS	(1,587)	-	-	(1,587)
- ELECTRIC CUSTOMER SERVICE & RELIABILITY PERFORMANCE	-	69	70	139
- ADJUSTMENT FOR DECEMBER 2004 POWER SUPPLY OVERBILLING TO RECO	-	(420)	-	(420)
- ADJUSTMENT FOR JUNE 2006 FIT FACTOR FOR CHARGES BILLED TO RECO	-	-	(319)	(319)
- PROPERTY TAX REFUNDS RETAINED (10%)	(99)	(94)	(155)	(348)
	(1,758)	(518)	(479)	(2,755)
ADJUSTED OPERATING INCOME AFTER INCOME TAXES, INTEREST SYNCH. & ADJUSTMENTS	$ 35,020	$ 39,315	$ 40,869	$ 115,204

ORANGE AND ROCKLAND UTILITIES, INC
AVERAGE ELECTRIC RATE BASE
(THOUSANDS OF DOLLARS)

	12 Months Ended June 30, 2004	12 Months Ended June 30, 2005	12 Months Ended June 30, 2006	3 Year Total
UTILITY PLANT				
ELECTRIC PLANT IN SERVICE	$ 577,712	$ 597,162	$ 625,656	$ 1,800,530
ELECTRIC PLANT HELD FOR FUTURE USE	981	760	1,047	2,788
COMMON UTILITY PLANT (ALLOCATED)	85,558	88,101	89,559	263,218
CWIP NOT TAKING INTEREST	9,190	8,642	7,850	25,682
TOTAL UTILITY PLANT	673,441	694,665	724,112	2,092,218
UTILITY PLANT RESERVES				
ACCUM PROV. FOR DEPRECIATION OF ELECTRIC PLANT	(199,800)	(206,666)	(212,683)	(619,149)
ACCUM PROV. FOR DEPRECIATION OF COMMON PLANT (ALLOCATED)	(39,500)	(43,226)	(45,816)	(128,542)
TOTAL UTILITY PLANT RESERVES	(239,300)	(249,892)	(258,499)	(747,691)
NET PLANT	434,141	444,773	465,613	1,344,527
ADJUSTMENTS TO NET PLANT				
WORKING CAPITAL REQUIREMENTS				
WORKING CAPITAL - O&M	13,249	11,464	11,513	36,226
WORKING CAPITAL - M&S	3,519	3,398	3,848	10,765
WORKING CAPITAL - PREPAYMENTS	5,485	5,277	4,698	15,460
DSM - NET OF TAX	(1,166)	(1,173)	(1,115)	(3,454)
R & D EXPENDITURES - NET OF TAX	305	645	1,041	1,991
DEFERRED FUEL (NET OF RECOVERABLE FUEL) - NET OF TAX	(2,561)	(6,320)	(8,774)	(17,655)
M.T.A. SURTAX - NET OF TAX	952	372	(281)	1,043
UNDERGROUND CABLE GASIFICATION	113	-	-	113
SALE OF POWER PLANTS - WORKER'S COMP. - NET OF TAX	667	753	233	1,653
LOW INCOME PROGRAM - NET OF TAX	(642)	(523)	(365)	(1,530)
DEFERRED PENSION LIABILITY - ALLOWED - NET OF TAX	(6,513)	(6,403)	(6,403)	(19,319)
DEFERRED COSTS - APRIL 1, 1997 STORM - NET OF TAX	26	229	-	255
CUSTOMER ADVANCES FOR CONSTRUCTION - NET OF TAX	(131)	(169)	(157)	(457)
CON ED.SON MERGER - COSTS TO ACHIEVE	506	-	-	506
O&R NYPP ISO COSTS - NET OF TAX	(5)	-	-	(5)
ACRS / ADR	(59,111)	(60,381)	(61,286)	(180,778)
PROCEEDS FROM EPA - NET OF TAX	(6)	-	-	(6)
263A CAPITALIZED OVERHEADS	(11,460)	(14,629)	(13,981)	(40,070)
ACCUMULTAED DEFERRED SIT	(4,086)	(3,040)	(1,531)	(8,657)
ACCUMULATED DEFFERED FIT ON SIT	1,262	840	274	2,376
ACCUMULATED PROVISION FOR CONTINGENCIES - STORM DAMAGE - NET OF TAX	(589)	(601)	(601)	(1,791)
ACCUMULATED DEFERRED MTA (NYS STATE INCOME TAX)	(173)	103	190	120
GENERAL PLANT SALE - NET OF TAX	(110)	-	-	(110)
STATE INCOME TAX BENEFIT PRE 2000	-	205	379	584
ACCUMULATED DEFERRED INVESTMENT TAX CREDITS	(2,651)	(2,414)	(2,172)	(7,237)
TOTAL ADJUSTMENTS	(63,120)	(72,367)	(74,490)	(209,977)
AVERAGE ELECTRIC RATE BASE BEFORE EB - CAP ADJUSTMENT	371,021	372,406	391,123	1,134,550
EXCESS RATE BASE OVER CAPITALIZATION ADJUSTMENT	(15,666)	(15,546)	(21,686)	(52,897)
TOTAL AVERAGE ELECTRIC RATE BASE	$ 355,355	$ 356,860	$ 369,437	$ 1,081,653

ORANGE AND ROCKLAND UTILITIES, INC.
AVERAGE ELECTRIC EB - CAP
(THOUSANDS OF DOLLARS)

	12 Months Ended June 30, 2004	12 Months Ended June 30, 2005	12 Months Ended June 30, 2006	3 Year Total
CAPITALIZATION CALCULATION				
LONG - TERM DEBT	$ 277,809	$ 289,579	$ 317,974	$ 885,362
CUSTOMER DEPOSITS	10,593	11,736	11,443	33,772
INTEREST ON CUSTOMER DEPOSITS	730	751	806	2,287
COMMON STOCK	194,504	194,105	194,344	582,953
RETAINED EARNINGS	185,066	194,651	179,769	559,486
ADDITION TO RETAINED EARNINGS (SFAS 90)				
DIVIDENDS DECLARED	4,667	10,667	4,667	20,001
COMMERCIAL PAPER	48,198	32,096	89,445	169,739
TOTAL	721,574	733,586	798,448	2,253,608
LESS:				
INVESTMENT IN SUBSIDIARIES	160,134	138,335	143,940	442,409
NET RECEIVABLES / PAYABLES FROM SUBSIDIARIES	6,995	2,425	17,623	27,043
OTHER WORK IN PROGRESS	(183)	(82)	-	(265)
TEMPORARY CASH INVESTMENTS	1,974	13,263	169	15,406
TOTAL	168,920	153,941	161,732	484,593
TOTAL CAPITALIZATION	552,654	579,645	636,716	1,769,015
EB -CAP CALCULATION				
UTILITY PLANT				
ELECTRIC PLANT IN SERVICE	$ 577,712	$ 597,162	$ 625,656	$ 1,800,530
ELECTRIC PLANT HELD FOR FUTURE USE	981	760	1,047	2,788
COMMON UTILITY PLANT (ALLOCATED)	85,558	88,101	89,559	263,218
CWIP NOT TAKING INTEREST	9,190	8,642	7,850	25,682
TOTAL UTILITY PLANT	673,441	694,665	724,112	2,092,218
UTILITY PLANT RESERVES				
ACCUM PROV. FOR DEPRECIATION OF ELECTRIC PLANT	(199,800)	(206,666)	(212,683)	(619,149)
ACCUM PROV. FOR DEPRECIATION OF COMMON PLANT (ALLOCATED)	(39,500)	(43,226)	(45,816)	(128,542)
TOTAL UTILITY PLANT RESERVES	(239,300)	(249,892)	(258,499)	(747,691)
NET PLANT	434,141	444,773	465,613	1,344,527
ADJUSTMENTS TO NET PLANT				
WORKING CAPITAL REQUIREMENTS				
WORKING CAPITAL - O&M	13,249	11,464	11,513	36,226
WORKING CAPITAL - M&S	3,519	3,398	3,848	10,765
WORKING CAPITAL - PREPAYMENTS	5,485	5,277	4,698	15,460
DSM - NET OF TAX	(1,166)	(1,173)	(1,115)	(3,454)
R & D EXPENDITURES - NET OF TAX	305	645	1,041	1,991
DEFERRED FUEL (NET OF RECOVERABLE FUEL) - NET OF TAX	(2,561)	(6,320)	(8,774)	(17,655)
M.T.A. SURTAX - NET OF TAX	952	372	(281)	1,043
UNDERGROUND CABLE GASIFICATION	113	-	-	113
SALE OF POWER PLANTS - WORKER'S COMP. - NET OF TAX	667	753	233	1,653
LOW INCOME PROGRAM - NET OF TAX	(642)	(523)	(365)	(1,530)
DEFERRED PENSION LIABILITY - ALLOWED - NET OF TAX	(6,513)	(6,403)	(6,403)	(19,319)
DEFERRED COSTS - APRIL 1, 1997 STORM - NET OF TAX	26	229	-	255
CUSTOMER ADVANCES FOR CONSTRUCTION - NET OF TAX	(131)	(169)	(157)	(457)
CON EDISON MERGER - COSTS TO ACHIEVE	506	-	-	506
O&R NYPP ISO COSTS - NET OF TAX	(5)	-	-	(5)
ACRS / ADR	(59,111)	(60,381)	(61,286)	(180,778)
PROCEEDS FROM EPA - NET OF TAX	(6)	-	-	(6)
263A CAPITALIZED OVERHEADS	(11,460)	(14,629)	(13,981)	(40,070)
ACCUMULTAED DEFERRED SIT	(4,086)	(3,040)	(1,531)	(8,657)
ACCUMULATED DEFFERED FIT ON SIT	1,262	840	274	2,376
ACCUMULATED PROVISION FOR CONTINGENCIES - STORM DAMAGE - NET OF TAX	(589)	(601)	(601)	(1,791)
ACCUMULATED DEFERRED MTA (NYS STATE INCOME TAX)	(173)	103	190	120
GENERAL PLANT SALE - NET OF TAX	(110)	-	-	(110)
STATE INCOME TAX BENEFIT PRE 2000	-	205	379	584
ACCUMULATED DEFERRED INVESTMENT TAX CREDITS	(2,651)	(2,414)	(2,172)	(7,237)
TOTAL ADJUSTMENTS	(63,120)	(72,367)	(74,490)	(209,977)
AVERAGE ELECTRIC RATE BASE BEFORE EB - CAP ADJUSTMENT	371,021	372,406	391,123	1,134,550
INTEREST BEARING ITEMS: FLOWS IN FROM EXCESS NET OF TAX IF APPLICABLE				
CONSTRUCTION WORK IN PROGRESS	5,746	5,708	15,152	26,606
GAS / OIL SUPPLIER REFUNDS	(1,626)	(603)	(282)	(2,511)
INTEREST ON PENSION / OPEB OBLIGATIONS - NET OF TAX	(174)	(174)	(174)	(522)
INTEREST ON STORM DAMAGE RESERVE - NET OF TAX	(18)	(35)	(100)	(153)
PROPERTY TAX REFUNDS ; INC. RAMAPO & GAS PROPERTY TAX OVERRECOVERIES, - NET OF TAX	(17)	-	-	(17)
INTEREST ON REFUNDABLE ARD CUSTOMER ADVANCES - NET OF FIT	(13)	(14)	(15)	(43)
GAS STORED UNDERGROUND - CURRENT	-	-	-	-
DEFERRED PENSION LIABILITY NON-ALLOWABLE PORTION) - NET OF FIT	(3,808)	(2,936)	125	(6,619)
COMPETITIVE ENHANCEMENT FUND - NET OF FIT	(601)	(224)	(51)	(876)
DEFERRED ELECTRIC ADMIN. CHARGES CASE 99-G-1695)	(43)	-	-	(43)
INTEREST ACCRUED - DIVESTITURE PROCEEDS	(80)	-	-	(80)
OPEBS & FAS 112 - NET OF FIT	(1,513)	(1,848)	(1,626)	(4,987)
NYS INCOME TAX - OVERCOLLECTION PORTION (2000/2001)	(3,349)	(1,409)	(8)	(4,766)
CUSTOMER ADVANCES - REFUNDABLE - NET OF FIT	(348)	(548)	(767)	(1,663)
DEFERRED ADMIN. INTEREST (CASE 99-G-1695)	(4)	-	-	(4)
STORM DAMAGE RESERVE - INT. BEARING PORTION -NET OF TAX	(1,029)	(811)	(176)	(2,016)
TOTAL ADJUSTMENTS	(6,877)	(2,894)	12,078	2,306
TOTAL INCLUDING INTEREST BEARING ITEMS - ELECTRIC	364,144	369,512	403,201	1,136,856
TOTAL INCLUDING INTEREST BEARING ITEMS - GAS	215,908	238,127	273,407	727,443
TOTAL INCLUDING INTEREST BEARING ITEMS - ELECTRIC & GAS	580,052	607,639	676,608	1,864,299
PERCENTAGE USED TO ALLOCATE EB-CAP ADJUSTMENT BEFORE DISCOUNT	62.78%	60.81%	59.59%	
ELECTRIC SUB-DISCOUNT	5.60%	5.28%	5.23%	
PERCENTAGE USED TO ALLOCATE EB-CAP ADJUSTMENT AFTER DISCOUNT - ELECTRIC	57.18%	55.53%	54.36%	
EB-CAP ADJUSTMENT - ELECTRIC & GAS	(27,398)	(27,994)	(39,892)	(95,284)
EB-CAP ADJUSTMENT - ELECTRIC	(15,666)	(15,546)	(21,686)	(52,897)

