conEdison, inc.

Joan S. Freilich
Executive Vice President and
Chief Financial Officer

November 21, 2003

Hon. Jaclyn A. Brilling
Acting Secretary
State of New York
Public Service Commission
Three Empire State Plaza
Albany, New York 12223

Dear Secretary Brilling:

Consolidated Edison Company of New York, Inc. ("Con Edison" or the "Company") proposes to increase the charges for steam service and make other changes to its Schedule for Steam Service, P.S.C. No. 3 – Steam, applicable to its customers in the Borough of Manhattan, New York City. The tariff leaves reflecting the proposed changes are identified in Appendix A.

The Company's schedule leaves are issued as of November 21, 2003, to become effective on and as of December 21, 2003. The Company's expectation is that the Commission will issue appropriate orders suspending the effective dates of the proposed schedule changes through September 30, 2004, so that the proposed rates and other changes may become effective on October 1, 2004, upon termination of the current Con Edison steam rate agreement that was approved in Case No. 99-S-1621.

Fifteen copies of the prepared written testimony and exhibits, which comprise the Company's direct case in support of this rate filing, are also submitted herewith.

Proposed Rate Changes

Summary of Proposed Changes

By this filing, the Company proposes to increase the charges to customers under tariff rates in its Schedule for Steam Service, PSC No. 3. As described in more detail below, this increase is necessary to allow the Company to continue to provide steam customers with safe and reliable service and, at the same time, provide revenues to

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the Company consistent with the need to upgrade and enhance the steam system infrastructure, especially production-related facilities.

The filed leaves reflect the traditional method of calculating the revenue requirement for the rate year, the twelve months ending September 30, 2005. After the expected fuel savings from the new East River Repowering Project ("ERRP") are taken into account, the net impact to customers would be $65 million, or 14.6% of total steam revenues. The increase in base rates would be $128.9 million prior to reflecting the expected ERRP fuel savings. In order to moderate rate increase over the next several years and provide customers with relatively stable and predictable rates, the Company is also proposing a three-year rate plan that would permit the Company to increase rates in the first year as filed, and then provides for only small increases in the second and third years, to cover limited cost changes, and for reconciliations. The plan would, similar to prior Con Edison rate plans, require the Company to commit to refrain from filing for a general rate increase prior to November 1, 2006.

Except for a small increase in the first year of the most current rate plan, the Con Edison steam system has experienced stable rates for many years. There are several factors contributing to the current need for increased steam revenues. These include increased capital and O&M expenditures necessary to address the immediate and long-term needs of production-related facilities and associated depreciation expenses, increased property taxes, the commercial operation of the state-of-the art ERRP, environmental enhancements, lower sales growth, and diminished earnings from pension funds that have previously supported steam operations. The Company's presentation makes it clear that the rate relief requested herein is essential to allow the Company to maintain the integrity of the steam system and reliable service to steam customers, while enabling the Company's steam operations to be financially viable. This includes a return to investors adequate to support the financial strength needed in the current environment. The proposed three-year plan, which would limit rate changes in the second and third years to adjustments for changes in expenses for such items as property taxes, health insurance and labor, would give customers certainty and stability as to steam rates through October 1, 2007, while giving the Company a strong incentive to work within the rate plan to maximize efficient operations that will ultimately inure to the benefit of ratepayers.

Appendix B shows that the rates have been designed to permit recovery in base rates of a total increase of $128,899,000: $125,728,000 plus gross receipts taxes of $3,171,000, for the rate year, i.e., 12 months ending September 30, 2005. Appendix B also shows the estimated effect on customers' bills and Company revenues, after reflecting the estimated fuel savings of about $64 million from the ERRP, based on sales and revenues for the historical period, i.e., the 12 months that ended on June 30, 2003.

Proposed Increased Revenue Allocation Among the Customer Classes

The revenue increase was allocated to the Company's service classifications ("SC"s) in the following manner:

- An overall percentage increase was developed by dividing the $125,728,000 pure base revenue requirement increase by the pure base revenues applicable to the rate year. The overall percentage was then applied to SC 1, 2, 3 and 4 rate year pure base revenues to determine the increased revenue requirement for each class. No increase was allocated to SC 5, because customers under this SC are charged based on negotiated contractual terms. ERRP fuel savings would be allocated to customers on a $/Mlb basis.

- In accordance with the Commission's Order Implementing Tax Law Changes on a Permanent Basis, dated June 28, 2001, the current level of state income tax, reduced by gross receipts tax, was eliminated from the Increase in Rates and Charges and reflected in sales revenues before the rate change. It was also reflected in rates at the proposed revenue level. The effect of this rate change for collecting state income tax is neutral to customers and will not affect the Company's overall revenues. Any over- or under-collections of state income tax expense related to periods prior to October 1, 2004 will continue to be collected through the Increase in Rates and Charges.

Proposed Rate Design Within the Classes

The increased revenue requirement proposed for the rate year is reflected in rates developed for SC 1, 2, 3 and 4, as described below.

- SC 1: The Company proposes to collect the rate increase in SC 1 by increasing the customer charge and block rates (excluding the base cost of fuel) by a uniform percentage.

- SC 4: The Company proposes to collect the SC 4 increase through a Rate I customer charge set equal to the proposed SC 2 customer charge, a Rate II customer charge set equal to the proposed SC 3 customer charge, and on- and off-peak usage charges (excluding the base cost of fuel) and contract demand charges increased by a uniform percentage.

- SC 2 and SC 3: The Company is proposing a rate design change for SC 2 and SC 3 customers that would collect revenues associated with fixed costs through a seasonally determined access charge (Mlb/hour) rather than through usage-based charges, as is currently the case. [1]

  Each customer's fixed cost contribution for each monthly bill of the winter period (November through April) will equal the customer's winter capacity reservation

[1] The Company's filing also includes a proposal for a Weather Normalization Clause ("WNC"), as a second-choice alternative to the proposed rate redesign for SC2 and SC3. The Company will submit proposed tariff language on its WNC proposal, if required, at a later date.

(a surrogate for metered demand) times the SC's winter access charge. Under the access charge, each customer's seasonal contribution to fixed costs will be essentially the same under the new rate structure as under the old structure, assuming normal weather. This rate structure will better reflect cost causation than existing rate structures, because charges related to fixed costs will not depend on Mlb sales; it will introduce customers to a rate form having a fixed-cost component; and it can be implemented without any change in metering.

Costs that vary with usage will be collected in SC 2 and SC 3 through a usage charge. That charge - $6.708/Mlb – will recover the $5.049 base cost of fuel, $0.809 for the forecasted cost of electric, water and chemicals, and $0.85 in incremental fixed costs. There will continue to be a customer charge and fuel adjustment in SC 2 and SC 3.

Demand Metering

In addition to the rate redesign described above for SC 2 and SC 3 customers, the Company further proposes to implement revised billing for approximately 180 of the Company's largest steam customers based on their demand for steam. While the required meters are being installed, the Company would develop a Rate II in each service classification with proposed charges (using available load research and data for these new meters) to replace the access charge for these customers. For 12 months, commencing October 2004 or as soon thereafter as practicable, customers would receive, in addition to bills at then current rates, "dummy bills" showing the amount determined under illustrative Rate II rates. Within 10 months of commencing issuance of dummy bills, the Company would file proposed Rate II rates (developed using actual data from these new meters) with the Commission for its approval. The filed rates would yield the same total annual revenue for these customers, on a class-by-class basis, as then-existing rates. Twelve months after commencing issuance of dummy bills, subject to the Commission's approval, all bills for these customers would be issued under Rate II rates. After commencing billing under Rate II, the Company would periodically evaluate the program to determine whether program changes should be made.

Rate II rates would have seasonal on-peak and off-peak contract charges. On-peak contract charges would be applied based on the highest maximum demand that occurred during the winter period between 6 AM and 11 AM. Off-peak contract charges would apply only if the highest maximum demand that occurred at any time exceeds the on-peak maximum demand.

Other Tariff Changes

Additional tariff changes are described below:

- Text for Increase in Rates and Charges has been modified based on the change in the method of collection of state income taxes, as described above.

- SC 6 – Transportation Service has been eliminated. There have been no subscribers to this service since its inception during the current rate plan period, and no subscribers are expected in the foreseeable future. Furthermore, given that the cost of providing this service is highly dependent on site-specific circumstances, the SC 6 rate may not be cost-based in many instances.

- The Annual Credit Adjustment in the Fuel Adjustment, which caps the steam system variance, has been replaced by an Annual Adjustment that reconciles, for each 12-month period commencing October 1, 2004, actual expenses incurred for fuel used by the Company, plus the contractual variable cost of steam purchased from others for resale and the Special Monthly Adjustment, to actual recoveries for the annual period. Any under- or over-recoveries will be reflected in the monthly Fuel Adjustment over the successive 12 months commencing November.

- The Special Monthly Adjustment to the Fuel Adjustment has been modified to include credits due to customers for any month in which the ERRP is not in commercial operation on or after October 1, 2004, to offset overcollections in base rates of ERRP-related costs.

- The Steam Repair Service has been modified as follows: (a) to require prepayment of estimated charges, instead of upon completion of the repair; (b) to price materials based on their fair market price, instead of average storeroom price (increased by 12% for handling); and (c) to reconcile estimated and actual charges for labor and materials and bill/refund any difference.

- To encourage new customer extensions, the provision concerning extension or reinforcement of mains has been changed to require a prepayment to cover the estimated cost of the main extension or reinforcement only if estimated revenue over a two-year period, rather than over a one-year period, is less than the expenditure.

- To attract and retain steam customers, the Company proposes a new Rider E – Negotiated Steam Fuel Cost, applicable to SC 2 and SC 3 customers. Under Rider E, a customer may negotiate fuel costs with the Company for a fixed volume of its requirements and, thus, avoid volatility in charges due to monthly changes in the cost of fuel. For the fixed volume, the Company would charge the customer the agreed upon cost for fuel, including all other fuel related (e.g., storage and handling) and transaction costs, in lieu of the average cost of fuel. The customer would pay all rates and charges applicable under the customer's Service Classification exclusive of the Fuel Adjustment but inclusive of the Special Monthly Adjustment component of the Fuel Adjustment and the difference between the agreed-upon cost and the base cost of fuel, which difference might be a credit or a debit. Any steam usage in excess of the agreed upon volume would be served under the rates and charges of the customer's Service Classification, inclusive of all components of the Fuel Adjustment. If the customer used less than the agreed upon volume of steam, the customer would be

required to pay the negotiated steam fuel price for the entire agreed upon volume. Non-participating customers would not be affected by this proposal, because the full cost of the fuel supply and any hedging would be borne by participating customers.

The Need for Steam Rate Relief

The Company's direct case in support of this rate filing demonstrates the need for rate relief. Recent experience has shown that the current steam rates are clearly inadequate to allow the Company to maintain current levels of investments in infrastructure needed to maintain safe and reliable steam service, let alone meet the increasing investment needs of the steam system. For the first rate year under the current steam plan, the actual steam return on equity was 6.68%, despite winter weather that was colder than normal. For the second rate year, due in large part to abnormally warm winter weather, the actual steam return on equity was 0.72%, which is grossly inadequate by any measure. For the third rate year, notwithstanding the colder than normal weather, the actual steam return on equity reached only 9.17%. These rates of equity returns are clearly insufficient to enable the Company to recover its costs of providing service and make the necessary investments in steam infrastructure.

An upgraded, reliable infrastructure is vital to steam customers, who demand a reliable energy source for heating, air conditioning and other uses. The continued integrity of the steam system and its service reliability are imperative not only for continuing to provide excellent service to existing customers -- who include large office building, hospitals, hotels, universities, cultural institutions and numerous governmental buildings -- but also for continuing to attract new business and accommodate potential growth. However, in order to continue to provide reliable service that customers can depend on, the Company must be able to make the investments that are necessary to keep pace with customer needs and the natural obsolescence of aging equipment. Absent the necessary investment to repair and replace aged and deteriorating structures, equipment and facilities, as proposed in this rate filing, the Company's ability to continue to provide high-quality, reliable steam service, which customers deserve and have come to expect, will be seriously compromised.

In order to maintain current levels of service reliability, Con Edison will have to spend substantially more capital and maintenance dollars than are covered by current rates to address the immediate and longer-term needs of its production-related facilities. The Company's steam capital plan includes expenditures to repair aging boilers and other major plant components, refurbish major structures, including various building roofs, facades, stacks and docks, and upgrade outdated or obsolete control systems and equipment. In addition, the Company has undertaken various expense programs for major repairs and maintenance of aged production plant equipment, structures and facilities necessary for equipment integrity, performance efficiency and operating reliability.

While the Company is continuing its ongoing efforts to reduce the cost of its steam operations and to retain the competitiveness of the steam service, it cannot

continue to provide customers with reliable service without investing in sorely-needed upgrades. The Company believes that the investments and level of spending proposed in this rate filing accomplish these objectives and will enable the continued provision of highly reliable service to customers.

The Company will discuss with the Staff and other parties to the rate proceeding its proposal for a multi-year rate plan, with a view toward establishing a rate plan for steam operations covering the three-year period ending September 2007. We believe that such a multi-year plan would benefit both the Company and its customers and balance the objective of rate moderation and stability with the need to maintain a strong energy infrastructure and a financially viable steam service.

Newspaper Publication

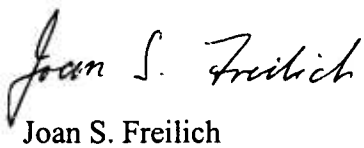
The Company will provide for public notice of the changes proposed in this filing by means of newspaper publication on November 28, December 5, December 12, and December 19, 2003.

Conclusion

The testimony and exhibits submitted herewith establish the need for the rate changes requested by the Company. The Company will pursue discussions with the Commission Staff and other parties to the proceeding in an effort to reach agreement on the issues presented. The Company respectfully requests that, in the absence of agreement of the parties, the Commission approve the changes to become effective on October 1, 2004, the day following the expiration of the current rate plan.

Very truly yours,

CONSOLIDATED EDISON COMPANY OF NEW YORK, Inc.



Joan S. Freilich
Executive Vice President and
Chief Financial Officer

cc: New York State Consumer Protection Board
(two sets of filing)

P.S.C. No. 3 – Steam

Twelfth Revised Leaf No. 2
Superseding Eleventh Revised Leaf No. 2

Fifth Revised Leaf No. 2-A
Superseding Fourth Revised Leaf No. 2-A

Fourteenth Revised Leaf No. 3
Superseding Thirteenth Revised Leaf No. 3

Twelfth Revised Leaf No. 3-A
Superseding Eleventh Revised Leaf No. 3-A

Fourth Revised Leaf No. 4
Superseding Third Revised Leaf No. 4

Thirteenth Revised Leaf No. 6-A
Superseding Twelfth Revised Leaf No. 6-A

Second Revised Leaf No. 7-F
Superseding First Revised Leaf No. 7-F

Original Leaf No. 13-A

Thirteenth Revised Leaf No. 14-A
Superseding Twelfth Revised Leaf No. 14-A

Fourth Revised Leaf No. 14-B
Superseding Third Revised Leaf No. 14-B

Fifteenth Revised Leaf No. 15
Superseding Fourteenth Revised Leaf No. 15

Eighth Revised Leaf No. 15-A
Superseding Seventh Revised Leaf No. 15-A

Thirtieth Revised Leaf No. 20
Superseding Twenty-ninth Revised Leaf No. 20

P.S.C. No. 3 – Steam - Continued

Thirtieth Revised Leaf No. 21
Superseding Twenty-ninth Revised Leaf No. 21

Nineteenth Revised Leaf No. 21-A
Superseding Eighteenth Revised Leaf No. 21-A

Third Revised Leaf No. 21-B
Superseding Second Revised Leaf No. 21-B

Thirtieth Revised Leaf No. 22
Superseding Twenty-ninth Revised Leaf No. 22

Twelfth Revised Leaf No. 22-A
Superseding Eleventh Revised Leaf No. 22-A

Third Revised Leaf No. 22-B
Superseding Second Revised Leaf No. 22-B

Third Revised Leaf No. 23
Superseding Second Revised Leaf No. 23

First Revised Leaf No. 30
Superseding Original Leaf No. 30

First Revised Leaf No. 31
Superseding Original Leaf No. 31

First Revised Leaf No. 32
Superseding Original Leaf No. 32

First Revised Leaf No. 33
Superseding Original Leaf No. 33

First Revised Leaf No. 34
Superseding Original Leaf No. 34

Appendix B

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.

STEAM - Estimated Effect on Customers' Bills and Company Revenues Resulting from
Proposed Steam Rates - Based on Sales and Revenues for the Twelve Months Ended June 30, 2003

SERVICE CLASSIFICATION	TOTAL REVENUE AT CURRENT RATE EFFECTIVE 12/08/2000	FUEL SAVINGS FROM EAST RIVER RE-POWERING PROJECT *	PROPOSED ANNUAL INCREASE **	NET ANNUAL INCREASE	NET PERCENTAGE INCREASE	NUMBER OF CUSTOMERS' MONTHLY BILLS		
						INCREASED	DECREASED	UNCHANGED
1 - GENERAL SERVICE	$19,116,466	-$2,002,716	$7,602,608	$5,599,892	29.29%	7,438	0	0
2 - ANNUAL POWER SERVICE	$336,141,852	-$48,714,410	$94,796,118	$46,081,708	13.71%	6,212	1,553	2
3 - APARTMENT HOUSE SERVICE	$140,976,570	-$20,986,411	$37,873,109	$16,886,698	11.98%	5,611	1,012	4
4 - BACKUP / SUPPLEMENTARY SERVICE	$132,955	-$7,627	$71,250	$63,623	47.85%	12	0	0
TOTAL	$496,367,843	-$71,711,164	$140,343,085	$68,631,921	13.83%	19,273	2,565	6

* Based on sales and revenues for the rate year, 12 months ending September 30, 2005, estimated fuel savings from East River Re-Powering Project equate to $65,600,000, including Gross Receipts Tax.

** Based on sales and revenues for the rate year, 12 months ending September 30, 2005, the increase in Con Edison revenues equates to $128.9 million.

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Service Classifications as Listed Below:

APPLICABLE TO	FOR	NUMBER	
(Territory or Area)	(Service classified according to use or uses as shown on service classification leaves)	Service Classification	Leaf
Borough of Manhattan in The City of New York, subject to stipulations and requirements noted herein...	General Service...	1	20
Same as above...	Annual Power Service...	2	21
Same as above...	Apartment House Service...	3	22
Same as above...	Back-up/supplementary Service...	4	23
Same as above...	Negotiated Agreement Service...	5	28

GENERAL INFORMATION

I. Territory to Which the Rate Schedule Applies

The Borough of Manhattan, City of New York

II. Definitions and Abbreviations of Terms Used in this Rate Schedule

(1) The following abbreviation is used:
Btu British thermal unit(s)

(2) The term "access controller" is a party known to the Company to be in control of access to the metering equipment of a Customer, and to have an active account of its own with the Company.

(3) The term "actual reading" is one obtained by the Company from either the meter or a remote registration device attached thereto.

(4) The term "arrears" are charges for which payment has not been made more than 20 calendar days after payment was due.

(5) The term "authorities" include the Public Service Commission of the State of New York, the municipal authorities and any other agencies legally authorized to regulate or inspect the Customer's installation or equipment.

(6) The term "backbill" is that portion of any bill, other than a levelized bill, which represents charges not previously billed for service that was actually delivered to the Customer during a period before the current billing cycle. A bill based on an actual reading rendered after one or more bills based on estimated or Customer readings (commonly called a catch-up bill) which exceeds 50 percent or more the bill that would have been rendered under the Company's standard estimation program is presumed to be a backbill.

(7) The term "business day" is any Monday through Friday when the Company's business offices are open.

(8) The term "Capacity Reservation" refers to the demand assigned to the Customer by the Company, expressed in 1,000 pounds per hour, and is a component of the Access Charge in Service Classification ("SC") Nos. 2 and 3. A Customer's "Winter Capacity Reservation" means (a) that Customer's pure base revenue for the billing periods commencing November 2002 and ending April 2003, less revenue from the Customer Charge for those periods adjusted to the forecast for the rate year ending September 2005, (b) divided by the SC's Access Charge rate per 1000 pounds of steam per hour. A Customer's "Summer Capacity Reservation" means (a) that Customer's pure base revenue for the May and June 2003 billing periods and the billing periods commencing July 2002 and ending October 2002, less revenue from the Customer Charge for those periods adjusted to the forecast for the rate year ending September 2005, divided by (b) the SC's Access Charge rate per 1000 pounds of steam per hour. "Pure base revenue," for purposes of calculating the Capacity Reservation, means the total sales revenue, net of the Increase in Rates and Charges, less revenues from (i) the Base Cost of Fuel, (ii) the Fuel Adjustment, (iii) the recovery of electric, water and chemical costs, and (iv) an amount equal to $0.85 per 1,000 pounds of steam that is associated with fixed costs. For new Customers and Customers who did not take service for the full 12 months ending June 2003, the Capacity Reservation is determined by the Company based an estimate.

(9) The term "Company" means Consolidated Edison Company of New York, Inc.

(10) The term "Company deficiency" means any action or inaction by the Company or one of its authorized agents that does not substantially conform to the rules and regulations of the Public Service Commission, the Company's tariffs, or the Company's written business procedures.

(11) The term "Customer" includes both a present consumer of and an applicant for the Company's steam service.

(12) The term "deferred payment agreement" is a written agreement for the payment of outstanding charges over a specified period of time. It must be signed in duplicate by a Company representative and the Customer, and each must receive a copy, before it becomes enforceable by either party.

(13) The term "delinquent non-residential Customer" is a Customer who has made a late payment on two or more occasions within the previous 12 month period.

(14) The term "late payment" means any payment made more than 20 calendar days after the date payment was due. Payment is due whenever specified by the Company on its bill, provided such date does not occur before personal service of the bill or 3 calendar days after the mailing of the bill.

(15) The term "levelized payment plan" is a billing plan designed to reduce fluctuations in a Customer's bill payments due to varying, but predictable, patterns of consumption.

(16) The term "meter" means the steam metering device used by the Company to measure the service supplied to the Customer, including any equipment furnished by the Company as part of such metering device.

(General Information - Continued on Leaf No. 3-A)

GENERAL INFORMATION - Continued

II. Definitions and Abbreviations of Terms Used in this Rate Schedule - Continued

(17) The term "new Customer" is a Customer who was not the last previous Customer at the premises to be served, regardless of whether such Customer previously was or is still a Customer of the Company at a different location.

(18) The term "non-residential applicant" is any person, corporation or other entity who has requested service under this Rate Schedule who is not a residential applicant.

(19) The term "non-residential Customer" is any person, corporation or other entity supplied with service under this Rate Schedule and pursuant to an accepted application for service who is not a residential Customer.

(20) "Payment" is considered to be made on the date when it is received by the Company or one of its authorized agents.

(21) The term "point of service termination" means the point at which the Company terminates its service line and the Customer begins his/her piping.

(22) The term "Rate Schedule", also sometimes referred to as the "Tariff", means the Company's Schedule for Steam Service as filed with the New York Public Service Commission.

(23) The term "residential applicant" is any person who requests steam service at a premises to be used as his or her residence or the residence of a third party on whose behalf that person is requesting service where (a) the Company's effective tariff specifies a residential rate for such service; (b) such service will primarily be used for the user's residential purposes, the applicant has so notified the Company, and the applicant will be receiving service under a rate not normally used for residential service; or (c) the Company knows or reasonably should have known that any such service will be provided through a single meter to both units of a two-family dwelling.

(24) The terms "residential Customer" or "current residential Customer" refer to any person who, pursuant to an application for service made by such person or a third party on his or her behalf, is supplied directly by the Company with steam service at a premises used in whole or in part as his or her residence where:
- (a) the Company's effective tariff specifies a residential rate;
- (b) service is primarily used for his or her residential purposes, the Customer has so notified the Company, and the Customer is receiving service under a rate not normally used for residential service; or
- (c) the Company knows or reasonably should have known that any of such service is provided through a single meter to both units of a two-family dwelling.

(25) The terms "rules", "regulations", "rules and regulations of the Public Service Commission", or any combination thereof, refer to the rules and regulations duly adopted by the Public Service Commission for publication in Title 16 of the State of New York Official Compilation of Codes, Rules and Regulations (NYCRR), and to any lawful orders of the Public Service Commission.

(26) The term "seasonal Customer" is a Customer who applies for and receives service periodically each year, intermittently during the year, or at other irregular intervals.

(27) The terms "service" or "steam service" mean the supply of steam provided by the Company.

(28) The term "service line" means the pipes and equipment for delivering steam from the Company's distribution system to the piping system of the Customer's building or premises.

(29) The term "short-term or temporary Customer" is:
- (a) a non-residential Customer who requests or receives service for a period of time up to two years; or
- (b) a residential Customer who requests or receives service for a period of time up to one year.

(30) The term "tampered equipment" means any service related equipment that has been subjected either to unauthorized interference so as to reduce the accuracy or eliminate the measurement of the Company's service, or to unauthorized connection occurring after the Company has physically disconnected service.

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GENERAL INFORMATION - Continued

III. General Rules, Regulations, Terms and Conditions under Which Steam Service Will Be Supplied, Applicable to and Made a Part of All Agreements for Steam Service - Continued

1. How to Obtain Service - Continued

(e) **Prepayment for Extension or Reinforcement of Mains:** Should an extension or reinforcement of the Company's mains be required to serve the Customer's premises, and the estimated average revenue over a two-year period from the Customer connected to such main be insufficient to justify the expenditure involved, the Customer will be required to make a prepayment covering the estimated cost of such main extension or reinforcement. Such estimated average two-year revenue is the estimate of the total revenues from the Customer for service from such main extension or reinforcement, less revenues attributable to the Increase in Rates and Charges, less fuel adjustment revenues, and less the base cost of fuel, all as provided in this Rate Schedule. The estimated cost of construction will be based on the size of main required for the service requested but in no event on less than the estimated cost of an 8 inch main. The estimated cost of construction hereunder shall include, where applicable, the cost of a service line and service equipment. During the first ten years starting from the date when service is first supplied, the prepayment will be repaid to the Customer, without interest, in monthly installments equal to one-tenth of the amount of each bill for steam supplied to the Customer and to any other Customer connected to such main extension by a service. The unrefunded prepayment, if any, remaining at the expiration of the said ten year period or at the end of a lesser period in the event that the use of steam is permanently discontinued at the Customer's premises will be retained by the Company. The Customer or Company may apply to the Public Service Commission for a ruling as to the necessity for, or reasonableness of, the prepayment required.

(f) **Temporary Service:** When service is to be used at construction sites or in other non-permanent structures where the facilities installed to provide service will not be used for permanent supply, or where the use of service will be temporary for any reason, the Customer will be required to pay in advance to the Company a sum of money, as determined by the Company and endorsed upon the agreement for service, which shall be the estimated non-recoverable cost of furnishing and installing all facilities of the Company necessary to provide such service, and the removal thereof. The Customer shall not be relieved from his obligation to fulfill the term and minimum charge provisions of his agreement for service. The provisions of this Rate Schedule for refundable payments for main extensions and for Company service lines and service equipment shall not apply to the supply of temporary service.

(g) **Emergency Limitation Upon Service:** The Company's offer to supply steam service and the supply of steam service, including extensions of mains and service lines, and furnishing of fuel for leased boiler plants, are each subject to and modified by the provisions, conditions and limitations from time to time imposed by governmental emergency statutes or by orders, rules, regulations or ordinances promulgated thereunder and are contingent upon the Company's ability to obtain and use the necessary equipment, materials, facilities and labor.

2. Company's Service Lines, Meters and Service Equipment

(a) **Service Lines:** Within a reasonable time after acceptance by the Company of the Agreement for Service, the Company will install a service line to a point at the property line or suitable subsidewalk space, determined by the Company to be convenient and practicable. Where a basement wall or vault wall is located at such point, the Company will extend its service line through a sleeve provided and installed by the Customer in such wall to a point immediately inside the wall. The point to which the Company so extends its service line shall constitute the point of service termination.

Steam service will be supplied to the Customer's premises through a single service line, except where for reasons of Company economy, conditions on the Company's distribution system, improvement of service conditions, or volume of the Customer's requirements, the Company elects to install more than one service line.

The Company reserves the right to determine the location of any service line, and to avoid misunderstanding, the Customer before starting work shall consult the Company as to the exact location of the point of service termination.

(b) **Prepayment for Installation of Service Line and Furnishing of Service Equipment:** Where the estimated cost to the Company of furnishing and installing the service line and of furnishing service equipment, or any part thereof determined by the Company to be required, exceeds an amount equal to 20% of the estimated charges to be made for the steam service to be supplied during the first five years (or lesser term) of the initial term of the Agreement for Service, the Customer will be required to make a prepayment to the Company equal to such excess cost. Such estimated charges are the estimate of the total revenues from the Customer for service from such service line and service equipment, less revenues attributable to the Increase in Rates and Charges, less fuel adjustment revenues, and less the base cost of fuel inclusive of the factor of adjustment ratio, all as provided in this Rate Schedule. The amount of such prepayment will be repaid to the Customer, without interest, in monthly installments equal to one-tenth of the amount of each bill for steam supplied to the Customer after the expiration of the initial term of the Agreement for Service.

(General Information - Continued on Leaf No. 5)

GENERAL INFORMATION - Continued

III. General Rules, Regulations, Terms and Conditions under Which Steam Service Will Be Supplied, Applicable to and Made a Part of All Agreements for Steam Service - Continued

4. Metering and Billing - Continued

(d) Meter Reading and Billing Period: Thirty days is considered a month for billing purposes. In the ordinary course of business, meters are scheduled by the Company to be read and bills are rendered monthly (approximately 30 days). The Company prepares such schedules in advance. The Company reserves the right to read meters and render bills at any other interval of time. The Company shall attempt to obtain an actual meter reading for each scheduled meter reading for each Customer account by a visit to the Customer's premises. In the case of non-residential Customers the visit shall be between 8 am and 5 pm on a business day.

Where the Company has billed a non-residential Customer's account based on the readings of a remote registration device for six consecutive months, the Company shall, at the time of every subsequent reading attempt and, until successful, try to gain access to and read the meter.

(e) Proration of Monthly Rates and Charges: Where the Company renders a bill for other than a 30 day period, the rates and charges will be prorated on the basis of the number of elapsed days divided by 30; provided, however, that the Access Charge in Service Classification Nos. 2 and 3 will only be prorated for initial or final bills that cover less than 30 days.

(f) Backbills: The Company shall not backbill a non-residential Customer; (i) more than 6 months after the Company actually became aware of the circumstances, error, or condition that caused the underbilling, unless a court extends the time to render a backbill; (ii) for service rendered more than 12 months before the Company actually became aware of the circumstances, error, or condition that when the failure was due to Company deficiency caused the underbilling, unless the Company can demonstrate that the Customer knew or reasonably should have known that the original billing was incorrect; (iii) for service rendered more than 24 months before the Company actually became aware of the circumstances, error or condition that caused the underbilling, unless the Company can demonstrate that the Customer knew or reasonably should have known that the original billing was incorrect.

Backbilling for residential and non-residential Customers is subject to the rules of the Public Service Commission.

(g) Estimated Bills: The Company may render an estimated bill for a regular cycle billing period only when:

(1) the Company has failed to obtain access to the meter(s);

(2) circumstances beyond the control of the Company made obtaining an actual reading of the meter(s) extremely difficult, despite having access to the meter area; provided, however, that estimated bills for this reason may be rendered no more than twice consecutively without the Company advising the Customer in writing of the specific circumstances and the Customer's obligation to have the circumstances corrected;

(3) the Company has good cause for believing that an actual or Customer reading obtained is likely to be erroneous, provided, however, that estimated bills for this reason may be rendered no more than twice consecutively without the Company initiating corrective action before the rendering of the next cycle bill;

(4) circumstances beyond the control of the Company prevented the meter reader from making a premises visit;

(5) an actual reading was lost or destroyed; provided, however, that an estimated bill for this reason shall be rendered no more than once without the Company initiating corrective action before the rendering of the next cycle bill;

(6) an estimated reading has been prescribed or authorized by the Commission for a particular billing cycle;

(7) an estimated reading is the approved billing method in accordance with the Company's tariff for the billing; or

(8) an unmetered condition was in existence during the period.

(h) No Access Procedure - Non-Residential Accounts:

1. The Company shall provide no access notices for non-residential accounts when the bill has been estimated pursuant to General Rule III, 4(g) (1) or (2) commencing with: the fourth consecutive estimated bill or the tenth consecutive bill based on a remote registration device or a Customer reading.

2. The no access notices and charges shall be directed only to the access controller. In any case where the access controller is not the Customer of the subject account, a copy of these no access notices shall also be sent to the Customer at the same time.

(General Information - Continued on Leaf No. 6-B)

GENERAL INFORMATION -Continued

III-A. Special Services Performed by the Company for Customers at a Charge

1. **Special Services at Stipulated Rates:** Upon the Customer's request, the Company will perform the following special services for a Customer and will charge the Customer at the stipulated rates:

(A) Temporary Disconnection of Service and Reconnection of Such Service

There will be a charge for each temporary disconnection of service and for each reconnection of such service requested by a Customer in excess of one temporary disconnection and one reconnection performed in a 12-month period. The charge will be $186.00 for a disconnection or reconnection during the period 7:30 A.M. to 3:00 P.M., Monday through Friday, excluding holidays, and $222.00 for a disconnection or reconnection begun or completed during any other time.