ORANGE AND ROCKLAND UTILITIES, INC.
AVERAGE CAPITALIZATION
(MILLIONS OF DOLLARS)

12 Months Ended June 30, 2006	CAPITAL	RATIO	WEIGHTED COST RATES	RATE OF RETURN
LONG-TERM DEBT	$ 333.7	49.93%	6.49%	3.24%
CUSTOMER DEPOSITS	13.8	2.07%	3.01%	0.06%
SUB TOTAL	347.5	52.00%		3.30%
COMMON EQUITY	355.6	48.00% (A)	16.17%	7.76%
TOTAL CAPITALIZATION	$ 703.1	100.00%		11.06%

12 Months Ended June 30, 2005	CAPITAL	RATIO	WEIGHTED COST RATES	RATE OF RETURN
LONG-TERM DEBT	$ 312.8	49.56%	6.72%	3.33%
CUSTOMER DEPOSITS	15.4	2.44%	2.42%	0.06%
SUB TOTAL	328.2	52.00%		3.39%
COMMON EQUITY	370.7	48.00% (A)	15.85%	7.61%
TOTAL CAPITALIZATION	$ 698.9	100.00%		11.00%

12 Months Ended June 30, 2004	CAPITAL	RATIO (1)	WEIGHTED COST RATES	RATE OF RETURN
LONG-TERM DEBT	$ 301.0	49.86%	6.78%	3.38%
CUSTOMER DEPOSITS	12.9	2.14%	2.22%	0.05%
SUB TOTAL	313.9	52.00%		3.43%
COMMON EQUITY	361.5	48.00%	13.38%	6.42%
TOTAL CAPITALIZATION	$ 675.4	100.00%		9.85%

ORANGE AND ROCKLAND UTILITIES, INC.
INTEREST SYNCHRONIZATION ADJUSTMENT - ELECTRIC
(THOUSANDS OF DOLLARS)

INTEREST SYNCHRONIZATION CALCULATION		12 Months Ended June 30, 2004	12 Months Ended June 30, 2005	12 Months Ended June 30, 2006	3 Year Total
AVERAGE RATE BASE		$ 355,355	$ 356,860	$ 369,437	$ 1,081,653
AVERAGE INTEREST BEARING CWIP		5,746	5,708	15,152	26,606
		$ 361,101	$ 362,568	$ 384,589	$ 1,108,259
WEIGHTED COST OF DEBT		3.43%	3.39%	3.30%	3.37%
CALCULATED INTEREST ON DEBT		$ 12,386	$ 12,291	$ 12,691	$ 37,368
ACTUAL INTEREST EXPENSE		$ 11,714	$ 11,942	$ 14,596	$ 38,252
INTEREST SYNCHRONIZATION AMOUNT		$ 672	$ 349	$ (1,905)	$ (884)
INTEREST SYNCHRONIZATION ADJUSTMENT TO INCOME @ 39.875%	39.875%	$ 268	$ 139	$ (760)	$ (352)

ORANGE AND ROCKLAND UTILITIES, INC.
ADJUSTMENTS TO INCOME
(THOUSANDS OF DOLLARS)

	12 Months Ended June 30, 2004	12 Months Ended June 30, 2005	12 Months Ended June 30, 2006	3 Year Total
- PSA EQUALIZATION ADJUSTMENT	$ 120	$ 121	$ 125	$ 366
- MERGER SAVINGS	2,640	-	-	2,640
- ELECTRIC CUSTOMER SERVICE & RELIABILITY PERFORMANCE	-	(115)	(117)	(232)
- ADJUSTMENT FOR DECEMBER 2004 POWER SUPPLY OVERBILLING TO RECO	-	699	-	699
- ADJUSTMENT FOR JUNE 2006 FIT FACTOR FOR CHARGES BILLED TO RECO	-	-	530	530
- PROPERTY TAX REFUNDS RETAINED (10%)	165	156	258	579
	2,924	862	796	4,581
LESS FIT @ 39.875%	(1,166)	(344)	(317)	(1,827)
NET AFTER TAX	$ 1,758	$ 518	$ 479	$ 2,754

* ELECTRIC AT 60.125%

ORANGE AND ROCKLAND UTILITIES, INC.
REBUTTAL TESTIMONY OF
KENNETH A. KOSIOR

Q. Please state your name and business address

A. Kenneth A. Kosior, One Blue Hill Plaza, Pearl River, New York 10965.

Q. Have you previously testified in this proceeding?

A. Yes. I submitted direct testimony in this proceeding on behalf of Orange and Rockland Utilities, Inc. ("O&R" or the "Company"). I submitted my credentials previously as part of my direct testimony.

Q. What is the purpose of your rebuttal testimony in this proceeding?

A. I will respond to certain statements contained in the direct testimony of Mr. Robert A. Burke submitted on behalf of the New York State Department of Public Service regarding adjustments to direct labor expense and the disposition of property tax benefits.

Q. Please begin by addressing Mr. Burke's adjustment to direct labor expense.

A. In developing the labor cost estimates in this case, the Company included, among other things, a normalizing adjustment to annualize the effect of the addition of 10.5 electric third class linemen positions that became effective in September 2006. Labor costs for these positions for the four month period September 2006 through December 2006 were included in the test period in this case. The normalizing adjustment, which amounted to $385,000, represented an additional eight months of costs in order to annualize these expenses. This adjustment was appropriate because these 10.5 positions were permanent additions to the full compliment of

electric operations department personnel. As Mr. Burke noted in his direct testimony (at 10-11) the Company has agreed that the $385,000 should be reduced by $69,000 in order to recognize program costs attributable to the Company's subsidiaries, RECO and Pike, making the corrected amount of the normalizing adjustment $316,000. Mr. Burke (at 10-11) recommends the elimination of the entire normalizing cost to O&R of the 10.5 positions (i.e., $316,000).

Q. What is the rationale for Mr. Burke's elimination of the annualized cost of the 10.5 positions?

A. Mr. Burke's argues that between the time of the completion of the Company's line school in September 2006 and February 2007 the electric operations employee count decreased by three positions and that the "decline is reasonable to predict since the school training program is intended to maintain the Company's compliment of linemen by providing replacements for anticipated retirements." He further states that he "believe[s] that the Company's updating of historic labor data through December 31, 2006 provides an adequate compliment of employees absent any specific showing as to the need for additional levels."

Q. Do you agree with Mr. Burke's recommendation?

A. No. A monthly recap of the actual number of employees in the Company's electric operations department for the period June 2005 through December 2006 was provided in response to interrogatory DPS (RAB) No. 1. This data was updated for the months of January and February 2007 in response to interrogatory DPS (RAB) No. 44. This data shows that the

average number of employees in the electric operating department for the twelve months ended December 31, 2006 was 204.8 employees. The payroll expense reflected in the test year ended December 2006 is commensurate with the average employee level for that period (i.e., 204.8 positions).

As can be seen from an examination of the employee level data that was provided in response to the interrogatories referred to above, the employee level for the first eight months of the year 2006 ranged between 199 and 203 positions, and, for the last four months, reflecting the completion of the Company's line school, employee count ranged between 213 and 214 positions. Then, for the first two months of 2007 the employee level was 211 positions and for March and April 2007 the employee level was 210. In addition, the average employee level for the past eight months (September 2006 – April 2007) equals 212 positions which are indicative of future employee levels and representative of the scheduling of line schools to address attrition. In fact, the employee level at the time of the close of the 2006 line school (i.e., September 2006, electric operations department headcount of 214) is expected to approximate the department's full complement of employees going forward. For ease of reference, Rebuttal Exhibit KAK No. 1 sets forth the electric operating department employee levels for the period January 2006 through April 2007.

Without a normalizing adjustment as proposed by the Company in its direct case, labor expense will be based the average historic test year

employee level and labor expense (i.e., 204.8 employees), which, as can be seen from the employee level data discussed above, is not representative of the current, or future, employee level of the electric operations department.

Q. Please address Mr. Burke's recommendation regarding the disposition of property tax benefits received from the Towns of Haverstraw and Orangetown.

A. In his direct testimony (at 38-43), Mr. Burke discusses this issue and recommends that the Company should be allowed to retain ten percent of the property tax refunds and/or credits against future tax payments actually received by the Company during the term of the Proposal and resulting from the Company's efforts.

Q. Do you agree with Mr. Burke's recommendation?

A. No, I do not. The Petition Of Orange and Rockland Utilities, Inc. Regarding Disposition Of Property Tax Benefits From The Towns Of Haverstraw And Orangetown ("Petition"), a copy of which is attached to Mr. Burke's direct testimony as Exh. __ (RAB-4), discusses the extensive efforts that the Company expended to achieve these property tax refunds and/or credits against future tax payments. I will not repeat those efforts here, but I would note that they justify the Company's request that it be allowed to retain 25% of the cash refunds of approximately $2.75 million (i.e., $688,000) to be received from the Towns. Such a 25 percent sharing of the cash refunds appropriately recognizes that the Company's efforts produced tax benefits to customers far above the cash refunds to be

shared. For example, the two tax settlements also provide for future tax credits in lieu of refunds. Accordingly, in recognition of the Company's aggressive tax reduction efforts and to provide an incentive to continue such efforts in the future, a 25 percent sharing would be appropriate. Further, a 25 percent sharing of these refunds is necessary for there to be a fair and reasonable implementation of the Commission's tax refund incentive policies.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

Rebuttal Exhibit
KAK No. 1

ORANGE AND ROCKLAND UTILITIES, INC.
ELECTRIC OPERATIONS EMPLOYEE LEVEL
ACTUAL JANUARY 2006 - APRIL 2007

	January 2006	February 2006	March 2006	April 2006	May 2006	June 2006	July 2006	August 2006	September 2006	October 2006	November 2006	December 2006	Avg 12 Mos. 12/31/06
ELECTRIC OPERATIONS													
31 MGR. & STAFF	6.0	6.0	7.0	6.0	6.0	7.0	7.0	6.0	6.0	6.0	6.0	6.0	6.3
33 EASTERN LINE OPERATIONS	69.0	69.0	69.0	67.0	68.0	68.0	68.0	66.0	83.0	82.0	76.0	75.0	71.7
34 CENTRAL LINE OPERATIONS	34.0	34.0	35.0	36.0	35.0	33.0	32.0	35.0	34.0	34.0	35.0	35.0	34.3
35 WESTERN LINE OPERATIONS	39.0	39.0	37.0	37.0	38.0	39.0	38.0	39.0	38.0	37.0	40.0	41.0	38.5
38 JOINT USE DIST FACILITIES	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0
62 TRANSMISSION DIST MAINT.	6.0	6.0	6.0	6.0	6.0	6.0	6.0	5.0	5.0	6.0	6.0	6.0	5.8
64 EHV LINE OPERATIONS	7.0	7.0	6.0	6.0	5.0	6.0	6.0	6.0	6.0	6.0	8.0	8.0	6.4
76 EASTERN UNDERGROUND	21.0	21.0	21.0	24.0	23.0	22.0	22.0	22.0	22.0	21.0	21.0	20.0	21.7
77 NORTHERN UNDERGROUND	15.0	14.0	14.0	17.0	17.0	17.0	16.0	16.0	16.0	17.0	17.0	18.0	16.2
79 OPERATION FLAGPERSON GROUP	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
TOTAL ELECTRIC OPERATIONS	**201.0**	**200.0**	**199.0**	**203.0**	**202.0**	**202.0**	**199.0**	**199.0**	**214.0**	**213.0**	**213.0**	**213.0**	**204.8**

	September 2006	October 2006	November 2006	December 2006	January 2007	February 2007	March 2007	April 2007	Avg 8 Mos. 4/30/07
ELECTRIC OPERATIONS									
31 MGR. & STAFF	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0
33 EASTERN LINE OPERATIONS	83.0	82.0	76.0	75.0	73.0	66.0	71.0	70.0	74.5
34 CENTRAL LINE OPERATIONS	34.0	34.0	35.0	35.0	35.0	39.0	37.0	37.0	35.8
35 WESTERN LINE OPERATIONS	38.0	37.0	40.0	41.0	41.0	44.0	40.0	41.0	40.3
38 JOINT USE DIST. FACILITIES	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0
62 TRANSMISSION DIST. MAINT.	5.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	5.9
64 EHV LINE OPERATIONS	6.0	6.0	8.0	8.0	8.0	8.0	8.0	8.0	7.5
76 EASTERN UNDERGROUND	22.0	21.0	21.0	20.0	20.0	21.0	22.0	22.0	21.1
77 NORTHERN UNDERGROUND	16.0	17.0	17.0	18.0	18.0	17.0	16.0	16.0	16.9
79 OPERATION FLAGPERSON GROUP	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
TOTAL ELECTRIC OPERATIONS	**214.0**	**213.0**	**213.0**	**213.0**	**211.0**	**211.0**	**210.0**	**210.0**	**211.9**

BEFORE THE NEW YORK STATE PUBLIC SERVICE COMMISSION

In the matter of:

APPLICATION OF ORANGE AND	)	
ROCKLAND UTILITIES, INC.	)	CASE NO. 06-E-1433 _____
FOR AN INCREASE IN ELECTRIC RATES	)	
	)	

REBUTTAL TESTIMONY

OF

ROGER A. MORIN, PhD

May 2007

ORANGE AND ROCKLAND UTILITIES, INC.