(B) Historical Usage and Billing Information

A statement of the account's usage and billing information, if available, will be provided at a Customer's request at a charge of $15.00 per year of information from two to not more than six years from the date of the request. There will no charge for a statement of usage and billing information for up to the most recent 24 months.

(C) Steam Repair Service

Upon a Customer's request, the Company will perform steam repair service, such as repairs and replacement of flange gaskets, valve packing, screwed piping on high pressure trap lines, and welding. The charge for this service will be based on (1) labor costs at an hourly rate of $93.00 during the hours of 7:30 A.M. to 3:00 P.M., Monday through Friday, excluding holidays, and $111.00 during all other times, and (2) the price of materials at fair market value plus 12% for handling ("material costs"). The aforementioned labor costs are inclusive of the appropriate increase in rates and charges. Material costs are subject to the applicable percentage as explained in General Information Section VII. Sales taxes will be added where applicable. Labor for part of an hour will be charged at the hourly labor rate. Labor overlapping two labor rate periods will be charged at the higher of the two rates. Labor costs will be inclusive of travel time.

The Company will provide an estimate of labor and material costs to the Customer. The Company will treat all gaskets, valve packing, and insulation as asbestos, unless visual identification is possible or the Company is provided with documentation to the contrary. The cost of asbestos removal and disposal will be included in the estimated price. Upon a Customer's acceptance of the estimate and prepayment of estimated charges, the Company will perform repairs described in the estimate. Upon completion of the repairs, the Company will send the Customer an itemized bill, separately from the monthly bill for steam usage, which will credit the Customer's prepayment against actual charges. If the estimate was higher than billing based on actual charges for labor and materials, the Customer will receive a refund for the difference. If the estimate was lower than billing based on actual charges for labor and materials, the Customer will be billed for the difference. A late payment charge of 1½ percent per month will be applied to all amounts billed, including arrears, and unpaid late payment charges which are not received by the Company within at least 20 days of the date payment is due.

(General Information - Continued on Leaf No. 7-G)

GENERAL INFORMATION - Continued

VI. Service Classification Riders (Available on Request) - Continued

RIDER E - NEGOTIATED STEAM FUEL COST
(Applicable to Service Classification Nos. 2 and 3)

Service will be provided under this Rider to a Customer who has a written agreement with the Company for the fuel cost component of a fixed volume of the Customer's steam requirements.

For an agreed-upon volume of steam to be purchased by the Customer during the term of the agreement, the Company will charge the Customer an agreed upon cost for fuel, including all other fuel related (e.g., storage and handling) and transaction costs, in lieu of the average cost of fuel. The Customer will pay all rates and charges applicable under the Customer's Service Classification exclusive of the Fuel Adjustment but inclusive of the Special Monthly Adjustment component of the Fuel Adjustment and the difference between the agreed-upon cost and the base cost of fuel, which difference may be a credit or a debit. Any steam usage in excess of the agreed upon volume will be served under the rates and charges of the Customer's Service Classification, inclusive of the Fuel Adjustment as described in General Rule VII. If the Customer uses less than the agreed upon volume of steam, the Customer will be required to pay the negotiated steam fuel cost for the entire agreed upon volume.

The additional rules, regulations, terms and conditions in the General Information Section of this Rate Schedule are applicable to and made a part of all agreements for service under this Rider, to the extent not inconsistent with the provisions of this Rider, the Customer's Service Classification, or the terms of any individually-negotiated agreement.

(General Information - Continued on Leaf No. 14)

GENERAL INFORMATION - Continued

VII. Adjustment of Rates Related to Changes in the Cost of Fuel-Continued

C. Average Cost of Fuel - Continued

Storage and Handling Costs

Commencing with the annual period beginning with the first billing cycle date of October 1998, storage and handling costs will be collected through a uniform monthly per unit charge that will be calculated prior to the beginning of each annual period by dividing the projected storage and handling costs to be recovered over the annual period by the corresponding projected sales, expressed to the nearest tenth of a cent. Such unit amount will be included in the calculation of the monthly adjustment as described in Section A.

At the end of each annual period beginning with the 12 months commencing with the first billing cycle date of October 1998, the Company will compare the actual amount recovered to the actual incurred storage and handling costs to be recovered and any over/undercollection will be reflected through an adjustment over the subsequent 12 month period starting with the first November billing cycle date of each year.

BNYCP Adjustments

Effective October 1997, when the operating conditions of the steam system require the Company to convert BNYCP steam energy to electric energy to the benefit of the steam system rather than the electric system, the contractual premium, if any, paid for the electric energy, which is expressed as the excess, if any, of the variable steam price over the variable electric price will be recovered through the steam fuel adjustment on a monthly basis, starting with the first November 1997 billing cycle, as follows:

(a) The kWh of electric energy resulting from the conversion will be computed by dividing the lbs of converted steam energy by the contractual steam conversion factor.
(b) The excess, if any, of the variable price of steam energy over the variable price of electric energy will be determined by subtracting (i) the product of the kWh of electric energy produced by the conversion and the contractual variable electric price from (ii) the product of the mlbs of steam converted and the contractual steam variable price.
(c) The resulting difference, if positive, will be recovered through the monthly steam fuel adjustment.

D. Special Monthly Adjustments

The following charges and credits will be reflected in the Monthly Adjustment: (a) actual non-fuel operation costs of the 74th Street and 59th Street steam stations that are not being recovered through a monthly charge in electric rates, to the extent not already reflected in steam base rates; (b) New York City sewer use charges, when incurred; (c) any tariff-based charges for electricity used at steam generating stations, to the extent such costs are not already recovered in steam base rates, unless the amounts are deferred for later recovery pursuant to Commission order; and (d) credits due to Customers for any month in which ERRP is not in commercial operation on or after October 1, 2004, to offset overcollections in base rates of ERRP-related costs.

(General Information - Continued on Leaf No. 14-B)

GENERAL INFORMATION - Continued

VII. Adjustment of Rates Related to Changes in the Cost of Fuel - Continued

E. Annual Adjustment

At the end of each annual period beginning with the 12 months ending September 30, 2005, actual expenses incurred for fuel used by the Company plus the contractual variable cost of steam purchased from others for resale (including BNYCP charges as described under the paragraph entitled "BNYCP Adjustments") and the Special Monthly Adjustment (as described in paragraph D) will be reconciled to actual recoveries for the annual period.

Any under-collections or over-collections will be reflected in the Monthly Adjustment over the subsequent 12 months beginning November. Surcharge or credit amounts shall bear interest at the rate prescribed by the Commission on unamortized balances.

The Annual Adjustment surcharge or credit shall be shown separately on the monthly Fuel Statement. At the end of each annual period, the actual amount to be collected or credited through the fuel adjustment will be compared to the actual amount collected or passed back. If the reconciliation is greater than plus or minus .5 percent, an adjustment will be made in a subsequent month.

F. Fuel Statement

The rate adjustments per 1000 pounds of steam as determined above shall be effective during the succeeding billing month after the month for which the average cost shall have been determined and shall continue in effect until changed.

(General Information - Continued on Leaf No. 14-C)

GENERAL INFORMATION - Continued

VIII. Increase in Rates Applicable

The rates and charges under all Service Classifications shall be increased to reflect the taxes imposed on the Company pursuant to the following statutes:

(1) New York Tax Law, Sections 186-a (Gross Receipt Tax), 209-B, and 1201(a);
(2) New York Tax Law 186-c;
(3) General City Law Section 20-b;
(4) Village Law Section 5-530.

Refund of all such increases will be made to a Customer who is a vendor of electricity to the extent that revenue derived from such vendor to which such increase was applied is not taxed to the Company under such statutes, as shown by the Customer's resale remission certificate.

Statement of Percentage Increase in Rates and Charges

The Statement of Percentage Increase in Rates and Charges ("Statement") sets forth the applicable percentage increase in rates and charges in effect for the City of New York. The Statement will reflect: the effective rate under Section 186-a of the New York Tax Law; the effective rate under Section 186-c of the New York Tax Law; a tax surcharge to recover the tax expense imposed by the Temporary Metropolitan Transportation Business Tax Surcharge under Tax Law Section 209-B; the currently effective rates under the New York Tax Law Section 1201(a), General City Law Section 20-b and Village Law Section 5-530; and a tax surcharge to reconcile State Income Taxes under New York State Tax Law Section 209 that were collected through the separate percentage increase that was in effect prior to October 1, 2004. The percentage increases will be applied to the Company's commodity revenues, revenues derived from transmission and distribution services, and the Company's other income.

Revisions to the Statement of Percentage Increase in Rates and Charges will be made, if appropriate, in accordance with the procedure for other changes in the Statement, to reflect periodic reconciliations for actual tax expense incurred under all Sections of the New York Tax Law and the revenues collected to recover such tax expense.

When a new revenue tax or an increase in the rate of revenue taxes is enacted by a city or a village, the Company will file with the Public Service Commission a revised Statement, apart from this Rate Schedule, not less than fifteen business days before the date on which the Company proposes to increase the percentage increase in rates and charges, but no sooner than the date of the tax enactment to which the Statement responds. When a municipality eliminates or reduces the rate of revenue taxes, the Company will, within the following five business days, cancel the Statement then in effect and, where applicable, replace such canceled Statement with a revised Statement setting forth the reduced percentage increase in rates and charges. All such revised Statements shall become effective no sooner than the date when the tax enactment is filed with the Secretary of State and shall be applicable to bills subject to the tax enactment that are rendered on or after the effective date of the Statement. A copy of the Statement in effect will be available to the public at Company offices at which applications for service may be made.

(General Information - Continued on Leaf No. 15-A)

GENERAL INFORMATION - Continued

VIII. Increase in Rates Applicable - Continued

Temporary Metropolitan Transportation Business Tax Surcharge

The rates and charges under all Service Classifications shall also be adjusted to recover the tax expenses imposed on the Company by the Temporary Metropolitan Transportation Business ("MTA") Tax Surcharge pursuant to Tax Law Sections 186-c and 209-B, as applicable, and reflected on the Statement of Percentage Increase in Rates and Charges ("Statement"). Any changes to the Company's MTA tax expense pursuant to Tax Law Sections 186-c and 209-B shall be reflected on a revised Statement filed with the Public Service Commission not less than fifteen days before the effective date of any change. Each such change filed pursuant to this paragraph shall remain in effect for a twelve-month period. A new Statement reflecting changes to the Company's MTA tax expense shall be filed for each year the MTA Tax Surcharge is applicable. In the second month following the conclusion of each twelve-month period, the Company will reconcile the revenues collected during that twelve-month period with the actual tax surcharge expense incurred by the Company in the corresponding year. In the event the revenues collected in each twelve-month period are substantially higher or lower (equal to or greater than plus or minus 0.5 percent) than the tax expenses incurred, the Company will make a one-time reconciliation adjustment after each twelve-month period.

State Income Tax

The rates and charges under all Service Classifications shall be adjusted by the application of a percentage to reflect the reconciliation of the State Income Taxes imposed on the Company under New York Tax Law Section 209 and reflected on the Statement of Percentage Increase in Rate and Charges ("Statement") prior to October 1, 2004. The additional surcharge shall be reflected on a revised Statement filed with the Public Service Commission not less than fifteen days before the effective date of any change.

(General Information - Continued on Leaf No. 15-B)

SERVICE CLASSIFICATION NO. 1
GENERAL SERVICE

Applicable to Use of Service for
All Purposes

Character of Service
Continuous; supplied at an average gauge pressure in excess of 125 pounds.

Rate
Base Rate (in each monthly period)

For the first	20,000 pounds	$ 9.206	per 1000 pounds
For the next	30,000 pounds	29.959	per 1000 pounds
For the next	950,000 pounds	23.287	per 1000 pounds
For excess over	1,000,000 pounds	22.394	per 1000 pounds

Customer Charge per month $619.56

A Customer who requests a temporary discontinuance of service will be required to pay the monthly customer charge for each month that service is discontinued. A Customer whose service is discontinued for non-payment and who applies for service within twelve months at the same location will be regarded as having taken a temporary discontinuance of service and will be required to pay the monthly customer charge for each month that service was discontinued.

Fuel Adjustment

The charges to the Customer set forth herein shall be subject to a fuel adjustment per 1000 pounds of steam supplied hereunder when changes from the base cost of fuel occur (as explained in General Information Section VII).

Increase in Rates and Charges

The rates and charges under this Service Classification including fuel adjustment and customer charge are increased by the applicable percentage as explained in General Information Section VIII and shown on the related Statement.

Terms of Payment

Net cash on presentation of bill.

Term

The term of the agreement for service shall be for a period to be fixed in such agreement and shall continue after the end of such period until terminated by the Customer upon thirty days' prior written notice, or by the Company in accordance with law or the provisions of this Rate Schedule.

(Service Classification No. 1 - Continued on Leaf No. 20-A)

SERVICE CLASSIFICATION NO. 2
ANNUAL POWER SERVICE

Applicable to Use of Service for

Power, Heat, or Power and Heat

Character of Service

Continuous; supplied at an average gauge pressure in excess of 125 pounds.

Rate

(a) **Access Charge** per monthly bill

$2,393.79 per 1000 pounds of steam per hour of the Customer's Winter Capacity Reservation, during monthly billing periods terminating within the months of November through April; and

$539.42 per 1000 pounds of steam per hour of the Customer's Summer Capacity Reservation, during monthly billing periods terminating within the months of May through October.

The Access Charge will be prorated only in the case of an initial bill or a final bill that covers less than the full monthly period, based on the number of days in the billing period. A Customer who requests a temporary discontinuance of service will be required to pay the Access Charge for each month that service is discontinued. A Customer whose service is discontinued for non-payment and who applies for service within twelve months at the same location will be regarded as having taken a temporary discontinuance of service and will be required to pay the Access Charge for each month that service was discontinued.

(b) **Usage Charge** ..... $6.708 per 1000 pounds of steam

(c) **Customer Charge** per month $2,716.58
A Customer who requests a temporary discontinuance of service will be required to pay the monthly customer charge for each month that service is discontinued. A Customer whose service is discontinued for non-payment and who applies for service within twelve months at the same location will be regarded as having taken a temporary discontinuance of service and will be required to pay the monthly customer charge for each month that service was discontinued.

Fuel Adjustment

The charges to the Customer set forth herein shall be subject to a fuel adjustment per 1000 pounds of steam supplied hereunder when changes from the base cost of fuel occur (as explained in General Information Section VII).

Increase in Rates and Charges

The rates and charges under this Service Classification including fuel adjustment and customer charge are increased by the applicable Percentage as explained in General Information Section VIII and shown on the related Statement.

(Service Classification No. 2 - Continued on Leaf No. 21-A)

SERVICE CLASSIFICATION NO. 2 - Continued
ANNUAL POWER SERVICE

Terms of Payment

Net cash on presentation of bill, subject to late payment charge in accordance with provisions of General Rule III- 4(j).

Term

The term of the agreement for service shall be for a period ending no less than one year from the beginning of service under this Service Classification, and shall continue after the end of such period until terminated by the Customer upon thirty days' prior written notice, or by the Company in accordance with law or the provisions of this Rate Schedule.

Special Provisions

A. Service will not be available under this Service Classification to Customers eligible for service under Service Classification No. 4.

B. A Customer may request a temporary discontinuance of service by notifying the Company in writing at least five days in advance of the date on which each temporary discontinuance is to begin specifying the date on which service is to be discontinued and the date on which service is to be resumed. The Company may elect not to physically disconnect service at the service valve. In the event that a Customer takes service during a temporary discontinuance period the Customer will be billed in accordance with this Service Classification.

C. A Customer having transferred from this Service Classification to another Service Classification may not transfer back to this Service Classification except on a date in any year which corresponds with the date when service was first supplied under this Service Classification.

D. Where a Customer installs a new or replacement steam air conditioning system on or after October 1, 2000, the Usage Charge in each monthly billing period for service furnished under this Service Classification during monthly billing periods terminating within the months of May to October, inclusive, will be reduced by an amount equal to $2.00 per 1000 pounds of steam used in excess of the first 250,000 pounds of steam used. A Customer applying for the foregoing reduction must notify the Company at least two months before installation of the air conditioning system. Such Customer will be eligible for the rate reduction effective with the first summer monthly billing period that commences subsequent to the date on which the Company receives written notice from the Customer that the installation is complete. Service will be provided under this Special Provision under the following conditions:

(1) in total, no more than 75,000 tons of new or replacement steam air conditioning capacity will be accepted under this Special Provision and Special Provision D of Service Classification No. 3;

(2) the Company will provide service under this Special Provision until at least September 30, 2004, after which time the level of the rates and charges and the terms and conditions of service may vary from those initially offered; and

(3) to facilitate Customers' investment decisions, the Company may, at its sole discretion, negotiate the term of service under this Special Provision with a Customer who agrees to use steam for air conditioning and other purposes during the service term.

(Service Classification No. 2 - Continued on Leaf No. 21-B)

SERVICE CLASSIFICATION NO. 2 - Continued

ANNUAL POWER SERVICE

Special Provisions – Continued

E. Where a Customer does not own a steam air conditioning system and installs a new steam air conditioning system to replace or supplement existing electric air conditioning equipment, the Usage Charge in each monthly billing period for service furnished under this Service Classification during monthly billing periods terminating within the months of May to October, inclusive, will be reduced by $2.00 per 1000 pounds of steam used in excess of the first 250,000 pounds of steam used. A Customer applying for the foregoing reduction must notify the Company at least two months before installation of the air conditioning system. Such Customer will be eligible for the rate reduction effective with the first summer monthly billing period that commences subsequent to the date on which the Company receives written notice from the Customer that the installation is complete. Service will be provided under this Special Provision under the following conditions:

(1) service under this Rider will not be available until after a total of 25,000 tons of new or replacement steam air conditioning capacity is accepted under Special Provision D of this Service Classification and Special Provision D of Service Classification No. 3;

(2) in total, no more than 25,000 tons of new steam air conditioning capacity will be accepted under this Special Provision and Special Provision E of Service Classification No. 3;

(3) steam purchased from the Company must be used solely for operating air conditioning equipment and only during the months of May to October, inclusive;

(4) the Company will provide service under this Special Provision until at least October 1, 2003, after which time the level of the rates and charges and the terms and conditions of service may vary from those initially offered; and

(5) to facilitate Customers' investment decisions, the Company may, at its sole discretion, negotiate the length of the term of service under this Special Provision with a Customer who does not own a steam air conditioning system and installs a new steam air conditioning system to replace or supplement existing electric air conditioning equipment.

F. The foregoing rates and charges shall apply to all steam service supplied hereunder on and after the effective date hereof. Where a bill includes periods before the effective date and after the effective date, the rates and charges applicable will be prorated based on the number of days of service rendered before the effective date and on and after the effective date related to the total number of days in the billing period.

G. The following Riders may be applied to this Service Classification: A, B, C, D, and E on Leaf Nos. 11 to 13-A, inclusive.

H. For form of application under this Service Classification, see Leaf Nos. 16-18.

SERVICE CLASSIFICATION NO. 3
APARTMENT HOUSE SERVICE

Applicable to Use of Service for

Power, Heat, or Power and Heat, for buildings containing three or more separate living apartments, the aggregate cubic contents of which constitute at least half the total of such buildings.

Character of Service

Continuous; supplied at an average gauge pressure in excess of 125 pounds.

Rate

(a) **Access Charge** per monthly bill

$2,544.63 per 1000 pounds of steam per hour of the Customer's Winter Capacity Reservation, during monthly billing periods terminating within the months of November through April; and

$536.76 per 1000 pounds of steam per hour of the Customer's Summer Capacity Reservation, during monthly billing periods terminating within the months of May through October.

The Access Charge will be prorated only in the case of an initial bill or a final bill that covers less than the full monthly period, based on the number of days in the billing period. A Customer who requests a temporary discontinuance of service will be required to pay the Access Charge for each month that service is discontinued. A Customer whose service is discontinued for non-payment and who applies for service within twelve months at the same location will be regarded as having taken a temporary discontinuance of service and will be required to pay the Access Charge for each month that service was discontinued.

(b) **Usage Charge** ..... $6.708 per 1000 pounds of steam

(c) **Customer Charge** per month.....$1317.64
A Customer who requests a temporary discontinuance of service will be required to pay the monthly customer charge for each month that service is discontinued. A Customer whose service is discontinued for non-payment and who applies for service within twelve months at the same location will be regarded as having taken a temporary discontinuance of service and will be required to pay the monthly customer charge for each month that service was discontinued.

Fuel Adjustment

The charges to the Customer set forth herein shall be subject to a fuel adjustment per 1000 pounds of steam supplied hereunder when changes from the base cost of fuel occur (as explained in General Information Section VII).

Increase in Rates and Charges

The rates and charges under this Service Classification including fuel adjustment and customer charge are increased by the applicable percentage as explained in General Information Section VIII and shown on the related Statement.

(Service Classification No. 3 - Continued on Leaf No. 22-A)

SERVICE CLASSIFICATION NO. 3 - Continued
APARTMENT HOUSE SERVICE

Terms of Payment

Net cash on presentation of bill, subject to late payment charge in accordance with provisions of General Rule III- 4(j).

Term

The term of the agreement for service shall be for a period ending not less than one year from the beginning of service under this Service Classification, and shall continue after the end of such period until terminated by the Customer upon thirty days' prior written notice, or by the Company in accordance with law or the provisions of this Rate Schedule.

Special Provisions

A. Service will not be available under this Service Classification to Customers eligible for service under Service Classification No. 4.

B. A Customer may request a temporary discontinuance of service by notifying the Company in writing at least five days in advance of the date on which each temporary discontinuance is to begin specifying the date on which service is to be discontinued and the date on which service is to be resumed. The Company may elect not to physically disconnect service at the service valve. In the event that a Customer takes service during a temporary discontinuance period the Customer will be billed in accordance with this Service Classification.

C. On and after February 10, 1981, any new Customer requesting apartment house service will not be eligible for service under Service Classification Nos. 1 and 2.

D. Where a Customer installs a new or replacement steam air conditioning system on or after October 1, 2000, the Usage Charge in each monthly billing period for service furnished under this Service Classification during monthly billing periods terminating within the months of May to October, inclusive, will be reduced by $2.00 per 1000 pounds of steam used in excess of the first 50,000 pounds of steam used. A Customer applying for the foregoing reduction must notify the Company at least two months before installation of the air conditioning system. Such Customer will be eligible for the rate reduction effective with the first summer monthly billing period that commences subsequent to the date on which the Company receives written notice from the Customer that the installation is complete. Service will be provided under this Special Provision under the following conditions:

(1) in total, no more than 75,000 tons of new or replacement steam air conditioning capacity will be accepted under this Special Provision and Special Provision D of Service Classification No. 2;

(2) the Company will provide service under this Special Provision until at least September 30, 2004, after which time the level of the rates and charges and the terms and conditions of service may vary from those initially offered; and

(3) to facilitate Customers' investment decisions, the Company may, at its sole discretion, negotiate the term of service under this Special Provision with a Customer who agrees to use steam for air conditioning and other purposes during the service term.

(Service Classification No. 3 - Continued on Leaf No. 22-B)

SERVICE CLASSIFICATION NO. 3 - Continued

APARTMENT HOUSE SERVICE

Special Provisions – Continued

E. Where a Customer does not own a steam air conditioning system and installs a new steam air conditioning system to replace or supplement existing electric air conditioning equipment, the Usage Charge in each monthly billing period for service furnished under this Service Classification during monthly billing periods terminating within the months of May to October, inclusive, will be reduced by $2.00 per 1000 pounds of steam used in excess of the first 50,000 pounds of steam used. A Customer applying for the foregoing reduction must notify the Company at least two months before installation of the air conditioning system. Such Customer will be eligible for the rate reduction effective with the first summer monthly billing period that commences subsequent to the date on which the Company receives written notice from the Customer that the installation is complete. Service will be provided under this Special Provision under the following conditions:

(1) service under this Rider will not be available until after a total of 25,000 tons of new or replacement steam air conditioning capacity is accepted under Special Provision D of this Service Classification and Special Provision D of Service Classification No. 2;

(2) in total, no more than 25,000 tons of new steam air conditioning capacity will be accepted under this Special Provision and Special Provision E of Service Classification No. 2;

(3) steam purchased from the Company must be used solely for operating air conditioning equipment and only during the months of May to October, inclusive;

(4) the Company will provide service under this Special Provision until at least October 1, 2003 after which time the level of the rates and charges and the terms and conditions of service may vary from those initially offered; and

(5) to facilitate Customers' investment decisions, the Company may, at its sole discretion, negotiate the length of the term of service under this Special Provision with a Customer who does not own a steam air conditioning system and installs a new steam air conditioning system to replace or supplement existing electric air conditioning equipment.

F. The foregoing rates and charges shall apply to all steam service supplied hereunder on and after the effective date hereof. Where a bill includes periods before the effective date and after the effective date, the rates and charges applicable will be prorated based on the number of days of service rendered before the effective date and on and after the effective date related to the total number of days in the billing period.

G. The following Riders may be applied to this Service Classification: A, B, C, D, and E on Leaf Nos. 11 to 13-A, inclusive.

H. For form of application under this Service Classification, see Leaf Nos. 16-18.

SERVICE CLASSIFICATION NO. 4
BACK-UP/SUPPLEMENTARY SERVICE

Applicable to Use of Service for

Power, Heat, or Power and Heat to Customers who utilize both steam supplied by the Company's steam system for any purpose and another energy source for the same purpose at any time during the months of November through April, inclusive, subject to the Common Provisions and Special Provisions of this Service Classification.

Character of Service

Continuous; supplied at an average gauge pressure in excess of 125 pounds.

Rate I

Applicability: To Customers who would otherwise be served under Service Classification No. 2 if they did not utilize both steam supplied by the Company's steam system and another energy source for the same purpose during the months of November through April, inclusive.

Contract Demand Charge (per 1000 pounds per hour of the contract demand in each monthly billing period) *pursuant to Special Provision B hereof*

On-Peak Contract Demand Charge, applicable to a Peak Period Customer $1047.29
Off-Peak Contract Demand Charge, applicable to an Off-Peak Period Customer $788.85

Usage Charge (per 1000 pounds of steam in each monthly billing period) *pursuant to Special Provision B hereof*

On-Peak Usage Charge, applicable to a Peak Period Customer $11.291
Off-Peak Usage Charge, applicable to an Off-Peak Period Customer $14.490

Customer Charge per month $2,716.58

Rate II

Applicability: To Customers who would otherwise be served under Service Classification No. 3 if they did not utilize both steam supplied by the Company's steam system and another energy source for the same purpose during the months of November through April, inclusive.

Contract Demand Charge (per 1000 pounds per hour of the contract demand in each monthly billing period) *pursuant to Special Provision B hereof*

On-Peak Contract Demand Charge, applicable to a Peak Period Customer $1,285.46
Off-Peak Contract Demand Charge, applicable to an Off-Peak Period Customer $956.07

Usage Charge (per 1000 pounds of steam in each monthly billing period) *pursuant to Special Provision B hereof*

On-Peak Usage Charge, applicable to a Peak Period Customer $9.897
Off-Peak Usage Charge, applicable to an Off-Peak Period Customer $11.421

Customer Charge per month $1,317.64

(Service Classification No. 4 - Continued on Leaf No. 24)

[RESERVED FOR FUTURE USE]

[RESERVED FOR FUTURE USE]

[RESERVED FOR FUTURE USE]

[RESERVED FOR FUTURE USE]

[RESERVED FOR FUTURE USE]

STATE OF NEW YORK)
)
COUNTY OF NEW YORK)

JOAN S. FREILICH, being duly sworn, says:

I am Executive Vice President and Chief Financial Officer of CONSOLIDATED EDISON COMPANY OF NEW YORK, INC., the applicant above-named, on behalf of which I have subscribed the foregoing application and know the contents thereof and the same is true to the best of my knowledge, information and belief.

Joan S. Freilich

Subscribed and sworn to
before me this 21st day of
November, 2003.

Stephen Ianello

STEPHEN IANELLO
NOTARY PUBLIC, STATE OF NEW YORK
NO. 31-4837907
QUALIFIED IN NEW YORK COUNTY
COMMISSION EXPIRES AUGUST 31, 2005

NEW YORK PUBLIC SERVICE COMMISSION

STEAM CASE _____

CONSOLIDATED EDISON COMPANY

OF NEW YORK, INC.

TESTIMONY

VOLUME 1

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.
STEAM CASE WITNESSES

TAB NO.	NAME
1	Helen L. Lee
2	Robert Muccilo
3	Kevin F. Fitzmartin
4	Robert G. Rosenberg
5	Steve Fetter
6	Charles D. Hutcheson
7	Frank C. Yaegel
8	John P. Ricco
9	Edward J. Rasmussen
10	Kevin Burke
11	Andrew L. Jacob
12	Rick Shansky
13	Victor C. Gonnella
14	Ronald H. Bozgo
15	Anthony Adinolfi
16	Irina Northup
17	Bahman Litkouhi
18	Robert S. Boyle
19	Hector J. Reyes
20	Anthony B. Codner
21	Randolph S. Price
22	Steam Rate Panel: Joel Charkow Christine M. Colletti Allan S. Cohen

Q. Please state your name and business address.

A. My name is Helen L. Lee. My business address is Consolidated Edison Company of New York, Inc. ("Con Edison" or the "Company"), 4 Irving Place, New York, N.Y. 10003.

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

A. I have been employed by Con Edison since June 1970, and currently I hold the position of Department Manager in the Regulatory Accounting Section of Corporate Accounting.

Q. Please state briefly your educational background.

A. I graduated from Bernard M. Baruch College in June 1970, with a degree in Bachelor of Business Administration.

Q. Please explain your work experience with Con Edison and your current general responsibilities.

A. From June 1970 to August 1984, I worked in the General Accounts Section of the Corporate Accounting Department in various capacities up to Assistant Manager of the section. In August 1984, I was transferred to the Rate Matters Section as Administrator and held increasing levels of responsibility up to Department Manager. In January 1998, I was assigned to Central Operations as Department Manager, Finance and Budget, reporting to

the Senior Vice President on administrative, budgets and financial matters. In July 1999, I returned to my prior position in Corporate Accounting. By July 2001, the regulatory function also included those for Orange and Rockland Utilities, Inc. ("O&R") and the section separated into two groups, Regulatory Filings and Regulatory Accounting. I currently manage the Regulatory Accounting section but my section also contributes toward the regulatory filing function.

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

A. Yes. I submitted testimony in the Company's Steam Rate Case 96-S-1065 and Case 99-S-1621.

Q. To the best of your knowledge and belief, has the Company maintained its books and accounts in accordance with the Uniform System of Accounts prescribed by the Commission and with accounting orders of the Commission?

A. Yes, it has.

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

A. I will testify to various historic financial and statistical data for the steam department. In addition, I will also address certain normalizations

and program changes to arrive at the rate year level of expenses, Other Operating Revenues, Taxes Other Than Income Taxes, the general escalation rate and the elements of expense that the Company intends to update at an appropriate time in this proceeding.

Q. Was the document entitled "CONSOLIDATED EDISON COMPANY OF NEW YORK, INC. - FINANCIAL AND STATISTICAL DATA - INDEX TO SCHEDULES", set forth as Exhibit ___- (HLL-1), which lists therein eight schedules containing certain accounting and statistical information covering the operations of Con Edison for the years 1999, 2000, 2001, 2002 and the twelve months ended June 30, 2003 with particular reference to the Company's steam operations, prepared under your direction and supervision?

A. Yes, it was.

MARK FOR IDENTIFICATION AS EXHIBIT ___ (HLL-1)

Q. What information is contained in Exhibit ___ (HLL-1)?

A. The Exhibit consists of an index and eight separate schedules containing financial data and the results of operations. The balance sheets are shown as of December 31 for the years 1999 through 2002, and as of June 30, 2003, while details of the income accounts are shown for the years 2000 through 2002 and the twelve

months ended June 30, 2003. The arrangement of the schedules is as follows:

- Balance Sheets are shown on Schedule 1.
- Income Statements are shown on Schedule 2.
- Unappropriated Retained Earnings are shown on Schedule 3.
- Steam Utility Operating Income, before and after income taxes, is presented in Schedule 4.
- Steam Operating Revenues by account classification with revenues shown in dollar amounts and in equivalent cents per MLBS sold are shown on Schedule 5.
- MMLBS of steam supplied by Service Classification and the revenues realized therefrom are shown on Schedule 6. This schedule also reflects revenue in equivalent cents per MLBS sold.
- Steam Operation and Maintenance Expenses consisting of eight pages are shown on Schedule 7. Page 1 is a summary statement, which shows the operation and maintenance expenses on a functional basis, both in dollar amounts and equivalent cents per MLBS sold. Pages 2 to 8 show the details of the various functional groups by account number, in dollar

amounts and in equivalent cents per MLBS sold, except for pages 2 and 3, which show steam production expenses in equivalent cents per MLBS produced.

- Taxes Other Than Income Taxes - Steam is shown on Schedule 8.

All of the information in Exhibit ___ (HLL-1) comes from the books and records of the Company; where revenues or expenses are stated in cents per MLBS sold or produced, these figures have been computed.

Q. Turning back to Exhibit ___ (HLL-1), Schedule 7, page 2, Production Expenses - Steam, are generating stations classified as electric plant also used in the production of steam for delivery to the Company's steam customers?

A. Yes. Steam is produced at three of the Company's generating stations that are classified as electric plant: Waterside, East River and at the Hudson Avenue Annex.