REBUTTAL TESTIMONY OF DR. ROGER A. MORIN

Q. ARE YOU THE SAME ROGER A. MORIN WHO PREVIOUSLY SUBMITTED SUPPLEMENTAL TESTIMONY IN THIS PROCEEDING?

A. Yes, I am.

Q. WHAT IS THE PURPOSE OF THIS REBUTTAL TESTIMONY?

A. I have been asked to rebut Staff witness Craig Henry's rate of return (cost of capital) testimony.

Q. PLEASE SUMMARIZE STAFF'S RATE OF RETURN RECOMMENDATION.

A. Mr. Henry recommends that a return on common equity ("ROE") allowance of only 8.95% be employed on the common equity capital of Orange and Rockland Utilities, Inc. ("O&R"). In determining O&R's cost of common equity capital, Mr. Henry applies a two-stage DCF analysis to a group of 30 electric utilities. For the first-stage growth component of the DCF analysis, Mr. Henry relies on Value Line's forecast dividend estimates over the next few years. For the more important second-stage growth component that drives the vast majority of the DCF results, he uses the earnings retention method, also known as the "sustainable growth" method, again using Value Line estimates as input data.

Mr. Henry also applies a Capital Asset Pricing Model ("CAPM") and an Empirical CAPM ("ECAPM") analysis to the same group of companies, using long-term Treasury bond yields as proxies for the risk-free rate and Value Line beta estimates. Mr. Henry bases his estimate of the market risk premium ("MRP") component of the CAPM on a single Merrill Lynch estimate. Applying a weight of two-thirds to his DCF results and a

weight of one-third to his ECAPM-ECAPM average result, Mr. Henry concludes that O&R's cost of common equity capital is 8.95%, inclusive of a flotation cost allowance of 9 basis points. It is not clear as to why Mr. Henry did not simply round his double precision recommendation of 8.95% to 9.0%, given the enormous amount of judgment employed throughout his testimony and the lack of scientific precision of the DCF methodology.

Q. WHAT IS YOUR GENERAL REACTION TO MR. HENRY'S COST OF COMMON EQUITY RECOMMENDATION?

A. My general reaction to his testimony, even before I engage in a more technical critique, is that it contains major infirmities. His single-digit recommendation of 8.95% rests heavily on the results of a DCF analysis and on a particularly fragile rendition of the DCF approach. The latter is largely based on the questionable results of the earnings retention growth version of the DCF model. That method requires Mr. Henry to assume the investor's expected ROE. But the latter is precisely what we are trying to determine in this proceeding. It is therefore profoundly illogical and circular to assume an ROE in order to determine an ROE. Not only has Mr. Henry relied heavily on a circular methodology but he has also put most of his eggs in the DCF basket which causes him to recommend returns that are below investors' required returns. His CAPM and ECAPM analyses are also questionable because of an understated MRP component, as I discuss later.

Q. WHAT ARE THE BASIC CONCLUSIONS OF YOUR REBUTTAL TO MR. HENRY'S COST OF EQUITY TESTIMONY?

A. Mr. Henry understates O&R's cost of common equity by a minimum of 100 basis

points (1.0%), which would bring his recommended ROE to 10.0%. A proper application of cost of capital methodologies would give results substantially higher than those that he obtained. As stated in my conclusions, correcting for the various flaws in Mr. Henry's testimony would suggest much higher returns (11%) that are virtually identical to my own recommendation. I consider my critique conservative, for it does not reflect the consistent tendency of the DCF to understate the cost of equity, nor does it reflect the understatement of the cost of equity which results from the plain vanilla annual form of CAPM analysis used by Mr. Henry.

Q. PLEASE SUMMARIZE YOUR COMMENTS ON MR. HENRY'S TESTIMONY.

A. I stress from the start that I agree with some of Mr. Henry's views and procedures. I agree broadly with: (i) the use of several methodologies in estimating a fair return on common equity, although I disagree with the weights accorded to each method, (ii) his sample of electric utility companies in the DCF and CAPM analyses; and (iii) the magnitude of the beta estimates in the CAPM analysis.

I have eleven (11) specific disagreements with Mr. Henry's testimony:

1. Unreliable Recommendation. His cost of equity recommendation is unreasonably low, and is not a reliable estimate of O&R's cost of equity capital given the heavy reliance on one particular and fragile cost of equity methodology which is known to understate investor returns, namely, the DCF method.

2. Allowed returns. Mr. Henry's recommended return is completely outside the zone of currently allowed rates of return for his sample companies and would constitute the lowest allowed ROE in the country for a major electric utility.

3. **The DCF Model Understates the Cost of Equity.** It is well-known that application of the DCF model to utility stocks understates the investor's expected return when the Market-to-Book (M/B) ratio exceeds unity. This is particularly relevant in the current capital market environment where utility stocks, including Mr. Henry's sample companies, are trading at M/B ratios well above unity.

4. **DCF Functional Form.** Mr. Henry relies on the annual form rather than on the quarterly version of the DCF model, understating the cost of equity by 20 basis points.

5. **The use of an average 6-month stock price in the DCF model.** His application of the DCF model violates market efficiency principles and mismatches stock price and expected growth.

6. **DCF Earnings Retention Growth.** Mr. Henry's principal, and in fact only, technique for estimating the long-term growth component of the DCF model is the earnings retention growth technique. There is a logical inconsistency in the retention growth technique because Mr. Henry is forced to assume the answer to implement the method. From Mr. Henry's own evidence, investors expect substantially higher returns for utilities than what he recommends.

7. **DCF Growth Rates: Analysts' Forecasts.** Investors are expecting substantially higher growth rates than Mr. Henry's growth rate for his sample companies.

8. **DCF Growth Rates: Long-term Economic Growth.** Mr. Henry's long-term growth forecast for his comparable group of electric utilities based on the earnings retention growth method understates the long-term expected GDP nominal growth by approximately 140 basis points (1.4%).

9. CAPM Market Risk Premium. Mr. Henry's MRP is understated and ignores the vast literature on the subject. Using the appropriate MRP, Mr. Henry's CAPM estimates are to be raised by 100 basis points from this correction alone.

10. Flotation Costs. Mr. Henry's DCF estimates of equity costs are downward-biased by approximately 20 basis points to the extent that not all the flotation costs associated with past equity issues have been expensed or recovered in the past.

11. Criticisms of my testimony. Mr. Henry's criticisms of my ROE recommendation are without foundation.

1. UNRELIABLE RECOMMENDATION

Q. MR. HENRY RELIES HEAVILY ON ONE METHODOLOGY, NAMELY THE DCF METHOD. DOES THIS AFFECT THE RELIABILITY OF HIS RESULTS?

A. Yes, very much so. The 8.95% cost of equity recommended by Mr. Henry is unreasonably low and outside reasonable limits of probability, and is not a reliable estimate of O&R's cost of equity capital.

There are four broad generic methodologies available to measure the cost of equity: DCF, Risk Premium, CAPM, which are market-oriented, and Comparable Earnings, which is accounting-oriented. Each generic market-based methodology in turn contains several variants. Mr. Henry has chosen to rely heavily on the DCF method and to a much smaller extent on the CAPM, giving two-thirds weight to the DCF results, only one-third to the CAPM and ECAPM results, and no weight at all to the Risk Premium methodology.

As I discussed in my Supplemental Testimony, when measuring equity costs, which essentially deals with the measurement of investor expectations, no one single methodology provides a foolproof panacea. Each methodology requires the exercise of considerable judgment on the reasonableness of the assumptions underlying the methodology and on the reasonableness of the proxies used to validate the theory. The failure of the traditional infinite growth DCF model to account for changes in relative market valuation, and the practical difficulties of specifying the expected growth component, discussed in my original testimony, are vivid examples of the potential shortcomings of the DCF model. It follows that several methodologies should be employed in arriving at a judgment on the cost of equity and that these methodologies should be weighted equally.

There is no single model that conclusively determines or estimates the expected return for an individual firm. Each methodology possesses its own way of examining investor behavior, its own premises, and its own set of simplifications of reality. Each method proceeds from different fundamental premises which cannot be validated empirically. Investors do not necessarily subscribe to any one method, nor does the stock price reflect the application of any one single method by the price-setting investor.

There is no monopoly as to which method is used by investors. Absent any hard evidence as to which method outdoes the other, all relevant evidence should be used and weighted equally, in order to minimize judgmental error, measurement error, and conceptual infirmities. There is no guarantee that a single DCF result is necessarily the ideal predictor of the stock price and of the cost of equity reflected in that price, just as there is no guarantee that a single CAPM or Risk Premium result constitutes the perfect

explanation of that stock price.

Q. DOES THE FINANCIAL LITERATURE SUPPORT THE USE OF SEVERAL METHODOLOGIES?

A. Yes, it does. As I discussed in my supplemental testimony, the financial literature strongly supports the use of multiple methods. While it is certainly appropriate to use the DCF methodology to estimate the cost of equity, there is no proof that the DCF produces a more accurate estimate of the cost of equity than other methodologies. Heavy reliance on the DCF model ignores the capital market evidence and financial theory formalized in the CAPM and other risk premium methods. The DCF model is one of many tools to be employed in conjunction with other methods to estimate the cost of equity. It is not a superior methodology that supplants other financial theory and market evidence.

Q. DOES THE DCF MODEL NEED TO BE APPLIED WITH EXTREME CAUTION?

A. Yes, it does. Caution has to be used in applying the DCF model to utility stocks for four reasons. The first reason is that the stock price used as input in the dividend yield component may be unduly influenced by structural changes and changing investor expectations in the utility industry. Stock prices can also be influenced by mergers and acquisitions possibilities, by speculation concerning asset restructurings and deregulation of certain assets, and by corporate takeover rumors.

The second reason is that the traditional DCF model is based on a number of assumptions, some of which may be unrealistic in a given capital market environment. For example, the standard infinite growth DCF model assumes a constant market valuation multiple, that is, a constant price/earnings (P/E) ratio. In other words, the model assumes

that investors expect the ratio of market price to dividends (or earnings) in any given year to be the same as the current price/dividend (or earnings) ratio. This must be true if the infinite growth assumption is made. This assumption is somewhat unrealistic given the surges in P/E ratios experienced by utility stocks in the last decade.

Several fundamental and structural changes have transformed the utility industry from the times when the standard DCF model and its assumptions were developed by Professor Gordon. Increased competition triggered by national policy, such as FERC Order 636, represcription of capital recovery rates, changes in customer attitudes regarding utility services, the evolution of alternative energy and information sources, deregulation, and mergers-acquisitions have all influenced stock prices in ways vastly different from the early assumptions of the DCF model developed in the early 1970s. These changes suggest that some of the raw assumptions underlying the standard DCF model are questionable, and that the DCF model should be complemented by several alternate methodologies to estimate the cost of common equity.

Contrary to the standard DCF assumption of a constant P/E ratio, stock price may not necessarily be expected to grow at the same rate as earnings and dividends by investors. This is especially true in the short run. Investors may very well assume that the P/E ratio will in fact continue to increase in the short run, fueling the expected rate of return. The converse is also true. P/E ratios have proved volatile and unstable in recent years. The essential point is that the constancy of the P/E ratio required in the standard DCF model may not always be a valid assumption. To the extent that increases (decreases) in relative market valuation are anticipated by investors, especially myopic investors with short-term investment horizons, the standard DCF model will understate (overstate) the cost of equity.

Another concern deals with the realism of the constant growth rate assumption and with the difficulty of finding an adequate proxy for that growth rate. The standard DCF model assumes that a single growth rate of dividends is applicable in perpetuity. It is difficult to imagine that today's energy utility industry can be described as stable. Not only is the constant growth rate assumption somewhat unrealistic, but it is difficult to proxy. Analysts' growth forecasts are usually made for not more than two to five years, or if they are made for more than a few years, they are dominated by the near-term earnings and dividends picture. In short, the perpetual growth term of the DCF model does not square well with the shorter-term focus of institutional investors.

In summary, caution and judgment are required in interpreting the results of the DCF model. There is a clear need to go beyond the DCF model, accord it the weight it deserves, and to examine the results produced by several alternate methodologies as I did in my supplemental testimony.

Q. IS THERE ANY EVIDENCE THAT MR. HENRY'S DCF RESULTS ARE UNRELIABLE?

A. Yes, there is. I have examined Mr. Henry's DCF results set forth in his Exhibit _(CEH-6)(Page 3 of 3). The DCF results shown in the last column are scattered all over, ranging from a low of 5.99% to a high of 14.63%. Several estimates are barely above, and even below, the cost of debt for these companies. The huge variability in the results demonstrates the lack of reliability of the DCF approach and the need to employ, and rely more heavily upon, a variety of methodologies when estimating the cost of capital.

2. ALLOWED RETURNS

Q. IS MR. HENRY'S RATE OF RETURN RECOMMENDATION COMPATIBLE WITH CURRENTLY ALLOWED RETURNS IN THE UTILITY INDUSTRY?

A. No, it is not. Allowed returns, while certainly not a precise indication of a company's cost of equity capital, are nevertheless important determinants of investor growth perceptions and investor expected returns. They also serve to provide some perspective on the validity and reasonableness of Mr. Henry's recommendation.

I have examined the ROEs currently allowed for the 30 electric utilities in Mr. Henry's comparable group as reported in the AUS Utility Reports survey for April 2007. The currently authorized ROEs for Mr. Henry's sample of electric utilities, shown in Table 1 below, average 11.1%.