Q. Would you explain the accounting for electric production expenses chargeable to steam operations?

A. Yes. The production of steam at these electric generating stations for sale by the steam department involves charges for the fuel used to produce this

steam, plus processing charges for water, labor, and chemicals. The charges for the fuel used to produce steam for sale by the steam department are made directly to steam production expense and are included in Account 703, Fuel, whereas the processing charges for such steam are charged to Steam Production Expenses, Station Supplies and Expenses, Account 705.2, and credited to Electric Production Expenses.

Q. How are the charges to the steam department determined for steam produced at these electric stations?

A. Company witness Northup will discuss in her testimony the computations of quantities of fuel used to produce this steam for steam operations. Company witnesses Northup and Adinolfi address the processing charges.

Q. Have you prepared an exhibit, which shows the breakdown of steam production costs by station for the twelve months ended June 30, 2003?

A. Yes. It is the document entitled "CONSOLIDATED EDISON COMPANY OF NEW YORK, INC. - PRODUCTION EXPENSES - STEAM - (INDIVIDUAL STATIONS) - TWELVE MONTHS ENDED JUNE 30, 2003", set forth as Exhibit ___ (HLL-2).

MARK FOR IDENTIFICATION AS EXHIBIT ___ (HLL-2)

Q. Please describe Exhibit ___ (HLL-2).

A. This exhibit consists of two pages and shows the allocation by station of steam production expenses in the historical year, the twelve months ended June 30, 2003. The total amount of production expenses is also shown on Exhibit ___ (HLL-1), Schedule 7, page 2. Included on the second page of Exhibit ___ (HLL-2) are the production costs as shown on page 1 expressed in terms of equivalent cents per MLBS produced.

Q. Was the document entitled "CONSOLIDATED EDISION COMPANY OF NEW YORK, INC. - CALCULATION OF FEDERAL INCOME TAXES - FOR THE TWELVE MONTHS ENDED JUNE 30, 2003" consisting of 4 pages, set forth as Exhibit ___ (HLL-3), prepared under your direction and supervision?

A. Yes, it was.

MARK FOR IDENTIFICATION AS EXHIBIT ___ (HLL-3)

Q. Please describe Exhibit ___ (HLL-3).

A. Pages 1 through 3 set forth the calculation of Federal income tax for steam operations, including accruals, deferrals and amortizations of deferrals. Page 4 shows the calculation of New York State income tax for steam operations. These amounts are also included on Exhibit ___ (HLL-1), Schedule 2, page 4.

Q. Was the document entitled "CONSOLIDATED EDISON COMPANY OF NEW YORK, INC. - BOOK COST OF UTILITY PLANT - STEAM

- AS OF DECEMBER 31, 1999, 2000, 2001, 2002 AND JUNE 30, 2003", set forth as Exhibit ___ (HLL-4), prepared under your direction and supervision?

A. Yes, it was.

MARK FOR IDENTIFICATION AS EXHIBIT ___ (HLL-4)

Q. What is shown on Exhibit ___ (HLL-4)?

A. This exhibit shows the book cost of Utility Plant - Steam - by utility plant account at December 31, 1999, 2000, 2001, 2002 and June 30, 2003. The amounts shown for Steam Plant in Service and Construction Work in Progress are taken directly from the books and records of the Company.

Q. Do the figures shown for steam plant in service on Exhibit ___ (HLL-4) represent the original cost of existing property, which is used and useful as of the dates indicated?

A. To the best of my knowledge and belief they do. The plant accounts are maintained in balance with the continuing property records, which show the original cost of the existing property classified in accordance with established continuing property record units.

Q. Was the document entitled "CONSOLIDATED EDISON COMPANY OF NEW YORK, INC. - ACCUMULATED PROVISION FOR DEPRECIATION OF STEAM PLANT IN SERVICE AS OF DECEMBER

31, 1999, 2000, 2001, 2002 AND JUNE 30, 2003", set forth as Exhibit ___ (HLL-5), prepared under your direction and supervision?

A. Yes, it was.

MARK FOR IDENTIFICATION AS EXHIBIT ___ (HLL-5)

Q. Please describe this exhibit.

A. This exhibit shows the accumulated provision for depreciation of Steam Plant in Service as of December 31, 1999, 2000, 2001, 2002 and June 30, 2003. The amounts shown on this exhibit are taken from the books and records of the Company. Company witness Hutcheson's testimony addresses the accumulated provision for depreciation.

Q. Have you prepared an exhibit showing the working capital requirements for steam operations?

A. Yes, I have.

Q. Was the four-page document, entitled "CONSOLIDATED EDISON COMPANY OF NEW YORK, INC. - WORKING CAPITAL - STEAM - TWELVE MONTHS ENDED JUNE 30, 2003", set forth as Exhibit ___ (HLL-6), prepared under your direction and supervision?

A. Yes.

MARK FOR IDENTIFICATION AS EXHIBIT ___ (HLL-6)

Q. Please describe Exhibit ___ (HLL-6).

A. Exhibit ___ (HLL-6) shows the development of the working capital requirements for steam operations for the twelve months ended June 30, 2003. The study was made in accordance with the modified Federal Energy Regulatory Commission ("FERC") formula. For the purpose of this exhibit, working capital is comprised of materials and supplies, prepayments and cash working capital. Cash working capital is an amount that recognizes the Company's need to finance from its own generated funds the cash necessary to enable it to meet its daily obligations. The exhibit shows that the working capital required by the Company for steam operations during the twelve months ended June 30, 2003 amounted to $48,018,000.

Q. Would you explain by reference to Exhibit ___ (HLL-6) how you arrived at this estimate for working capital?

A. The elements of working capital for Steam are listed on page 1 of Exhibit ___ (HLL-6), with further details set forth on pages 2, 3 and 4. The first item shown on page 1, materials and supplies, is comprised of two parts. The first, the average balance of materials and supplies, excluding fuel, is detailed on page 2. The second, the average balance of liquid fuel is detailed on page 3.

Q. Was the average balance of liquid fuel calculated in the same manner as in past steam rate cases?

A. Yes.

Q. Please continue with your explanation of the next element of working capital.

A. The second item on page 1 of Exhibit ___ (HLL-6) is Prepayments. The development of the average balance, based on monthly balances, is shown on page 4.

Q. Please explain the derivation of the final element of working capital appearing on page 1 of Exhibit ___ (HLL-6), Cash Working Capital.

A. Cash working capital is detailed on page 1 of the exhibit. The use of the 1/8 factor is in accordance with the "modified" FERC formula. The derivation of the 1/12 factor applied to recoverable fuel costs is based only on the billing lag of 30 days (1/12) and not the service and billing lag of 45 days (1/8). Since recoverable fuel charges are included in rate base as deferred fuel charges until the amounts are billed to customers, there is no service lag associated with recoverable fuel charges. These three elements of working capital produce a total working capital requirement of $48,018,000.

Q. I show you a document entitled "CONSOLIDATED EDISON COMPANY OF NEW YORK, INC. - REVENUES AND OPERATING EXPENSE DATA", set forth as Exhibit ___ (HLL-7), and I ask you if it was prepared under your direction and supervision?

A. Yes, it was. The first page contains an index of the 10 schedules included in the exhibit.

MARK FOR IDENTIFICATION AS EXHIBIT ___ (HLL-7)

Q. Will you describe Schedule 1 of this exhibit?

A. Schedule 1, page 1 is a statement of Steam Operating Income before income taxes by component for the historic year ended June 30, 2003, and for the rate year ending September 30, 2005. Column 1 shows the data as recorded on the Company's books of account for the 12 months ended June 30, 2003. Column 2 reflects the changes made to normalize the historic year costs and to provide for increased or decreased costs and activity levels or other linkage to arrive at the rate year estimate shown in column 3. The historic year revenues and costs were developed from various schedules from Exhibit ___ (HLL-1). Total steam operating revenues are shown on Exhibit ___ (HLL-1) whereas operation and maintenance expenses by cost element as summarized on page 1 of Schedule 1, are

detailed in this exhibit on Schedule 1, page 3 and were developed from various other schedules in the exhibits I am presenting.

Q. How were sales revenues and associated fuel costs developed for the rate year?

A. Company witness Yaegel provided the sales forecast. The changes from the historic year to the rate year are explained in his testimony. Incurred fuel costs were developed by Company witness Northup and fuel costs were then adjusted by me to an accounting basis.

Q. How were Other Operating Revenues, and Other Operating Income Deductions, as shown on line 2 and lines 6 - 8 of Schedule 1 determined?

A. The historic year levels were developed from Exhibit ___ (HLL-1). I developed the rate year forecasts for Other Operating Revenues, Taxes Other than Income Taxes and Loss from Disposition of Utility Plant. The first two items are shown on Schedule 1, pages 2 and 4, respectively. Company witness Hutcheson developed the rate year level for Depreciation and Amortization expense.

Q. Please explain the derivation of the operation and maintenance expenses for the rate year shown on page 3 of Schedule 1.

A. Page 3 shows the derivation of the projected costs in the rate year from the historic year costs. Various Company witnesses, including myself, will explain normalizing adjustments and program changes. In addition, I will explain general escalation. Company witness Muccilo explains labor escalation. For the sake of convenience, his development of labor escalation is included in Exhibit ___ (HLL-7) as Schedules 2 and 3. Schedule 4 summarizes the historic and rate years' operation and maintenance expenses by Major Account Group (MAG) function and the changes between the two periods. The totals correspond to Schedule 1, page 3. Schedule 5 shows the historic year elements of expense by MAG. Schedule 6 shows a summary by function of the operating and maintenance expenses for the historic year and the changes in the forecast to the rate year ending September 30, 2005.

Q. Please continue with Schedules 7 and 8.

A. When a normalizing adjustment or program change affects an individual element of expense, this is shown as an addition or subtraction from the historic year, at the historic year price level. The normalizing adjustments are shown on Schedule 7 and program changes are shown

on Schedule 8, and depending on the specific change, they are addressed by various Company witnesses.

Q. Who are the witnesses sponsoring normalizing adjustments as shown on Schedule 7?

A. Company witness Adinolfi will address normalizing adjustments for the cost elements Water and Water Chemicals, Allocation of Support Services and Contract Labor, lines 2, 7 and 8, respectively, in his testimony. I will address the balance of the adjustments, i.e., Electric Usage, Company Labor, Rate Case Accounting - Interference, and all those under MAG 49, Administrative and General Expenses.

Q. Who are the witnesses sponsoring program changes as shown on Schedule 8?

A. Company witness Adinolfi discusses Waterside/East River Transition, Guard Service, Water and Water Chemicals, Plant Component Upgrade, Plant Inspection and Repair, and Water/Sewer, lines 1, 9, 10, 13, 14, and 20, respectively. Company witness Price addresses Environmental, Health and Safety and MGP/Superfund programs, lines 4, 16 and 37. Company witness Northup will explain Fuel and Other Fuel charges, lines 5 and 7, respectively. Company witness Codner will discuss lines 8, 19 and 42, Research and Development costs.

Company witness Boyle will address Interference, line 23, and Company witness Muccilo will discuss Company Labor line 30. Company witness Reyes will address Employee Welfare Expenses, line 31. I will address the balance of the program changes, i.e., New Communication System, Electric Usage, Interdepartmental Rents, Security (in addition to the security costs and expenses addressed by Company witness Adinolfi), Fringe Benefits - New Employees, Injuries and Damages, Insurance premiums, the allocations of Environmental, Health and Safety and MGP/Superfund costs discussed by Company witness Price, Pensions and OPEBs, PricewaterhouseCoopers consultant fees, Shared Services and Strike Contingency.

Q. Please describe Schedule 9 of your Exhibit ___ (HLL-7).

A. Schedule 9 shows the Company's steam operating and maintenance expenses subject to escalation.

Q. Please describe the general escalation rate you used.

A. The general escalation rate reflects cost increases anticipated to occur as the result of inflation. The labor content has been extracted from each element of expense and the residual amounts were then escalated either specifically for known cost increases or generally to reflect the overall anticipated rate of

inflation. The general escalation factor is based on the projected increase in the Gross Domestic Product ("GDP") price deflator.

Q. What are the forecasted rates of increase in the GDP price deflator that were used to develop the general escalation factor, and what are their sources?

A. Since Blue Chip will not publish a GDP deflator forecast for 2005 until the January 10, 2004 issue, the increase for January through September 2005 was derived from the Blue Chip quarterly rate forecast which was projected at 1.6 percent annually from the fourth quarter of 2003 to the third quarter of 2005. Utilizing these forecasts, I calculated the increase from the average of the historic year ended June 30, 2003 through the average of the rate year ending September 30, 2005 to be 3.53%. As with past practice in the Company's rate cases, I will update the inflation factors to reflect the latest available inflation forecasts later in this proceeding. As I mentioned earlier, Schedule 9 of Exhibit ___ (HLL-7) lists the various operation and maintenance expenses, which are subject to general escalation.

Q. Please describe Schedule 10 of Exhibit ___ (HLL-7).

A. Schedule 10 of this exhibit lists those cost elements that the Company plans to update and also the witnesses sponsoring the various cost elements.

OTHER OPERATING REVENUES

Q. Does Exhibit ___ (HLL-7) show the details of Other Operating Revenues?

A. Schedule 1, page 2 of Exhibit ___ (HLL-7) shows the details of Other Operating Revenues both in the historic and rate years. The historic year level of $27.604 million is forecasted to increase by $75.956 million, for a rate year level of $103.560 million.

Q. Please explain the first line item, Revenue Offset Re: 74/59 St. Transfer from Electric.

A. As discussed in Mr. Rasmussen's testimony, this line item reflects the proposed continuation of the recovery of the non-fuel operating costs of the 74/59th Street Stations from electric customers until the steam department realizes its allocation of the net gains from the sale of the First Avenue properties. As the operating costs of 74/59th Street Stations are currently carried on steam books, the Company offsets the increased operating costs to steam via a credit entry to Other Operating Revenues with a concomitant

debit to electric Other Operating Revenues. The change in operating expenses as projected by Company witness Adinolfi is $2,228,000 and Company witness Hutcheson provided me with an increase of $1,103,000 in property taxes for the 74th Street Station.

Q. How was line 2, Interdepartmental Rents revenue of $78.2 million for the rate year developed?

A. This revenue represents carrying charges that the steam department charges the electric department for facilities it uses jointly with steam. Carrying charges on shared facilities include components for rate of return, depreciation and taxes. The carrying charges are applied to the book value of the facility. Interdepartmental rents revenue for the historic year was derived from the joint usage of the Hudson Avenue Tunnel. For the rate year, revenue also includes the East River Repowering Project, a joint steam and electric production facility. For ERRP, the total annual carrying charges for the rate year are $114,252,000. The charge to the electric department during the rate year for the ERRP facility is $76,168,000. Company Witness Gonnella supplied me with the allocation of the carrying charges between electric

and steam operations, with approximately two-thirds chargeable to electric and one-third to steam

Q. Please continue with line 3.

A. Line 3 represents profits related to the Fuel Management Program. The Company seeks to optimize the value of its storage capacity through the storage of fuel by third parties. However, for the forecast rate year, the Company does not expect to generate revenues for the Fuel Management Program due to the loss of a third-party agreement.

Q. Please continue.

A. Line 4 is the forecast of late payment charges in the amount of $736,000 for the rate year. The historic year included an adjustment for late payment charges assessed KeySpan that were reversed in March 2003 as a result of a settlement. Line 5, Special Services Repair Program, represents the steam repair program and other special services, such as turn-ons/turn-offs, pursuant to the 2000 rate agreement. The Company estimates the rate year level for turn-ons/turn-offs at $289,000 and repair services at $36,000, for a total of $325,000, a decrease of $105,000 from the historic year and a decrease of $350,000 from the levels estimated by the Steam Rate Panel in the current rate agreement.

The decrease is attributable to both limited resources on the part of the Company to perform repair services and a decline in the number of turn ons/turn offs that were performed in the historic year. Line 6 represents the allocation to steam operations of $72,000 in revenue from Cablevision Lightpath, Inc. for the placement of fiber optic cables in a portion of the Company's Hudson Avenue Tunnel. The billing is $36,225 biannually in the months of May and December. In the historic year, the May 2002 billing was rendered in August 2002; thus, the historic year included three payments instead of the two reflected in the rate year. This agreement expires in May 2006.

Q. What is the next group entitled Regulatory Accounting?

A. These items reflect the impacts of various Commission decisions. Line 7, represents the reconciliation of the collection for the New York State income tax law change of 2000 from customers per Case 00-M-1556. This line item will not be necessary during the rate year ending September 30, 2005 as the New York State income tax will be included in base rates and no longer reconciled. Line 8, represents the adjustment to the steam Fuel Adjustment Clause to eliminate the estimated credit to customers for the return component and

depreciation expense associated with the retirement and sale of a barge per Case 02-M-0604, as the barge is included in steam base rates for the remaining term of the 2000 Settlement ending September 30, 2004. Lines 9 through 12 represent the effects of the 2000 Settlement adopted by the Commission in Case 99-S-1621. Line 9, Rate Case 99-S-1621 Amortizations, represents the effect on the historic year the amortizations made pursuant to the Settlement. The amortizations for previously deferred oil storage and handling costs and O&R merger savings due customers will expire September 30, 2004. Line 10, Air Conditioning Discounts and Special Contracts Programs, reflects the costs of two programs established to attract and retain customers with a viable competitive alternative. Revenue shortfalls from full base tariff rates, net of base fuel, associated with any rate discounts are shared 80% by customers and 20% by the Company, with the ratepayers' share deferred until the end of the rate agreement. The Steam Rate Panel proposes in this filing to include such programs in base rates and the effects are reflected in Company witness Yaegel's forecast. Company witness Muccilo's testimony seeks a three-year recovery of the deferred costs.

Q. Please continue.

A. The Steam Rate Moderation Mechanism, line 11, was designed to smooth the required base rate increases over the four-year period of the Settlement. This mechanism expires September 30, 2004. Last, the Line Loss Incentive/Penalty Mechanism is not applicable to the rate year.

DEPRECIATION AND AMORTIZATION

Q. Please explain Depreciation and Amortization shown on Exhibit ___ (HLL-7), Schedule 1, page 1.

A. Depreciation expense using existing rates in effect is projected for the rate year to be $42,819,000. This was provided to me by Company witness Hutcheson and is fully discussed in his testimony.

LOSSES FROM DISPOSITION OF UTILITY PLANT

Q. Please explain the forecast of losses from disposition of utility plant as shown on your Exhibit ___ (HLL-7), Schedule 1, page 1.

A. The item in the historic year represents the Company's loss on the sale of a barge per Case 02-M-0604. The forecast does not include any loss from disposition of utility plant.

TAXES OTHER THAN INCOME TAXES

Q. Please explain the line items on your Schedule 1, page 4, Taxes Other than Income Taxes.

A. The first item is New York City Property Taxes consisting of New York City real estate and special franchise taxes for the 12 months ended June 30, 2003 applicable to steam operations of $38,189,000. The rate year forecast of $65,158,000 was provided to me by Company witness Hutcheson and is fully described in his testimony. Line 2 represents the reconciliation of actual property taxes to the levels established per the Settlement in Case 99-S-1621. The line item is not applicable to the rate year.

Q. Please describe how you developed Revenue Taxes for the rate year on line 4 of Schedule 1.

A. Revenue taxes consist of taxes derived from base and fuel rider revenues. Revenue taxes for the rate year are projected to be $9.394 million.

Q. Please describe the increase in Payroll Taxes, line 5.

A. The increase in payroll taxes from the historic year to the rate year is due principally to increased base wages subject to FICA. The Company will revise payroll taxes for known changes, if any, in the FICA rate and base in the update stage of this proceeding. Any

change in payroll taxes resulting from tax legislation in any jurisdiction will also be reflected.

Q. Please explain the increase in Sales and Compensating Use Tax, line 6.

A. The forecast of sales and compensating use taxes for the rate year were estimated based on the historic year plus escalation at 3.53%.

Q. Please continue with Subsidiary Capital Tax, line 7.

A. The Subsidiary Capital Tax applies only to New York City and the forecast was based on the latest return filed for 2001; the forecast for the 12 months ended September 30, 2005 is $179,000. The Company received an extension for filing its Year 2002 return and will file it by year-end 2003.

Q. Please describe All Other Taxes, line 8.

A. All other taxes represent minor taxes and include the normalization of a correction entry in the historic year. Minor taxes include such taxes as commercial rent and occupancy tax, motor vehicle taxes, state gasoline tax, state highway use tax, Federal diesel and gasoline taxes and the New York State tax on insurance premiums.

NORMALIZING ADJUSTMENTS

Q. Please discuss each normalization adjustment, as reflected in Exhibit ___ (HLL-7), Schedule 7, for which you are responsible.

A. My first normalizing adjustment to the steam department's forecast of expenses relates to electric usage at the stations, line 1. The cost for electric usage is based upon annual cost studies, and the rate charged to steam effective January 2002 equated to 10.9 cents per kwhr. This represented a significant increase in the usage rate for steam department. In July 2002, the Company reversed the charges retroactive to January 2002 and continued to use the 5.9 cents per kwhr rate inherent in the Steam Agreement. This normalization is to eliminate the July 2002 entry. My second, Company labor costs on lines 3, 5, 9, 11 and 16 represent the elimination from Company labor expense, the allocation to steam for an over accrual of management compensation in the historic year. My third adjustment for Rate Case Accounting - Interference, line 12, eliminates the reconciliation of steam interference expenses, which were higher than anticipated in the 2000 Settlement. My fourth normalization, line 14, relates to the allocation to

steam for unresolved bank reconciliations in the historic year.

Q. Please continue.

A. My fifth adjustment, line 15, normalizes in the historic year, the steam portion of a re-allocation of common costs made on the Company's books in July 2002 retroactive to January 2002. This re-allocation affected several cost elements. The Company's current electric, gas and steam rate agreements are based on the historic 1999 data and the allocations of common plant and expenditures were based on time studies performed during 1999. The Company in July 2002 adjusted its books to reflect the 1999 allocations inherent in the rate agreements. The next adjustment, line 17, eliminates the allocation to steam of the cost of the executive incentive plan because this item is being borne by shareholders rather than recovered through rates. Line 18, merger costs, relates to the amortization of costs to achieve resulting from the Company's merger with Orange and Rockland Utilities, Inc. The amortization expires July 31, 2004.

Q. Please continue with line 19.

A. The Other A/R Reserve adjustment related to various write-offs of miscellaneous accounts receivables deemed

non-collectible. Line 20, relates to an allocation to steam in the historic year for the deferral of previously expensed consulting fees incurred for a tax planning project. My last adjustment, line 21, Rate Case Accounting - Pension/OPEBs relates to an amortization of previously deferred pension/OPEBs cost pursuant to the 2000 Settlement.

PROGRAM CHANGES

Q. What is the first program change you will discuss?

A. I will start with New Communication System shown on lines 2, 12, 18, 22, 25, 27 and 34. This item represents the allocation to steam for various increases in communication costs, including maintenance costs related to the new 800 MHz and the auto-loop re-closure systems, increased cellular phone units and leased circuit rate increases offset by savings in land line usage costs.

Q. Please continue.

A. My next program change relates to electric usage, line 3. The adjustment reflects an increase to steam department for its electric usage at the plants from the 5.9 cents per kwhr rate, previously mentioned above, to a rate more representative of the estimated

costs of 10.644 cents per kwhr. Environmental, Health and Safety, lines 4 and 16, represent the allocations to gas for a program change sponsored by Company witness Price relating to a surcharge on the generation of hazardous waste. The next change is Interdepartmental rent expense, lines 6, 17, and 33. The decrease of $942,000 on line 6 under MAG 42 - Production Operation represents the retirement of the Waterside plant by the end of 2004. The Steam department is charged for the use of the feedwater treatment facility at Waterside station and, as the plant will be replaced by the ERRP in the rate year, the cost is not applicable. The increase in line 17 under MAG 46 - Distribution Maintenance represents the increased cost of the Ravenswood Tunnel and the increase in line 33 under MAG 49 - Administrative and General expense is primarily due to common capital expenditure increases for such items as computers, mobile equipment, communication equipment, etc.

Q. What program changes will you next address?

A. I will address all of the program changes under MAG 49 - Administrative and General expenses not previously discussed above. Line 29, Security, represents an increase of the equivalent of 5.5 additional personnel

in the Company's Security Services group, which includes the cost of additional personnel, EDP software and other related expenses. The total increase is $338,000 of which the steam allocation is $16,000. As required by the Commission's September 30, 2003 Order Directing Further Action in Case 02-M-0953, Con Edison is evaluating physical and cyber security recommendations made by security consultants retained pursuant to the Commission's earlier order in that case. Upon completion of that evaluation, the Company may propose additional security enhancements and will reflect these in the update filing in this proceeding. Line 32, Fringe Benefits - New Employees represents the increase in employee welfare expenses and payroll taxes related to the increase in human resources as sponsored by Company witnesses Muccilo, Adinolfi and myself.

Q. Please continue with Injuries and Damages, line 35.

A. In accordance with prior Commission practice, the rate year level of injuries and damages is equivalent to the annual average of all claim disbursements for the three-year period July 2000 to June 2003. The allocation to steam is an increase of $326,000. This three-year average will be updated during the course of the proceeding.

Q. Please continue.

A. The increase of $1,942,000 on line 36, Insurance, represents primarily increases in premiums for property and liability insurance. The increase of $1,316,000 on line 37, MGP/Superfund, represents an allocation to Steam of the increased program costs for remediation of manufactured gas plants and superfund sites as discussed in Company witness Price's testimony. Environmental remediation costs are considered to be corporate-wide expense and, as such, are allocated to the Company's three services.

Q. Please discuss Pensions & OPEBs on line 38.

A. The estimate reflects the actuarially-determined level of expenses for employee pensions and other post employment benefits ("OPEBs"), which was based on a study performed by the Company's actuary, Buck Consultants. The study was based on the Company's actual 2002 experience. Assumptions used in the forecast of pensions were a discount rate of 6.75% and an expected return on plan assets of 9.20%. Assumptions for OPEBs were the same, plus a health care cost trend rate of 9.0% for 2003 with the rate decreasing gradually to 4.75% for 2009.

Q. Please sum up the estimate of steam employee pensions/OPEBs expense.

A. The net amount of the actuarially determined level of expenses for employee pensions/OPEBs and other payments net of capitalization, allocable to steam for the historic year is ($7,955,000). The rate year allocation to steam is ($60,000).

Q. How did you arrive at this allocation?

A. The historic amount of ($7,955,000) plus the normalization of ($1,460,000) I previously discussed for common allocations and as shown on line 15, Schedule 7 of Exhibit (HLL-7), and a program change of $9,355,000 results in a rate year forecast for pensions/OPEBs of ($60,000). Line 39, represents an increase in fees in 2004 the Company will pay to PricewaterhouseCoopers for such services as auditing, research, accounting advice and consultations.

Q. Please explain the Shared Services program change shown on line 40.

A. Shared services reflect the allocation or billing of costs from Con Edison and Consolidated Edison, Inc. ("CEI") for administrative and general services provided to Orange and Rockland Utilities, Inc. such as

accounting, treasury and tax services. These costs are detailed into labor, fringes and other cost components.

Q. How did you determine the rate year shared service expense?

A. I started with the actual shared services for the historic year, the 12 months ended June 30, 2003, of $28,000. I then escalated the labor component of the shared service billing by the labor escalation factor of 4.99% and the other components of the billing by the general inflation factors to arrive at the rate year amount of $176,000. I then added a charge to O&R of $86,000 for its share of the projected rate year cost of directors and officers liability insurance included in my previous program change for the element of insurance cost. The total net billing to O&R is $262,000, or an increase of $234,000.

Q. What is your next program change?

A. My next and last program change relates to the potential work stoppage by the Company's Local 1-2 and Local 3 employees at the expiration of their current labor contracts, which expire on June 26, 2004 and June 25, 2004, respectively. The preparation cost for the potential work stoppage is estimated at $1 million. I propose a three-year recovery of the cost, with the

steam allocation at $19,000 per rate year. Strike contingency costs include the cost incurred for negotiating the union contract, consultants, the cost of food procurement, support services, rental of refrigerated trucks and trailers, rental of passenger vehicles, contract instructors and course material for contingency preparation, etc.

Q. Does this conclude your testimony?

A. Yes, it does.

Q. Please state your name and business address.

A. My name is Robert Muccilo. My business address is Consolidated Edison Company of New York, Inc. ("Con Edison" or the "Company"), 4 Irving Place, New York, N.Y. 10003.

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

A. I have been employed by Con Edison since June 1978 and currently hold the position of Assistant Controller in the Corporate Accounting Department.

Q. Briefly state your educational background.

A. I graduated from Fairleigh Dickinson University in May 1983, with a Masters Degree in Finance. In 1978, I graduated from Jersey City State University with a Bachelors Degree in accounting.

Q. Please explain your work experience with Con Edison and your current general responsibilities.

A. From 1978 to 1998, I worked in the General Accounts and Accounting Research and Procedures ("ARP") sections of Corporate Accounting in increasing levels of responsibility up to and including Manager of ARP. In 1999, I was promoted to Assistant Controller responsible for General Accounts and ARP. In 2002, I assumed the responsibilities for Financial Forecasting and Budgets and Electric Revenue and Volume Forecasting

and in 2003, I assumed the additional responsibility of Regulatory Accounting and Filings. I have also served on and led several Corporate Teams including the establishment of the Holding Company and the Orange and Rockland merger transition team.

Q. Have you been involved in industry-wide utility issues?

A. Yes, for many years I have been an active member of both the EEI and AGA committees on accounting principles.

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

A. My testimony will address the development of labor expenses from the historic year labor expense amount to the rate year amount, explain a labor related program change, describe the historic and rate year average rate bases, demonstrate the basis for the revenue requirement herein requested, and address the accounting adjustments made to steam operating income for the rate year.

LABOR FORECASTS

Q. Please explain the derivation of the 4.99% labor factor used by Company witness Lee to escalate the historic year labor expense level to the rate year.

A. As shown on Exhibit ___(HLL-7), Schedule 2, page 1,

column 1, total Company salaries and wages for the twelve-months ended June 30, 2003 amounted to $984,406,000. For the rate year, the twelve-months ending September 30, 2005, total Company salaries and wages, as shown in column 2 are as follows: Union Wages: Straight Time - $508,166,000 (including Temporary Summer Employees); Premium Time - $23,628,000; Overtime - $77,730,000; Management Salaries: Straight Time - $405,399,000; and Compensatory Time - $18,601,000. The total of these salaries and wages amounts to $1,033,524,000. The increase in total Company labor dollars from the historic year level of $984,406,000, to the rate year level of $1,033,524,000, represents a 4.99% increase. Company witness Lee applied this increase to the historic year steam labor expense to arrive at the rate year steam labor expense.

Q. Please outline the development of your total Company rate year labor forecast.

A. The total number of employees for the rate year was first determined as shown on Exhibit ___(HLL-7), Schedule 3. Starting with the total number of employees on roll with pay for the week ending June 28, 2003 of 12,726, I assumed a 1% annual productivity

reduction from July 2003 to September 2005 or a total reduction of 284 employees. The resulting employee level at September 2005 is 12,442.

Q. Please continue.

A. Schedule 2, page 4 shows the computation of the average wages and salaries in the rate year for Weekly and Management employees. For Weekly employees, I assumed a general wage increase of 3.5% in June 2004 and June 2005 and the effective semi-annual progression increase of 0.3%. For Management employees, I assumed a 3.5% salary increase in April 2004 and April 2005.

Q. Mr. Muccilo, do you intend to update the estimated wage increases for employees after the results of the new collective bargaining agreements, to replace the existing collective bargaining agreements that expire in June 2004, become known?

A. Yes.

Q. Please continue.

A. Having developed the rate year average staffing levels and average rates of pay, I used these amounts to develop the total Company rate year straight-time wages and salaries as shown on Schedule 2, page 2.

Q. Would you please explain Schedule 2, page 3?

A. Page 3 shows the calculation of salaries and wages

other than straight-time payrolls. In the historic year, actual weekly premium time and overtime payrolls were $22,291,000 and $73,333,000, respectively. I then increased the historical year payroll amounts by the estimated contractual wage awards. Management compensatory time is determined by starting with the historic year actual level of $17,763,000 and then applying the average rate of increase, as previously determined, to arrive at the rate year amount.

LABOR PROGRAM CHANGE

Q. Mr. Muccilo, are you sponsoring a labor related program change that Company witness Lee has included in her rate year forecast of Company labor?

A. Yes, I am. The Company intends to hire 9 management employees in the Financial area of the Company prior to the start of the rate year, as follows: 3 Accountants and 3 Auditors, as a result of an increased work load related to requirements under the Sarbanes-Oxley Act of 2002; plus 3 employees in the Financial Reporting area related to Financial Transparency and the enhanced reporting requirements established by the SEC. I have priced the basic labor cost to be $841,000 in total, of which 5.10% or $43,000 is applicable to steam operations. Other Company witnesses address labor

related program changes for other than the Financial area.

RATE BASE CALCULATION

Q. What is the next subject of your testimony?

A. I will now discuss the calculation of average rate base for both the historic year and rate year, as well as proposed adjustments to the rate year level.

Q. I show you a document entitled, "CONSOLIDATED EDISON COMPANY OF NEW YORK, INC. - RATE BASE - STEAM - AVERAGE TWELVE MONTHS ENDED JUNE 30, 2003 AND AVERAGE TWELVE MONTHS ENDING SEPTEMBER 30, 2005", consisting of three pages and ask if this was prepared under your direction and supervision?

A. Yes, it was.

MARK FOR IDENTIFICATION AS EXHIBIT ___(RM-1)

Q. Would you please describe Exhibit ___(RM-1)?

A. Page 1 shows the average rate base for the actual twelve-months ended June 30, 2003 in column 1; the adjustments to the historic year to reflect conditions in the rate year absent a rate filing in column 2; the average rate base for the rate year absent a rate filing in column 3; the adjustments to the average rate base in the rate year as a result of this filing in column 4; and, the fully adjusted average rate base for

the rate year upon which the proposed rate increase is based in column 5. Page 2 details the items in working capital as shown on page 1, line 10. Page 3 details the adjustments to the average rate base in the rate year as contained in column 4 of page 1.

Q. Turning to page 1 of Exhibit ___(RM-1), will you please describe the various items that are listed in the first three columns?

A. Lines 1, 2 and 3 show the average book cost, accumulated provision for depreciation and net plant balance. Line 4 shows Non-Interest Bearing Construction Work in Progress (NIB-CWIP). Historic year levels on lines 1 through 4 were developed from the books and records of the Company. The rate year levels were provided by Company witness Ricco, the basis for which is described in his testimony. Lines 5 and 6 reflect the steam portion of preferred stock expense and the unamortized balance of debt discount, premium and expense as additions to rate base. This rate base treatment was directed by the Commission's Order on Rehearing in Electric Case 27353. Line 7 represents the average balance of deferred fuel, net of Federal income tax. This amount represents 30 days of recoverable fuel costs. The rate year forecast of the

average deferred fuel balance is based on the level of incurred fuel costs as forecasted by Company witness Northup.

Q. Please continue with your explanation of lines 8 through 11.

A. Line 8 represents the balance of customer advances for construction. These are funds provided by customers for the construction of utility services on their premises. Line 9 represents the average balance of the Metropolitan Transportation Authority ("MTA") surcharge paid but not yet collected from customers, net of Federal income tax. Line 10 is the working capital included in rate base. I will explain the details later in my testimony.

Q. Please continue with your explanation of rate base.

A. Line 11 reflects the required adjustment to bring rate base equal to capitalization. This adjustment is consistent with prior rate case treatment, including the last steam rate Case 99-S-1621.

Q. Please explain lines 12 and 13.

A. Line 12 reflects the average unamortized balance of prior rate case amortizations and line 13 reflects the reconciliation of the unamortized balance of Pension/OPEBs costs related to the 1993 Settlement

Agreement in Case 93-S-0997. This item will be fully amortized prior to the beginning of the rate year in this proceeding.

Q. Please continue with line 14.

A. Line 14 reflects an unamortized balance associated with the steam portion of property taxes previously deferred in the 1997 settlement agreement. Line 15 represents the unamortized amount associated with the deferred tax on the Boiler Fuel Sales Tax refund. Line 16 shows the deferred tax balance associated with the steam portion of the provision for Refund - Net Post Merger savings as derived from the merger with Orange and Rockland Utilities, Inc ("O&R").

Q. Please continue.

A. Line 17 reflects the steam portion of the unamortized balance of O&R Merger savings net of Federal income taxes. Line 18 shows the steam portion of balances associated with the sale/appropriation of various Company locations. Line 19 reflects the unamortized balance of the Special Franchise tax refund net of Federal income taxes. Lines 20 and 21 represent the steam portion of transferred book cost and various other deferred costs associated with the sale of the First Avenue properties.

Q. Please describe lines 22 through 28, related to rate case reconciliations.

A. Lines 22 through 28 represent unamortized balances of various items subject to reconciliation per Commission order in Case 99-S-1621. I will discuss their derivation in the section of my testimony wherein I discuss the rate treatment for these items.

Q. Please continue with line 29.

A. Line 29 represents the accumulated deferred Federal income taxes resulting from the normalization of tax depreciation. The average balance of accumulated deferred taxes for the rate year was developed by starting with the June 30, 2003 actual balance and was increased each month, through the rate year, to the extent of tax depreciation normalized for book purposes offset in part by the flow-back of tax depreciation previously deferred.

Q. Please continue with line 30.

A. Line 30 represents the accumulated deferred Federal income taxes on Vested Vacation.

Q. Please explain why taxes paid on unbilled revenues are included in rate base as shown on line 31.

A. The Commission, in its Statement of Policy on Accounting and Ratemaking Procedures to Implement

Requirements of the Tax Reform Act of 1986, issued July 7, 1987 in Case 29465, directed utilities to normalize the effect of the higher income tax expense due to the inclusion of unbilled revenues in taxable income.

Q. Please continue with lines 32 and 33.

A. Line 32 reflects the accumulated deferred Federal income taxes associated with contributions in aid of construction which, under TRA-86, are reflected in taxable income and normalized in accordance with Commission directive. Line 33 represents the accumulated deferred Federal income taxes on capitalized interest. The Commission, in Case 29465, concluded that utilities should normalize the income tax expense for the additional interest required to be capitalized for tax purposes under TRA-86.

Q. Please continue.

A. Line 34 represents accumulated deferred Federal income tax on advanced refunding of mortgage bonds. Line 35 reflects accumulated deferred Federal income tax associated with the current tax deduction of overheads under Section 263A of the IRS Code.

Q. Please explain line 36.

A. Line 36 represents the deferred Federal income tax effect resulting from the payment of call premiums when

redeeming long-term debt prior to its maturity date. The call premium paid is a current deduction for Federal income tax purposes, but amortized over the remaining life of the redeemed issue in accordance with Commission order.

Q. Please explain lines 38 and 39.

A. These items reflect the deferred balance of New York State income tax less the Federal income tax effect thereon.

Q. Will you now turn to page 2 of Exhibit ___(RM-1) and explain the items of working capital?

A. Working capital is comprised of three categories: Inventories (materials and supplies and liquid fuel), Prepayments and Cash Working Capital.

Q. How did you determine the average balance of liquid fuel and other materials and supplies for the rate year as reflected in column 5 of page 2?

A. The Company's liquid fuel inventory is comprised of residual fuel oil. Based upon the usage of barrels of residual oil that the Steam Business Unit is projecting during the rate year for generation, I determined that 89.56% is applicable to steam operations. I then applied this percentage to the average residual inventory of $10,606,000 to arrive at an average steam

liquid fuel inventory of $9,249,000 for the rate year. The average balance of liquid fuel is then reduced to the extent that the balance is financed by amounts owed by the Company to fuel vendors. Based upon the historic year, the Company has computed that 86.84% of the average liquid fuel inventory is financed by accounts payable. Therefore, while the average amount of liquid fuel inventory for the rate year is $9,499,000, 86.84% or $8,249,000 is assumed to be financed by accounts payable. The remaining $1,250,000 is included in rate base. To develop the rate year amount of materials and supplies, excluding fuel, I took the average balance for the historic year of $8,403,000 and escalated it using the general escalation factor of 3.53% developed by Company witness Lee to arrive at the increase of $297,000 shown in column 2.

Q. Please continue with your explanation and describe the components of prepayments.

A. Steam prepayments consist of insurance, property taxes, the P.S.C. assessment, and other miscellaneous items. To develop prepayments applicable to "other" miscellaneous items, I took the average prepayment balance for the historic year of $136,000, and

escalated this amount by the general escalation factor of 3.53% to arrive at $141,000, which represents an increase of $5,000 for the rate year.

Q. How did you develop the level of prepaid insurance and property taxes?

A. Prepaid insurance for the rate year was forecasted by assuming that 50% of insurance premiums are prepaid. I then applied this factor to the Company's estimate for insurance premiums in the rate year of $4,040,000 to arrive at the rate year forecast for insurance prepayments of $2,020,000. This treatment is consistent with the Commission's determination in the Company's prior steam cases. Prepayments for New York City real estate and special franchise taxes were forecasted based on the Company's actual level of steam property taxes for fiscal year 2002/2003 and the estimated levels for fiscal year 2003/2004, 2004/2005 and 2005/2006. Payments for property taxes are currently made to New York City in July and January of each year. Based on the forecast level of expense, prepayments for New York City real estate and special franchise taxes in the rate year are estimated to be $13,670,000.

Q. Please explain the prepayment for the P.S.C.

assessment.

A. I developed the prepayment amount for the P.S.C. assessment by taking the latest known steam assessment of $1,188,000 for the fiscal year ending March 31, 2004 and reflected prepayments on a quarterly basis in June, September, December and March. When a revised assessment is received during the course of this proceeding, I will update the prepayments accordingly.

Q. Would you please explain the last item of working capital?

A. The last item of working capital is the allowance for cash working capital. The historic year calculation is described in Company witness Lee's testimony. For the rate year, I started with operation and maintenance expenses of $332,392,000 as shown on Exhibit __(HLL-7), Schedule 1, page 1. I then deducted from this amount purchased power expenses, the gas portion of fuel, interdepartmental rents, recoverable fuel costs and non-cash items. To the residual amount I applied a 1/8 factor in accordance with the "modified" FERC formula to arrive at a cash working capital allowance of $20,274,000 for the rate year. I then applied a 1/12 factor to recoverable fuel costs, or $4,256,000, for a total cash working capital allowance of $24,530,000 as

shown in column 3.

Q. Mr. Muccilo, will you now go on and describe your adjustments to the average rate base for the rate year as reflected on Exhibit ___(RM-1), page 3 and which are also shown on page 1, column 4?

A. The first adjustment I made reflects the change in the average accumulated depreciation reserve resulting from the proposed changes in depreciation rates. Adjustment 2 reflects the impact on cash working capital resulting from the adjustments to operation and maintenance expenses. Adjustments 3 through 11 merely reflect the effect on average rate base of amortizing over a three-year period the balances of previously deferred items and reconciliations. Again, these items and reconciliations will be discussed in greater detail in the following section of my testimony, wherein I discuss the basis for the revenue requirement.

REVENUE REQUIREMENT AND ACCOUNTING ADJUSTMENTS

Q. Please describe the basis for the revenue requirement in this case.

A. The rate year in this proceeding is the twelve-months ending September 30, 2005, which anticipates the first twelve months that rates set in this proceeding will be in effect. The revenue requirement is based upon our

forecast of steam operations for the twelve-months ending September 30, 2005, and an overall rate of return requirement of 9.02%. Company witness Fitzmartin provides the overall rate of return that the Company is requesting as part of this proceeding. The increase in the Company's revenue requirement is $128,899,000, inclusive of gross receipts taxes. In his testimony, Company witness Rasmussen discusses a proposal for a three-year rate plan for the period ending September 30, 2007.

Q. Have you prepared a rate of return exhibit?

A. Yes, I have.

Q. I show you a document, the first page of which is entitled, "OPERATING INCOME, RATE BASE AND RATE OF RETURN FOR STEAM OPERATIONS SHOWING THE EFFECT OF THE PROPOSED INCREASE IN RATES - TWELVE MONTHS ENDING SEPTEMBER 30, 2005" and ask if it was prepared under your direction and supervision?

A. Yes, it was.

MARK FOR IDENTIFICATION AS EXHIBIT ___(RM-2)

Q. Mr. Muccilo, will you please describe Exhibit __(RM-2)?

A. Exhibit ___(RM-2) consists of three schedules. Schedule 1 summarizes the development of operating income, average rate base and rate of return for the

rate year as adjusted for the rate increase. Column 1 shows operating income and rate of return unadjusted, or as it would be reflected in the books of account, for the rate year. The operating income before income taxes is as shown on Company witness Lee's Exhibit ___ (HLL-7), Schedule 1, page 1, column 3. The New York State and Federal income tax computations in this column are detailed on Schedule 2, pages 1 and 2, respectively, and the average rate base in this column is as reflected on Exhibit ___(RM-1). Column 2 summarizes certain adjustments to operating income that are detailed on Schedule 3. The adjustments to average rate base in this column are as reflected on Exhibit ___(RM-1), pages 2 and 3. Column 3 is the summation of columns 1 and 2. Column 4 shows the effect of the $128,899,000 rate increase. Column 5, which is a summation of columns 3 and 4, shows operating income, average rate base and rate of return for the rate year after factoring in the rate increase.

Q. What rate of return does Schedule 1 show?

A. The unadjusted rate of return in column 1 is 3.11%. After factoring in the adjustments to operating income, rate base and the proposed rate increase, the rate of return on average rate base is 9.02%.

Q. What was the Steam department's rate of return for the actual twelve-month period ended June 30, 2003?

A. As shown on Exhibit ___(HLL-1), Schedule 2, page 4, steam operating income for the twelve-month period ended June 30, 2003 was $46,869,000. The steam department's average rate base for the actual twelve-month period ended June 30, 2003, as shown on Exhibit ___(RM-1), page 1 was $580,604,000. Accordingly, the actual rate of return for the twelve-month period ended June 30, 2003 was 8.07%.

Q. Will you please explain Schedule 2, page 1?

A. Schedule 2, page 1 details the New York State income tax computation for each of the 5 columns shown on Schedule 1. Column 1 of Schedule 2, page 1 is the calculation of New York State income tax expense for steam operations. Starting with book operating income before income taxes as shown on line 1, I then set forth on lines 2-29 the various required tax adjustments to book operating income to determine taxable income as shown on line 30. I then compute the amount of New York State income tax payable on line 31 using the statutory rate applicable to such taxable income. From the New York State income tax payable so calculated, I reflect on line 32 normalizations for

certain items reflected as adjustments to taxable income to arrive at New York State income tax expense as shown on line 33. The items detailed on column 2 of this schedule, which reflect rate case adjustments, are more fully detailed on Schedule 3, pages 1 and 2 of my exhibit and are discussed later. Column 3 is the sum of columns 1 and 2. Column 4 is the additional New York State income tax to be paid as a result of the additional revenue requirement and column 5 is the sum of columns 3 and 4.

Q. Will you go on and explain Schedule 2, page 2?

A. Schedule 2, page 2 details the Federal income tax computation for each of the 5 columns shown on Schedule 1. Column 1 of Schedule 2, page 2 is the calculation of Federal income tax expense for steam operations. Starting with book operating income before income taxes as shown on line 1, I deducted on line 2 the amount of New York State income tax previously determined on Schedule 2, page 1 to arrive at book operating income before Federal income tax on line 3. I then set forth on lines 4-38 the various required tax adjustments to book operating income to determine taxable income as shown on line 39. I then compute the amount of Federal income tax payable on line 40 using the statutory rate

applicable to such taxable income. From the Federal income tax payable so calculated, I reflect on lines 41-45 normalizations for certain items reflected as adjustments to taxable income as well as amortizations for items normalized in the rate year or in prior periods to arrive at Federal income tax expense as shown on line 46. The items detailed on column 2 of this schedule, which reflect rate case adjustments, are more fully detailed on Schedule 3, pages 1 and 2 of my exhibit and will be discussed later. Column 3 is the sum of columns 1 and 2. Column 4 is the additional Federal income tax to be paid as a result of the additional revenue requirement and column 5 is the sum of columns 3 and 4.

Q. Please explain the adjustments to operating income as shown on Schedule 3.

A. Schedule 3 consists of 2 pages and details the adjustments to operating income as shown on Schedule 1, column 2 by functional income statement category.

Q. Please describe the adjustments that you made to sales revenues as shown on page 1 of Schedule 3.

A. My first adjustment is a billing day adjustment. In the instant proceeding, the rate year sales forecast as provided by Company witness Yaegel assumes 365.43

billing days of sales revenues. Because there is a leap year every four years, I will assume for ratemaking purposes that there are 365.25 billing days, on average, in any given year. Therefore, I have decreased Company witness Yaegel's sales forecast by ($157,000) to account for a decrease of 0.18 billing days. My second adjustment of $320,000 eliminates the fuel rider under-recovery and reconciles fuel rider revenues with recoverable fuel costs. Absent this required adjustment, any calculated difference between fuel rider revenues and recoverable fuel costs would be included in the calculation of the requested base rate change. This adjustment is consistent with past rate case decisions and the Commission's generic rule in Case 80-24. My final adjustment to sales revenues of ($1,510,000) reflects the amount of New York State income tax credit that would have been reflected as a revenue tax credit during the rate year absent a rate filing. Therefore, the revenue requirement in this proceeding need only reflect the incremental amount of New York State income tax resulting from the increase in the revenue requirement.

Q. Please describe your adjustments to other operating revenues.

A. My first adjustment of ($725,000) reflects the recovery over a three-year period of $2,176,000 of revenues accrued by the Company in November and December of Year 2000 to recognize the effect of the December 8, 2000 rate change in the prior Agreement and Settlement retroactive to October 1, 2000. My second adjustment seeks to recover annually over a three-year period, 80% of discounts provided to 1) steam air conditioning customers ($545,000) and 2) customers with viable alternatives to Con Edison's steam service who have negotiated steam service agreements ($488,000). The recovery of these discounts is as provided for under the terms of the currently effective steam Agreement and Settlement. My third adjustment to other operating revenues of ($676,000) seeks to recover from ratepayers over a three-year period the estimated amount of interest of $2,028,000 calculated at the unadjusted customer deposit rate on the after-tax deferred balances subject to reconciliation during the period of the existing Agreement and Settlement.

Q. Please describe the adjustment you made to fuel costs as shown on page 1 of Schedule 3?

A. My adjustment to fuel costs of ($63,000) is related to my first adjustment to sales revenues. Because I have

adjusted the rate year level of sales revenues to reflect 365.25 billing days, I must also adjust the level of fuel costs to reflect an equal number of days of sendout.

Q. Please describe your adjustments to operation and maintenance expenses as reflected on Schedule 3, page 1.

A. My first adjustment to operation and maintenance expenses reflects the recovery over a three-year period of the estimated under-collection of interference expenses that are subject to reconciliation during the term of the currently effective Agreement and Settlement. The estimated under-collection over the period is $5,269,000, 1/3 of this amount is my adjustment of $1,756,000. My second adjustment to operation and maintenance of $1,620,000 seeks to recover over a three-year period a portion of the Company's actual interference expenditures through September 30, 2003, plus interest thereon, related to the World Trade Center incident. These expenditures relate to interference costs that are not expected to be reimbursable to the Company as a result of any governmentally sponsored program. The actual level of expenditures total $4,681,000 plus interest of

$179,000. The testimony of Company witness Rasmussen addresses this adjustment. My final adjustment relates to the estimate of storage and handling costs refunded to customers through base rates during the period of the currently effective Agreement and Settlement adopted in Case 99-S-1621. In that agreement, it was contemplated that storage and handling costs would be over-collected by $6,688,000 for the two-year period prior to the start of the rate plan period, and that this amount would be refunded to ratepayers over the four-year period covered by the current rate plan. When the actual data was known, the amount that should have been refunded to ratepayers was $4,488,000, or $2,000,000 less than the estimate. My adjustment of $667,000 recovers this excess refund over a three-year period.

Q. What are your next adjustments as shown on Schedule 3, page 2?

A. My first adjustment to steam depreciation and amortization expenses of $1,574,000 relates to proposed changes in steam depreciation rates. My second adjustment of $4,920,000 represents the annual amortization of the steam depreciation reserve deficiency in order to eliminate the existing

deficiency over a 15-year period. The basis for both of these adjustments is fully described in the testimony of Company witness Hutcheson.

Q. Please explain the adjustments you made to taxes, other than income taxes.

A. My first adjustment of $247,000 recovers over a three-year period the remaining balance of $741,000 of New York City property tax expenses that were originally deferred as a result of the 1997 Settlement Agreement and later as a result of the 2000 Agreement and Settlement. My second adjustment of $6,953,000 recovers over a three-year period the estimated reconciliation of New York City property taxes recoverable as a result of the currently effective Agreement and Settlement. Under that settlement, the Company was allowed to collect after September 30, 2004, 86% of property taxes above a predetermined annual level in each rate year. Total property taxes over the period of the current rate plan are estimated to exceed the sum of the predetermined annual levels by $24,256,000, 86% of which is $20,860,000. This deferral and recovery excludes the effects of a Special Franchise Tax reduction on the Company's steam property subject to the New York City Special Franchise Tax. My

third adjustment of ($5,487,000) returns to ratepayers over a three-year period their 86% share, $16,482,000, of this tax benefit. The testimony of Company witness Hutcheson will fully discuss this Special Franchise Tax reduction. My fourth adjustment is directly related to my first and second adjustments to sales revenues. My fifth and final adjustment is directly related to my third adjustment to sales revenue. Both of these adjustments relate to revenue taxes.

Q. Mr. Muccilo, do you plan to update your adjustments related to items subject to reconciliation during the term of the currently effective Agreement and Settlement, as actual levels for the final rate year of the existing agreement are known.

A. Yes. The Company will provide updates of the final rate year reconciliations as close to the Commission's opinion in this proceeding as possible.

Q. Mr. Muccilo, does this conclude your testimony?

A. Yes, it does.

Q. Please state your name and business address.

A. My name is Kevin Fitzmartin. My business address is 4 Irving Place, New York, New York 10003.

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

A. I am employed by the Consolidated Edison Company of New York, Inc. ("Con Edison" or the "Company") as Department Manager, Financial Forecasting and Corporate Budgeting.

Q. Please state your work experience and education.

A. I have been employed by Con Edison since June 1975. I held various positions of increasing responsibility in Corporate Accounting from June 1975 to March 1992. In April 1992, I was assigned to the position of Controller Manhattan Customer Service. In December 1994, I returned to Corporate Accounting and was assigned to the Rate Section where I worked on the then-pending electric rate case filing as well as the 1995 gas and steam second stage filing. In May 1996, I was assigned to a position in the mergers and acquisition group of Corporate Planning. Between July 1999 and June 2002, I was assigned to the position of Department Manager of the General Accounts section of Corporate Accounting. Next, I was Department Manager of Accounting Research and Procedures from July 2002

through May 2003. I was assigned to my current position as Department Manager of Financial Forecasting and Corporate Budgeting in June 2003. I received a Bachelor of Business Administration degree in Accounting from Pace University in 1975 and a Master of Business Administration in Finance from Pace University in 1980.

Q. What are your responsibilities in your current position?

A. I am responsible for the coordination of the corporate budget and the preparation of the corporate financial forecast.

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

A. I will present the rate of return required in the rate year and the source and use of funds in the rate year.

Q. Was the document entitled "CONSOLIDATED EDISON COMPANY OF NEW YORK, INC. - RATE OF RETURN REQUIRED FOR THE RATE YEAR - TWELVE MONTHS ENDING SEPTEMBER 30, 2005", set forth as Exhibit __ (KF-1), prepared under your direction and supervision?

A. Yes, it was.

MARK FOR IDENTIFICATION AS EXHIBIT __ (KF-1)

RATE OF RETURN

Q. Please describe Exhibit __ (KF-1), Schedule 1.

A. This exhibit shows the projected average capital structure for the rate year, the twelve months ending September 30, 2005, the average cost rate for each component of the capital structure, and the related cost of capital. Con Edison's overall weighted cost of capital for the rate year is 9.02%.

Q. How did you derive the amount of average long-term debt for the rate year?

A. To derive the average long-term debt for the rate year ending September 30, 2005, I first determined the amount of long-term debt outstanding at the end of each month from September 2004 through September 2005. I then utilized these amounts to calculate the average of long-term debt outstanding. Changes in the outstanding amount of debt from month-to-month during the rate year resulted from the elimination of the 6.625% Debenture Bond Series 1995A in the amount of $100 million maturing on July 1, 2005. The amount of average long-term debt for the rate year ending September 30, 2005, after the above adjustment is made, is $5,733.5 million, the details of which are shown in Schedule 2 of Exhibit __ (KF-1).

Q. Is there any short term debt included in the projected capital structure?

A. No, we have excluded the average level of short term debt because it falls below the average level of interest bearing CWIP.

Q. Please explain Exhibit __ (KF-1), Schedule 3, the average cost of preferred stock for the rate year.

A. To determine the average amount of preferred stock for the rate year ending September 30, 2005, I first determined the amount of preferred stock outstanding at the end of each month from September 2004 through September 2005. I then utilized these amounts to calculate the average.

Q. Please explain how you derive the average customer deposits, set forth on Exhibit __ (KF-1), Schedule 1, for the rate year ending September 30, 2005.

A. I started with the balance outstanding at September 30, 2003 of $208 million. The balance is expected to grow by approximately 0.1% per month, bringing the September 2005 balance to $216 million. After determining the monthly customer deposit balances during the rate year, an average of $213.8 million was calculated.

Q. What is the average cost rate of Con Edison's long-term debt?

A. Con Edison's long-term debt is comprised of tax-exempt debt issued through NYSERDA and debenture bonds. The average annual cost rate of this debt is calculated by dividing the average annual interest requirements for all long-term debt issues, including the average annual amortization of the net amount of any premiums or discounts realized when the securities were sold and the cost and expense of issuance, by the amount of long-term debt outstanding. As shown on Schedule 2 of Exhibit __ (KF-1), the average cost of long-term debt for the rate year is 6.27%, which is determined by dividing the sum of the average annual interest requirements plus amortization of debt discount and expense, $359.8 million, by the average aggregate amount of long-term debt outstanding of $5,733.5 million.

Q. How did you determine the average cost rate of Con Edison's preferred stock?

A. On average, Con Edison will have an estimated total of $212.6 million in preferred stock outstanding during the rate year. The average annual cost of the preferred stock is calculated by dividing the average annual dividend requirement of $11.6 million, including the expense associated with the amortization of

expenses associated with the refunded series, by the average amount of preferred stock outstanding of $212.6 million. As set forth on Schedule 3 of Exhibit __ (KF-1), the average cost of preferred stock for the rate year ending September 30, 2005 thus computed is 5.43%.

Q. What cost rate was assigned to customer deposits?

A. I reflected the current 2.45% cost rate, as mandated by the Commission. The Commission reviews this rate annually. I will update this rate for any change the Commission may make with respect to customer deposits, at the appropriate time.

Q. What cost rate has the Company reflected as the rate of return for common equity?

A. Based upon the recommendation of Company witness Robert Rosenberg, I have utilized a return for common equity of 12.0%. I therefore told Mr. Rasmussen to use an overall rate of return of 9.02%, which assumes a 12.0% return on common equity, in determining the revenue requirement in this case.

SOURCE AND USE OF FUNDS IN THE RATE YEAR

Q. Was the document entitled "CONSOLIDATED EDISON COMPANY OF NEW YORK, INC. - FUND REQUIREMENTS AND SOURCES - TWELVE MONTHS ENDING SEPTEMBER 30, 2005", set forth as

Exhibit __ (KF-2), prepared under your direction and supervision?

A. Yes, it was.

MARK FOR IDENTIFICATION AS EXHIBIT __ (KF-2)

Q. What does Exhibit __ (KF-2) reflect?

A. This exhibit reflects the Company's forecast of capital fund requirements and sources of capital funds, as well as certain financial statistics, for the 12 months ending September 30, 2005. The capital funds required during the rate year will be more than internal sources by $124 million.

Q. Please describe the three items contained in this exhibit under the heading "CAPITAL FUNDS REQUIRED".

A. The first item, requiring the largest amount of capital funds, is construction expenditures of $1,228 million. This amount is consistent with the Company's five-year forecast of total construction expenditures.

Q. Please continue.

A. The second item, maturing securities, in the amount of $100 million, are funds required by the Company to retire the Series 1995A Debenture Bonds due on July 1, 2005. The third item, $23 million of working capital additions, is the Company's estimate of its incremental working capital requirements.

Q. Please describe the items contained in the exhibit under the heading "INTERNAL SOURCES OF FUNDS".

A. The first item is retained earnings of $199 million. This estimate includes certain earnings and common dividend assumptions. The second item is depreciation. The third item, deferred tax accruals, is funds provided principally by the use of tax depreciation subject to normalization. The fourth item, non-cash pension expense and other charges is the non-cash portion of pension and other expenses. The fifth item, divestiture and property sales, is the cash proceeds from the sale of properties. The sixth item, HUD WTC reconstruction reimbursement, relates to reimbursements from Housing and Urban Development and others for expenditures related to reconstruction after the World Trade Center disaster. To date, the Company has expended about $270 million in this effort. We will reflect more up-to-date reimbursement information in the update stage of this proceeding.

Q. Is it your decision or do you participate in any decision making as to what the dividend of Consolidated Edison, Inc. (CEI) on common stock will be?

A. No. The Board of Trustees of CEI makes the dividend decision for that corporation, the parent corporation

of Consolidated Edison Company of New York, Inc. I am not a member of the Board of Trustees nor am I a participant in its meetings or meetings of the Finance Committee of the Board.

Q. Then, I take it that your assumption of an estimated per annum dividend increase for CEI is not based upon any projections which the Board of Trustees may have made?

A. That is correct.

Q. Please describe the final section of Exhibit __ (KF-2).

A. The final section shows that at September 30, 2005, the Company will have temporary cash investments estimated in the amount of $10 million. Included in the calculation of the balance of $10 million is repayment of $124 million of commercial paper issues projected in the rate year ending September 30, 2005.

INTEREST COVERAGE

Q. Was the document entitled "CONSOLIDATED EDISON COMPANY OF NEW YORK, INC. - INTEREST COVERAGE - S.E.C. BASIS - PER BOOKS", set forth as Exhibit __ (KF-3), prepared under your direction and supervision?

A. Yes, it was.

MARK FOR IDENTIFICATION AS EXHIBIT __ (KF-3)

Q. Does your calculation of interest coverage only include the interest paid on long-term debt?

A. No. As shown in Exhibit __ (KF-3), the interest coverage calculation also includes "other" interest.

Q. Please explain what is included in "other" interest.

A. "Other" interest is comprised of interest on the following items: customer deposits, gas market rate adjustment, commercial paper, customer overpayments and other miscellaneous items.

Q. Does the Company currently have lines of credit available to it?

A. Yes. The Company, along with CEI and Orange and Rockland Utilities, Inc. (O&R), has agreements with various banks for a revolving credit line of $775 million, of which the Company's portion is $500 million. The Company has the ability to utilize the entire $775 million, assuming that CEI and O&R have not utilized their portions. The Company and its affiliates are in the process of renewing and revising their revolving credit agreements to integrate a previous standalone CEI line of credit of $175 million. While the Company's portion of the overall $950 million revolver will remain $500 million, it will be able to

utilize the entire $950 million, assuming that CEI and O&R have not utilized their portions.

Q. Does that conclude your testimony?

A. Yes.

NEW YORK STATE PUBLIC SERVICE COMMISSION

PETITION OF CONSOLIDATED EDISON COMPANY OF NEW YORK FOR AN INCREASE IN STEAM RATES	))))))	CASE NO. _____

DIRECT TESTIMONY

OF

ROBERT G. ROSENBERG
EDGEWOOD CONSULTING, INC.

November 2003

INDEX

I. INTRODUCTION

Q. Will you give your name, business address and occupation?

A. My name is Robert G. Rosenberg. My business address is 541 Bear Ladder Road, West Fulton, New York. I am an economist and principal of the firm of Edgewood Consulting, Inc. My qualifications are described in Appendix A to this testimony.

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

A. The purpose of my testimony is to determine the cost of equity capital for Consolidated Edison Company of New York (hereinafter referred to as CECONY or the Company). I will also examine the reasonableness of the common equity ratio CECONY is requesting in this proceeding.

Q. Would you provide an overview as to how your testimony will be organized?

A. I will begin by putting the issue of rate of return in the context of the current economic and financial climate. I will then determine the cost of equity for CECONY. In my analysis of the cost of equity, I (1) discuss the rationale for using several equity costing methodologies; (2) address the use of proxy companies to develop the cost of equity of CECONY; (3) calculate the cost of equity using four methodologies: the Discounted Cash Flow approach, the Capital Asset Pricing Model, the risk premium approach and the comparable earnings analysis; and (4) develop and recommend a cost of equity to be used in this proceeding. Finally, I assess the reasonableness of the common equity ratio employed by CECONY in its filing in this proceeding.

Q. Have you prepared an exhibit in conjunction with your testimony?

A. Yes. In support of my testimony, I have prepared Exhibit___(RGR-1), consisting of Schedules 1-5.

Q. Were these schedules prepared by you or under your supervision?

A. Yes, they were.

II. THE RATE OF RETURN IN CONTEXT

Q. Would you briefly discuss the importance of the level of rate of return in the current economic and financial climate?

A. The financial community has put the utility industry under more intense scrutiny of late. Utility bond downratings have far outnumbered bond upratings. S&P reported that for the year-to-date 2003, there had been 41 utility issuer credit rating downgrades compared with 8 upgrades (Standard & Poor's *Ratings Trends*, October 20, 2003). Similarly, for the twelve months ended June 31, 2003, Moody's had downgraded about one-third of the utilities it follows—significantly higher than the approximate 10 percent annual average downgrade rate for utilities over the past nineteen years (Moody's *Rating Actions and Reviews*, July 2003, p. 3). Clearly the bond rating agencies have become less tolerant of financial weakness in utility companies. Furthermore, the cost of financial weakness to companies has increased recently, given the widening spreads in bond yields between stronger and weaker entities.

The heightened negative attention given to utilities, along with substantial bond downratings, have made utility financing problematic in some instances. Standard & Poor's in its February 12, 2003 *CreditWeek* article entitled "U.S. Power Industry Experiences Precipitous Credit Decline in 2002; Negative Slope Likely to Continue" indicated that deterioration of creditworthiness in the industry could be traced, in part, to:

> Increasingly constrained capital market access as a result of investor skepticism over accounting practices and disclosure, more and more federal and state investigations and subpoenas, audits, and failing

> confidence in future financial performance that has created a liquidity crisis.

FERC Commissioner William Massey in a March 17, 2003 speech entitled "Current Issues 2003" echoed a similar theme:

> Sadly, the tsunami of the western energy crisis, coupled with the collapse of Enron, have left a devastating wake within the industry. Investor confidence has been shaken by these events, by a declining national economy, indictments of energy traders, accounting irregularities, downgrades by rating agencies, and continuing investigations by the FERC, CFTC, the SEC and the Justice Department. [These investigations] do have an impact on investor confidence and credit availability.... Many sources of funds have dried up, yet energy companies have billions in debt to refinance over the next two years.