Table 1 Authorized ROEs
Mr. Henry's Comparable Group

1	ALLETE	11.6%
2	Alliant Energy	11.1%
3	Amer. Elec. Power	11.1%
4	Ameren Corp.	10.4%
5	Cleco Corp.	11.3%
6	Consol. Edison	11.1%
7	DPL Inc.	11.0%
8	DTE Energy	11.0%
9	Edison Int'l	11.6%
10	Empire Dist. Elec.	10.9%
11	Energy East Corp.	10.9%
12	Entergy Corp.	11.0%
13	Exelon Corp.	10.1%
14	FPL Group	11.8%
15	Hawaiian Elec.	10.8%
16	IDACORP Inc.	
17	MGE Energy	11.0%
18	NiSource Inc.	11.8%
19	Northeast Utilities	9.8%
20	NSTAR	12.5%

21	PG&E Corp.	11.4%
22	Pinnacle West Capital	10.3%
23	PNM Resources	10.3%
24	Portland General	
25	Progress Energy	12.4%
26	Southern Co.	12.2%
27	Vectren Corp.	11.0%
28	Westar Energy	10.0%
29	Wisconsin Energy	11.2%
30	Xcel Energy Inc.	11.1%
	AVERAGE	**11.1%**

Source: AUS Utility Reports 02/2007

In short, Mr. Henry's ROE recommendation is well outside the mainstream of the allowed rates of return that were current during the period in which Mr. Henry performed his analysis, lies outside the zone of recently authorized ROEs for electric utilities and for his own sample of companies, and would constitute the lowest ROE allowance in the country for a major utility. The Commission is not bound by decisions of other regulators regarding allowed ROE, but one cannot overlook the glaring difference between Mr. Henry's recommendation and the returns currently allowed for the very same firms that Mr. Henry deems comparable in risk.

Unreasonable rate treatment for a New York utility, if implemented, may have serious public policy implications and repercussions for the State of New York which are not mentioned in Mr. Henry's testimony. For example, the quality of regulation and the reasonableness of rate of return awards clearly have implications for regulatory climate, economic development and job creation in a given territory. The consistency of regulation in a given state has similar implications. It is my belief that Mr. Henry's recommended return has negative implications on these grounds and is not consistent with the economic well-being of the State.

3. DCF MODEL UNDERSTATES THE COST OF EQUITY

Q. DO MR. HENRY'S DCF RESULTS UNDERSTATE THE COST OF EQUITY?

A. Yes, they do, and so does my own DCF results for that matter. Application of the DCF model produces estimates of common equity cost that are consistent with investors' expected return only when stock price and book value are reasonably similar, that is, when the M/B ratio is close to unity. The simple numerical illustration shown in my supplemental testimony demonstrated that when the DCF cost rate is applied to a book value rate base well above the market price, the DCF cost rate understates the investor's required return. This is particularly relevant in the current capital market environment where utility stocks are trading at M/B ratios well above unity and have been for two decades. The converse is also true, that is, the DCF model overstates the investor's return when the stock's M/B ratio is less than unity. The reason for the distortion is that the DCF market return is applied to a book value rate base by the regulator, that is, a utility's earnings are limited to earnings on a book value rate base.

Therefore, the DCF cost rate understates the investor's required return when stock prices are well above book, as is the case presently, and Mr. Henry's DCF results understate O&R's cost of common equity capital.

Q. DO REGULATORS SHARE THESE RESERVATIONS ON THE RELIABILITY OF THE DCF MODEL?

A. Yes, I believe they do. As I indicated in my supplemental testimony, while a vast majority of regulatory commissions do not rely solely on the DCF model results in setting the allowed rate of return on common equity, some regulatory commissions have explicitly recognized the need to avoid excessive reliance upon the DCF model and have

acknowledged the need to adjust the DCF result when M/B ratios exceed one[1].

4. DCF FUNCTIONAL FORM

Q. WHAT IS THE APPROPRIATE FORM OF THE DCF MODEL?

A. The annual DCF model used by Mr. Henry ignores the time value of quarterly dividend payments and assumes that dividends are paid once a year at the end of the year. Since investors are aware of the quarterly timing of dividend payments, this knowledge is reflected in stock prices. As I show in Chapter 11 of my book, *The New Regulatory Finance*, the use of the annual version of the DCF model understates the cost of equity by approximately 20 basis points, depending on the magnitude of the dividend yield component.

By analogy, a bank rate on deposits which does not take into consideration the timing of the interest payments understates the true yield if you receive the interest payments more than once a year. The actual yield will exceed the stated nominal rate. To illustrate, if an investor has a choice between investing $1,000 in a bank account which promises a return of 10% compounded annually and another bank account which promises a return of 10% but compounded quarterly, he will clearly select the latter. Due to the quarterly compounding of interest, the investor earns an effective return of 10.38% on the latter bank account versus 10% on the former. The same is true for the return on common stocks.

5. DCF STOCK PRICE

[1] See the Indiana Utility Regulatory Commission decision in Indiana Mich. Power Co. (IURC 8/24/90), Cause No. 38728, 116 PUR4th 1, 17-18. See also the Iowa Utilities Board decision in U.S. West Communications, Inc., Docket No., RPR-93-9, 152 PUR4th, 459. See also the Hawaii Public Utilities Commission decision in Hawaiian Electric Company, Inc., Docket No. 6998, PUR4th, 134. More recently, see the Pennsylvania Public Utility Commission decision in Pennsylvania-American Water Company, Docket 130680, PUR4th, 1/25/02.

Q. CAN YOU COMMENT ON MR. HENRY'S STOCK PRICE IN HIS DCF MODEL?

A. In his implementation of the DCF model, shown on Exhibit _(CEH-6), Mr. Henry uses the average dividend yield over the six months prior to April, 2007. I disagree with the use of such a stale stock price to calculate dividend yield reaching as far back as October 2006. The stock price to employ is the current price of the security at the time of estimating the cost of equity, rather than some historical average stock price reaching back six months. The reason is that the analyst is attempting to determine a utility's cost of equity in the future, and since current stock prices provide a better indication of expected future prices than any other price according to the basic tenets of the Efficient Market Hypothesis, the most relevant stock price is the most recent one. The Efficient Market Hypothesis, which is widely accepted, states that capital markets, at least as a practical matter, incorporate into security prices relevant publicly available information, such that current security prices reflect the most recent information and thus are the best representation of investor expectations. Use of any other price violates market efficiency principles.

There is yet another justification for using current stock prices. In measuring the cost of equity as the sum of dividend yield and growth, the period used in measuring the dividend yield component must be consistent with the estimate of growth with which it is paired. Since the current stock price is caused by the growth foreseen by investors at the present time and not at any other time, it is clear that the use of spot prices is preferable. Mr. Henry has essentially mismatched a stale average stock price reaching as far back as October 2006 with a current estimate of expected growth. This not only violates market

efficiency principles, but also constitutes a mismatch in the application of the DCF model. A stock price dating back six months reflects stale information and is not representative of current market conditions.

An analogy with interest rates will clarify this point. If, for example, interest rates have climbed from 5% to 6% over the past three months, it would be incorrect to state that the current interest rate is in the range of 5% to 6% just because this is the interest rate range for the past six months. Analogously, it is incorrect to state that the cost of equity, which has also risen along with interest rates, is in some given six-month range. Just as the current interest rate is 6%, the cost of equity estimate is that which is obtained from the standard DCF using current spot prices.

6. EARNINGS RETENTION GROWTH METHOD

Q. WHAT SPECIFIC DCF METHODOLOGY DID MR. HENRY EMPLOY TO DETERMINE THE COST OF EQUITY?

A. Mr. Henry applied a two-stage DCF analysis to a sample of 30 electric utilities, using the earnings retention growth method as a proxy for the expected long-term growth component in the second stage. Using an average retention growth rate of 5.1% [next to last column Exhibit _(CEH-6) (Page 3 of 3)] produced an average DCF cost of equity estimate of 8.29% reported on the last column of the same exhibit.

Q. PLEASE COMMENT ON MR. HENRY'S GROWTH ESTIMATE IN THE DCF MODEL.

A. **Mr. Henry relies exclusively on the earnings retention growth method in the crucial** second stage of his DCF analysis, where the growth rate is based on the equation g = b(ROE), where b is the percentage of earnings retained and ROE is the expected ROE.

He also accounts for the impact of external stock financing on growth by adding an external growth term (g = sv).

I disagree with earnings retention growth technique for four reasons: 1) the method is logically circular, for it required Mr. Henry to assume the ROE answer to begin with, 2) inconsistency with the academic empirical evidence, 3) the potential lack of representativeness of Value Line's forecasts as proxies for the market consensus, and 4) a technical error.

Q. ARE THE GROWTH RATES USED BY MR. HENRY CONSISTENT WITH HIS RATE OF RETURN RECOMMENDATION?

A. No, they are not. Mr. Henry's retention growth methodology contains a puzzling logical contradiction. This is because the method requires an explicit assumption on the ROE expected from the retained earnings that drive future growth. Mr. Henry bases his ROE estimate on Value Line's forecast ROE for the period through 2011. But the ROEs used by Mr. Henry in calculating his retention growth rate do not match Mr. Henry's ROE recommendation. The table below replicates the ROE forecasts used by Mr. Henry in deriving his retention growth rates.

The average expected ROE 11.3% used in Mr. Henry's retention growth computation and reported on Exhibit _ (CEH-6) exceeds his recommended 8.95%. Mr. Henry is assuming in effect that his sample companies will earn a ROE exceeding what he has determined to be their cost of equity forever. That is, **he is assuming that these companies will earn a ROE higher than that granted by their regulators and reflected in their rates.** While this scenario implicit in Mr. Henry's retention growth method may be imaginable for an unregulated company with substantial market power, **it**

is implausible for a regulated company whose rates are set by its regulator at a level designated to permit the company to earn a return equal to its cost of capital. I consider this logical flaw damaging to the integrity of Mr. Henry's analysis, and consider it to be a sufficient basis for rejecting Mr. Henry's results produced by this method, which constitute the cornerstone of his ROE recommendation. In essence, Mr. Henry is using an ROE that differs from his final recommended cost of equity, and is requesting the Commission to make two inconsistent findings regarding ROE. I am perplexed as to why Mr. Henry assumes that his group of comparable electric utilities is expected to earn 11.3% forever, while at the same time he recommends an ROE of only 8.95% for the Company. The only way that these utilities can earn an ROE of 11.3% is if rates are set so that they will in fact earn 11.3%. The only logical conclusion to be drawn from the data is that the group's cost of equity is 11.3%, since these are the returns implied in Mr. Henry's retention growth analysis. So, how can the cost of equity be any different from 11.3%?

Table 2 Mr. Henry's Forecast ROE

1	ALLETE	14.1%
2	Alliant Energy	10.0%
3	Amer. Elec. Power	9.0%
4	Ameren Corp.	13.0%
5	Cleco Corp.	9.9%
6	Consol. Edison	9.0%
7	DPL Inc.	19.8%
8	DTE Energy	9.3%
9	Edison Int'l	11.6%
10	Empire Dist. Elec.	11.1%
11	Energy East Corp.	9.4%
12	Entergy Corp.	13.4%
13	Exelon Corp.	20.6%
14	FPL Group	12.6%
15	Hawaiian Elec.	10.3%

16	IDACORP Inc.	8.5%
17	MGE Energy	13.2%
18	NiSource Inc.	8.1%
19	Northeast Utilities	8.7%
20	NSTAR	15.7%
21	PG&E Corp.	11.2%
22	Pinnacle West Capital	8.4%
23	PNM Resources	8.5%
24	Portland General	9.0%
25	Progress Energy	9.4%
26	Southern Co.	13.1%
27	Vectren Corp.	11.1%
28	Westar Energy	9.8%
29	Wisconsin Energy	11.0%
30	Xcel Energy Inc.	11.2%
	AVERAGE	**11.3%**

Source: Mr. Henry Exhibit _(CEH-6) Page 3

Q. IS THE RETENTION GROWTH RATE TECHNIQUE CONSISTENT WITH THE EMPIRICAL EVIDENCE?

A. No, it is not. The second difficulty with the retention growth rate approach is that the empirical finance literature demonstrates this particular method of determining growth is a very poor explanatory variable of market value, and is not as significantly correlated to measures of value, such as stock price and price/earnings ratios.

Q. ARE VALUE LINE'S ROE AND RETENTION RATIO ESTIMATES REPRESENTATIVE OF THE MARKET CONSENSUS?

A. No. The third difficulty with Mr. Henry's retention growth rates is that exclusive reliance on Value Line forecasts of ROE and retention ratio runs the risk that such forecasts are not representative of investors' consensus forecast.

Q. PLEASE DISCUSS THE FOURTH PROBLEM WITH MR. HENRY'S

RETENTION GROWTH ESTIMATES.

A. The fourth difficulty with Mr. Henry's retention growth approach is that the forecasts of the expected return on equity published by Value Line are based on end-of-period book equity rather than on average book equity. The following formula, discussed and derived in Chapter 9 of my latest book, The New Regulatory Finance, adjusts the reported end-of-year values so that they are based on average common equity, which is the common regulatory practice:

$$r_a = r_t \frac{2\,B_t}{B_t + B_{t-1}}$$

Where:
- r_a = return on average equity
- r_t = return on year-end equity as reported
- B_t = reported year-end book equity of the current year
- B_{t-1} = reported year-end book equity of the previous year

The result of this error is that Mr. Henry's DCF estimates are understated by some 10-20 basis points, depending on the magnitude of the book value growth rate.

7. DCF GROWTH RATES: ANALYSTS' FORECASTS

Q. WHAT DOES THE PUBLISHED ACADEMIC LITERATURE SAY ON THE SUBJECT OF GROWTH RATES IN THE DCF MODEL?

A. Published studies in the academic literature demonstrate that growth forecasts made by security analysts are reasonable indicators of investor expectations, and that investors rely on analysts' forecasts.

Q. DO YOU SEE ANY DANGERS IN RELYING ON VALUE LINE AS AN EXCLUSIVE SOURCE OF FORECASTS IN APPLYING THE DCF MODEL?

A. Yes, I do. Mr. Henry relies exclusively on Value Line forecasts for his major inputs into the DCF analysis, including short-term dividend forecasts, expected return, and expected retention ratio. Mr. Henry's heavy reliance on Value Line growth forecasts runs the risk that such forecasts are not representative of investors' consensus forecast. One would expect that averages of analysts' growth forecasts such as those contained in First Call and/or Zacks, rather than one particular firm's forecast, are more reliable estimates of the investors' consensus expectations likely to be impounded in stock prices.

Q. ARE INVESTORS EXPECTING GROWTH RATES EQUAL TO MR. HENRY'S RANGE?

A. No. The best evidence shows that investors are expecting growth rates higher than Mr. Henry has found. For his group of 30 electric utilities, Mr. Henry has found [see upper panel of Exhibit _(CEH-6) (Pages 2 and 3)] average growth rates of 4.3% and 5.1% for the first and second stage of his DCF analysis, respectively. The table below reports the consensus analysts' long-term growth forecast from both Value Line and Zacks Investment Research, as reported in the Value Line database. The average long-term growth forecast for the group from Value Line and Zacks are nearly identical at 6.4% and 6.5%, respectively. This is almost 200 basis points (2.0%) above Mr. Henry's long-term growth estimate of 4.3% - 5.1% (midpoint 4.7%). Incidentally, it is not clear as to why Mr. Henry computed near-term dividend growth using Value Line's forecast of yearly dividends rather than simply relying on Value Line's dividend growth forecast that is directly available from the Value Line database. It is inexplicable as to how Mr. Henry

computed a near-term growth rate of 4.3% while Value Line projects 6.5% for his sample companies.

Q. HOW WOULD MR. HENRY'S DCF RESULT CHANGE USING ANALYSTS GROWTH FORECAST INSTEAD OF THE ILL-FATED EARNINGS RETENTION GROWTH METHOD IN HIS SECOND DCF ANALYSIS?

A. Using the Value Line dividend forecast and/or the consensus growth forecast of 6.4% - 6.5% instead of Mr. Henry's 4.3% - 5.1% in Mr. Henry's Exhibit _(CEH-6) would increase the DCF estimate of the cost of common equity by 200 basis point (2%), that is, from 8.29% to approximately 10.30%.

Table 3 Mr. Henry's Comparable Companies
Analysts' Growth Forecasts

	Company	Value Line Projected Dividend Growth	Zacks Analysts Growth
1	ALLETE	14.0	5.0
2	Alliant Energy	5.5	4.0
3	Amer. Elec. Power	7.5	4.7
4	Ameren Corp.		6.7
5	Cleco Corp.	4.0	12.0
6	Consol. Edison	1.0	3.5
7	DPL Inc.	3.5	6.3
8	DTE Energy	2.5	5.7
9	Edison Int'l	15.0	8.3
10	Empire Dist. Elec.		
11	Energy East Corp.	4.5	3.5
12	Entergy Corp.	7.5	10.8
13	Exelon Corp.	7.5	10.5
14	FPL Group	6.5	9.4
15	Hawaiian Elec.		5.2
16	IDACORP Inc.	-2.0	5.0
17	MGE Energy	1.0	
18	NiSource Inc.	1.5	3.5
19	Northeast Utilities	6.5	13.0

20 NSTAR	8.0	6.3
21 PG&E Corp.	33.0	7.8
22 Pinnacle West Capital	5.0	6.7
23 PNM Resources	8.5	7.3
24 Portland General		6.5
25 Progress Energy	1.5	4.4
26 Southern Co.	3.5	4.0
27 Vectren Corp.	3.0	4.5
28 Westar Energy	6.0	4.0
29 Wisconsin Energy	6.5	8.4
30 Xcel Energy Inc.	5.5	4.5
Averages	**6.4**	**6.5**

Source: Value Line Investment Analyzer 04/07

8. DCF GROWTH: LONG-TERM ECONOMIC GROWTH

Q. IS MR. HENRY'S CHOICE OF GROWTH RATES CONSISTENT WITH THE LONG-TERM GROWTH OF THE U.S. ECONOMY?

A. No, it is not. Mr. Henry's average growth rates of 4.3% - 5.1% are quite inconsistent with the very long-term growth of the economy. Because the growth term of the DCF model is perpetual in nature, it is quite reasonable to assume that a utility's long-term growth profile will match the overall growth of the economy.

Long-term forecasts of nominal growth in GDP are available from commercial sources, such as Standard & Poor's DRI and Blue Chip Forecast. Additionally, a long-term forecast of nominal growth in GDP can be formulated by combining a long-term inflation estimate with a long-term real growth rate forecast as follows:

GDP Nominal growth = GDP Real Growth + Expected Inflation

The growth rate in U.S. real GDP has been reasonably stable over time. Therefore, its historical performance is a reasonable estimate of expected long-term

future performance. The growth in real GDP for the 1929-2005 period was approximately 3.4%. The long-term expected inflation rate can be obtained by comparing the yield on long-term U.S. Treasury bonds with the yield on inflation-adjusted bonds of the same maturity. The current yield on 20-year Treasury bonds is 4.9%, and the yield on inflation-adjusted bonds ("Treasury Inflation Protected Securities," or "TIPS") for the same maturity is 2.4%. The difference between the two securities yields an approximate inflation rate of 2.5% (4.9% – 2.4% = 2.5%).

Using the above formula, the long-term expected GDP nominal growth is approximately 5.9% (3.4% + 2.5% = 5.9%). In sum, Mr. Henry's growth forecast of 4.3% - 5.1% (midpoint 4.7%) for his comparable group of electric utilities understates the long-term expected GDP nominal growth by approximately 120 basis points (1.2%).

Q. HOW WOULD MR. HENRY'S DCF RESULT CHANGE IF A MORE REASONABLE GDP GROWTH FORECAST IS USED IN HIS SECOND DCF ANALYSIS?

A. Using the projected long-term growth of GDP of 5.9% instead of Mr. Henry's 4.3% - 5.1% (midpoint 4.7%) in Mr. Henry's Exhibit _(CEH-6) would increase the DCF estimate of the cost of common equity from 8.29 to 9.50% from this flaw alone.

9. CAPM: MARKET RISK PREMIUM (MRP)

Q. WHAT INPUTS DOES MR. HENRY USE IN HIS CAPM ANALYSIS?

A. Three inputs are required in order to implement the CAPM: the risk-free rate, the beta risk measure, and the MRP. For the risk-free rate, Mr. Henry uses 4.77%. For beta, he uses 0.92, based on Value Line beta estimates for his sample of electric companies. For the MRP, he uses 6.1%, based solely on a Merrill Lynch forecast.

Q. DO YOU AGREE WITH MR. HENRY'S RISK-FREE RATE?

A. Yes, I do.

Q. DO YOU AGREE WITH MR. HENRY'S BETA ESTIMATES?

A. Yes, I do.

Q. HOW DOES MR. HENRY ESTIMATE THE MARKET RISK PREMIUM COMPONENT OF THE CAPM?

A. In order to determine the MRP component of the CAPM, Mr. Henry relies on Merrill Lynch's in-house forecast of 10.9% for the overall equity market. Subtracting Mr. Henry's risk-free rate of 4.77%, we obtain a MRP of 6.1%

Q. IS MERRILL LYNCH'S ESTIMATE OF THE MRP REPRESENTATIVE OF THE MARKET CONSENSUS?

A. No. The major difficulty with Mr. Henry's MRP estimate is that exclusive reliance on Merrill Lynch's in-house forecast is not representative of investors' consensus forecast.

Q. IS MR. HENRY'S ASSESSMENT OF THE MRP OF 6.1% CONSISTENT WITH THE VAST LITERATURE ON THE SUBJECT?

A. No, not quite. Ibbotson's *Stocks, Bonds, Bills, and Inflation 2007 Yearbook* is a primary source of data on U.S. capital market returns. This annual publication compiles monthly returns to various asset classes from 1926 to date. From Ibbotson 2006, a broad market sample of U.S. common stocks outperformed long-term U.S. government bonds by 6.5%. The historical MRP over the income component of long-term Treasury bonds rather than over the total return is 7.1%. It has been common practice to assume that this historical result provides an adequate basis for the expected MRP.

In their widely-used textbook, Brealey, Myers & Allen state:

We have no official position on the exact market risk premium, but we believe a range of 6 to 8 percent is reasonable for the United States[2].

Published work by Dimson, Marsh, and Staunton[3] report returns over the period 1900 to 2000 for twelve countries, representing 90% of today's world market capitalization. They report an average risk premium over long bond returns over all countries of 5.6%, with the U.S. at 7.0%. The premium was generally higher for the second half century than for the first. For example, the U.S. had 5% in the first half, compared to 7.5% in the second half, again in excess of Mr. Henry's 6.1% estimate.

A second approach to estimate the MRP is prospective in nature and consists of applying the DCF model to an aggregate equity index, as I did in my supplemental testimony. A prospective study cited in my supplemental testimony and published in *Financial Management* by Harris, Marston, Mishra, and O'Brien ("HMMO") provides estimates of the ex ante expected returns for S&P 500 companies over the period 1983-1998.[4] From that study, the average MRP estimate for the overall period is 7.2%, again in excess of Mr. Henry's 6.0% estimate.

Q. IS MR. HENRY'S MRP ESTIMATE CONSISTENT WITH REGULATORY DECISIONS?

A. No, it is not. It is useful to examine the "reverse" MRP estimates implicit in regulatory ROE decisions. The CAPM framework can be used to quantify the MRP implicit in the allowed risk premiums for regulated utilities. According to the CAPM, the

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[2]Brealey, R., Myers, S., and Allen, P., *Principles of Corporate Finance,* 8th editionm, New York: McGraw-Hill, 2006.

[3]Dimson, Elroy, Paul Marsh and Mike Staunton (2000) "Risk and Return in the 20th and 21st centuries." *Business Strategy Review* 11(2): 1-18.

[4] Harris, R. S., Marston, F. C., Mishra, D. R., and O'Brien, Henry. J., "*Ex Ante* Cost of Equity Estimates of S&P 500 Firms: The Choice Between Global and Domestic CAPM," *Financial Management*, Autumn 2003, pp. 51-66.

risk premium is equal to beta times the market risk premium:

$$\text{Risk Premium} = \beta (R_M - R_F)$$

$$\text{Risk Premium} = \beta \times \text{MRP}$$

Solving for MRP, we obtain:

$$\text{MRP} = \text{Risk Premium} / \beta$$

I examined the MRPs implied in 178 regulatory decisions for electric utilities in the United States over the period 1997-2006. Using the allowed average risk premium of 5.6% in these decisions over the last decade and an average beta of 0.80 for U.S. electric utilities during that period, the implied market risk premium is 7.0%, again in excess of Mr. Henry's estimate of 6.1%.

Q. WHAT DO YOU CONCLUDE ON MR. HENRY'S MRP ESTIMATE?

A. All and all, the evidence points to a MRP estimate of at least 7%, well in excess of Mr. Henry's 6.1% estimate. The net result is that Mr. Henry's CAPM estimate of O&R"s cost of common equity is understated by almost 1.0%, which is the difference between 7.0% and 6.1% times Mr. Henry's Value Line beta estimate of 0.92. That would raise Mr. Henry's CAPM estimate shown on Exhibit _(CEH-7) by about 100 basis points, that is, from 10.41 - 10.53% to almost 11.41% - 11.53%.

10. FLOTATION COSTS

Q. IN YOUR SUPPLEMENTAL TESTIMONY, YOU STATED THAT THE RETURN ON EQUITY SHOULD BE ADJUSTED TO INCLUDE AN ALLOWANCE FOR FLOTATION COSTS. PLEASE COMMENT ON FLOTATION COSTS.

A. Flotation costs are very similar to the closing costs on a home mortgage. In the case

of issues of new equity, flotation costs represent the discounts that must be provided to place the new securities. Flotation costs have a direct and an indirect component. The direct component represents monetary compensation to the security underwriter for marketing/consulting services, for the risks involved in distributing the issue, and for any operating expenses associated with the issue (printing, legal, prospectus, etc.). The indirect component represents the downward pressure on the stock price as a result of the increased supply of stock from the new issue. The latter component is frequently referred to as "market pressure."

Flotation costs for common stock are analogous to the flotation costs associated with past bond issues which, as a matter of routine regulatory policy, continue to be amortized over the life of the bond, even though no new bond issues are contemplated. In the case of common stock, which has no finite life, flotation costs are not amortized. Therefore, the recovery of flotation cost requires an upward adjustment to the allowed return on equity.

As demonstrated in my original testimony, the expected dividend yield component of the DCF model must be adjusted for flotation cost by dividing it by (1 - f), where f is the flotation cost factor.

Q. WHAT FLOTATION COST TREATMENT DID MR. HENRY RECOMMEND IN THIS CASE?

A. Both Mr. Henry and I agree on the need for a flotation cost adjustment, but we disagree on its magnitude. He recommends an allowance of only 9 basis points versus my 30 basis points. The magnitude of the flotation cost adjustment formula used by Mr. Henry is only correct if the flotation costs associated with all past common equity issues

have been recovered. The standard flotation cost allowance used in my supplemental testimony is designed to recover the flotation costs associated with all past issues that were not expensed, but rather written off against common equity.