Rate of return on equity plays a significant part in how the financial community regards a particular utility company. Standard & Poor's in its May 24, 2002 publication *Regulatory Support For U.S. Electric Utility Credit Continues To Disappoint*, indicated that:

> Standard & Poor's views the future rating trend of the electric industry to be decidedly negative, with insufficient regulated authorized returns and expanding nonregulated investments providing the most downward pressure.

Standard & Poor's in its *Corporate Ratings Criteria*, page 23, also stressed the importance of the level of return on capital:

> Profit potential is a critical determinant of credit protection. A company that generates higher operating margins and returns on capital has a greater ability to generate equity capital internally, attract capital externally, and withstand business adversity. Earnings power ultimately attests to the value of the firm's assets as well.

S&P in "Regulation and Credit Quality in the U.S. Utility Sector," February 19, 2003, noted that:

> A Standard & Poor's-sponsored survey of regulatory commissioners throughout the U.S. a year ago indicated that credit quality ranked low on their list of priorities.... Notably, commission attention to having a strong and financially vibrant utility has waned in recent years. Certainly, commissions still want their utilities rated highly, but will they provide the returns necessary to that end? It will be interesting to see what type of working relationship electric companies and regulators form going forward.

Standard & Poor's also indicated in its November 18, 2002 report entitled *Constructive Regulation for U.S. Utilities is More Important Than Ever* that:

> ...regulation in general will once again play the pivotal, if not far and away the most pivotal, role in determining credit quality in the utility sector.

Thus, the level of a utility's allowed rate of return cannot be regarded in isolation, but instead is a key ingredient in overall financial integrity.

III. ESTIMATION OF THE COST OF EQUITY

A. Rationale for Using Several Equity Costing Methodologies

Q. Do you believe it is reasonable to employ several approaches for estimating the cost of equity?

A. Yes. The cost of equity is not directly observable in the marketplace. Therefore, to estimate the cost of equity, one must take cognizance of financial theory, the legal and regulatory framework for ratemaking and investor perceptions and judgments. There is no one approach that is now recognized, or should be recognized, as the way to determine the cost of equity. Moreover, I believe that currently there is the potential for more error of estimation than normal in determining the cost of equity of a utility.

Q. Why do you believe that presently there is a potential for large measurement error associated in determining the cost of equity for utilities?

A. While it was always good financial practice to employ several methods to estimate the cost of equity in order to reduce measurement error associated with any particular methodology, that notion has special relevance today. The assessment of utility risk and potential performance is in flux currently due to the uncertainties associated with regulatory restructuring, competitive developments and consolidation in the industry. *The Value Line Investment Survey* of July 6, 2001 stated that:

> The industry is in a state of flux and will probably remain so for some time to come.

Value Line of April 4, 2003 continued the same theme by stating:

> The industry is still in a state of flux.

The Standard & Poor's *Electric Utility Industry Survey* of August 8, 2002 indicated that:

> We expect the performance of both the electric utility sector and the individual companies within the sector to remain volatile over the next several years.

The S&P *Electric Utility Industry Survey* of February 20, 2003 stated:

> Utility stocks often benefit the most (as in 2000) when the broader market is in a state of decline and investors look for a "safe haven" for their investments. However, this haven is not as safe as it once was: utility stocks have become much more volatile in recent years, sometimes experiencing sharp swings—often in the opposite direction of the broader market—within a short period of time.

Therefore, when we attempt to estimate the cost of equity for a particular utility, this uncertainty is likely to lead to more estimation error than under circumstances where that company's more easily forecasted fundamentals are the prime determinant of its stock prices and where that company's risk seems clearly delineated to investors.

Q. What conclusion do you reach from the above discussion?

A. As I indicated above, because I believe that there is more error of estimation than normal in determining the cost of equity of an electric utility, I will employ several different analyses in this proceeding. Such an approach leads to a broader-based set of estimates and will prevent any spurious results from biasing the cost of equity determination.

Q. What methods do you use in this proceeding to estimate the cost of common equity capital?

A. I will employ four separate approaches including: (1) a discounted cash flow (DCF) analysis; (2) a capital asset pricing model (CAPM) analysis; (3) two risk premium analyses; and (4) a comparable earnings analysis.

B. Use of Comparison Companies to Determine the Cost of Equity of CECONY

Q. Can you explain why you are using a proxy group to determine the cost of equity of CECONY?

A. CECONY is a subsidiary of Consolidated Edison, Inc.. Therefore, CECONY has no publicly traded stock. It is my opinion that the use of a group of companies to estimate CECONY's cost of common equity helps attenuate the vagaries in any one company's data or results. As further support for the use of a proxy group, I note that the touchstone *Bluefield* and *Hope* decisions indicated that a fair rate of return to a regulated company is, in part, one that is equal to that earned in enterprises of similar risk.

Q. Would you indicate how you selected the group of proxy companies upon which you conducted your cost of equity analysis?

A. Companies were selected for the proxy group if they were included in Value Line's listing of electric utility companies (the category to which Value Line assigns CECONY's parent company).

Additionally, the comparison company utility subsidiaries had to have an overall senior bond rating of Aa/A from Moody's and AA/A from Standard &

Poor's. In past testimonies, I have used an A/A bond rating as one of the criteria to select proxy groups. However, given the consolidation of the industry through mergers and the increase in unregulated activities, there are fewer candidate companies than formerly that can be included in the proxy group. To expand possible candidates for the proxy group, I have, in addition to the A/A bond rating criterion, also considered companies with an Aa/AA bond rating for inclusion in the proxy group. Currently, CECONY has a rating of A1/A. Since Aa/AA companies are, if anything, less risky than CECONY as indicated by the bond rating, this expansion of the bond rating selection criterion is conservative. The median senior bond rating of the group that I have selected is A1/A-. Thus, the risk of the comparison companies, as indicated by bond rating, is comparable to CECONY.

Companies were excluded from the proxy group if they are currently involved in any major merger activity. Removing companies with merger activity from the cost of equity calculation eliminates companies whose prices and evaluations may be based on short-term merger-related considerations, rather than the long-term prospects of the company. As I explain in more detail in the discussion of the DCF methodology, merger activity has the potential for biasing the DCF result in a potentially significant manner. Companies were also excluded from the proxy group if they had significant unregulated operations. Since unregulated operations have the potential for being of different risk than regulated utility operations, this criterion insures that the companies in the proxy group have

predominantly regulated utility operations. I also excluded companies not paying a dividend or for whom a dividend cut was forecast by Value Line.

The list of companies in the proxy group is shown on Schedule 1.

C. DCF Analysis

Q. Before proceeding with the presentation of the DCF analysis for estimating the cost of equity, would you please give a general description of the DCF method.

A. This method produces an estimate of the market-required return based upon investor evaluation of a company's earnings and dividends, as reflected by the prices that investors pay in the stock market. Basic DCF theory is predicated on the notion that the price that is paid for a company's stock in the market represents the sum of the present value of all future expected dividends. Algebraically, this can be written as:

$$(1) \quad P_0 = \frac{D_1}{(1+k)^1} + \frac{D_2}{(1+k)^2} + \frac{D_3}{(1+k)^3} + \frac{D_4}{(1+k)^4} + \Lambda$$

where: P_0 = the recent price of the stock

D = the expected dividend for the period specified

k = the investors' discount rate, or required rate of return (expressed in decimal form, *e.g.*, 0.15)

The dots at the end of this formula indicate that the equation continues to infinity—in other words, the next two terms would be $D_5/(1+k)^5$ and $D_6/(1+k)^6$, and so on.

The above formula indicates that investors establish the price they are willing to

pay for a stock based upon the expected future stream of dividends, discounted back to the present time.

Q. Do you believe that there is the potential for large measurement error associated with the DCF at the present time?

A. Yes, I do. To apply the DCF method, needed elements include the price that investors are paying for a stock in the marketplace and a reliable estimate of the growth expectations that led investors to bid the observed price. If investors' growth expectations have been correctly estimated, then such estimate is congruent with the market price. If all the factors influencing the market price are not reflected in the growth estimate used by an analyst, then measurement error is introduced into the DCF analysis and the resulting cost of equity estimate will be biased.

As can be seen from the formulation presented above, in order to correctly assess investors' required return in a DCF context, one must ascertain the dividend stream that investors are expecting over the long run. Analysts typically do this in a framework of estimating constant expected growth (if the future is expected to be relatively stable) or multiple stages of growth (if there is an expectation that growth may change in the future). It is my opinion that the DCF method is more prone to measurement error currently due to a lack of congruence between the market price and the growth estimate employed due to a lessening of the clarity of investor growth expectations. Many companies in the industry are in flux currently, transitioning to a restructured environment where the final rules have not yet been established.

Typically, investment analysts provide 5-year growth projections for the companies they cover and investors often employ these projections as their expected growth in the future. However, given the changes occurring in the industry, it is my opinion that these 5-year projections may not be good proxies for the long-term expected growth for utilities at the current time. Many utilities have been assuming a more conservative payout policy either due to the need for more internally generated cash flow or to help deal with the higher risk of earnings fluctuations.

Some utility companies are engaged in repurchases of their common stock. This near-term phenomenon of stock buybacks creates a short-term demand for the stock which raises stock prices above what they would have been, absent the buyback plan.[1]

Investors are also aware that mergers have occurred in the utility industry and more are possible in the near future. The potential for additional mergers could influence investor expectations in several ways. Mergers have generally occurred at a premium above the pre-merger-announcement market price, leading to capital gains for investors. Investors may see mergers as a win-win situation—offering both rate reductions to ratepayers and enhanced return prospects for stockholders. To the extent that there is speculation about future merger activity among utilities,

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[1] This is simply because, in a rising market, the fact that a company, itself, is buying back stock, merely adds to the buying pressure already in effect from a buoyant market. If investors think that stock prices might decline, the fact that the company is likely to be a large-scale buyer in a weak market would certainly provide investors with a cushion. Given both of these effects, stock buybacks would raise the price of a utility's stock above what it would be otherwise. Stock buyback plans often are implemented over a number of years. Thus any accretion in growth resulting from the buyback will be expected to be phased in gradually over time.

such influence would be reflected in the price, but not in the growth projections made by analysts. The effect on the DCF of such speculation would be to bias the cost of equity estimate downward (due to the mismatch between the merger-speculation-inflated price and business-as-usual growth estimates).

The recent change in the level of income tax that investors must pay on dividends also complicates the DCF analysis currently. This tax change was enacted **during** the pricing period that I employ in my DCF analysis, specifically on May 28, 2003. While companies and investors base their payout policy and investment strategy, respectively, on long-term considerations, the dividend tax reduction has a sunset provision (i.e., unless specifically reauthorized, the dividend tax reduction will expire at the end of 2008). This serves to compound estimation over **long-term** growth expectations of investors.

Therefore, due to the complex set of phenomena currently affecting utility stock prices, it is my opinion that a DCF estimate will have the potential for more measurement error than DCF calculations performed in the past under more stable circumstances where investor expectations were determined with more certainty.

Q. Given the difficulties you outline above, how will you proceed with implementing the DCF approach for determining the cost of equity for the comparison companies?

A. The use of the constant-growth DCF formulation (D/P + g) for a regulated utility often may have been a reasonable assumption in the past when the financial and regulatory environment in which regulated utilities operated was more stable than currently. During that time, trends could reasonably be expected to continue and

long-term future growth could be predicted with substantial accuracy. However, as established earlier in this testimony, the utility industry currently is in a state of flux. In light of this, I will employ a two-stage DCF approach to estimate the cost of equity of the comparison companies.

Q. How did you determine the appropriate pricing period for your DCF analysis?

A. The price component of the DCF analysis should reflect recent data over a representative period of time that is neither so short as to merely represent the "luck of the draw" nor so long as to encompass stale data. The pricing period should be long enough to smooth out the effects of any temporary market fluctuations. In the DCF analysis, I will employ a pricing period encompassing the six months ending September 2003.

On Schedule 2, I show the average prices for the comparison companies over the 6-month period ending September 2003. Each month's price was calculated by averaging the monthly high and low prices. The six-month average price is also shown in Column (1) of pages 1-3 of Schedule 3, which provides the inputs to the DCF calculation. The dividend level (*i.e.*, the dividends paid during my pricing period, annualized) for each of the comparison companies shown in Column (2) of pages 1-3 of Schedule 3.

Q. How do you determine the expected growth component of the DCF model for the comparison companies?

A. As noted above, given the regulatory, competitive, risk, payout policy, and other changes noted above, it is difficult to ascertain, with great clarity, investor growth expectations at the current time. I will employ a two-stage growth formulation of

the DCF method to estimate investors' future growth expectations. For the determination of near-term (*i.e.*, first-stage) growth, I rely on an average of earnings projections made by Value Line and First Call, a unit of Thomson Financial. These projections for the comparison companies and the average of the two are shown in Columns (3)-(5) of pages 1-3 of Schedule 3.

The estimation of second-stage, long-term growth is more problematic. I am not aware of any specific projections that are made by financial analysts for this timeframe. However, I will employ three proxies for investors' expected long-term growth.

First, I will employ the long-term projected nominal GDP (Gross Domestic Product) growth as a proxy for expected long-term second-stage growth for an individual company.[2] The Energy Information Administration (EIA) of the Department of Energy published the *Annual Energy Outlook 2003* which contains data that can be used to derive a long-term projection of growth in nominal GDP. Using data from that source, I have calculated projected growth in GDP for the period 2008-2025 to be 5.91 percent.

For the second proxy for investors' expected long-term growth, I employ projected sustainable growth, calculated using Value Line projections.[3] The

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[2] In the absence of a clear picture of long-term future growth specific to electric utilities, investors might employ a generalized measure of economy-wide growth as a proxy for expected utility growth.

[3] Sustainable growth is comprised of two factors—growth from the retention of earnings (i.e., internal growth) and growth from the sale of common stock (i.e., external growth). Internal growth can be calculated as the product of "b" (the expected retention ratio) and "r" (the expected return on equity). External growth can be calculated as the product of "s" (the growth in aggregate common equity due to the issuance of new common stock) and "v" (a function of the price-book ratio reflecting the fraction of funds obtained from

projected sustainable growth rates are shown in Column (6) on page 2 of Schedule 3.

For the third estimate of investors' expected long-term growth, I employ a projection of expected industry growth. Given the competitive and regulatory uncertainties facing utilities, discussed above, investors might look at projected industry growth as a proxy for projected long-term growth for individual companies. Zacks, Value Line, S&P and First Call project growth for the industry to be 4.5, 5.9, 5.7 and 5. 0 percent, respectively. As a proxy for projected industry growth, I will use a figure of 5.3 percent.

Q. Would you review the components of the two-stage DCF analyses for the comparison companies?

A. The DCF analyses using GDP growth, sustainable growth and industry growth are shown on Schedule 3, pages 1, 2 and 3, respectively. Columns (1) and (2) of pages 1-3 of Schedule 3 show the 6-month average price and the indicated dividend for the comparison companies. Columns (3)-(5) show the Value Line, First Call and average projected earnings growth rates. Column (6) of page 1 of Schedule 3 shows the long-term projected growth in GDP, which is assumed to occur after the first-stage growth period. Column (7) of page 1 of Schedule 3 shows the DCF cost of equity estimate for each company calculated by an iterative process employing the internal rate of return. (For calculational purposes, I continue the second-stage growth for 200 years because any growth after that point has a negligible effect on any present value or internal rate of return calculation.)

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the sale of common stock that accrues to the existing stockholders).

Page 2 of Schedule 3 shows the two-stage DCF analysis employing projected sustainable growth for the long-term expected growth rate. Columns (1)-(5) show the same inputs as on page 1 of Schedule 3. Column (6) of page 2 of Schedule 3 shows the projected sustainable growth, which I employ as the long-term projected growth assumed to occur after the first-stage growth period. Column (7) of page 2 Schedule 3 shows the DCF cost of equity estimate for each company.[4] Page 3 of Schedule 3 shows the two-stage DCF analysis employing projected industry growth for the long-term expected growth rate. Columns (1)-(5) show the same inputs as on pages 1 and 2 of Schedule 3. Column (6) of page 3 of Schedule 3 shows the projected industry growth, which I employ as the long-term projected growth assumed to occur after the first-stage growth period. Column (7) of page 3 of Schedule 3 shows the DCF cost of equity estimate for each company.

Q. What are the results of your DCF calculations?

A. Below, I show a table summarizing the results of the DCF calculations described above:

[4] Note that the cost of equity estimate for CH Energy is 6.8 percent which is only about at the level of utility bond yields. (CH Energy has been discussed in the financial press as a potential acquisition target and its stock price may well include an acquisition premium.) Since it is nearly universally agreed that the cost of equity does, and should, exceed the cost of debt, when a cost of equity estimate is only about at the level of bond yields, this is clearly an understated estimate and should be discarded. For example, FERC in Opinion No. 445 re Southern California Edison Company, July 26, 2000, 92 FERC ¶ 61,070, deleted a cost of equity estimate even somewhat above the concurrent bond yield. FERC indicated at page 27 of that Opinion that: "Because investors generally cannot be expected to purchase stock if debt, which has less risk than stock, yields essentially the same return, this low-end return cannot be considered reliable in this case." FERC excluded this low figure from its calculation of the cost of equity. I will exclude this CH Energy estimate from further consideration in my analysis.

Long-Term Growth Rate	Schedule Page	Range	Midpoint of Range	Median	Average
GDP	Sch. 3, p.1	9.1 - 11.5	10.3	10.8	10.6
Sustainable	Sch. 3, p.2	8.2 - 15.8	12.0	9.8	10.7
Industry Avg.	Sch. 3, p.3	8.6 - 11.0	9.8	10.3	10.1

Based on the results and analysis presented above, I will use a DCF range of 10.00-10.75 percent in my further discussion of the determination of the cost of equity. However, noting the possibility of measurement error and understatement associated with the application of the DCF method currently, it is my opinion that these results should be considered in conjunction with the results of the other methods that I employ.

D. CAPM Analysis

Q. What is the basis of the CAPM approach you will employ?

A. Assuming rationality on the part of investors, the greater the risk of an investment, the higher the return that investors will demand of that investment. The yield on risk-free assets such as U.S. Treasury securities is readily determinable in the marketplace. Given that fact, if we know the risk premium that investors require to invest in the stock of the comparison companies rather than a U.S. Treasury security, we can determine the required rate of return, or cost of common equity, for the comparison companies. In this section of my testimony, I will employ the capital asset pricing model (CAPM) method to calculate this risk premium and the cost of equity for the comparison companies.

Q. Would you briefly outline the theory underlying the CAPM method?

A. In recent developments in financial theory, the total risk (variance) of an asset has been partitioned into two components: unsystematic risk and systematic risk. Unsystematic risk represents risk (*i.e.*, fluctuations in returns) due to events specific to the particular company in question (*e.g.*, a long strike at the company's plants; the loss of a large government contract; the release of a highly profitable motion picture, etc.). Unsystematic risk is company-specific and is unrelated to changes in the economy as a whole. Systematic risk, on the other hand, represents the variability in the returns on an investment due to the effect on the firm of economy-wide forces. The level of a firm's systematic risk is determined by the firm's sensitivity to the totality of macroeconomic forces in the economy.

Modern financial theory calls for the evaluation of an asset, not in isolation, but in the context of a well-diversified portfolio. If enough stocks are held in a well-diversified portfolio, the firm-specific (unsystematic) risks of the individual firms will tend to cancel each other out. The theory is that if there are enough assets in the portfolio from diverse industries, some of the assets will experience higher than expected returns while other assets will experience lower than expected returns, but the portfolio as a whole will yield the average expected return. Thus, the exposure of an investor to the risk related to firm-specific events (unsystematic risk) can be eliminated by holding a well-diversified portfolio. Systematic risk, on the other hand, cannot be diversified away in a portfolio context.

Since unsystematic risk can be eliminated in a well-diversified portfolio, according to CAPM theory the investor need only concern himself with the degree

of systematic risk possessed by an asset. Beta is a measure of the systematic risk of an asset. The level of beta of an asset indicates the risk contribution of that asset to the overall risk of a well-diversified portfolio. The higher the expected risk (*i.e.*, beta) of an investment in an individual asset, the higher the risk contribution of that asset to the risk of a portfolio and, thus, the higher will be the return which an investor would require to be willing to make such an investment.

The beta value of all assets, on average, is equal to 1.0. If a particular asset has a beta of 1.0, this means that the variability in its returns due to macroeconomic events will be equal to, and in phase with, the variability of returns in the economy as a whole. An asset with a beta of, say, .5 is only half as responsive to economy-wide events as the market index. When the market index goes up 10 percent, the price of this stock will only go up 5 percent. If the market index declines 30 percent, the price of this investment will only decline 15 percent. An asset with a beta of 2.0 has twice the volatility of the market index. If the market index goes up 20 percent, the price of this asset will go up 40 percent. If the market index declines 5 percent, the price of this asset will decline 10 percent.

Under CAPM theory, the basic formula which can be used to determine the market-required rate of return for a company is:

$$R_i = R_f + b_i\,[E(RP)]$$

where:

R_i = required return on security i

R_f = current return on risk-free investments

b_i = beta for security i

E(RP) = expected market risk premium, *i.e.*, the expected difference between the return in the market and the rate of return on a risk-free investment

In the above formulation, the required rate of return for a company is equal to the current return on a risk-free investment plus the product of that company's beta times the expected market risk premium. The market risk premium is that extra return that investors require for an investment in assets of the market as a whole as compared to the return on a risk-free investment.

In addition to the "traditional" formulation of the CAPM shown above, I will also employ an "empirical" formulation of the CAPM.[5] The empirical CAPM is used due to both empirical and theoretical concerns that the "traditional" CAPM may provide an understated required return estimate for utilities. Empirical tests in the academic literature show that the "traditional" CAPM understated the required return for companies with beta below 1.0 and overstated the required return for companies with beta above 1.0. The empirical version of the CAPM reflects considerations that no estimate of the market return—in particular just using a

[5] This formulation of the CAPM is also sometimes known as the two-factor CAPM, or zero-beta CAPM.

stock market proxy—can truly represent the whole range of investments and returns available to investors and that investors who borrow money incur a cost of funds that exceeds the risk-free rate. I will use an empirical formulation[6] that is designed to alleviate the biases that may be reflected in the "traditional" CAPM:

$$R_i = R_f + .75(b_i)(RP) + .25(RP).$$

Q. What data requirements are necessary to implement the CAPM approach?

A. In order to use the CAPM approach for the comparison companies, three parameters must be estimated—beta, the current risk-free rate and the expected market risk premium.

Q. How do you determine beta for the CAPM calculation?

A. The average beta of the comparison companies is 0.65, per *The Value Line Investment Survey*. I will employ a beta of 0.65 in the CAPM calculation.

Q. How do you determine the current risk-free rate of return?

A. Since we are trying to determine the cost of common equity capital for the comparison companies and equity capital is a long-term investment, it is my belief that the yield on long-term government bonds best reflects the risk-free rate in this context.

Common stock is a long-term investment—it has no maturity date.[7] In this context, it is interesting to note that the discounted cash flow (DCF) approach determines the cost of equity in terms of a long horizon—*i.e.*, dividends are discounted to infinity in the DCF calculation. Even if an investor sells his or her

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[6] See Roger Morin, *Regulatory Finance*, pages 334-336.

[7] The common stock of a utility will remain outstanding unless a company merges or becomes defunct, or if an investor voluntarily sells his shares back to the company.

common stock after only a few years, the successor investor determines the price that the original investor can receive, and so on. Based on the above, equity capital should be considered as a long-term investment and, therefore, the yield on long-term Government bonds best reflects the risk-free rate in this context.

Under a long-term investment horizon, if one purchased, say, 3-month Treasury securities and then kept rolling over the proceeds each three months as the investment matures, there would be substantial uncertainty (risk) as to what return one would earn over a long horizon by just investing in 3-month Treasury bills. In contrast, in the context of a long horizon, if a long-term Treasury bond is held until maturity, then there is no uncertainty as to the expected return—the interest payments and principal are guaranteed in nominal terms. Thus, using a long-term Government bond more closely matches the long-term investment horizon of equity and is therefore appropriate to use in a CAPM analysis for estimating the cost of equity.

I note that short-term Treasury securities are used by the Federal Reserve to implement its policy objectives for credit tightening and expansion. Thus, short-term Treasury security yields are greatly influenced by short-term Federal Reserve policy moves. These short-term adjustments should not be used to measure the long-term risk and return evaluations of investors for common stock.

The average yields on long-term Treasury securities over the April-September 2003 period, per the *Federal Reserve Statistical Release*, were as follows:

	Average Yield
10-Year	3.9 %
20-Year	4.9
Long-Term*	5.0

* Bonds with at least 25 years or more remaining until maturity.

Recent long-term Treasury bond futures yields have been close to 5.5 percent. Based on all the above-described data, I believe it would be appropriate to use a risk-free rate of 5.0 percent in the CAPM calculation.

Q. How do you determine the expected market risk premium?

A. For the third parameter needed for the CAPM approach, we must estimate the expected market risk premium—*i.e.*, the expected difference between the market-required return on common stocks and the yield on long-term government bonds.

Expectational risk premium data are not directly observable in the marketplace. Therefore, to estimate the expected market risk premium, I follow two approaches. The first approach employs historic long-term risk premium data from Ibbotson Associates *Risk Premia Over Time Report: 2003*. In the second approach I calculate a current cost of equity estimate for the market, in general, using a DCF approach and then subtract the estimate of the risk-free rate from this figure in order to determine the expected market risk premium.

Q. Will you now describe how you will use historic data from the Ibbotson publication to estimate the expected market risk premium?

A. As I indicated earlier, expectational risk premium data are not directly observable in the marketplace. Therefore, one can use estimates of historic realized return

spreads as proxies for expected risk premiums. This approach is reasonable since it is plausible to assume that investors use the historic experience as a guide when forming their expectations of risk premiums in the future.

Ibbotson Associates publishes the *Risk Premia Over Time Report: 2003* in which the returns on common stocks and long-term government bonds are reported for the 1926-2002 period. Based on these data, the spread between common stock returns and returns on long-term government bonds has been 7.0 percentage points on an historical basis. I will use this 7.0 percent figure as the expected market risk premium in this CAPM analysis.

In the above discussion, I have employed figures reflecting the arithmetic mean rather than the geometric mean of the data. I believe that a rational investor would employ the arithmetic mean and would not use the geometric mean, because that would provide an understatement of expected future return. (I note that Ibbotson Associates states that the arithmetic mean is the correct measure to use in estimating the cost of equity capital.) Since the explanation of why the arithmetic mean should be used is quite lengthy, I have included it in Appendix B to this testimony. Appendix B shows that the arithmetic mean is the appropriate figure to use when investors are making forecasts about the future and dealing with uncertainties inherent in making projections.

A simple example also shows that the arithmetic mean is the correct approach to use in this context. Let us assume that you are faced with the prospect of betting on a coin toss where you win 50 percent of your bet if the coin comes up

heads, but lose 50 percent of the bet if the coin comes up tails.[8] Common sense indicates that because the coin is a fair coin (*i.e.*, a 50 percent chance of landing on heads and a 50 percent chance of landing on tails), the bettor would expect to only break even (*i.e.*, they would expect to lose 50 percent of their bet half the time and expect to win 50 percent of their bet half the time). The arithmetic average of the return prospects a bettor would face in these circumstances is zero. Thus, the common sense expectation of a bettor in this example reflects the arithmetic average of return possibilities. In sharp contrast, the geometric average of an equal prospect of two returns (one plus 50 percent and one minus 50 percent) is -13.4 percent. A rational bettor would not go into a coin toss of the type described above with the expectation of a loss of 13.4 percent over time—they would expect to break even, as reflected in the arithmetic mean of zero. Clearly, they would not use a geometric average of return possibilities as their expected value, but would, instead, use the arithmetic average.

Q. Can you explain why it is reasonable to assume that investors look at achieved return spread results of the past in formulating their risk premium expectations for the future?

A. I examined historical return spread data over the 1926-2002 period and the results represent 77 years of return experience. The data that I examined, which represents the experience of a large number of companies over a lengthy period of time,

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[8] Implicit in this discussion is an assumption that the coin used is fair—it is not biased (*e.g.*, weighted) to land disproportionately on either heads or tails.

indicates what return spreads investors have actually achieved, on average, in the past. It is not unreasonable to assume that, given the very extensive return spread experience examined, that investors would use this historic experience in formulating their expected risk premium for the future. Put simply, they see what return spread has been achieved in the past and use that experience as an expectation of what might be achieved in the future. Because of this consideration, I believe that the average historic return spread is appropriate to use as the expected risk premium in a CAPM analysis.

The 2002 Ibbotson *Yearbook* states that:

> A proper estimate of the equity risk premium requires a data series long enough to give a reliable average without being unduly influenced by very good and very poor short-term returns.... Some analysts estimate the expected equity risk premium using a shorter, more recent time period on the basis that recent events are more likely to be repeated in the near future; furthermore, they believe that the 1920s, 1930s, and 1940s contain too many unusual events. This view is suspect because all periods contain "unusual" events. Some of the most unusual events of this century took place quite recently, including the inflation of the late 1970s and early 1980s, the October 1987 stock market crash, the collapse of the high-yield bond market, the major contraction and consolidation of the thrift industry, the collapse of the Soviet Union, and the development of the European Economic Community—all of these happened in the last 20 years.... The 76-year period starting with 1926 is representative of what can happen: it includes high and low returns, volatile and quiet markets, war and peace, inflation and deflation, and prosperity and depression. Restricting attention to a shorter historical period underestimates the amount of change that could occur in a long future period. Finally, because historical event-types (not specific events) tend to repeat themselves, long-run capital market return studies can reveal a great deal about the future. Investors probably expect "unusual"

> events to occur from time to time, and their return expectations reflect this.

I agree with the sentiments expressed above and think it is appropriate to assume that investors would use the full range of experience available to them.

It should be noted that in individual years in the period under study, realized return spreads fluctuated significantly and even were negative in some cases. However, the expected risk premium of investors in each year must be positive; if not, a rational investor would never be willing to purchase a risky asset. One must always keep in mind that the risk premium concept is expectational. While investor ex ante risk premium expectations will not be matched in every year by the achieved ex post return spreads, investors will look at the average achieved return spread over a long period to get a sense of what would be realistic to expect for the future. The realized return spreads that I analyzed reflect a body of historic experience based on which investors would reasonably form their return expectations for the future. Of course, it is those future expectations that we are trying to ascertain. Atypically high or low results in any given historic period are not indicative of investors' expectations. Moreover, a negative return spread in any particular historic year or period does not cause investors to expect that in the future they will only be able to achieve negative return premiums, on average. It is, therefore, my view that the average realized return spread over a long period is likely to be viewed by investors as a reasonable estimate of the expected risk premium.

Q. How do you specifically implement the CAPM approach for the comparison companies using the Ibbotson market risk premium?

A. The beta for the comparison companies, per Value Line, is 0.65. The expected market risk premium is 7.0 percent. The risk-free rate is 5.0 percent. Using these inputs, the average required return for the comparison companies is calculated below:

Traditional CAPM

$$R_i = 5.0 + 0.65(7.0) = 9.6\%$$

Empirical CAPM

$$R_i = 5.0 + 0.75(.65)(7.0) + .25(7.0) = 10.2\%$$

Q. Will you now describe how you use S&P 500 data to estimate the expected market risk premium?

A. I first calculate an estimate of the expected (required) return for the S&P 500 using the DCF method and then subtract the risk-free rate employed in my analysis in order to determine the expected market risk premium under this second approach.

The recent dividend yield for the S&P 500 has been about at the 1.75 percent level. According to First Call, projected earnings growth for the companies in the S&P 500 averages about 12.0 percent. Per S&P, the average projected earnings growth for the companies it covers is about 14.0 percent. Using 13.0 percent as the estimate of expected growth and a 1.75 percent dividend yield, the DCF estimate of the expected return for the S&P 500 is 14.75 percent. Using a risk-free rate of 5.0 percent, the expected market risk premium would be 9.75 percent (14.75– 5.0 = 9.75). Employing this expected market risk premium for the S&P 500, the average required return for the comparison companies is calculated below:

Traditional CAPM

$R_i = 5.0 + 0.65(9.75) = 11.3\%$

Empirical CAPM

$R_i = 5.0 + 0.75(.65)(9.75) + .25(9.75) = 12.2\%$

Q. Are there any other factors to consider that may not be captured by the CAPM calculations described above?

A. Yes, there are. Ibbotson Associates indicates that companies with market capitalization in the mid- or low-capitalization range (including many utilities) require higher returns than indicated by the CAPM formulation I have employed above. As a way to account for this phenomenon, a size premium can be added to the CAPM results.

According to the Ibbotson Associates *Risk Premium Over Time Report: 2003*, size premiums of 82 and 152 basis points are appropriate for mid- or low-capitalization companies, respectively. I will use a 60 basis point size premium for the comparison group to recognize that six of the companies (Alliant, NSTAR, Pinnacle West, SCANA, Vectren and Wisconsin Energy) are in the mid-capitalization range and two of the companies (CH Energy and MGE Energy) are in the low-capitalization range.

Q. Would you summarize the results of your CAPM analyses?

A. The CAPM results are summarized in the table below:

CAPM Formulation	Market Risk Premium Based on:	CAPM Result	CAPM Result + Size Premium
Traditional	Ibbotson	9.6 %	10.2 %
	S&P 500	11.3	11.9
Empirical	Ibbotson	10.2	10.8
	S&P 500	12.2	12.8

Based on the above data, I conclude that the CAPM estimate of the cost of equity is in the 10.75-11.50 percent range.