By analogy, in the case of a bond issue, flotation costs are amortized over the life of the bond, and the annual amortization charge usually is embedded in the cost of debt for ratemaking purposes. This is done whether the company intends to issue bonds in the future or not and/or whether the company has issued bonds in the past or not. The recovery of bond flotation expense continues year after year irrespective of whether the company issues new debt capital until recovery is complete, in the same way that the recovery of past investments in plant and equipment through depreciation allowances continues in the future even if no new construction is contemplated. In the case of common stock, which has no finite life, flotation costs are not amortized to a specific issuance as is the case for a bond. However, the recovery of flotation costs requires a similar upward adjustment to the return on equity that is allowed for ratemaking purposes. Unlike the case of bonds, common stock has no finite life so that flotation costs cannot be amortized and must therefore be recovered via an upward adjustment to the allowed return on equity. As in the case of bonds, the recovery continues year after year regardless of whether the utility raises new equity capital until the recovery process is terminated.

To the extent that O&R's flotation costs associated with past common equity issues have not been recovered, the only recovery mechanism available for the recovery of such costs is an upward adjustment to the return on equity as was used in my supplemental testimony.

In short, Mr. Henry's DCF estimates of equity costs are downward-biased by approximately 20 basis points to the extent that the flotation costs associated with past equity issues have not been expensed or recovered in the past.

11. RESPONSE TO MR. HENRY'S CRITICISMS

Comparable Group

Q. HOW DO YOU RESPOND TO MR. HENRY'S CRITICISM OF YOUR COMPARABLE GROUP OF ELECTRIC UTILITIES?

A. On page 43-44 of his direct testimony, Mr. Henry expresses concern that my comparable group of electric utilities is not suitable as a proxy for O&R. That is a strange criticism given that the average beta risk of my group, 0.92, is identical to the average beta risk of Mr. Henry's group, and the same is true of the average bond rating of each group.

Historical Risk Premium

Q. DO YOU AGREE WITH MR. HENRY'S FIRST CRITICISM OF YOUR HISTORICAL RISK PREMIUM STUDY?

A. No, I do not. On page 49, Mr. Henry argues that I have not demonstrated whether O&R is more or less risky than the companies that make up Moody's Electric Utility Index. I disagree, given the fragile status of its existing credit ratings. I believe that O&R is at least as risky as the average electric utility. O&R's credit ratings are already fragile as indicated by the recent downgrading by Moody's of its bonds due in part to weak financial ratios. O&R has a substantial construction program in the future. The Company's ability to tap capital markets and attract funds on reasonable terms occurs at a crucial point in time

when the Company has an ambitious capital expenditures program and will require external financing. O&R's large capital expenditure program over the next several years increases its dependence on capital markets which have become volatile and more unpredictable. This is no time to reduce the company's return relative to its industry peers.

Moreover, over most of the period that covers my historical risk premium study, 1926-2005, the electric utility was relatively homogenous in risk and under the umbrella protection of regulation for all of its functions (power generation, transmission, distribution).

Q. DO YOU AGREE WITH MR. HENRY'S SECOND CRITICISM OF YOUR HISTORICAL RISK PREMIUM STUDY?

A. No, I do not. On page 50, Mr. Henry critiques the risk premium method on the grounds that the method assumes that the risk premium is constant over time.

This criticism is unwarranted. I employed returns realized over long time periods rather than returns realized over more recent time periods. Realized returns can be substantially different from prospective returns anticipated by investors, especially when measured over short time periods. A risk premium study should consider the longest possible period for which data are available. Short-run periods during which investors earned a lower risk premium than they expected are offset by short-run periods during which investors earned a higher risk premium than they expected. Only over long time periods will investor return expectations and realizations converge, or else, investors would never commit any funds.

I have ignored realized risk premiums measured over short time periods, since they are heavily dependent on short-term market movements. Instead, I have relied on

results over periods of enough length to smooth out short-term aberrations, and to encompass several business and interest rate cycles. The use of the entire study period in estimating the appropriate market risk premium minimizes subjective judgment and encompasses many diverse regimes of inflation, interest rate cycles, and economic cycles.

To the extent that the historical equity risk premium estimated follows what is known in statistics as a random walk, one should expect the equity risk premium to remain at its historical mean. The best estimate of the future risk premium is the historical mean. As I explained in my supplemental testimony, since I found no evidence that the market price of risk or the amount of risk in common stocks has changed over time, that is, no significant serial correlation in the successive market risk premiums from year to year, it is reasonable to assume that these quantities will remain stable in the future.

Q. IS THE RISK PREMIUM METHODOLOGY CONSISTENT WITH FINANCIAL THEORY?

A. **It certainly is. The Risk Premium approach is conceptually sound and firmly rooted in** the conceptual framework of Capital Market Theory. It is widely used by analysts, investors, and expert witnesses. Most college-level corporate finance and/or investment management texts contain detailed conceptual and empirical discussion of the risk premium approach[5]. The latter is typically recommended as one of the three leading methods of estimating the cost of capital[6]. Techniques of risk premium analysis are widespread in investment community reports. Professional certified financial analysts are certainly well versed in the use of this method.

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[5] See Bodie, Z., Kane, A., and Marcus, A. J., *Investments*, McGraw-Henry Irwin, 6th ed., 2005., a recommended textbook for Chartered Financial Analyst certification and examination.

[6] See Brigham and Erhhardt (2005), Corporate Finance: A Focused Approach, 2nd ed., Thomson 2006.

Data requirements to implement the method are not prohibitive. The methodology is responsive to changes in capital market conditions and provides a timely signaling device for current interest rate trends in contrast to the DCF method, which may be sluggish in detecting changes in return requirements, especially when based on historical data. One advantage of risk premium over DCF is that the former takes a broader time-series perspective rather than a snapshot point-in-time viewpoint, and is therefore less vulnerable to the vagaries of any one particular capital market environment.

Allowed Returns

Q. PLEASE RESPOND TO MR. HENRY'S CRITICISM OF ALLOWED RISK PREMIUMS BY REGULATORS.

A. On pages 50-51 of his testimony, Mr. Henry argues that the determination of an allowed return is flawed because it assumes that O&R possesses the same degree of risk as the returns allowed by regulators for the industry. I have already commented on O&R's relative degree of risk and reject that criticism.

Mr. Henry also argues that I have not factored in particular features associated with past ROE decisions, such as multi-year rate plans and stayout premiums. I note that several ROE awards are part of incentive mechanism with substantial upside potential, so that the allowed risk premium is more often than not understated. In other words, my allowed risk premium is estimate is very likely a conservative one.

Q. PLEASE COMMENT ON MR. HENRY'S CRITICISM OF YOUR DCF ANALYSIS.

A. On page 45 of his testimony, Mr. Henry criticizes my DCF earnings growth rates on the grounds that I have not addressed how these earnings growth estimates relate to the

dividend payout policies of my companies and whether they are sustainable over time. I totally disagree with this point of view. One of the key assumptions that underlies the DCF model is that earnings, dividends, book value, and market price all grow at a constant rate forever. In other words, the dividend payout ratio remains constant over time. That is the assumption I made, and that is the assumption that Mr. Henry also made in the second stage of his DCF analysis. In my supplemental testimony and earlier in my rebuttal, I discussed the merits of using consensus analysts' earnings growth forecasts in the DCF model and the supportive empirical literature.

CONCLUSIONS

Q. WHAT RETURNS ARE INVESTORS EXPECTING FOR MR. HENRY'S GROUP OF COMPANIES?

A. As shown in Table 2, investors are expecting an average ROE of 11.3%.

Q. WHAT IS THE AVERAGE AUTHORIZED ROE FOR MR. HENRY'S GROUP OF COMPANIES?

A. As shown in Table 1, the average authorized ROE for these comparable companies is 11.1%.

Q. WHAT ROE DOES MR. HENRY RECOMMEND?

A. Mr. Henry's recommended ROE is 8.95%.

Q. WHAT IS MR. HENRY'S AMENDED ROE?

A. Applying the various changes and corrections I have outlined in my rebuttal, Mr. Henry's analysis indicates a conservative return of 11%, as shown below.

Q. WHAT DO YOU CONCLUDE FROM MR. HENRY'S COST OF CAPITAL TESTIMONY?

A. My general conclusions are:

1. Unreliable Recommendation. His cost of equity recommendation is unreasonably low, and is not a reliable estimate of O&R's cost of equity capital given his heavy reliance on one particular and fragile cost of equity methodology which is known to understate investor returns.

2. Allowed returns. Mr. Henry's recommended return is well outside the zone of currently allowed rates of return for his comparable companies.

3. The DCF Model Understates the Cost of Equity. It is well-known that application of the standard DCF model to utility stocks understates the investor's expected return when the M/B ratio exceeds unity. This is particularly relevant in the current capital market environment where utility stocks, including Mr. Henry's group of comparable companies, are trading at M/B ratios well above unity.

4. DCF Functional Form. Mr. Henry relies on the annual form rather than on the quarterly version of the DCF model, understating the cost of equity by 20 basis points.

5. Stock Price in the DCF model. His application of the DCF model violates market efficiency principles and mismatches stock price and expected growth.

6. DCF Earnings Retention Growth. There is a logical inconsistency in the retention growth technique because Mr. Henry is forced to assume the answer to implement the method. From Mr. Henry's own evidence, investors expect substantially higher returns for utilities than what he recommends.

7. DCF Growth Rates: Analysts' Forecasts. Investors are expecting substantially higher growth rates than Mr. Henry's 4.3% first-stage growth rate and 5.1%

second-stage growth rate for his comparable companies. Using Value Line's dividend growth forecast and the analysts consensus growth forecast increases Mr. Henry's DCF estimates by 200 basis points.

8. DCF Growth Rates: Long-term Economic Growth. Mr. Henry's long-term growth forecast of 4.36% for his comparable group of electric utilities based on the earnings retention growth method understates the long-term expected GDP nominal growth by approximately 120 basis points (1.2%).

9. CAPM Market Risk Premium. Mr. Henry's MRP is understated and ignores the vast literature on the subject. Using the appropriate MRP, Mr. Henry's CAPM estimates are to be raised by 100 basis points from this correction alone.

10. Flotation Costs. Mr. Henry's DCF estimates of equity costs are downward-biased by approximately 25 basis points to the extent that not all the flotation costs associated with past equity issues have been expensed or recovered in the past.

11. Criticisms of my testimony. Mr. Henry's criticisms of my recommendation are without foundation.

Q. WHAT IS YOUR MAJOR CONCLUSION FROM MR. HENRY'S ROE RECOMMENDATION?

A. Mr. Henry's recommended ROE is vastly understated. Recognition of the proper functional form of the DCF model (20 basis points), the proper flotation cost allowance (20 basis points), and a much greater emphasis on analysts' growth forecasts in the DCF analysis (200 basis points), would raise his DCF estimate from 8.29% to 10.7%. Mr. Henry's corrected result of 10.7% is conservative for it does not include a small-cap effect.

Recognition of the appropriate MRP in the CAPM analysis raises his CAPM estimates from 10.41 - 10.53% to almost 11.41% - 11.53% (midpoint 11.5%) without flotation costs. Giving a two-third weight to the amended DCF result of 10.7% and a one-third weight to the amended CAPM result of 11.5% brings Mr. Henry's recommendation to 11%, virtually identical to my own recommendation. All and all, correcting for the various flaws in Mr. Henry's testimony would suggest much higher returns that are quite close to my own ROE recommendation for O&R. I consider my critique conservative, for it does not reflect the consistent tendency of the DCF to understate the cost of equity, nor does it reflect the understatement of the cost of equity which results from the plain vanilla annual form of CAPM analysis used by Mr. Henry.

Q. DR. MORIN, IN YOUR OWN CALCULATION OF THE REQUIRED RETURN AND IN YOUR CONCLUSIONS CONCERNING MR. HENRY'S ROE RECOMMENDATION HAVE YOU TAKEN INTO ACCOUNT THE ADDED RISK OF A COMPANY OPERATING UNDER TEMPORARY RATES, AS IS THE CASE FOR O&R PURSUANT TO THE COMMISSION'S RECENT ORDER IN THIS CASE?

A. No. My recommended return does not take into account the higher risks associated with a company operating under temporary rates, which essentially strip a regulated company from investor protections against retroactive ratemaking. These risks almost certainly result in a higher cost of capital because investors necessarily have a less clear understanding of the financial fundamentals and prospects of a company whose revenues are subject to refund. As a result, my recommended return on equity is conservative.

Q. DOES THIS COMPLETE YOUR REBUTTAL TESTIMONY?

A. Yes, it does.

Case No. 06-E-1433

ORANGE AND ROCKLAND UTILITIES, INC.
REBUTTAL TESTIMONY OF
JOHN E. PERKINS

Q. Please state your name.

A. John E. Perkins.

Q. Are you the same John E. Perkins who previously submitted direct testimony in this case?

A. Yes, I am.

Q. What is the purpose of this rebuttal testimony?

A. The purpose of this rebuttal testimony is twofold. First, I will reply to Staff witness Henry's assertions concerning the interest rates we have used for Orange and Rockland Utilities, Inc.'s ("Orange and Rockland" or the "Company") projected debt issuances. Second, I will reply to Mr. Henry's derivation of a hypothetical capital structure for Orange and Rockland.

INTEREST RATES

Q. Have you have reviewed staff witness Craig Henry's testimony (at 18-21) concerning the interest rates used for the Company's projected debt issues?

A. Yes, I have. Mr. Henry has proposed the use of the sum of Treasury interest rates as of a certain date, plus a spread equal to the spread on our latest bond issue, rather than our proposed rates.

Q. Do you agree with this approach?

A. I do not. Interest rates as of a certain date have in the past been, and will in the future be, affected by any number of short-term, extraneous factors as

demonstrated in recent months in reaction to the sub-prime mortgage crisis and Chinese equity markets. Other short-term factors, such as the latest speculations concerning monetary policy and the flow of funds into the U.S Treasuries in reaction to foreign crises, have similar impacts.