The above CAPM cost of equity estimates are conservative when compared with the CAPM results produced by an empirical (zero-beta) CAPM formulation sometimes used by the Commission Staff. In testimony in the Nine Mile Point 2 sale proceeding (Case No. 01-E-0011), filed in April 2001, a Staff Policy Panel indicated at page 36 that it chose to use a 50/50 zero-beta CAPM weighting rather than a 75/25 weighting because it will "tend to produce less volatile results." Use of the 50/50 weighting would raise the result of the zero-beta CAPM formulation for the calculations based on Ibbotson and S&P inputs to 10.8 and 13.0 percent, respectively, before consideration of the size premium.

E. Risk Premium Analysis

Q. Would you provide an overview of your risk premium calculations?

A. I employ two risk premium approaches. The first analysis is based on the historic average spread between utility stocks and bonds. The second relies on a regression analysis to measure how utility risk premiums vary with the level of interest rates.

Q. Will you explain the rationale behind a risk premium analysis?

A. The higher the perceived risk of an investment, the higher will be the return that investors require from that investment. If two investments offer the same expected return but have differing risks, investors will prefer the investment with lesser risk. Investors do so because they are said to be risk averse—*i.e.*, they prefer to take on less risk, rather than more risk, other things being equal.

It is nearly universally agreed that investors require a higher rate of return for an investment in the common equity for a particular company than they do in its debt. This is so for two important reasons. First, if an enterprise fails, debtholders have priority over equityholders as to the remaining assets of the company. Second, for an ongoing business, debtholders must be paid their contractual level of interest before equityholders can receive anything. Because of this basic fact of financial life, companies may reduce their dividend payments to equityholders when under some financial strain. The cessation of payments to debtholders is a much rarer occurrence and will usually result in bankruptcy, unless corrected. In summary, debt is thought to be less risky than equity because debtholders have priority over equityholders as to: (1) distribution of assets in the case of dissolution of the company and (2) distribution of earnings in the case of everyday operations. Because equityholders "take second," they require a higher return than do debtholders. In order to be induced to choose a higher risk investment, an investor

would have to be offered an expectation of some increment in return—a premium for incurring additional risk. This incremental return is often known as the "risk premium" and it reflects the additional return that investors require to invest in common equity rather than debt.

The cost of equity is not directly observable, but must be estimated using inferences and judgment. In contrast, a bond yield is observable and if we know, or can estimate, the risk premium that common equity investors require to invest in common equity rather than debt, we can employ the risk premium approach to estimate the cost of common equity. In the well-known *Hope* decision, the U.S. Supreme Court said:

> From the investor or company point of view, it is important that there be enough revenue not only for operating expenses, but also for the capital costs of the business. These include service on the debt and dividends on the stock. By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital. [Federal Power Commission v. Hope Natural Gas Co., 320 U.S. 591, 603 (1944).]

While this decision speaks in terms of returns commensurate with those being earned on investments of comparable risk, implicitly a company must also earn a return far enough above investments of lesser risk in order to be able to attract capital. Thus, if we apply the risk premium approach correctly, we will ensure that the subject company is allowed a high enough return on its common equity, compared with investments of lesser risk, so as to be able to attract capital and to meet the standards laid down by the *Hope* decision.

In general, the equity risk premium can be expressed in the following manner:

$$RP = K_e - K_d$$

The above equation implies that the equity risk premium is equal to the required return on equity (K_e) minus the required return on debt (K_d).

Q. Would you please describe your first risk premium analysis?

A. To measure the expected risk premium between utility common stock and utility bonds, I use the average return spread actually achieved by investors in these instruments in the past. Between 1932 and 2001, Moody's electric utility common stock index achieved a market return of 10.93 percent, on average. (The market return in any given year was calculated by summing the dividend paid during that year and the year-end market price and dividing that sum by the beginning-of-year market price.) Over that same period, the average of Moody's composite bond yields for electric utilities was 6.64 percent. Thus, the historically achieved spread between electric utility stock returns and electric utility bond yields was 4.29 percent (10.93 - 6.64 = 4.29). If we add this average spread to the recent level of bond yields, we can obtain an estimate of the return on utility common stocks that investors are currently expecting/requiring.

Over the six-month period ending September 2003, the average bond yield for Moody's A rated utility bonds was 6.52 percent. Adding this recent average bond yield to the historic average spread between electric utility common stock returns and electric utility bond yields of 4.29 percent, we obtain a cost of equity estimate for the proxy group of 10.81 percent.

Q. In your second risk premium analysis, is there a proxy for required returns on equity that you use?

A. Yes, there is—returns on common equity allowed to electric utilities by regulation.[9] Most regulatory commissions frequently refer to movements in, or the level of, interest rates in their decisions establishing an allowed return on equity. Since authorized returns appear to be interest-rate sensitive, employing allowed returns from across the United States in calculating the risk premium serves to use outside, objective evidence as to what the consensus of regulation believes is the spread between the cost of equity and bond yields.

Q. How specifically did you perform your second risk premium analysis?

A. I first conducted an analysis of risk premiums implied by allowed returns on equity since 1980. Specifically, quarterly average allowed returns for the first quarter 1980 through the third quarter 2003 were obtained from data in Regulatory Research Associates *Regulatory Focus*. These data reflect the average of allowed returns for all electric utility cases decided in the quarter specified. An implied risk premium (which can also be thought of as an allowed return spread) was derived by comparing the average allowed return in a given quarter with the average yield for Moody's Utility Composite Bond Index in the two quarters prior to the average allowed return.

In deriving the implied risk premium, the utility bond yields were lagged behind the allowed returns on equity because of the likelihood that changes in

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[9] Regulators sometimes allow companies to keep earnings above the nominally allowed return on equity. Thus, the use of allowed returns in this analysis may well understate the returns investors actually expect a company to earn.

allowed returns on equity often lag somewhat behind changes in bond yields. This could be so for two reasons—one economic and one practical. The economic reason is that commissions might want to be convinced that a change in interest rates actually represented a trend that might persist before reflecting such change in the allowed return on equity. The practical reason simply deals with the logistics of a rate case—the record that a commission examines may be several months old by the time it renders a decision. (While certain commissions update record data in their decisions, many commissions do not do so.) Furthermore, the simple logistics of writing a decision may cause a delay between the period upon which the allowed return was based and the date on which the decision was released to the public.

To determine the sensitivity of the implied risk premiums described above to the level of interest rates, a regression analysis was conducted. In this regression, the implied risk premium described above was the dependent variable and the level of interest rates, as proxied by the yield on long-term Treasury bonds lagged two quarters behind the allowed return on equity, was the independent variable. This model attempts to capture the statistical relationship between implied risk premiums (*i.e.*, allowed returns minus utility bond yields) and the level of interest rates (as indicated by the yields on long-term Treasury bonds), with the interest rates being lagged two quarters behind the allowed return on equity. The regression equation is reported below:

$$\text{Risk Premium} = 6.477 - 0.432 \left\{ \begin{matrix} Yield\ on\ Long-Term \\ Treasury \\ Bonds \end{matrix} \right\}$$

The adjusted R^2 of the regression (which measures the proportion of variation in the dependent variable explained by variation in the independent variable) is 0.78. Thus, this regression relationship demonstrates that changes in the level of interest rates explain a substantial proportion of the changes in implied risk premiums.

One might well ask why one should go through the process of creating the model described above when one could merely just examine recent levels of allowed returns. There are justifications for the model in this context. First, it is possible that in certain quarters there are an insufficient number of allowed returns to use as a guide by themselves. Second, allowed returns are not a perfect proxy for required returns and the use of the long-term relationship between allowed returns and bond yields allows us to overcome any unusual allowed return results in a particular period.

The average yield on long-term Treasury bonds for the six months ending September 2003 is 4.95 percent. Inserting this into the model shown above, I obtain a calculated risk premium of 4.36 percent as follows:

Risk Premium = 6.477 - 0.432(4.95)

Risk Premium = 4.34%

The average yield on Moody's A rated bonds in the six months ending February 2003 was 6.52 percent. Adding the yield of 6.52 percent to the risk premium derived above of 4.34 percent produces an implied cost of equity of 10.86 percent. Thus, my second risk premium cost of equity estimate for the proxy group of utilities is 10.86 percent according to the above-described analysis.

Q. Would you summarize the results of your risk premium analyses?

A. The first risk premium approach that employs the historic average spread between utility common stock returns and utility bond yields produced a cost of equity estimate for the proxy group of 10.81 percent. The second risk premium approach which is based on a regression analysis measuring how utility risk premiums change as the level of interest rates change produced a cost of equity estimate of 10.86 percent for the proxy group. Based on these results, I will use a range of 10.8-10.9 percent as the risk premium cost of equity estimate in my further discussion.

F. Comparable Earnings Analysis

Q. Can you explain why the comparable earnings approach is helpful in assessing what return should be allowed in this proceeding?

A. The basic criteria for determining what constitutes a fair rate of return for a regulated enterprise were set forth by the U.S. Supreme Court in the *Bluefield* and *Hope Natural Gas* cases. In the *Bluefield* case the Court said:

> A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties; but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. [Bluefield Waterworks & Improvement Company v. Public Service Commission of West Virginia, 262 U.S. 679, 692-693 (1923).]

In *Hope*, the Court said:

> From the investor or company point of view, it is important that there be enough revenue not only for operating expenses, but also for the capital costs of the business. These include service on the debt and dividends on the stock. By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital. [Federal Power Commission v. Hope Natural Gas Co., 320 U.S. 591, 603 (1944).]

In those decisions, the Court enumerated a two-part standard for a fair rate of return: (1) a fair rate of return to a regulated company is one that is equal to that earned in other enterprises of similar risk and (2) the fair rate of return must also provide enough earnings to enable the company to maintain its credit standing[10] and to attract capital. The first part has come to be known as the "comparable earnings standard" while the second part is referred to as "the capital attraction standard."

The comparable earnings approach (*i.e.*, determining the return earned by companies of similar risk) directly meets one of the basic criteria set forth by the Supreme Court in the *Bluefield* and *Hope* decisions. But, in addition, the Court set forth the criterion that the rate of return on equity should also be sufficient for the company to attract capital. It must be acknowledged that a firm whose return is the same as that of "other enterprises having corresponding risks" is not necessarily earning enough to attract capital; but in reasonably prosperous periods, one can expect that the great majority of companies are earning enough to attract capital,

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[10] Bond rating agencies have subjected the financial ratios of utilities to more rigorous scrutiny of late. Since the rating agencies emphasize **cash flow** measures, adequate cash flow is crucial to a company's credit standing.

and that one can also identify those that are not. Thus, if comparisons are made with a reasonably broad range of companies over a reasonably representative time period, one can be confident that a return high enough to match that of other enterprises with corresponding risks will probably also be high enough to attract capital and maintain financial integrity.

In addition to being prescribed as a standard by the *Bluefield* and *Hope* decisions, there are other reasons why a comparable earnings analysis may be helpful in determining the return to be allowed a regulated company. The comparable earnings method analyzes the question of what return should be allowed a regulated company from a different perspective than an approach such as the DCF method. It can be argued that the price that investors pay in the stock market for a utility depends, at least in part, on the return that investors expect a commission will allow that company. In turn, however, the return that a commission will allow a company depends, at least in part, on the price of that company in the stock market. As one commentator has stated:

> Moreover, since the most important risk to the investor is the risk as to the attitude of the regulatory commission, current security prices inevitably reflect projections not only of future physical and general economic developments of the utility and its area, but also of the anticipated rulings of the commission. For the commission to "rely" on such anticipations is palpably circular reasoning.... Commissions and investors cannot sensibly continue to look behind one another like endless images in multiple mirror.[11]

[11] Harold Leventhal, "Vitality of the Comparable Earnings Standard for Regulation of Utilities in a Growth Economy," *The Yale Law Journal*, May 1965, page 1007.

Thus there is an element of circularity in using an approach such as the DCF method to estimate the cost of equity of a utility. The comparable earnings method, which derives its results from a conceptually different approach, can shed additional light on the question of the appropriate allowed return for a utility.

Another advantage of a comparable earnings analysis is that it provides a perspective different from that implicitly employed using an approach that satisfies the capital attraction standard. If the capital attraction standard is strictly and rigidly applied, it would keep a company on the knife-edge of financial health—any shortfall in return might make it difficult for a company to attract capital. As another commentator has stated:

> It should be evident that a rate of return which is barely adequate to allow for the raising of new capital is not necessarily a fair rate of return.[12]

The comparable earnings approach is not a market-based methodology. However, the examination of returns earned, or expected to be earned, by a large group of companies with risks similar to electric utilities, in combination with the results of various other methodologies, will produce a reasonable estimate of the return to be allowed for electric utilities.

Q. Would you now describe the comparable earnings analysis you conducted?

A. Under the comparable earnings approach, I first evaluate the risk of the comparison companies versus that of companies in the U.S. economy in general and based on this analysis determine what return on equity is appropriate.

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[12] Herman Roseman, "Comparable Earnings and the Fair Rate of Return," 1970 *Annual Report*, Section of Public Utility Law of the American Bar Association, page 26.

Q. How do you evaluate the relative risk of the comparison companies versus companies in general?

A. I use the Value Line Safety Rank. *The Value Line Investment Survey* provides a safety rank for the 1700 or so companies that it follows. For the determination of Safety Rank, stocks are ranked from 1 to 5, with 1 being the safest and 5 being the most risky. Value Line defines the Safety Rank as a measure of the total risk of a stock and describes the Safety Rank as one of the main criteria investors should consider in selecting stocks. Value Line derives the Safety Rank by averaging two variables: (1) the volatility of the stock as measured by its Index of Price Stability and (2) the Financial Strength Rating as determined by Value Line analysts. Value Line defines the price stability index as being based upon a ranking of the standard deviation of weekly percent changes in price of a stock over the last five years. Value Line evaluates the Financial Strength of a company on a scale of A++ down to C. This is a relative ranking comparing the subject company's financial strength to all other companies. The rating is based upon financial leverage, business risk, company size and the judgment of Value Line analysts. The analysts examine various ratios such as coverage, return variability, accounting methods and size.

To implement the comparable earnings analysis, I examined recent earned and projected returns on shareholders' equity earned by companies with a safety factor of 2 as reported in *The Value Line Investment Survey*.[13]

Q. Does this group of companies with the Safety Rank of 2 include unregulated companies?

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[13] The safety rank of the proxy group I employ is 2.

A. Yes, it does. It is a financial fact of life for a utility company that it competes in the marketplace to obtain capital not only with other utilities, but with all economic enterprises. Furthermore, the *Hope* decision, which is a touchstone in the area of rate of return regulation, indicates that a company should be compared to other firms of comparable risk and did not limit this comparison only to other regulated firms. Value Line measures the risk embodied in the safety rank it assigns consistently across the 1700 or so companies that it follows to derive its safety rank and thus it measures risk in a uniform manner for both regulated and unregulated firms.

Q. What returns are companies with a Safety Rank of 2 earning?

A. The earned return on shareholders' equity in any one given year is not necessarily the return that investors expect a firm to earn in the future. A company could have runs of good luck or bad luck or particular accounting adjustments so that the return earned in any one year is not necessarily a meaningful indicator of what it ought to be earning in light of the risks being borne. In order to temper the earned return data, I examined earned returns on shareholders' equity over two recent historic years. In addition, Value Line projected earned returns for 2003 (the current year), 2004 and for a period 3-5 years into the future were also employed. Thus, by looking at both the earnings experience of the recent past as well as projections for the future, unusual figures are smoothed and the end result is appropriate to employ as the comparable earnings result. To further temper the data, median results, rather than average figures, were used in any year.

The median returns on shareholders' equity in 2001 and 2002 for companies accorded by Value Line a safety factor of 2 are 14.2 and 13.7 percent, respectively. The median projected returns on shareholders' equity for these companies in 2003 and 2004 were 14.0 percent in both years. The median return for these companies projected by Value Line for the near-term future (2006-2008) is 14.5 percent.

In summary, a conservative estimate[14] of the return to be allowed on common equity using the comparable earnings approach is in the range of 14.0-14.5 percent.

G. Determination of the Cost of Equity

Q. Would you describe the results of each of the four methods?

A. The DCF method produced a cost of equity range of 10.00-10.75 percent. As I indicated earlier in my testimony, I believe that a utility DCF estimate will have the potential for more measurement error than during periods in which a company's more-readily-determined future earnings and dividends prospects were the main consideration. Therefore, I believe that it is important to also consider the results of the other methods that I presented, which approach the determination of the return on equity to be allowed in this proceeding from different perspectives.

[14] The data that I examined reflect the return earned on shareholders' equity, rather than the return on common equity. Since the companies examined are financed in part by some preferred equity in addition to common equity, the returns on common equity would be higher than those reported. In addition, Value Line reports return on year-end shareholders' equity, whereas it is appropriate to use return on average equity for the comparable earnings analysis.

The CAPM approach can be thought of as calculating a risk premium for the market as a whole and then adjusting it for the risk of the particular utility in question. Under the CAPM approach, risk is measured by a company's beta. My CAPM analysis produced a cost of equity range of 10.75-11.50 percent.

While the CAPM approach calculates a market-wide risk premium that is then adjusted for company-specific risk, the two risk premium analyses that I performed directly estimate the risk premium for a utility. The results of these risk premium analyses produced a cost of equity estimate in the range of 10.8-10.9 percent.

The comparable earnings approach (*i.e.*, determining the return earned by companies of similar risk) directly meets one of the basic criteria set forth by the Supreme Court in the *Bluefield* and *Hope* decisions. As utilities face a more competitive environment, investors will carefully evaluate how utility returns compare with those of unregulated enterprises. The comparable earnings analysis produced a return on equity[15] range of 14.0-14.5 percent. These expected returns on equity of comparable-risk investment alternatives would certainly be taken into account by investors in forming their return requirements for a utility. As discussed above, it is difficult to ascertain with clarity at the current time what the prospects of the utility industry will be in the future. However, the use of rates of return of companies of comparable risk across a diversity of industries provides an important benchmark as to the return to be allowed in this proceeding.

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[15] As indicated above, the reported range reflects returns on year-end shareholders equity (including preferred equity); returns on average common equity would be somewhat higher.

Below, I present a summary of the results I discussed above:

Cost of Equity Method	Range
1. DCF	10.00 - 10.75%
2. CAPM	10.75 - 11.50
3. Risk Premium	10.8 - 10.9
4. Comparable Earnings	14.0 - 14.5

Determination of the cost of equity requires inferences regarding investor expectations and requirements, which are not directly observable. Each of the above methods approaches the estimation of the cost of equity from a different perspective—which I believe to be a strength of this four-method approach.

Q. Are there any other factors to consider in reaching a recommendation about the return on equity to be allowed to CECONY in this proceeding?

A. Yes, there are two—issuance costs and the three-year stayout the Company is proposing. I will address each of these factors, in turn, below.

Q. Can you explain why a cost of issuance adjustment is necessary for a utility in general?

A. Regulated utilities are allowed to collect in rates sufficient funds to pay all their operating expenses plus a return to compensate the capital invested in the business. The costs of issuing new common stock, including fees and discounts provided to underwriters, printing, attorney's fees, etc., are often referred to, ensemble, as issuance costs, or flotation costs. These costs are incurred in running a company's business, just as would be expenses for labor or utility plant. Because issuance

costs are a legitimate business expense of a company, that company deserves the opportunity to recover such costs. The cost of equity, before consideration of issuance costs, represents the rate of return that investors require on an investment in the common stock of a company. When a company attracts common equity capital by the sale of shares of stock, the companies' earnings on the proceeds of the sale should be at least equal to the return that investors require. It is therefore necessary to provide a cost of issuance adjustment to the investors' required return in order to give the company in question a reasonable opportunity to earn the return that investors require.

Q. Why is a cost of issuance adjustment necessary for CECONY, in particular?

A. In May 2003, CECONY's parent, Consolidated Edison, Inc., had a large common stock offering, the proceeds of which were infused into CECONY.[16] The DCF formulation can be employed in order to determine the size of the increment to the investors required return that is necessary in order to recognize an issuance cost adjustment. By applying this adjustment, we are converting the dividend-price ratio to a dividend-net proceeds ratio. The adjustment to the investor required return can be determined as follows:

[16] Consolidated Edison, Inc. will also be issuing new shares of common stock over the next several years through its various stock option, DRIP, DISCOP and other stock purchase plans. (Note that under the DISCOP plan, shares are purchased at an 11 percent discount.)

$$k^* = \frac{D}{P}\left\langle \frac{1}{(1-f)} - 1 \right\rangle$$

where:

k^* = issuance cost adjustment to required return

$\frac{D}{P}$ = dividend yield

f = level of issuance costs

Issuance costs for the recent Consolidated Edison stock offering were about 2.8 percent.[17] Using Consolidated Edison's dividend yield of 5.5 percent and issuance costs of 2.8 percent, the issuance cost adjustment is 16 basis points:

$$k^* = .055\left\langle \frac{1}{(1-.028)} - 1 \right\rangle$$

$$k^* = 0.0016 \quad \text{or} \quad 0.16\%$$

Thus, an increment to the investor required return of 16 basis points to account for issuance costs is appropriate in this proceeding.

Q. Would you now discuss the implications for the allowed return on equity of a stayout for CECONY?

A. The Company has informed me that it will be proposing a three-year rate plan. This exposes CECONY to the risk that the cost of equity may go up during the course of the rate plan, without the Company having an opportunity to reset the allowed return to reflect such an increase. Interest rates currently are lower than they have been in many years. It seems likely that upward changes in interest rates

[17] The Company has informed me that these issuance costs were unusually low due to the current market conditions and the Company's aggressive pursuit of cost savings; the level of issuance costs in the future may well be higher.

may be more likely than downward changes. (For example, there is not much downside room to the Federal funds rate—currently about at the 1 percent level—that the Federal Reserve uses to implement its monetary policy.) Goldman Sachs in an October 16, 2003 writeup concerning Consolidated Edison, Inc. noted that the company was increasingly sensitive to a potential rise in Treasury yields.

In the past, the Commission has used the differential between 3-year and 1-year Treasury securities to provide guidance as to what the "stayout premium" in such circumstances should be.[18] For the six months ended September 2003—the pricing period used in my cost of equity analyses—the differential between 3-year and 1-year Treasury securities was 80 basis points. The differential averaged over 1 year and 5 years was 78 basis points and 56 basis points, respectively.

Q. Based on your discussion and analyses, what return do you recommend for the Company?

A. Based on the cost of equity analyses presented above and considering the issuance cost adjustment and the prospect of a 3-year "stayout," I recommend that CECONY be allowed a return on equity of not less than 12.0 percent.

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[18] Note that this differential only reflects the "financial" risk aspect of a stayout—the risk that the cost of capital in general in the economy might rise in the next few years. It does not account for the "business" risk aspect of a stayout. As indicated earlier, there is more unpredictability today regarding unanticipated events that can have major impacts on a utility's service and/or revenues and its need for additional capital. Investors likely require more of a risk premium today, than in the past, as compensation for exposure to this greater unpredictability in a stayout context.

IV. THE APPROPRIATE COMMON EQUITY RATIO

Q. How important is CECONY's common equity ratio to its financial condition?

A. Having a strong common equity ratio is extremely important for the investment community's assessment of CECONY's financial strength. In a writeup concerning CECONY dated June 3, 2003, S&P stated that:

> Historically, the New York Public Service Commission (PSC) has supported a healthy financial profile, and **this support is a key underpinning for the utility's strong ratings.** [Emphasis added.]

S&P noted that it had downrated CECONY in May 2003 due in part to: (1) a weakening of financial ratios and (2) S&P's decision to have a larger adjustment related to the debt equivalents associated with purchased power agreements. (The per books debt ratio is adjusted upward by more than 2 percentage points to account for the added risk of purchased power contracts.) S&P further stated in its analysis that:

> The utility's financial profile remains weak for the revised ratings, but Standard & Poor's expects the company to bring debt levels back in line by 2005 through equity issuances and regulatory rate relief.

Note that S&P wrote this assessment **after** the Consolidated Edison, Inc. stock issuance in May 2003.

Moody's, in a review of CECONY on September 15, 2003 echoed these sentiments. Moody's noted that:

> Con Ed's A1 senior unsecured debt rating reflects its solid earnings performance and sound balance sheet. These have consistently been supported by conservative financial practices and constructive rate treatment....

Moody's specifically indicated that a downrating could result if there was:

> A shift toward less conservative financing strategies and/or less improvement in cash flow and coverage ratios than currently expected in the next couple of years.

From the above rating agency commentary, it is clear that the level of the common equity ratio is crucial to CECONY's bond rating. The rating agencies have indicated that they expect improvement in CECONY's financial ratios over the next several years and that a decline in the ratios could possibly lead to a bond downrating.

Q. What capital structure is CECONY requesting in this proceeding?

A. The Company is requesting an average capital structure for September 30, 2005 as shown below:

	Ratio
Long-Term Debt	47.16 %
Preferred Stock	1.75
Customer Deposits	1.76
Common Equity	49.33

Q. Do you believe that this is a reasonable capital structure to be employed in this proceeding?

A. Yes, I do.

Q. Can you explain why this capital structure is appropriate?

A. It reflects the actual ratios of capital being employed to serve the customers of CECONY. It is not a target nor a hypothetical capital structure, but, instead, reflects the proportions of the actual capital being used in CECONY's business. Furthermore, this capital structure is reasonable when compared to the capital structure of other utilities. Below I show the median capital structure ratios for the

electric utilities followed by Value Line for 2004 and 2006-2008, which I, hereinafter, for ease of discussion, will label as being "2007":

	Median Electric Utility Industry Capital Structure Per Value Line			
	All Companies		Excluding Companies with Utility Subsidiaries Below Investment Grade	
	2004	2007	2004	2007
Long-Term Debt	54%	49%	53%	48%
Preferred Stock	2	2	2	2
Common Equity	45	49	46	50

Note: Figures may not add due to rounding.

Earlier in this testimony, I employed a proxy group of utilities in order to estimate the cost of common equity for CECONY. The projected Value Line capital structure for these companies for 2004 and 2007 is shown on Schedule 4 of my exhibit and the median capital structure ratios for this proxy group are summarized below:

	Median Proxy Group Capital Structure Per Value Line	
	2004	2007
Long-Term Debt	50%	47%
Preferred Stock	2	2
Common Equity	47	52

Note: Figures may not add due to rounding.

As can be seen from the above figures, the proxy group projected common equity ratios are consistent with the average common equity ratio of 49.3 percent for CECONY for September 30, 2005.

On Schedule 5 of my exhibit, I show the 2002 common equity ratios[19] for the utility subsidiaries of the proxy group companies I employ in my cost of equity analysis. The median 2002 common equity ratio for these companies is about 51 percent.

Q. What is your conclusion as to the reasonableness of CECONY's requested common equity ratio in this proceeding?

A. Based on the above analysis and discussion, I conclude that the 49.3 percent common equity ratio requested by CECONY in this proceeding is reasonable. The requested equity ratio reflects the Company's actual common equity ratio and that equity ratio is in line with industry, proxy group and subsidiary utility companies and thus is appropriate to use in this proceeding. (Recall that when the debt equivalents of purchased power contracts are considered, rating agencies regard CECONY's common equity ratio as being lower than the per books level.) Furthermore, the bond rating agency commentary that I noted earlier indicates that the rating agencies expect CECONY to improve on the common equity ratio level extant in 2003 and that a weakening of the equity ratio could have adverse bond rating consequences.

Q. Does this conclude your testimony?

A. Yes, it does.

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[19] I have excluded securitization debt from total capital in these figures.

EDUCATION AND EMPLOYMENT BACKGROUND OF ROBERT G. ROSENBERG

Education

I have a Bachelor of Arts degree in Political Science, with a minor in Economics, from Hunter College. I received a Master of Business Administration degree with a major in Finance at the New York University Graduate School of Business Administration.

Employment

From 1969 through mid-March 1983, I was employed by the firm of National Economic Research Associates (NERA), reaching the position of Senior Economic Analyst. In March of 1983, I became a principal of Benrose Economic Consultants, Inc., a consulting firm in New York City. In April 2000, I became a principal of Edgewood Consulting, Inc., a firm located in the Capital District area of New York. Edgewood Consulting performs economic research and consulting services for companies, law firms, government agencies and trade associations. Throughout this period, I have concentrated on the analysis of regulated industries, including electric and gas utilities, insurance and steamship companies. I have prepared direct and rebuttal testimony related to financial aspects of utility rate proceedings--e.g., cost of common equity, capital structure, etc. Along with these "typical" rate case issues, I have also testified regarding more unusual matters: intra-company royalty payments; the correct procedure to use in calculating the cost of debt; whether a cogeneration

project met Qualifying Facility ownership standards; and responsibility for stranded costs.

I have had numerous assignments involving evaluation, consultation and/or internal reports to clients. Examples of this include: (1) analyzing issues relating to industry restructuring (e.g., implications of Commission-ordered divestiture, the risks associated with the institution of incentive plans, unbundling electric rates, etc.); (2) consulting with a utility company concerning the financial and regulatory aspects of a potential merger and the possible regulatory treatment of an acquisition premium; (3) evaluating the feasibility of instituting an administrative securitization proposal; (4) determining incremental risks flowing from purchased power contracts; and (5) analyzing studies regarding property values near transmission lines.

Outside the regulatory arena, I have estimated financial damages related to (1) breach of contract and (2) earnings losses as a result of injuries. I have also examined stock prices to see if alleged manipulation was likely and have performed economic valuation for employee stock option plan purposes.

I have presented lectures at the Pace University Center for International Business Studies regarding the regulatory process. A number of articles that I authored have been published in *Public Utilities Fortnightly* (PUF).

Appearances Before Regulatory Agencies

I have presented testimony before the Federal Energy Regulatory Commission and the regulatory agencies in the following states: Arizona, Kentucky, Massachusetts, Minnesota, Mississippi, New Hampshire, New Jersey, New York, Pennsylvania, Rhode

Island, South Dakota and Vermont. These testimonies were presented on behalf of: Blackstone Valley Electric Company, Boston Edison Company, Central Hudson Gas & Electric Corporation, Citizens Communications Company, Consolidated Edison Company, Kentucky Utilities Company, Long Island Lighting Company, Louisville Gas and Electric Company, Minnesota Power & Light Company, Mississippi Power Company, New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation, Northern States Power, Orange & Rockland Utilities, Pacific Gas & Electric Company, Pike County Light & Power Company, Public Service Company of New Hampshire, Public Service Company of New Mexico, Rochester Gas & Electric Corporation and Rockland Electric Company. In addition, I have testified before: the Society of Maritime Arbitrators concerning the estimation of damages in the matter of Empresa Publica de Abastecimento de Cereais (an agency of the Government of Portugal) vs. Point Endeavor Corporation and Tradigrain, Inc.; U.S. Bankruptcy Court regarding financing for an office building in Chapter 11; and the Federal Maritime Commission regarding the fair return for Matson Navigation Company.

WHY THE ARITHMETIC, RATHER THAN THE GEOMETRIC, MEAN SHOULD BE USED IN ESTIMATING EXPECTED FUTURE RETURNS

It has been suggested that in using the Ibbotson historic rate of return data as a proxy for the expected future return, one should employ the geometric mean of the data, rather than the arithmetic mean. I will demonstrate why that contention is incorrect. The only appropriate historic average to use in forecasting expected returns for the future is the arithmetic mean. It is incorrect to use the geometric mean and the use of the geometric mean results in an understated expected future return, as will be demonstrated below.

Before beginning the discussion on this issue, it is perhaps helpful to review the basic definition of the return on an investment that an investor expects (requires). The expected (required) rate of return is the discount rate that equates the future cash flows that an investor expects to receive from an investment with the initial value (i.e., the present value) of that investment. Keeping that basic definition in mind, I will now explain why the arithmetic mean of historic return data is appropriate to use in trying to forecast the expected return in the future.

In examining complicated issues, economists often simplify the actual very complex data or situation of the real world so that the issue in question is more easily examined in the simplified context. I will do so in my discussion below, but note that the principles hold even in the more complex situation of the real world. Let us assume that over a past period, an investment earned a rate of return of either 15 percent or 5 percent, with equal probability. Thus, if we examined an historic period of, say, 100 years, we would expect to find that 50 of those years experienced a 15 percent return,

while the remaining 50 years experienced a 5 percent return. Since the two possible returns in this simplified hypothetical example have the same probability, the arithmetic average of these two possible returns would be 10 percent. Having established that the arithmetic average of past returns for the series described is 10 percent, we will now examine whether it is appropriate to use that return as a proxy for expected future returns.

On Attachment 1, I show a hypothetical example of future possible investment outcomes if we assume that the distribution of possible returns from the past continues on into the future--i.e., that the only two possible returns are 15 percent or 5 percent, each with a 50 percent probability. In Column (1) of Attachment 1, I show the two possible returns that can be expected to occur in the future, given that these were the only two returns that occurred in the past in our hypothetical example. In Column (2) of Attachment 1, I show that the initial amount invested is assumed to be $1.00. In Column (3) I show that at the end of Year 1 an investor could either end up with $1.15 if the 15 percent return outcome happens or $1.05 if the 5 percent return possibility happens. Since the $1.15 outcome and the $1.05 outcome are equally likely to happen under the hypothesized circumstances, the average possible result (known in financial parlance as the expected value) of this investment at the end of Year 1 is $1.10--the average of the two possible outcomes that have equal probability. This expected value of the investment of $1.10 is shown near the bottom of Column (3) of Attachment 1. If the expected value of this investment at the end of Year 1 is $1.10 and $1.00 had been invested in Year 0, then clearly the discount factor that equates the expected cash flow

at the end of Year 1, should the security be sold, to the value of the initial investment is 1.10 or 10 percent.

Now let us see what are the possible investment outcomes for Year 2 under the hypothesized circumstances. The possible outcomes are shown in Column (4) of Attachment 1 and are explained below. If the investment earns $1.15 in Year 1 and again, fortunately, earns a 15 percent return in Year 2, then the value of the investment would be $1.3225 at the end of Year 2 ($1.15 x 1.15 = $1.3225). Another possible outcome would be if the investment earns $1.15 in Year 1 but only earns a 5 percent return in Year 2. This would produce a value at the end of Year 2 of $1.2075 ($1.15 x 1.05 = $1.2075). I will now explain how the third number in Column (4) is derived. If the investment in question earns a 5 percent return in Year 1, but then earns a 15 percent return in Year 2, then the expected value of the investment at the end of Year 2 would be $1.2075 ($1.05 x 1.15 = $1.2075). The fourth possibility in Year 2 is if the investment, unfortunately, only reaches the $1.05 level at the end of Year 1 and in Year 2 again only experiences a 5 percent return. This would produce the fourth outcome in Column (4), namely $1.1025 ($1.05 x 1.05 = $1.1025).

I have thus explained how one obtains the four possible outcomes at the end of Year 2, as shown in Column (4) of Attachment 1. Given that each of these outcomes has the same probability (because in any given year there is an equal probability of experiencing either a 15 percent return, or a 5 percent return), if we add up the four possible returns and divide by 4, we obtain the expected value of the investment of $1.21. Thus, even though there are several possible outcomes in Year 2, the expected value of this investment at the end of Year 2 is $1.21 under the circumstances

hypothesized. If the investor expects to be able to sell the investment at the end of Year 2 with a value of $1.21, then the discount rate that equates the expected receipt of $1.21 at the end of Year 2 with the initial investment of $1.00 in Year 0 is 10 percent ($1.21/[(1.10)^2]=$1.00). Thus, again, as in Year 1, in Year 2 we find that the discount rate, or expected return, on this investment is 10 percent. This means that if an investor invested $1.00 in Year 0 and expected the return possibilities shown on Attachment 1, that the investor would expect to earn a 10 percent return on his or her investment in either Year 1 or in Year 2.

The data shown for Years 3 and 4, in Columns (5) and (6) on Attachment 1, are derived in a similar manner. I will briefly discuss the data for Year 3 to provide continuity for this explanation. There are eight possible outcomes in Year 3, each with the same probability. Thus, if we sum up the eight possible investment outcomes for Year 3 and divide by 8, we have the average possible outcome or the expected value of the investment at the end of Year 3. As shown in Column (5) on Attachment 1, the expected value of the investment at the end of Year 3 is $1.331. Thus, if an investor invested $1.00 in Year 0 and could expect to sell his investment at the end of Year 3 for $1.331, the expected return on that investment would be 10 percent. The data shown for Year 4, in Column (6) of Attachment 1, are derived in a similar manner and again it is indicated that were the investor to sell his investment at the end of Year 4, he would expect to earn a 10 percent return on the investment. This hypothetical example could be extended out further in time, but the calculations would obviously become very cumbersome. The point holds for future years, but the data for Years 1 through 4 will be used for illustrative purposes in the remainder of this discussion.

The hypothetical example shown on Attachment 1 has demonstrated that under the hypothesized circumstances, in each and every year in the future, investors will expect to earn a return of 10 percent. It is important to note that this 10 percent return that we have calculated that investors could expect in each of the years examined is the same return as the arithmetic average of the two possible return outcomes specified in the hypothetical example, namely 15 percent and 5 percent. Thus, if investors noted that historic return experience was either 5 or 15 percent, with an arithmetic average of 10 percent, and they used this arithmetic average of past returns as a projected return for the future, their projections would exactly match the expected return (or discount rate), derived in the hypothetical example on Attachment 1. Put simply, this demonstrates that the arithmetic average of past rates of return is the appropriate average to use in forecasting expected future returns, assuming that past conditions will continue on into the future.

Now let us leave the discussion of the arithmetic mean briefly in order to discuss the geometric mean. The geometric mean of two returns is calculated as follows:

$$\sqrt{(1 + r_1) \times (1 + r_2)} - 1$$

where r_1 and r_2 are the two returns in question and are expressed in decimal form.

Given that in the prior hypothetical example the only two possible returns were 15 percent or 5 percent, the geometric average of those returns would be calculated as follows:

$$\sqrt{(1 + .15) \times (1 + .05)} - 1 = .0989 \text{ or } 9.89\%$$

As can be noted above, the geometric mean rate of return for the hypothetical investment we have been discussing is 9.89 percent--less than the 10.00 percent arithmetic mean. From the calculations on Attachment 1, we have shown that if an investor invested $1.00 at Year 0 in our hypothetical investment, they could expect to have the following values of their investment for each of the years specified:

Initial Investment in Year 0	Expected Value of Investment			
	Year 1	Year 2	Year 3	Year 4
$1.00	$1.10	$1.21	$1.331	$1.4641

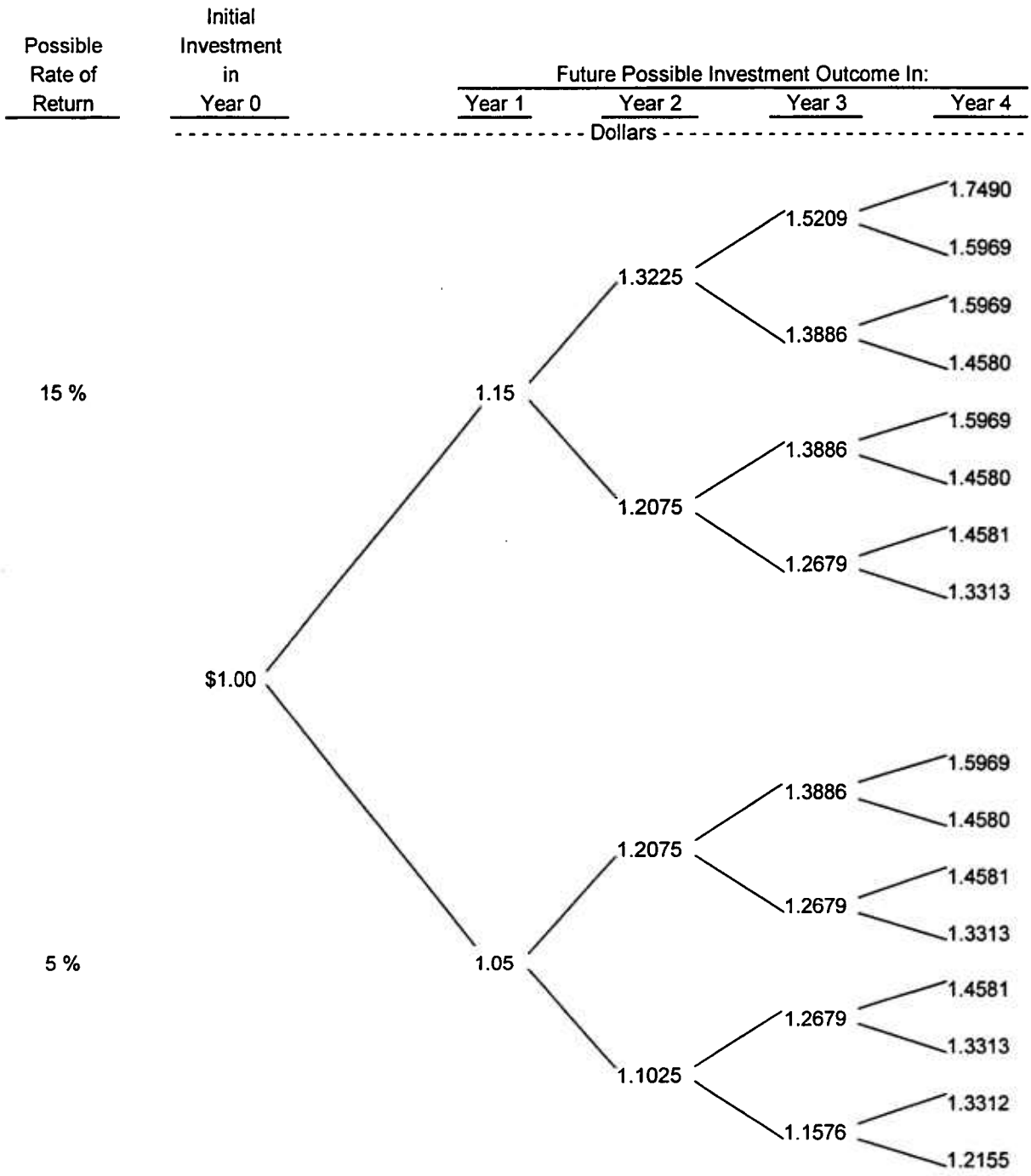
As noted previously, these expected values of the investment in each year could also be obtained by taking the arithmetic average of historic results (10 percent) and assuming that the investor expects to earn the arithmetic return in each year in the future.

Now let us assume that an investor mistakenly took the 9.89 percent geometric mean from the historic return series and used that to project the returns earned in the future. If an investor invested $1.00 in Year 0 and expected that he or she would only earn the 9.89 percent geometric mean, then using the geometric mean as a predictor would produce the following data:

Initial Investment in Year 0	Value Produced by Forecasting with Geometric Mean			
	Year 1	Year 2	Year 3	Year 4
$1.00	$1.0989	$1.2076	$1.3270	$1.4582

Note that the values produced above when one uses the geometric mean to forecast future investment outcomes are lower in each and every year than the actual expected value of the investment that was derived on Attachment 1. This means that the geometric mean will produce an understated prediction of the returns that investors expect in the future. As has been demonstrated throughout this discussion, the arithmetic mean of historic rate of return data produces the rate of return that investors expect in the future, assuming that future conditions parallel that of the past. In contrast, use of the geometric mean to forecast future rates of return based on past results will result in an understatement of the forecasted rate of return for the future.

HYPOTHETICAL EXAMPLE OF FUTURE
POSSIBLE INVESTMENT OUTCOMES



Expected Value of Investment		$1.10	$1.2100	$1.3310	$1.4641
Discount Factor		1.10	$(1.10)^2$	$(1.10)^3$	$(1.10)^4$

Q. Please state your name.

A. My name is Steven M. Fetter.

Q. Please state your current occupation.

A. I am President of Regulation UnFettered, an energy advisory firm I started in April 2002.

Q. Briefly describe your educational background.

A. I graduated with high honors from the University of Michigan in 1974 and received an A.B. degree in Communications. I graduated from the University of Michigan Law School with a J.D. in 1979.

Q. Please summarize your professional background.

A. I formed Regulation UnFettered to use the financial, regulatory, legislative and legal expertise that I gained through my work as a utility credit analyst and utility regulator to aid the deliberations of regulators, legislative bodies and the courts, and to assist in the evaluation of regulatory issues. My clients include electric and gas utilities, a non-utility energy supplier, an international consulting firm, an international financial services firm, and investors.

Prior to founding Regulation UnFettered, I was employed for eight-and-a-half years by Fitch, Inc. (Fitch), a credit rating agency based in New York and London. Prior to Fitch, I served on the Michigan Public Service Commission for six years, both as Chairman and as a Commissioner.

Q. Please describe Fitch.

A. Fitch is the third largest full service credit rating agency in the United States and the largest European rating agency. It is one of four Nationally Recognized Statistical Rating Organizations recognized by the U.S. Securities and Exchange Commission, and it also is recognized by the U.S. Department of Labor, state bank and thrift regulators, and the National Association of Insurance Commissioners. Fitch performs credit ratings of corporate obligations, asset-backed transactions, and government and municipal debt. Bond ratings represent Fitch's independent judgment based upon financial data provided by the bond issuer as well as additional quantitative and qualitative information gathered from third-party sources.

Q. Please describe your duties while at Fitch.

A. I was employed by Fitch from October 1993 until April 2002. After a little more than a year of regulatory analysis, in July 1995, Fitch promoted me to Manager of the Global Power Group in New York. In July 1998, I was promoted to Managing Director of the group. After the merger between Fitch and Duff & Phelps in 2000, my managerial responsibilities expanded to cover analysts in both New York and Chicago. I was serving in this position when I resigned in April 2002. Fitch retained me as an advisor shortly after I resigned.

At the time I was hired, Fitch intended to supplement the traditional quantitative analysis that went into the firm's credit ratings with a new emphasis on qualitative analysis. They sought my assistance on the regulatory, legislative

and political credit rating factors that would accompany U.S. movement toward a less regulated, more competitive utility environment, and I guided the Global Power Group in incorporating these issues into individual utility credit profiles.

Six months after I started with Fitch, the California Public Utilities Commission issued their electric utility restructuring proposal and analysis of the impact of competition on credit ratings became a major issue of concern at Fitch and its competitors, Standard & Poor's (S&P) and Moody's Investors Service (Moody's). As other states followed with their own deregulation plans – most notably, Pennsylvania, the New England states, Illinois, New York and Texas – regulatory analysis became a key component in the review of every utility's credit rating. Within regions with absolutely no movement on deregulation – primarily the Southeast U.S. – the lack of activity was factored into utility credit profiles as an indication of near-term stability.

Q. Please describe your experience on the Michigan Public Service Commission.

A. I served for six years on the three-member Michigan Public Service Commission (MPSC), the agency in Michigan that has regulatory responsibilities similar to those of the New York Public Service Commission (NYPSC). I was appointed as a Commissioner to the MPSC in October 1987 by Democratic Governor James Blanchard. In January 1991, I was promoted to Chairman by incoming Republican Governor John Engler, who reappointed me in July 1993. The MPSC was responsible for regulating Michigan's public utilities, telecommunications

services and intrastate trucking, and was responsible for establishing an effective state energy policy. During my tenure as Chairman, the MPSC eliminated the agency's case backlog for the first time in 23 years.

Q. Have you been engaged in any other professional endeavors relevant to your testimony?

A. During my time on the MPSC, I served as Chairman of the Board of Directors of the National Regulatory Research Institute (NRRI) at Ohio State University, the regulatory research arm of the state public utility commissions. I currently serve on the Keystone Energy Board, having previously participated in the Keystone Center Dialogues on Financial Markets and Energy Trading and on Regional Transmission Organizations.

Last year, I was appointed by the President of the National Association of Regulatory Utility Commissioners (NARUC) to serve as a public member of the NRRI Board – the 20-member board includes ten state public utility commissioners. In February 2002, I was appointed to the Board of Directors of CH Energy Group, Inc. (CHG), the parent company of Central Hudson Gas & Electric Co. in Poughkeepsie, New York. I currently serve as Chairman of the CHG Audit Committee and member of the Executive, Governance and Nominating, and Compensation Committees.

I also have served as an adjunct professor of legislation at American University's Washington College of Law. In addition, I have been a member of

the following organizations: the NARUC Executive, Natural Gas, and International Relations Committees; the Steering Committee of the U.S. Environmental Protection Agency/State of Michigan Relative Risk Analysis Project; the Federal Energy Regulatory Commission Task Force on Natural Gas Deliverability; and the International Advisory Council of Eisenhower Fellowships. In 1991, I traveled to Japan as an Eisenhower Fellow to study the Japanese utility structure, and, in 1992, I was a NARUC Fellow at the Kennedy School of Government.

Finally, I have served as Assistant Legal Counsel to Michigan Governor William Milliken, legal counsel to the Michigan Senate and Michigan Senate Majority General Counsel.

Q. Have you previously sponsored testimony before regulatory or legislative bodies?

A. Since 1990, I have on numerous occasions testified before the U.S. Senate, the U.S. House of Representatives, and various state legislative and regulatory bodies on the subjects of credit risk within the utility sector, electric utility restructuring, utility securitization bonds, and nuclear energy. In April 1995, I made a presentation in New York City in the NYPSC Competitive Opportunities Proceeding.

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

A. In this testimony, I offer my opinion, based upon my prior experience as head of the utility ratings practice at a major credit rating agency and chairman of a state

public utility commission, as to what comprises fair and economically prudent regulation in today's evolving electric utility industry. As part of my analysis, I discuss the impact on utility credit profiles resulting from the crisis that began in the utility sector in California and then spread to Enron and other participants in the wholesale electricity market. Based upon that analysis, I explain why I believe that utilities operating within today's more volatile financial environment and their regulatory authorities should seek to minimize the uncertainties that could affect a utility's financial profile and thus its credit ratings.

I then relate this financial market instability to Consolidated Edison Company of New York, Inc.'s (Con Edison or the Company) strong credit profile and credit ratings and their importance in allowing the Company to readily access the debt market on its own and the equity market through its parent company, Consolidated Edison, Inc. (CEI). I then offer cautions about how a NYPSC order in this proceeding that is not viewed as fully supportive could adversely affect that capital market access as well as potentially interfere with Con Edison's ability to respond to its major urban infrastructure challenges and ensure terrorism preparedness and potential emergency response.

I then discuss various risk factors that provide further support for both the use of the Company's actual capital structure as well as the setting of the Company's return on equity ("ROE") at the higher end of the range of the various approaches discussed by Mr. Rosenberg in his testimony.

I conclude by discussing Con Edison's key financial factors: (1) the appropriateness of Con Edison's capital structure, considered in light of the utility sector; and (2) the Company's weakening cash flow measures that indicate that, in the absence of regulatory rate relief, Con Edison's current credit ratings will be in jeopardy of being downgraded, leading to increased capital costs and higher customer rates.

Q. What are Con Edison's current credit ratings?

A. Con Edison currently has high-quality investment-grade ratings from the three major credit rating agencies. S&P maintains corporate and senior unsecured ratings of 'A' on Con Edison with a Stable outlook. Moody's has 'A1' issuer and senior unsecured ratings for Con Edison with a Negative outlook.[1] Fitch rates Con Edison's senior unsecured debt at 'A+' with a Stable outlook.

Q. Would you describe the credit ratings process?

A. Credit ratings reflect a credit rating agency's independent judgment of the general creditworthiness of an obligor or the creditworthiness of a specific debt instrument. Determinations are made through a committee process involving individuals with knowledge of the company, industry and regulatory environment. Rating designations of both Fitch and S&P have 'BBB-' as the lowest investment-grade rating and 'BB+' as the highest non-investment-grade rating. Comparable Moody's rating designations are 'Baa3' and 'Ba1,' respectively.

[1] Moody's' 'A1' rating is equivalent to an 'A+' rating on the S&P and Fitch rating scales.

Corporate ratings analysis considers both qualitative and quantitative factors to assess the financial and business risks of fixed-income issuers. A rating is an indication of an issuer's ability to service its debt, both principal and interest, on a timely basis. It also at times incorporates some consideration of ultimate recovery of investment in case of default or insolvency.

Prior to utility restructuring, the traditional credit rating process focused almost exclusively on quantitative factors. Since the early 1990s, however, all three rating agencies have elevated qualitative factors to almost equal status, with regulation leading the way in significance. These qualitative factors enter into a credit rating agency's analysis and determination of the appropriate credit rating to be assigned to a specific utility.

Q. Please describe these qualitative factors.

A. The most important qualitative factors include regulation, management and business strategy, and access to energy, gas and fuel supply with recovery of associated costs.

Q. Can you share your thoughts on the importance of regulation within the credit ratings process?

A. Yes. Regulation is a key factor in assessing the credit profile of a utility because a state public utility commission determines rate levels (recoverable expenses including depreciation and operations and maintenance, fuel cost recovery, and return on investment) and the terms and conditions of service.

Since the announcement of California's restructuring plan in 1994, regulation has become an even more important variable as the nature of a utility's responsibilities in providing energy services to customers has undergone dramatic change.

In some states, industry restructuring was the result of plans formulated by the state legislature. In other states, such as New York, the regulators, rather than the legislators, have determined the nature and pace of restructuring.

Under all of these plans, including New York's, utilities have been directed to foster the development of competitive alternatives to the services they provide, materially scale down their operations for certain functions, including divestiture of generation, while at the same time retaining what is commonly referred to as the provider of last resort ("POLR") responsibility. As the POLR, a utility, such as Con Edison, bears the ultimate responsibility to serve all of the customers in its service territory in the event of intermittent defaults or permanent failures by competitive suppliers to reliably discharge their responsibilities.

Although credit rating agencies factor the structure and manner of implementation of these plans into utility credit profiles, it is difficult at this point in the restructuring evolution to assess the full import of risks associated with POLR responsibilities, especially on a utility-specific or Con Edison-specific basis. Accordingly, as more experience is gained with the various restructuring frameworks around the U.S., I would expect rating agencies to supplement and/or

modify their current views with regard to the risks inherent in a utility's POLR responsibilities.

This situation thus affects utility investment decisions because, before major energy investors will be willing to put forward substantial sums of money, they will want to gain comfort that regulators understand the economic requirements and the financial and operational risks of a rapidly evolving industry and that their decision-making will be fair and will have a significant degree of predictability.

For these reasons, rating agencies look for the consistent application of sound economic regulatory principles by the commissions. If a regulatory body were to encourage a company to make investments based upon an expectation of the opportunity to earn a reasonable return, and then did not apply regulatory principles in a manner consistent with such expectations, investor interest in providing funds to such utility would decline, debt ratings would likely suffer and the utility's cost of capital would increase.

Thus, specific issues analyzed in an assessment of regulation include regulatory consistency with past commission policies and practices; regulatory independence or insulation from the political process; professionalism in the sense of the appointment of high-quality professionals with relevant backgrounds; the ability to fairly balance the competing interests of ratepayers and utility investors; sound economic decisions that recognize the necessity of new investments to

maintain quality infrastructure to enable the utility to maintain high quality, safe, and reliable service to its customers; regulatory policies that recognize that a financially-strong utility can better meet the risks and challenges of today's industry environment; and consideration of any jurisdictional division of authority between a state commission and the Federal Energy Regulatory Commission (FERC).

Q. Next, you mentioned management and business strategy. Please describe that factor.

A. An assessment of quality and depth of management personnel is made and consideration is given as to how a company's strategic plans and risk profile fit within its overall business and local regulatory environment, as well as how effective management is at implementing those plans. This includes consideration of management's ability to interact with regulators and executive and legislative branch officeholders in a way that allows the company to carry out its operations effectively and efficiently to the benefit of its key constituencies, including small and large customers and shareholders. Finally, in view of the volatile environment within the utility sector at this time, an assessment is made of the utility's capability to respond to extraordinary occurrences, including events outside management's control.

Q. And access to energy, gas and fuel supply with recovery of associated costs?

A. Access to secure and reasonably-priced sources of energy and gas is a key factor

for a utility. Although rating agencies attempt to evaluate utility plans for fulfilling the POLR role, uncertainty of the long-term nature of a utility's POLR responsibilities (as is the case in New York for both electric and gas utilities) and the use of the utility's credit to backstop other players, makes it difficult to fully appreciate the risks that utilities face, especially risks that may be unique to individual utilities because of the nature of their service territories.

Equally important are the extent to which the utility recovers its costs of fulfilling the POLR role, the mechanisms for timely recovery, and the level of confidence that investors have that the state commissions will stand behind the established recovery methodology, even under potentially difficult circumstances, such as market volatility and increasing prices.

Q. Now let's move to the quantitative factors used by the rating agencies. Please describe those factors.

A. Financial performance as measured by historical results and financial projections remains a very important element in credit rating analysis. Most significant within the rating agency review process is an assessment of a company's ability to generate cash, reflected in ratios that measure profitability and coverage on a cash flow basis. Credit rating agencies and fixed-income analysts ordinarily apply analytical ratios that reflect interest protection measures[2], cash flow measures[3],

[2] Interest protection measures include Earnings Before Interest and Taxes ["EBIT", also known as Pretax Income] / Interest Expense; and Earnings Before Interest, Taxes, Depreciation and Amortization ["EBITDA"] / Interest Expense.

and debt leverage[4] to understand the credit profile of a utility. These measures allow a credit rating agency to track over time a company's operations, competitive position and ability to secure funding for necessary purposes.

Q. What role, if any, do a utility's rates play in credit rating analysis?

A. Consideration of rate levels and their competitiveness is part of ratings analysis. An assessment is made of the adequacy of those rate levels to meet costs and provide a fair investor return. The return on equity granted through rates must be sufficient to generate the cash flow, along with other sources, to meet ratings criteria. This is particularly important for a company like Con Edison, which has relatively low cash flow from depreciation compared to the substantial size of its ongoing construction program. In addition, expected declines in deferred taxes will contribute to Con Edison's declining cash flow as well.

Q. Why is return on equity of consequence to investors in debt securities?

A. The existence of equity in a utility capital structure provides the company with the capacity to tolerate the normal ups and downs that come with operational business risks, while also providing a cushion to a company's lenders and bondholders (fixed-income investors). Fixed-income investors look to the

[3] Cash flow measures include Cash from Operations ["CFO", or at S&P, Funds from Operations or "FFO"](Before Interest Expense) / Interest Expense; Net Cash from Operations (after dividends)[also known as Internal Cash] / Capital Expenditures; and Cash from Operations (or FFO)/ Total Debt.

[4] Leverage ratios include Total Debt [Long-term and Short-term plus current maturities of long-term debt plus capitalized lease obligations] / Total Capital; and Total Debt / EBITDA. The rating agencies may adjust these ratios to reflect imputed debt and interest charges flowing from purchased power contracts and certain other off-balance sheet obligations.

earnings of shareholders as an additional margin available for the payment of interest and principal under adverse business circumstances. For example, a healthy return on equity is important to serve as a "buffer" in the event of extreme shocks, such as the impact of the September 11th attacks.

Q. Please continue.

A. An important ratio in analyses performed by fixed-income investors and credit rating agencies is the calculation of interest coverage (that is, income before or after income tax divided by total interest expense and fixed charges). Although fixed-income investors are entitled to receive only timely payments of interest and principal, the existence of income in excess of the bare minimum required to pay interest and principal is a hallmark of high-quality investment-grade debt.

A second benefit of earning a fair rate of return is that the company has favorable access to the capital markets and can raise additional money at reasonable rates in both the debt and equity markets. This provides financial flexibility, which reduces risk for fixed-income investors.

Q. What rating categories do you mean when you refer to "high-quality investment-grade debt"?

A. I am referring to long-term credit ratings in the 'A', 'AA', and 'AAA' rating categories. For example, the 'A' rating category includes 'A-', 'A', and 'A+.'

Q. In your opinion, do retail customers benefit from utility debt that has high-quality investment-grade credit ratings?

A. Yes, the benefit to customers is that a utility with debt of high-quality investment-grade status is able to easily raise debt capital, at a reasonable cost, when needed to fund infrastructure requirements necessary to meet growth in customer demand, and can refinance maturing (or callable) debt on more reasonable terms than a lower credit quality utility. This is especially true when volatility in the energy/utility sector (like we have experienced during the recent past) has tightened up liquidity within the debt market. Moreover, the ability to access the debt market when needed is important because if a company needs to expand or upgrade its generation, transmission or distribution infrastructure to maintain system reliability or undertake construction projects for environmental compliance, it is advantageous to balance debt funding with equity, as long as a strong equity ratio can be maintained.

Q. The S&P credit rating process utilizes, to a degree, publicly-stated analytical standards. Can you explain the S&P methodology?

A. As part of S&P's utility credit rating process, S&P arrives at a "Business Profile" designation that it considers in concert with S&P "Utility Financial Targets." S&P's Utility Financial Targets, which are quantitative ratios, differ depending upon a utility's Business Profile rating. The weaker the Business Profile designation, the stronger the Financial Targets must be to obtain an investment-grade rating. S&P published its Utility Financial Targets in June 1999 to assist analysts and investors in analyzing its credit rating methodology (Exhibit

_____(SMF -1). These targets remain valid today.

Q. What does S&P's Business Profile designation reflect?

A. The Business Profile designation reflects S&P's assessment of qualitative factors such as regulation, markets, operations, competitiveness, and management. This designation is on a scale of '1' (meaning very strong) to '10' (meaning very weak). Designations of 1 and 2 indicate "Well Above Average" business position; 3 and 4 indicate "Above Average"; 5 and 6 indicate "Average"; 7 and 8 indicate "Below Average"; and 9 and 10 indicate "Well Below Average."

Q. Generally, what Business Profiles apply to utilities?

A. Distribution and transmission companies usually have Business Profile ratings of '2' through '4.' Power generation and energy trading companies with significant commodity price risks usually have Business Profile ratings of '7' through '9.' Vertically-integrated utilities usually have Business Profile ratings in the middle of the scale, in the '4' to '6' range. Currently, S&P has Con Edison, a transmission and distribution company, rated a '3,' in the "Above Average" category.

Q. Why is S&P's methodology meaningful to you?

A. I believe that S&P's methodology helps facilitate a layperson's understanding of how a credit rating agency carries out the process of formulating a rating and the factors that go into a credit rating determination.

Q. Why are Con Edison's strong credit profile and high-quality investment-grade ratings important attributes within the current volatile utility environment?

A. The financial problems faced by California's utilities starting three years ago, the catastrophe surrounding Enron two years ago, and the financial turmoil experienced by most of the non-regulated and regulated energy companies during the recent past have altered the views of rating agencies and investors with regard to the utility sector. I was still at Fitch and involved in the policy-setting process when the firm stated its view in March 2002 that "[c]redit markets have become more volatile, as have the ratings of corporate bonds at all levels of the credit spectrum."[5] In 2000, Standard & Poor downgraded 65 utility holding companies and subsidiaries, versus 20 upgrades. The trend continued in 2001 with 81 downgrades and 29 upgrades, and in 2002 with 182 and 15, respectively. Year-to-date 2003 the numbers are 109 and 9, respectively.

Since that statement was made, the three major credit rating agencies have tightened up their credit oversight even more. Acceptable debt leverage percentages (total debt divided by total capitalization) are lower now than a couple of years ago, and the rating agencies have been more aggressive in sending signals to investors with regard to risks and uncertainties affecting a particular utility's credit profile. What would have previously resulted, at most, in a warning press release with no change in ratings outlook now can result in an

[5] "Comment on Market Volatility and Credit Ratings," FitchRatings press release, March 6, 2002.

outlook change or even issuance of a ratings watch. Indeed, issues that would have previously led to an outlook change or ratings watch today would more likely result in an immediate rating downgrade. Moreover, in some cases, most notably Pacific Gas and Electric Co. and Southern California Edison Co., there have been virtually unprecedented multiple-notch downgrades reflecting an explosion of increased risks and negative results that had never been contemplated. Other companies suffering such multiple-notch downgrades include Public Service Electric and Gas, Tampa Electric Co., Northern States Power and Baltimore Gas & Electric.

Moreover, it is important to emphasize that within the current volatile investment climate, it is far easier for a utility's ratings to slip down due to a financial "ding" than for that same utility to regain its earlier status once the deficiency has been remedied. For that reason, I do not believe that any weakening of Con Edison's credit profile now could, if the NYPSC changed its mind, be easily remedied in the Company's next proceeding. My advice to utility companies, investors and regulators alike is that nothing should be taken for granted in the current roiled investing environment.

Indeed, S&P recently reaffirmed its cautious view of the utility sector, stating that it "is not seeing much fundamental improvement in companies' financial condition...Basically, the strategy of borrowers and lenders appears to

be to ride out this difficult period and wait for the energy markets to improve."[6] Within this more volatile environment, any key issue or concern -- such as rate-setting policies that shake investor confidence -- will be closely scrutinized by investors and will influence their decision as to whether to invest their funds within a particular regulatory jurisdiction.

Q. Do you believe that the operations of transmission and distribution utilities, like Con Edison, entail very little risk within the utility sphere?

A. No, I do not. The two most jarring events to utility investors during the past several years – the California crisis and the Enron collapse – involved both regulated and non-regulated activities. The former – a state legislative/regulatory framework that called for capped retail rates notwithstanding exploding wholesale rates – resulted in the bankruptcy or near-bankruptcy of California's two largest *regulated* utilities, Pacific Gas & Electric Co. and Southern California Edison Co. The crisis had little to do with the non-regulated affiliates of these two companies. The electric market problems in California also crossed state lines and brought financial harm to "innocent" regulated investor-owned utilities in Nevada and self-regulated public power utilities in the Pacific Northwest.

On the other hand, the Enron collapse related almost solely to fraudulent behavior with regard to non-regulated activities. What these two situations tell me is that the turmoil within the utility sector is not appropriately described as a

[6] "US utilities' ratings erosion persists in Q3," S&P press release, October 16, 2003.

dichotomy between higher risk non-regulated activities and lower risk regulated activities. Rather, it is a contagion that has cut across the entire sector, affecting both non-regulated and regulated companies, especially those regulated utilities which, like Con Edison, have significant responsibilities with regard to procuring energy supply for their core customers. To the extent utilities have been dependent on the spot market for a significant part of that energy supply, the price volatility of the developing competitive wholesale markets has led some state regulators to defer or reduce full cost recovery of prudently-incurred purchased power costs.

Indeed, general concerns about a more volatile industry were reinforced by the blackout on August 14, 2003. Notwithstanding the substantial disaggregation of services (divestiture of power plants and provision of commodity by gas marketers and energy service companies), disruptions of utility service for whatever reason continue to be associated with the local transmission and distribution company. In addition to this continuing "headline risk", there now exists the expectation that substantial investment in transmission and distribution infrastructure will be required of regulated utilities during the foreseeable future in response to demands for increasingly higher reliability of service measures.