Q. What method have you used to develop rate forecasts?

A. We have used forecasts (based on the consensus of more than fifty economists) of Treasury rates from the publication Blue Chip Financial Forecasts, plus a spread to Treasuries based on current spreads in the near term and average historical spreads for later periods as our estimate of projected rates for the Company. This approach provides more stable results than simply using the most current rate.

Q. Do you have other concerns about using the spread on the latest Orange and Rockland bond issue?

A. Yes. Orange and Rockland is at risk for downgrades in its debt ratings based on inadequate rates of return. The Company may very well find itself incurring substantially higher interest costs by issuing lower rated debt when customer rates were set assuming an "A" credit rating.

Q. How should this contingency be handled?

A. If, as the position of the parties becomes known during the proceeding, the Company's credit rating is jeopardized, we will so inform the parties and request an update to our interest expense and related costs forecast.

Case No. 06-E-1433

ORANGE AND ROCKLAND UTILITIES, INC.
REBUTTAL TESTIMONY OF
JOHN E. PERKINS

CAPITAL STRUCTURE

Q. Does Mr. Henry make a proposal with respect to calculating capital structure?

A. Yes. He established separately the capitalization utilized by Consolidated Edison, Inc. ("CEI") to finance its utility and its non-utility operations based on actuals as of December 31, 2006.

Q. Please explain Mr. Henry's proposal.

A. Mr. Henry used CEI's filed financial statements to determine the capital structure of the regulated and non-regulated businesses by taking the total consolidated structure and subtracting the balance sheets of the regulated companies to approximate the non-regulated companies' capital structure. He then revised the non-regulated companies' capital structure to reflect a 50% equity ratio. This adjustment to the non-regulated equity and debt was subtracted from the regulated company capital structure. Mr. Henry then used projected changes to the regulated companies' debt and equity to arrive at a rate year capital structure for the regulated companies.

Q. Do you agree with Mr. Henry's proposal?

A. No. We have historically used a "stand-alone" capital structure, representing the actual sources of invested funds in Orange and Rockland, for purposes of determining the rate of return. The Commission has recognized that it is appropriate to use that structure through its adoption of recent Joint Proposals for

the Company's affiliate, Consolidated Edison Company of New York, Inc. ("Con Edison").

Q. Please explain.

A. For example, the Joint Proposal adopted by the Commission in the recent Con Edison steam case (Case 05-S-1376) relies upon Con Edison's actual capital structure in calculating the rate of return for purposes of the earnings sharing mechanism.

Q. Why else do you believe that it is appropriate to use Orange and Rockland's capital structure?

A. Such a structure should be used for rate-making purposes, without adjustment, so long as there is no "double-leverage," whereby the holding company issues debt and uses those funds to make equity investments in the utility subsidiary. As acknowledged by Mr. Henry (at 11), there is no double-leverage in the case of CEI's investments in Orange and Rockland. The equity dollars that have been raised by CEI have been used to build the regulated infrastructure in the same manner as the debt raised by Orange and Rockland.

Q. Do you agree with Mr. Henry's statement (at 10-11) that rating agencies base their ratings on the parent company's capital structure?

A. Two of the three major rating agencies that rate Orange and Rockland securities (Moody's and Fitch) use standalone financial ratios (including measures of

capital structure strength) in their analyses and rating decisions. In fact, Moody's specifically downgraded the debt of Orange and Rockland because of concerns that its **own** financial ratios were weak. In "Rating Action: Orange and Rockland Utilities, Inc." (September 5, 2006 at page 1) Moody's says:

> The downgrades of O&R and RECO reflect financial performance that is weaker than average for the rating category. In comparison to other regulated electric utilities with similar risk profiles, actual 2005 financial performance, and projected financial metrics for 2006 to 2008, are more consistent with the lower rating. O&R's interest coverage and total debt coverage from cash flow were 3.9x and 14% respectively in calendar 2005. RECO's cash flow to interest was 3.8x and cash flow to debt was 16.5% in calendar year 2005. The ratings also consider the potential for lower operating resilience given the relatively small scale of the companies' stand-alone operations and revenue generating capacity.

Thus, both standalone financial ratios and company-specific operational risks were taken into account in downgrading the rating. Imputing, and allowing returns on, a riskier capital structure will not improve this situation.

And Moody's has expressed a concern for the specific rate treatment of Orange and Rockland. In their "Rating Action: Moody's Places Orange & Rockland Utilities And Rockland Electric (Both A1) Under Review For Possible Downgrade; Affirms Consolidated Edison And CECONY (May 1, 2006, page 1)

> The rating action also reflects concerns about the terms of the company's electric and gas rate structure after the current rate plan terminates on October 31 of this year.

And again on page 1:

While the companies' relationships with the relevant regulators: FERC, the New York Public Utility Commission, the New Jersey Board of Public Utilities and the Pennsylvania Public Utility Commission have been generally constructive, the future results of both companies will be dependent on the final terms of the next rate plan.

Q. Do you believe the non-regulated utilities significantly affect the financial strength of the regulated entities?

A. No. From the point of view of the rating agencies, there is no significant extra risk arising from the CEI non-regulated subsidiaries. For example, the Standard & Poor's Business Profile rating of 2 is applied to both Con Edison and its parent, CEI.

Moreover, CEI has no plans to significantly increase its investments in its unregulated subsidiaries and is currently undertaking a strategic review of these investments.

Q. Do you believe Mr. Henry's adjustment of the non-regulated capital structure to be a sound allocation?

A. No. The reallocation of equity from the regulated companies to the non-regulated subsidiaries only represents a point in time and does not take into consideration changes to their capital structure before and through the rate year. The capital structure of the non-regulated entities changes over time in the same manner as that of the regulated companies. In fact, if Exhibit CEH-2 were produced using the 2002 10K SEC filing, the non-regulated subsidiaries would have shown an

equity ratio of 59% which would have increased Orange and Rockland's equity ratio over the standalone number using Mr. Henry's methodology.

Q. Leaving aside for the moment your concerns about the methodology used by Staff in proposing their capital structure, do you have any problems with the numbers used on their exhibit CEH-2?

A. Yes. Besides disagreeing with the validity of their entire approach, I reiterate my concern as expressed above that that they make a key assumption that the equity and debt in the non-regulated portion of our business will not change from the levels at December 31, 2006. This is not correct. As an example, the non-regulated subsidiary equity increased over the period September 30, 2006 to December 31, 2006 by more than $20 million, and has increased significantly in the first quarter of 2007. In turn, CEI expects to be able to retire debt and may add equity at the non-regulated subsidiaries. We have already called $325 million of holding company debt, which will be retired in May 2007. An additional $200 million of debt will mature in August 2008. The equity ratio for Orange and Rockland should not be set based on a level of debt at the holding company which is no longer relevant

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

ORANGE AND ROCKLAND UTILITIES, INC.
REBUTTAL TESTIMONY OF
JANE J. QUIN
NYPSC CASE NO. 06-E-1433

Q. Please state your name and business address.

A. Jane J. Quin, 390 West Route 59, Spring Valley, New York 10977.

Q. Have you previously testified in this proceeding?

A. Yes. I submitted supplemental testimony in this proceeding on behalf of Orange and Rockland Utilities, Inc. ("O&R" or the "Company"). I submitted my credentials as part of my supplemental testimony.

Q. What is the purpose of your rebuttal testimony in this proceeding?

A. I will respond to certain statements contained in the direct testimony of Ms. Christina Palmero on behalf of the New York State Department of Public Service ("DPS") regarding the Company's proposal to develop and implement an energy efficiency plan as described in my supplemental testimony.

Q. What is Ms. Palmero's position regarding the Company's proposal to develop and implement an Energy Efficiency Plan ("the Plan") designed to complement the programs currently offered and operated by the New York State Energy Research and Development Authority ("NYSERDA")?

A. Conceptually Ms. Palmero supports the Company's proposal to develop and implement an energy efficiency plan. However, Ms. Palmero believes that it is premature for O&R to develop and implement a portfolio of energy efficiency and demand response programs. Ms. Palmero testifies (at 5-6) that the Company should do additional planning and market

research to help ensure that the programs ultimately selected address key efficiency issues for O&R's customers as cost-effectively as possible.

Q. Do you agree with this position?

A. I agree in part with Ms. Palmero's position. In fact, the Company not only recognizes the need for additional planning and market research, it has already begun the process of preparing a Request for Proposals for a Market Potential Study ("Study") for its service territory. As noted in my supplemental testimony (at 9), the Company proposes that it utilize a portion of the unexpended funds identified in my supplemental testimony to fund this Study and to increase its energy services staffing by the addition of two positions so that it has adequate personnel to oversee this undertaking, as well as the development and implementation of the Plan. The Study will provide the Company with the necessary information to begin designing its proposed Plan, including a demographic evaluation of the service territory, energy consumption forecasts, information on energy usage, including end-use applications, equipment and peak usage trends. However, I do not agree that it was premature for the Company to suggest the type of programs that it has reviewed and considers suitable for its service territory. As noted in my supplemental testimony, O&R's proposal to undertake an energy efficiency plan in its service territory is motivated, in part, by its preliminary review of the market and the lack of certain types of energy efficiency programs being provided by NYSERDA, such as residential lighting and appliance programs and outreach and education. In this regard, the supplemental testimony outlines a starting point for

examining potential programs that may be well suited to the Company's service territory, which is approximately 85% residential, without being duplicative of the programs already offered by NYSERDA. The Company's proposal to move aggressively is consistent with the State's increased attention and focus on reducing demand for energy that Ms. Palmero acknowledges in her testimony (at 5).

Q. Does Ms. Palmero take any other positions with respect to the Company's energy efficiency proposal?

A. Yes. Ms. Palmero also testifies that the Company should pursue the development and implementation of an energy efficiency plan in collaboration with NYSERDA, Staff and other interested parties

Q. Does the Company plan on such collaboration?

A. Yes, it does. Once the Company completes its Study, it will prepare the Plan. The Company will collaborate with Staff, NYSERDA and interested parties on the design, goals and objectives, marketing plan, etc., of the programs proposed under its Plan. Specifically, O&R recognizes the need to work with NYSERDA in promoting energy efficiency in its service territory so that its customers are not confused by the roles that both entities will play in promoting energy efficiency programs and so that O&R's customers receive the maximum benefits possible from the program offerings of both NYSERDA and the Company.

Q. Does Ms. Palmero address the issues of cost recovery, incentives and recovery of lost revenues with regard to the Company's energy efficiency proposals?

A. Ms. Palmero testifies (at 8) that these issues should be addressed either as part of the collaborative process for developing the Company's overall Plan, to be approved by the Commission, or in a supplemental procedural phase addressing revenue decoupling.

Q. Do you agree with Staff's proposed approach to addressing these issues?

A. No, I do not. The Commission should make a threshold determination in the current phase of this proceeding that Company is entitled to cost recovery, recovery of lost revenues, and incentives with regard to the Company's energy efficiency proposals. Making such a determination will demonstrate that the Commission is serious about promoting energy efficiency in both the Orange and Rockland service territory and the State generally. I would note that the Commission made such a threshold determination in its decision in the most recent Consolidated Edison Company of New York, Inc. electric base rate case (Case 04-E-0572). With regard to incentives, as discussed in my supplemental testimony (at 11), the Company is proposing an incentive mechanism based on net resource savings. At this point I would elaborate that the Company proposes that it be allowed to retain 20% of the net resource benefits associated with the demand and energy reduction achieved under the Plan up to an annual goal to be established during the program design process. In addition, the Company proposes that it be allowed to retain 30% of the net resource benefits associated with the demand and energy reduction achieved under the Plan for amounts in excess of the Plan's targets. I would note that this proposed incentive mechanism may need to

be modified in the event that the Commission approves a revenue decoupling mechanism along the lines discussed in Company witness DiValentino's testimony. With respect to cost recovery, in my supplemental testimony (at 10), I proposed that after the deferred amount of $1,351,000 is expended, additional funding would be provided through the System Benefits Charge ("SBC") or a similar-type of surcharge developed for the recovery of costs associated with the development and implementation of the Plan.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

ORANGE AND ROCKLAND UTILITIES, INC.
REBUTTAL TESTIMONY OF
ANGELO M. REGAN

Q. Please state your name and business address.

A. Angelo M. Regan, 390 West Route 59, Spring Valley, New York 10977.

Q. Have you previously testified in this proceeding?

A. Yes. I submitted direct testimony in this proceeding on behalf of Orange and Rockland Utilities, Inc. ("O&R" or the "Company"). I submitted my credentials previously as part of my direct testimony.

Q. What is the purpose of your rebuttal testimony in this proceeding?

A. I will respond to certain statements contained in the direct testimonies of Mr. Robert A. Burke and Mr. Jason Pause, submitted on behalf of the New York State Department of Public Service regarding adjustments to tree trimming expense, and penalty increases pertaining to service reliability standards and performance.

Q. Please begin by addressing Mr. Burke's adjustment to tree trimming expenses.

A. As shown on Company Exhibit E-5, Schedule 9, Page 2 of 2, rate year tree trimming expense is forecasted at $6,087,000, and is based on the actual expenses of $5,880,000 for the twelve months ended June 30, 2006, adjusted for inflation. Mr. Burke points out in his direct testimony (at 16-17) that this level of tree trimming expense is "clearly not representative of past expenditures or of what is likely to happen into the future." Mr. Burke recommends reducing rate year tree trimming expense from $6,087,000 to $4,752,000 (a decrease of $1,335,000), which he

based on the actual year 2006 expenses of $4,636,000, adjusted for inflation.

Q. Do you agree with Mr. Burke's proposed adjustment to tree trimming expenses?

A. No. The increased level of expenses during the twelve months ended June 30, 2006 of $5,880,000 was the direct result of two factors: (1) the implementation of a "danger tree" program, and (2) the acceleration of the Company's trimming cycle in certain areas of the Company's service territory consistent with new regulatory policy regarding right-of-way ("ROW") management. Mr. Burke's reduced rate year tree trimming expense of $4,752,000, which is based on calendar year 2006, does not adequately reflect this increased level of expenses that the Company will incur during the rate year ending June 30, 2008.

Q. What is the "danger tree" program?

A. The danger tree program is an aggressive tree trimming program that the Company implemented in 2005 in direct response to internal data that indicated that trees located outside of the normal range of the Company's vegetation management trimming zone are the source of major outages that affect large numbers of customers, and thus significantly contribute to increasing the system average interruption frequency index ("SAIFI"). These "danger trees" are identified during circuit patrols and are addressed outside of the normal three-year (transmission) and four-year (distribution) trimming cycles. The Company anticipates that in calendar year 2007, it will spend $750,000 addressing danger trees on its

distribution system, and estimates annual expenditures of $750,000 to maintain this program going forward. Since the Company spent $250,000 on danger trees in 2006, $500,000 of the Company's estimated annual danger tree expenditures relating to its distribution lines is incremental and not included in the historical 2006 spending level. The Company also will be expanding its danger tree program to cover potential transmission line conflicts with respect to danger trees, and estimates annual incremental costs of $500,000 for the expansion of this program to cover the transmission system. In total then, the Company expects to expend an additional $1,000,000 annually to address danger trees. It does not appear that Mr. Burke has accounted for these increased expenditures in his year tree trimming expense of $4,752,000.

Q. Please go on.

A. Additionally, within the past year, the Company has been operating under more stringent New York State transmission line vegetation management regulations, based on recommendations from FERC and the New York Public Service Commission's Order Requiring Enhanced Transmission Right-Of-Way Management Practices By Electric Utilities, issued June 20, 2005 in Case 04-E-0822 ("Order"). There regulations require substantial ROW clearing and maintenance, including re-plantings that will be required on the Company's transmission ROWs to address compatible species issues attendant with the Order. The Company estimates additional costs of $150,000 annually to address these new regulations, as well as underground transmission right of way trimming issues that

have not previously been addressed. The total annual incremental costs for the Company's vegetation management initiatives and the danger tree program are estimated at $1,150,000. These are incremental to the recent historical spending data supplied by the Company in response to Interrogatory DPS (RAB) No. 4, which were approximately $4.7 million annually.

Q. Please address Mr. Pause's proposal to increase the amount of negative revenue adjustment for failure to meet the Company's overall annual reliability standards.

A. Mr. Pause agrees with the Company's proposal to reflect the Public Service Commission ("Commission")-approved updated service reliability standards so that the Company's overall SAIFI and CAIDI targets no longer reflect data established more than 20 years ago. However, he then proceeds to propose a material change to the Company's reliability performance mechanism by proposing to increase the amount of negative revenue adjustment for failure to meet the Company's new overall SAIFI and CAIDI targets from four basis points each to ten basis points each, for a possible total annual negative adjustment of 20 basis points.

Q. Do you agree with Mr. Pause's proposal to increase the penalties for failure to meet its SAIFI and CAIDI targets?

A. No, I do not. As indicated above, the Company is dedicating significant resources to improving service reliability. Staff has not alleged (and there is no evidence supporting) that the Company is somehow ignoring its service reliability responsibilities. Nor is there any basis for adjusting the

Company's penalty levels to reflect other utility-specific performance mechanisms that were accepted by such utilities and adopted by the Commission as part of comprehensive joint proposals. In light of these circumstances, a comparison of the Company's penalties for failure to meet its SAIFI and CAIDI targets to those of other utilities is irrelevant and inappropriate.

Q. Do you have any comments or further proposals with respect to Mr. Pause's recommendations?

A. Yes. While the Company does not agree with Mr. Pause's recommendation, if the Commission decides to revisit and modify the reliability performance mechanism, in determining reliability penalties, the Commission should assess the Company's performance with respect to SAIDI, as well as SAIFI and CAIDI. Specifically, if in any particular calendar year, the Company fails to meet either its SAIFI or CAIDI goal, the Company must also miss the calculated SAIDI goal (the product of SAIFI and CAIDI) for that calendar year, in order for any negative revenue adjustment penalties to be enforceable.

The Company believes that SAIDI is a better "referee" index to measure overall system performance than just SAIFI and CAIDI. Based on the Company's proposed SAIFI and CAIDI goals of 1.36 and 102.4 minutes respectively, the calculated SAIDI goal would be 139.3 minutes. As long as the SAIDI calculation for any one year continues to be better than 139.3 minutes, even if either SAIFI or CAIDI individually fails to meet its

target for that year, overall reliability will be considered to have been satisfied.

Q. Does the Company have any additional proposals with respect to the negative revenue adjustments proposed by Mr. Pause?

A. Yes. In order to motivate the Company to achieve superior service reliability and to otherwise establish an equitable incentive mechanism, the Commission should implement positive incentives. Specifically, the Company proposes should the Company exceed either of its overall SAIFI or CAIDI targets in any one calendar year by 7.5%, the Company would earn an additional 25 basis points on New York electric common equity for each target (or 50 basis points on New York electric common equity if the Company exceeds both the SAIFI and CAIDI targets by 7.5%). In the event that the Commission approves the Company's proposal to utilize SAIDI in the manner discussed above, the Company proposes that the Commission authorize an additional incentive that would be tied to the Company's performance regarding SAIDI. Specifically, should the Company's SAIDI performance meet or exceed its SAIDI goal by 15% during any one calendar year, as well as the Company meeting its SAIFI and CAIDI targets for that year, the Company would earn an additional 25 basis points on New York electric common equity.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

ORANGE AND ROCKLAND UTILITIES, INC.
REBUTTAL TESTIMONY OF
MICHAEL J. THORPE
NYPSC CASE NO. 06-E-1433

Q. Please state your name and business address.

A. Michael J. Thorpe, 390 West Route 59, Spring Valley, New York 10977.

Q. By whom are you employed and in what capacity?

A. I am employed by Orange and Rockland Utilities, Inc. ("Orange and Rockland", "O&R" or "the Company") as Section Manager – Customer Support Operations. In this position I manage a department responsible for the Company's credit, collection and accounts receivable processes, as well as complaint management process.

Q. Please describe your educational background and professional experience.

A. In 1988, I graduated from the State University of New York at Buffalo with a Bachelor of Engineering degree in Mechanical Engineering. In 1995, I graduated from Iona College, New Rochelle, New York with a Master of Business Administration degree in Management Information Systems. My first employment was with Consolidated Edison Company of New York, Inc. in 1988 as a Management Intern. In 1990, I joined O&R as an Associate Program Administrator – Demand-Side Management. I have since held the positions of Program Administrator – Demand Side Management, Sr. Energy Management Engineer, Regulatory Administrator and Section Manager – Retail Access / Energy Services prior to my present position.

Q. Have you ever testified before the New York Public Service Commission ("NYPSC")?

A. No.

Q. What is the purpose of your rebuttal testimony in this proceeding?

A. I will respond to certain statements contained in the direct testimony of Staff witness Mr. Martin Insogna regarding the Company's Customer Service Performance Incentive ("CSPI").

Q. Please address Staff witness Insogna's proposal to increase the amount at risk for the CSPI.

A. In his direct testimony (at 5), Staff witness Insogna proposes to increase the amount at risk under the CSPI from approximately $450,000 (12 basis points) to $1.1 million. This would increase by 144% the amount that the Company would be penalized for failing to meet an annual NYPSC complaint rate target, and targets for annual surveys of residential and commercial/industrial customers. As discussed below, Staff has failed to justify an increase in the amount the Company will be at risk for under the CSPI.

Q. Please go on.

A. In 2005, O&R and Staff worked collaboratively to develop a new complaint rate target based on the QRS/SRS complaint process implemented in June 2002. The new target/structure, including penalty levels, was approved by the NYPSC. Since implementing this approved complaint rate target and penalty tier structure mechanism, O&R has not shown any deterioration in service quality based on customer complaints. In fact, the Company achieved "exceptional" results in this area for 2005 and 2006. O&R's 12-month complaint rate of 0.8 complaints per 100,000 customers in 2005 and 2006 is among the best of the New

York State utilities. Based on this record of performance, there is no need or justification for any increase in the amount at risk for the complaint rate target.

Q. What about the other components of O&R's CSPI mechanism?

A. In October 2006, the Commission approved new residential and business customer surveys and associated survey targets filed by the Company, and reaffirmed existing penalty levels for failing to meet the survey targets under those new survey instruments. O&R is strongly opposed to any increase in the amount at risk for the customer surveys as they are currently designed.

Q. Do you have any other concerns?

A. Yes. In my opinion, Staff should be decreasing reliance on penalties, not increasing it. Penalties are negative and are a poor substitute for constructive regulation. If penalties are to be prescribed they should apply solely in cases where actions within reasonable control of the Company have led to plainly and unequivocally unacceptable service levels. In addition, even at existing penalty levels, any penalties are structured on an "all or nothing" basis. Accordingly, if the NYPSC decides to modify the survey portion of the CSPI, the Company would recommend that the NYPSC adopt tiered penalties similar to those relating to the complaint rate. Furthermore, the entire CSPI should be structured to provide for positive financial incentives for achieving "exceptional" performance in the complaint rate and for exceeding the benchmark targets by significant margins in the surveys. In the event that the NYPSC wishes to revisit this area, I have set forth as Attachment A to my testimony a proposal that provides for a

penalty tier system for the surveys and positive incentives for both the surveys and the complaint rate. The Company is willing to work collaboratively with Staff and other interested parties to establish the tier levels for the surveys.

Q. Are there any other reasons for the Company's opposition to increasing the amount at risk for the customer surveys?

A. Yes. While the Company's surveys include questions that distinguish between its gas and electric businesses, the scores, on which the amount at risk is assessed, do not. Therefore, while customer satisfaction could increase among the Company's electric customers, a decrease in satisfaction among its gas customers, because of high winter heating bills for example, would result in the Company suffering undeserved penalties in its electric business. Moreover, in the current design of the survey, "price opinion" has the highest weighting of the five measurement factors (i.e., 36%). Yet in today's deregulated environment, the Company has no control over the vagaries of the energy supply market. For example, Hurricane Katrina had a major impact on energy prices across the United States, particularly for natural gas during the 2005-06 winter heating season. Higher gas supply costs caused an increase of 28% in O&R's overall gas rates for its firm full service customers during that heating season. Plainly, the Company was not responsible for this increase. Nevertheless, despite the Company's best efforts to educate its customers about the reasons for higher energy costs and ways for customers to manage those costs, the "price opinion" factor dropped precipitously in O&R's June 2006 survey, thereby preventing the Company from meeting its overall

annual average residential and commercial/industrial benchmark targets and resulting in the Company unfairly suffering financial penalties. Staff's proposal to increase the amount at risk would only exacerbate these problems. At a minimum then, if the Commission adopts Staff's proposal, it also should eliminate "price opinion" from the surveys.

Q. Do you have any other comments regarding Mr. Insogna's testimony?

A. Mr. Insogna (at 6) attempts to justify his proposal on the grounds that:

> [T]here is a concern that downsizing and restructuring could lead to a decline in service quality. As many utilities have restructured, staffing levels have already been reduced, including reductions in customer service areas.

Mr. Insogna, however, has failed to provide any evidence that the Company has engaged in such downsizing or reduced staffing levels in customer service areas. These generic concerns do not apply to the Company and therefore do not support his proposal.

Q. Does this conclude your testimony?

A. Yes, it does.

ORANGE AND ROCKLAND UTILITIES, INC.
REBUTTAL TESTIMONY OF
MICHAEL J. THORPE
NYPSC CASE NO. 06-E-1433

Attachment A

PSC Complaint Rate (1)	Tier Range	Current (2)		Proposed
Incentive	<0.9			$ 150,000
		Current (2)		Proposed
Penalty	2.5	$50,000		$ 50,000
Penalty	2.6	$100,000		$ 100,000
Penalty	>2.7	$150,000		$ 150,000
Residential Customer Assessment Survey (RCAS)		Current (2)		Proposed
Incentive (6.11+1xmoe)	> =6.25			$ 150,000
	> =5.97 (3)			
Penalty (6.11-1x moe)	5.84 - 5.96	$150,000		$ 50,000
Penalty (6.11-2xmoe)	5.69 - 5.83			$ 100,000
Penalty(6.11-3xmoe)	< 5.69			$ 150,000
C& I Customer Assessment Survey (CICAS)		Current (2)		Proposed
Incentive (6.11+1xmoe)	>=6.40			$ 150,000
	> =5.96 (4)			
Penalty(6.18-1xmoe)	5.74 - 5.95	$150,000		$ 50,000
Penalty(6.18-2xmoe)	5.52 - 5.73			$ 100,000
Penalty(6.18-3xmoe)	< 5.52			$ 150,000
Maximum Incentive		$ 450,000		$ 450,000
Maximum Penalty		$ 450,000		$ 450,000

(1) Penalty payments for the minimum and intermediate tiers are reduced in any year in which the complaint rate for the preceding year is 0.9 or less.
(2) Assumed 4 basis points = $150,000
(3) RCAS Target of 6.11 less 2006 margin of error = 5.97. The survey year margin of error ("moe") will be used for tier range development.
(4) CICAS Target of 6.18 less 2006 margin of error=5.96. The survey year margin of error ("moe") will be used for tier range development