Q. How do you see these risk factors affecting utility credit ratings and bondholders in general?

A. I see negative utility industry occurrences as affecting not only credit ratings and

bondholders, but also having a significant impact on the first line of defense for a company's financial viability, the equity holder. The utility industry is very different than it was just three years ago when it entered this century with a heightened focus on Y2K risks and little concern about potential negative fallout from restructuring activities.

Prior to 2000, only three utilities had reorganized through Chapter 11 bankruptcy proceedings: El Paso Electric Co., Public Service Co. of New Hampshire, and Columbia Gas System/Columbia Gas Transmission – and a fourth, Tucson Electric Co., had restructured outside of bankruptcy. Restructuring missteps have already resulted in a greater number of post-2000 Chapter 11 filings: Pacific Gas and Electric Co., Enron Corp., PG&E National Energy Group, NRG, Mirant/Mirant Americas Generating Inc., Northwestern Corp., and Covanta Energy Corp. – and Southern California Edison can be added as a utility that has resolved its default status outside of bankruptcy.[7]

Accordingly, in view of the fact that regulatory and legislative restructuring policies, when coupled with a utility's provider of last resort responsibilities, could have a direct and negative effect on a utility's financial stability, investors will want to be compensated for those risks – debt holders through increased bond yields as credit ratings weaken, and equity holders through enhanced returns on equity in recognition of these additional stresses.

[7] "The Ripple Effect: Bankruptcies and Restructurings," Fitch Ratings 15th Annual Global Power Breakfast, at the Edison Electric Institute Financial Conference, Orlando, Florida, October 27, 2003.

Q, In addition to all of the risks that you have detailed above with regard to the utility industry in general and transmission and distribution utilities in particular, do Con Edison's investors have any special risks to be concerned about?

A. Con Edison faces many unique risks. The Company has been widely recognized for its outstanding service reliability. This excellent reliability is crucial in a dense urban environment that depends on electric, gas and steam not only for lighting, heating and air conditioning, but also for mass transit and water supply. To ensure that this reliability is maintained, the company must regularly raise funds from investors for expansion, strengthening, and modernization of its energy delivery infrastructure.

Of course, it goes without saying that my testimony's close focus on the importance of the capital markets in utility industry operations serves to highlight the negative repercussions that service disruptions can have on the financial markets, including their worldwide telecommunications and data operations. Thus, in order for Con Edison to be able to maintain these critical industries in the face of a myriad of infrastructure and even terrorist challenges, the bar is continually being set higher and higher to ensure continuity of service through investments in security and redundancy.

A particular risk that Con Edison faces in providing this highly reliable service is not only the density, but also the unusual concentration of its service area. An event that affects one part of its service area is far more likely than in

the case of other utilities to affect the entire service area. In addition to the potential for New York City to be a magnet for terrorist action, relatively small events occurring there can have a disproportionately greater impact on the city's economy and even the national economy. Finally, Con Edison's financial strength was crucial in allowing the Company to respond to the extraordinary post-September 11th aftermath in a timely and effective manner. Without such a sound financial footing, Con Edison would not have been able to mount such a formidable emergency response without significant risk to its financial standing and credit ratings. In light of today's high degree of focus on homeland security issues within the entire New York City Metropolitan region, I believe it would be a mistake for the NYPSC to lessen Con Edison's emergency preparedness by effectuating policies that would serve to weaken the Company's financial profile. Indeed, the impact of 9/11 not only meant that Con Edison faced incomparable challenges to rebuilding the energy infrastructure of Lower Manhattan, but the economic fallout for New York City was such that it had a very significant impact on the Company's revenues and earnings.

Q. Do you have any thoughts on Con Edison's capital structure?

A. Yes. I base my analysis on the testimony of Mr. Fitzmartin. I adjusted Mr. Fitzmartin's Exhibit 9 Schedule 1 to reflect the capital structure as viewed by rating agencies. I deleted Customer Deposits. I added short-term debt (an average of $182 million forecast for the Rate Year, 12 months ending September

30, 2005, based on discussions with the Company), and thereby derive the ratio of total book debt (short-and long-term) to capitalization of 48.79%. Con Edison's equity ratio (on a rating agency basis) for the Rate Year is 49.46% (See Exhibit __ (SMF-2)). However, when credit rating agencies evaluate a utility with long-term non-utility generator contracts, operating leases, and similar off-balance sheet obligations, they factor these items into its debt and coverage measurements. I have discussed the imputed debt (defined in accordance with Standard & Poor's methodology) with Company personnel. They estimate that the imputed debt (for the Rate Year) would be a little above $586 million. The imputed debt from these obligations raises the debt leverage ratio at the Company from 48.79% to 51.15%, with a corresponding drop in equity level to 47.18% (See Exhibit ___ (SMF-3)).

I believe that the Company's capital structure, including this equity ratio, is appropriate for its current ratings level and for the business risks that the Company faces, operating in what is unquestionably the most challenging infrastructure environment in the U.S. Furthermore, in view of the recent extreme volatility that has characterized the entire sector, I believe that, in general, utilities with strong credit profiles should be permitted, indeed encouraged, by regulators to maintain their sound financial status.

S&P has published Utility Financial Targets for each rating category (See Exhibit __ (SMF-1)). The midpoint debt ratio of S&P's Utility Financial Target

for an 'A'-rated utility with a Business Profile of 3 is 50.25%, offering support for my view that Con Edison's debt level (as adjusted for imputed debt) of 51.15% and equity level of 47.18% is within an appropriate range compared to the utility industry as a whole.

Of course, these ratios are based on forecasts, which by definition do not contemplate major unforeseen events such as new acts of terrorism or other unanticipated expenditures of capital funds. As an example, an unexpected need to spend an additional $400 million in capital would increase the debt ratio (as seen by S&P) by an additional 1.5%, to about 52.6% (See Exhibit __ (SMF-4)). My purpose in examining the capital structure in light of rating agency treatment is to emphasize that pro forma regulatory capital structures do not fully capture the current and potential impact on credit ratings.

My opinion is also based on my experience as a state regulator in Michigan. During my six years as both Chairman and Commissioner on the MPSC, two of the major electric and/or gas utilities within the state were facing financial distress and required financial support to help them return to financial health. The MPSC decided that such assistance served the overall public policy aims of the state and provided such aid. In those cases, the MPSC departed from its normal practice of utilizing actual equity levels in rate-setting and instead set rates based on a hypothetical *higher* equity percentage in order to assist the utilities to both return to financial health and, more importantly, be in a position to

provide reliable service to customers on into the future.

While it is possible that, in some circumstances, financial weaknesses in a non-regulated parent company or other subsidiaries could impact on the credit quality of a utility subsidiary, this is not the case for Con Edison's utility subsidiaries, as evidenced by the following statements by the rating agencies.:

> "Although parent company CEI is pursuing non-regulated business opportunities, most significantly in power generation in the Northeast, these will be funded conservatively, and they will continue to account for a small percentage of consolidated cash flows and capital commitments."
>
> --S&P Research on Consolidated Edison Co. of New York Inc., dated August 13, 2003.

> "For its non-regulated activities in the same five-year period [through 2007], the company has scaled down its projected investments significantly from last year's projected $1 billion, and capital expenditures are estimated to be approximately $225 million."
>
> --FitchRatings Credit Update on Consolidated Edison, Inc., dated September 12, 2003.

> "[CEI's unregulated] investments remain modest in size and collectively are currently making only modest contribution to consolidated earnings.

> We expect that CEI will carefully manage growth initiatives as spending in this area is being scaled back considerably from earlier levels."
>
> --Moody's Power and Energy Company Sourcebook, dated October 2003.

Q. Have the rating agencies highlighted any other potential areas of concern with regard to Con Edison's credit profile?

A. Yes. S&P, in its August 13, 2003 report on Con Edison, stated that "[t]he utility's financial profile remains weak for the rating...[and that S&P] expects the company to bring debt levels back in line by 2005 through equity issuances and regulatory rate relief." S&P focused on Con Edison's FFO (Funds From Operations) Interest Coverage as showing weakness that should be remedied; I would add another cash flow measure that points to near-term weakness: FFO/Total Debt, which at a current forecast of less than 20% (for the 12 months ending December 2003, as adjusted for imputed debt) is consistent with a rating of 'BBB+', two notches below Con Edison's current level. (See Exhibit __ (SMF-1)) I note that the Company has indicated to me that this financial weakness will be exacerbated after 2004 as the Company's "bonus" depreciation and deferred tax accounts are expected to decline substantially, further weakening the Company's key financial metrics.

It is therefore extremely important for Con Edison to improve its cash flow metrics in the next series of rate cases. Rates should be established so as to

improve cash flow as well as earnings.

Q. Does this conclude your testimony?

A. Yes, it does.

Q. Please state your name and business address.

A. My name is Charles D. Hutcheson. My business address is 4 Irving Place, New York, New York.

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

A. I am an employee of Consolidated Edison Company of New York, Inc. ("the Company" or "CECONY") and hold the position of Manager, Property Tax and Depreciation. My duties include responsibility for the property tax and depreciation functions for the regulated companies of Consolidated Edison, Inc.

Q. Please briefly outline your educational background and business experience.

A. I graduated from Hofstra University in May 1978 with the degree of Bachelor of Business Administration in Accounting. I have been employed by CECONY since January 2, 1979 and have held various positions of increasing responsibility within the Finance Department. My first assignment with CECONY was in the Depreciation Section. I spent my first 15 years of employment in that area rising to the position of Senior Accountant. In 1993, I moved to the Rates and Budget Section. In 1996, I transferred to the Financial Restructuring Team, where my duties were to assist on the development of CECONY's rate plan in the New York Public Service

Commission's Competitive Opportunities Proceeding. I moved to the Tax Department in 1997 to work as a Senior Tax Accountant in the Federal Tax Section. In September 1999, I was promoted to Manager, Property Taxes with responsibility for the property tax compliance function and the Company's efforts to hold down property taxes. In December 2001, I once again began working on depreciation matters when the Tax Department assumed responsibility for the book depreciation function for our regulated subsidiaries. My depreciation responsibilities include gathering the statistical data for and preparing plant mortality and net salvage studies and analyzing and interpreting the results of these studies.

Q. Are you a member of any professional societies?

A. Yes. I am a member of the Society of Depreciation Professionals. The group was formed to recognize the field of depreciation and those individuals contributing to the field. It also promotes the professional development of those practicing in the field of depreciation and serves as a forum to collect and exchange information and ideas related to depreciation. Membership is not restricted to the utility industry as the Society is represented by those in the fields of

government, education, and industry.

Q. Have you previously testified before any regulatory commission?

A. I have testified on the subject of depreciation in the Orange and Rockland Gas Case No. 02-G-1553 in New York and Rockland Electric Company Docket No. ER02100724 in New Jersey.

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

A. The purpose of my testimony is to present recommendations with respect to the annual book depreciation rates for the Company's Steam Plant. In addition, I will testify on the subject of property taxes including the Company's efforts to ensure that we pay no more than our fair share of property taxes.

DEPRECIATION

Q. What part does the average service life play in the determination of depreciation rates?

A. The estimated average service life is used in providing for the recovery of the original cost of plant over its useful life.

Q. What part does salvage play in the determination of depreciation rates?

A. In addition to providing for recovery of the original

cost of plant over its estimated average service life, the Company's annual depreciation rates include an estimated net salvage factor. The purpose of this estimated net salvage factor is to reflect, over the life of the plant, anticipated salvage less cost of removal upon retirement, in whole or on a piecemeal basis, of the assets included in each primary plant account.

Q. Have you reviewed the adequacy of the accumulated provision for depreciation per books and the factors that determine annual depreciation expense?

A. Yes, I have. The Company prepares annual studies of depreciation that test the accumulated provision for depreciation per books. The most recent study was based on plant mortality experience and historical net salvage studies for data through the year 2002.

Q. Based on these studies, are you recommending any changes to depreciation rates and life tables related to the Company's Steam Plant?

A. After a thorough review of the aforementioned annual studies of depreciation and other factors that may influence capital recovery, I have concluded that various changes to the Company's average service lives, net salvage factors, and life tables are required.

Q. Have you prepared an exhibit for this proceeding that summarizes your proposals?

A. Yes. I have prepared an exhibit titled "CONSOLIDATED EDISON COMPANY OF NEW YORK, INC., PROPOSED DEPRECIATION RATE CHANGES FOR STEAM PLANT AT DECEMBER 31, 2002".

MARK FOR IDENTIFICATION AS EXHIBIT __(CH-1)

The exhibit compares the annual provision for depreciation on a "book basis" and on a "proposed basis". Also on the exhibit is a comparison of the Accumulated Provision for Depreciation per Books at December 31, 2002 along with that reserve computed on a theoretical basis based on depreciation parameters currently in effect, and on the depreciation parameters I am proposing.

Q. Please generally describe the changes you propose affecting the average service lives of Steam plant.

A. For the reasons discussed later in my testimony, I have proposed to change the service lives of eight of the Company's primary plant accounts. Of these, seven reflect a change to a longer average service life.

Q. What is the effect on annual depreciation expense of a change to longer average service lives?

A. The depreciation expense accrual varies inversely with its underlying average service life. The longer the

service life the lower the annual depreciation rate and therefore the lower the annual depreciation expense.

Q. Concerning net salvage factors, please similarly describe your proposed changes.

A. For the reasons discussed later in my testimony, I have proposed to change six of the Company's primary plant accounts, all toward higher negative net salvage factors, which will have the effect of increasing the Company's annual depreciation expense.

Q. Please describe your changes to life tables.

A. Life tables or "h-curves" are survivor curves representing typical patterns of retirement dispersion. An h-curve, along with an average service life and a net salvage factor, is used to compute a theoretical reserve for depreciation. Changes to h-curves do not impact the annual depreciation expense accrual but they do affect Computed Reserves, as described herein, which are used to help determine whether the Company's depreciation reserve is adequate. I propose seven changes to h-curves to more adequately reflect observed retirement dispersion patterns. My proposal includes changes to four accounts reflecting lower h-values and three toward higher h values.

Q. What is the basis for the changes you have proposed in

this proceeding?

A. The proposed changes are based primarily on my review and analysis of the historical data comprising the Company's mortality and net salvage studies. These annual studies compute average service lives, h-curves, and net salvage percentages employing actuarial methods based on past experience. The data is organized into various groupings referred to as rolling or shrinking bands, which helps in the data analysis. In those instances where certain accounts do not have sufficient retirement results to produce statistically reliable mortality or net salvage data, I relied on existing depreciation parameters or on judgment. The changes I have noted above do not apply to the Boiler Plant Equipment Account (Account No. 9716) associated with the East River Repowering Project ("ERRP" or "the project") for the average service life and life table.

Q. What changes are you proposing for ERRP?

A. For all accounts other than the Boiler Plant Equipment Account (Account No. 9716), I propose to use the average service lives, net salvage factors, and life tables I have proposed in this case. In my discussions with our Steam Business Unit personnel, I have concluded that the equipment being installed at East River in connection

with the ERRP, other than the Boiler Plant Equipment, is similar in nature to other equipment the Company uses at its other facilities. I accordingly see no reason to believe that the future depreciation characteristics of that equipment will behave any differently from what has occurred in the past.

For the Boiler Plant Equipment, I propose the use of a 30-year average service life, and a life table of h 2.5. As discussed above, I am using the net salvage factor I have proposed for the non-ERRP related Boiler Plant Equipment for the ERRP Boiler Plant Equipment.

Q. Why do you propose to use different depreciation factors for the Boiler Plant Account equipment for ERRP?

A. I am proposing to depreciate the project assets in the Boiler Plant Account separately from the other equipment in the account because the major components of the project that will be accounted for in the Boiler Plant Account are unique compared to other steam equipment or property the Company currently owns. They are unique because the ERRP units primarily utilize waste heat from a Combustion Turbine Generator ("CTG") in combination with a Heat Recovery Steam Generator ("HRSG") to produce steam. Absent ERRP, the Company uses no other CTG/HRSG combination in its steam system. The process and

technology is much different from our existing production facilities. The process consists of firing fuel in the CTG, making electricity and exhausting the hot gases from this process into a HRSG to make steam. Supplemental duct firing is also used to increase steam production in the HRSG. The existing units on the system utilize burners with the intent of firing fuel in the burners to make steam. Although providing the same function as a field erected boiler, the HRSG's materials, designs, manufacturing, and construction make it unique when compared to other boilers on the system. The operating temperatures, pressures, and water chemistries have differences too. To include these assets with the other equipment in the account containing dissimilar equipment would not be appropriate for book depreciation purposes.

Q. How did you arrive at these depreciation parameters for ERRP's Boiler Plant Equipment?

A. Since the equipment represents the Company's initial investment in this type of facility and because of the absence of historical statistical experience for this type of plant, the selection of annual book depreciation rates and life tables should be based on industry surveys and informed judgment. I have spoken to Company

engineers and other Steam Business Unit personnel about how the plant will operate and its expected maintenance requirements. I have reviewed the conformance specification documents, which indicate that equipment shall be chosen for an expected useful life of 30 years. I have made a survey of other utilities that already have this type equipment to determine the service lives they have in use. I also took into consideration that the Company presently depreciates its gas turbine generators using a 25-year average service life. Although these gas turbines are not technologically similar to the ERRP equipment nor are nearly as large, I think the similarities are enough to consider their life in my selection process. After evaluating the survey responses, which included responses from 9 companies and resulted in a simple average of 29.5 years, and considering the other information I gathered as I described, I concluded that a 30-year life is appropriate at this time. For the life table, again in the absence of any historical statistical information, I have selected a dispersion curve at the mid-point of the h-curve spectrum.

Q. What are some of the other factors that influence selection of depreciation rates, and how did you address

them?

A. Obsolescence and technological innovations influence plant lives. To ascertain that influence, I spoke with Company personnel and physically visited plant sites to determine to what extent the experience of the recent past is representative of the plant currently on the system and indicative of current retirement and removal procedures and costs. I also discussed with operating personnel reasons for retirement and removal, particularly whether items were being retired due to obsolescence or technological reasons.

With respect to net salvage factors, the changes I have proposed are due to net salvage charges being labor intensive and increases in labor costs are the primary reasons leading to increases in negative net salvage factors. This is especially true for long-lived assets that are removed many years after their original placement in service. Other reasons why net negative salvage charges are increasing are due to increased costs experienced to allow the work to proceed in a safe manner and in compliance with environmental rules.

Q. Are there any considerations specific to the Company's Steam Plant that have influenced you conclusions on depreciation?

A. Yes, there are. Over the past 15 years, the Company's Steam Production Plant has changed significantly as to the type of plant within those primary plant accounts and in the dollars invested in those accounts. During this period, the production plant in Steam has grown considerably due to transfers of plants to Steam from the Company's electric operations. Specifically, at the end of 1986, the total original cost invested in Steam Production Plant was approximately $68 million. In the years since, the Company has transferred into Steam Plant the former steam-electric boiler facilities at our Hudson Avenue, 59th Street, and 74th Street stations. These three transfers alone added approximately $190 million of original book cost to our Steam operations. At the end of 2002, our plant balance in production amounted to $321 million. In addition, the plant transfers have significantly changed the type of plant in our steam production facilities. These transfers have brought their base load, field-erected boilers into steam to join the package boiler installations that previously made up the majority of our production plant. These facilities come to the Steam department already having been in service in the electric department for many years.

Q. Are there considerations in the distribution plant you would like to discuss?

A. The Company has now completed its Steam Enhancement Program which was a 10-year program undertaken to replace, remove, and strengthen our distribution system following the Gramercy incident. I considered the original cost retirements that were made during that program to arrive at an appropriate average service life for our distribution equipment. However, that program also included significant expenditures for the removal of equipment, which I have disregarded in developing the net salvage factors I consider appropriate today on the basis that that level of removal will not reoccur in the future.

Q. What effect will your proposed changes have on annual depreciation expense?

A. As summarized on Exhibit __ (CH-1), the amount of the annual provision for depreciation for the Company's total Steam Plant is approximately $18.5 million under the existing rates and approximately $20.2 million under the proposed rates.

Q. Since you have proposed changes affecting the Accumulated Provision for Depreciation, please explain the purpose of the depreciation reserve.

A. The Accumulated Provision for Depreciation, also referred to as the Reserve per Books is, in simple terms, an account balance that reflects the portion of the cost of the plant in service which has been recovered, according to the Company's accounting records. The original book cost of plant less the Reserve per Books comprises net plant. Net plant does not represent the plant's fair market value. The Reserve per Books may be compared to the Computed Reserve to test its adequacy. The Computed Reserve is calculated on a book basis using depreciation parameters currently approved by the Commission and may be calculated on a proposed basis using parameters per my analysis of the aforementioned depreciation studies.

Q. Please review your findings on the difference between the Accumulated Provision for Depreciation per Books and the Computed Reserve for depreciation.

A. Exhibit __ (CH-1) shows that for total Steam Plant at December 31, 2002, the Accumulated Provision for Depreciation per Books amounted to approximately $223.7 million. As noted on the exhibit, that amount has been adjusted from the actual reserve balance as of that date for net removal costs at ERRP that were determined to have been incorrectly charged to the Steam Department

and were transferred to the Electric Department during 2003. The Computed Reserve, summarized under the heading "book basis" was calculated on the basis of the average service lives, net salvage percentages, and life tables currently in use by the Company, and in total amounted to approximately $272.3 million. The Computed Reserve shown under the heading "proposed basis" was calculated on the basis of the average service lives, net salvage percentages and life tables proposed by me and in total amounted to approximately $297.5 million.

Q. What is the impact of the adjustment for ERRP that you just described?

A. The impact was to increase the Reserve per Books on the exhibit by $22.5 million, since I believe it more fairly represents what the true reserve balance should be for this proceeding since the accounting adjustment took place subsequent to the "as at" date of the exhibit. Making this adjustment also reduces the reserve variation, which I will address later.

Q. What have you concluded from the comparisons between the book and computed reserves for depreciation you just described and that are summarized in your exhibit?

A. The exhibit indicates that for total Steam Plant the Accumulated Provision for Depreciation per Books is

approximately 17.8% less than the Computed Reserve based upon the "book basis" and approximately 24.8% less than the Computed Reserve based upon the "proposed basis". With respect to these percentages, it is my opinion that the variation between the Accumulated Provision for Depreciation per Books and the Computed Reserve calculated using the proposed rates is not within the 10% variation which would be considered reasonable as a test of adequacy of the Company's accumulated provision for depreciation per books based upon actuarial studies of the Company's mortality experience for its Steam Plant.

Q. Has the reserve variation for Steam Plant been this deficient for some time?

A. Yes. Since 1992, our Steam Plant has been under-accrued each year by a significant amount. In dollars, the variation has grown from about $14 million in 1992 to about $49 million as of year-end 2002 based on rates in effect. Based on the proposed rates in this case, the variation is approximately $74 million. The deficiency expressed in percentage has grown from approximately 16% in 1992 to today's 17.8% on the book basis and 24.8% on the proposed basis.

Q. Have you prepared an exhibit demonstrating the history

of the steam reserve variation?

A. I have prepared an exhibit titled "CONSOLIDATED EDISON COMPANY OF NEW YORK, INC., SUMMARY OF THE ACCUMULATED PROVISION FOR DEPRECIATION AND THE THEORETICAL RESERVE FOR DEPRECIATION AND DEVELOPMENT OF THE PERCENTAGES OF VARIATION FOR THE YEARS INDICATED".

MARK FOR IDENTIFICATION AS EXHIBIT __ (CH-2)

Q. What is contained in this exhibit?

A. The exhibit summarizes the variation between the book and computed reserve for Steam at each year-end position since 1984. The amounts are taken from the annual study I prepare and are based on the rates in effect at each year end.

Q. What treatment was allowed by this Commission in the Company's recent rate proceedings concerning the reserve variation?

A. In Case No. 93-S-0997, the Commission recognized the existence of the reserve deficiency and the need to address it by granting the Company permission to amortize the deficiency by charging the reserve with additional depreciation expense of $1.4 million annually, to be completely amortized over a 15-year period. However, in the Company's last case, Case No. 99-S-1621, which was settled by the parties and approved

by the Commission, the Company was directed to stop that recovery. The settlement in that case again recognized the reserve deficiency and stated, in part:

> The settling parties acknowledge the existence of a steam system depreciation reserve deficiency, and the need to revise depreciation rates. They propose to discontinue the current amortization of the reserve deficiency, and to use the net gain from the sale of the First Avenue Properties allocable to steam operations to offset or partially offset, at the Commission's discretion, the reserve deficiency as determined by a study to be conducted once the ERRP is completed. Revised steam depreciation rates would also be considered at that time. In the event that such net gains allocable to steam operations are insufficient or are otherwise not used to fully offset the depreciation reserve deficiency, if any, or if the sale of the First Avenue Properties is not completed when this Settlement expires on September 30,2004, any remaining accumulated depreciation reserve deficiency will be addressed when base steam rates are reset. (Settlement, pp. 6-7).

Q. What are you proposing to do with the deficiency?

A. The above statement directed the Company to halt ongoing reserve deficiency amortization based upon the assumption there would be an already realized gain from the sale of the First Avenue Properties to channel toward the deficiency before the end of the rate plan. It is now clear that this sale will not be closed prior

to the end of the current rate plan and that it is not possible to fulfill the Agreement's intent. However, I do not believe it is in the Company's or our customers' best interests to delay the amortization any longer. I therefore propose to amortize the deficiency over a 15-year period, no longer subject to the First Avenue sales. I further propose that the amortization schedule be subject to modification to reflect the necessary adjustments that will be required after the sales are completed in order to satisfy the intent of the settling parties and the Commission.

PROPERTY TAXES

Q. Please provide some background on property taxes.

A. The property taxes Con Edison pays are based on the "value" of property and include taxes on land and the structures erected or affixed to the land. In New York State, utilities also pay property taxes on utility equipment located on land owned by the utility and on equipment located on or under the public streets and highways.

In New York State, public utility property is valued under a method known as the "Cost Approach." The New York City Assessor and the New York State Office of Real Property Services ("ORPS") determine value by using a

Reproduction Cost New Less Depreciation ("RCNLD") methodology for utility property. RCNLD calculates what it would cost to reproduce property at current construction costs, subtracts an allowance for depreciation and obsolescence, if any, and adds in the value of land to arrive at a "value" for the entire property. RCNLD is used only to value certain of the Company's structures and all of our equipment. The value of land is determined by comparable sales data. Annually, we review our property assessments to determine if they fall within a range of reasonableness when calculated under RCNLD. If the actual assessments substantially vary from our RCNLD calculations, we file complaints to formally protect our rights and those of our customers. We settle these complaints when we believe that a settlement is a more cost effective way of reducing our tax burden than prolonged and risky litigation. We resort to litigation only when our efforts to reach what we believe to be a fair compromise fail.

Q. What level of property taxes does the Company experience for its steam plant?

A. In 2002, we paid $610.1 million in total property taxes of which $37.2 million was charged to the Steam

Department. For 2003, I am forecasting that our steam property taxes will amount to approximately $46.4 million. The increase is principally due to the 18.5% across-the-board tax rate increase New York City implemented that became effective on January 1, 2003.

Q. Have you developed the rate year property taxes for this proceeding?

A. Yes. For the rate year ending September 2005, I have forecasted steam property taxes to be $65.2 million. To arrive at that amount, I used our 2003 forecast and actual assessments known for year 2003 as a starting point. To that amount, I have calculated the estimated taxes on the net plant being added, using Company witness Ricco's forecast in this proceeding. The property tax forecast reflects taxes on construction work in process balances related to ERRP effective July 2004. In July 2005, the full amount of ERRP taxes are estimated to be partially offset by a property tax abatement that I will discuss later in my testimony. In addition, the forecast assumes that a current reduction for economic obsolescence in our steam special franchise taxes will continue to be available to the Company. Any inability to obtain this benefit will be treated as part of the 100% reconciliation that I will propose to take

place annually. My proposal on the reconciliation is described in more detail herein. I will also discuss the nature of this reduction later in my testimony. Finally, I have estimated the property tax rate for New York City based on recent actual tax rate changes enacted by the City and on judgment.

Q. Please now discuss the Company's efforts to keep property taxes to a minimum.

A. Property tax amounts are a function of a tax rate multiplied by assessed value. Individual and corporate taxpayers have little influence over a tax rate in a municipality. Accordingly, our focus is on the fairness of assessments regardless of whether they are electric, gas, or steam properties.

Q. Have you had any recent successes?

A. Our recent efforts include securing a significant reduction in our steam plant special franchise assessments due to a request we submitted to recognize economic obsolescence in our steam system.

Q. Please describe why the Company was granted this reduction.

A. The Company submitted a complaint to the State Board of Real Property Services ("the Board"), the body appointed by the Governor that oversees ORPS' administration of

real property assessments in New York State. In our complaint, we asserted that a large portion of our steam system is economically obsolete because there is insufficient usage (i.e., steam sales) to produce a reasonable return on investment at rates that permit the system to remain competitive with alternative sources of energy. Finding that "decreased demand and an insufficient return on investment have been demonstrated," the Board determined that Con Edison "does have economic obsolescence in the steam plant", and approved a reduction in assessments for a one-year period.

Q. Please describe the reduction and tax benefits received by the Company.

A. The reduction was effective for the fiscal year ending in June 2003. Since it is an allowance based on annual performance, the Company needs to reapply annually for such allowance. We have also applied and were again granted a reduction for the fiscal years ending June 2004 and June 2005. We intend to continue to apply for this on an annual basis as long as it is warranted. This effort reduced our steam special franchise assessment from $178.8 million to $114.4 million, a 36% decrease, resulting in tax savings of approximately $6.8

million at the time of approval. In 2003/2004, the percentage reduction in assessment was again 36%, but due to the increase in the City's tax rates, the benefit to the Company grew to $8.0 million. Our 2004/2005 reduction was approved at 37%. It is important to note that this benefit will continue only as long as the Board rules in our favor.

Q. Has the steam department benefited from this reduction before?

A. No. In the past, the Board and ORPS would only allow an economic obsolescence reduction on the financial performance of the entire regulated company. Since our combined electric, gas, and steam operations did not produce an inadequate return, no reduction was available. Our efforts in another settlement with ORPS on our gas special franchise property values in 2001 provided us with the precedent to request a separate valuation for our steam department, which allowed us to petition for an economic obsolescence reduction.

Q. How do you determine which properties are over-valued?

A. In conjunction with our Systems Development personnel, we recently implemented a software system to evaluate our property assessments, including our special franchise property. The system uses the RCNLD method

and allows us the flexibility to evaluate our assessments under several different depreciation curves. We use the system to compare our actual assessments for any given municipality to their theoretical values.

Q. Do you pursue property tax abatements?

A. Yes. We have applied for abatements, which may limit property taxes for several years on qualified property, when we believe we are eligible to do so. For example, under New York City's Industrial and Commercial Incentive Program ("ICIP"), we have applied for such an abatement on the East River Repowering Project. If our application is approved in total, 100% of the property taxes due on eligible construction will be abated for eight years with additional savings for the next four years as the benefit phases-down to full taxation after that period. The ICIP is a limited program because it is not available in all areas of New York and does not apply to our special franchise property. It applies only to new construction or significant rehabilitations of existing facilities.

Q. Please describe any other pending actions on property taxes.

A. We have several pending actions in the court system, some of which have been ongoing for many years. In New

York City, proceedings are pending in the Supreme Courts of various counties challenging certain of the Company's property tax assessments for the years 1994/95 through 2003/04. A portion of each of these property tax claims relates to steam plant properties.

Q. With all of these efforts, why do property taxes continue to rise?

A. Local property taxes continue to increase. In addition, the City taxes most of our property in a separate utility class that isolates most utility property from other property classes in the City. The City will raise the tax rate on all of the property within that class whenever any single taxpayer receives a reduction to ensure that this class satisfies the revenue responsibility which the City has assigned to it. Because Con Edison comprises about three-quarters of the total property within that class, most of the benefit we receive from reduced assessments is paid for by an increased tax rate on that class.

Q. How are property taxes treated in the Company's current steam rates?

A. The Commission has recognized the volatility of property taxes and the effects that large changes in the amounts can have on the Company's financial position.

Accordingly, the Company is allowed to defer changes in the level of taxes for future disposition. From an accounting perspective, this is accomplished by allowing an expected level of taxes in rates and comparing that amount to the actual taxes incurred. A percentage of the variation is deferred and either collected from customers at a future date or credited to them.

Q. What percentage of this variation is deferred?

A. Under our current rate agreement in Steam, 86% of the variation is deferred.

Q. Are you proposing to change this treatment?

A. Yes.

Q. Please explain your proposal.

A. I propose the following, which I will refer to as the ("proposed policy"):

> 100% of changes in the Company's property taxes (allocated to steam operations) due to tax rate changes and 100% of changes in the Company's property taxes (allocated to steam operations) due to assessment changes will be reconciled, to the expense allowances. Any over- or under-collection will be deferred with interest accrued monthly on such amounts at the Other Customer Capital rate.
>
> Property tax refunds, including credits against future tax payments intended to return or offset past overcharges or payments determined by the taxing authority to have been in excess of the property tax liability appropriate for

the Company, shall be deferred, net of the expenses incurred by the Company to obtain such refund, for future disposition except for an amount equal to fourteen percent of the refund which shall be retained by the Company. The fourteen percent retention shall apply to all such property tax refunds and/or credits against future tax payments negotiated by the Company during the term of the Proposal.

Q. Why do you propose to change the reconciliation percentage from 86% to 100% for changes in property taxes?

A. The volatility of the tax and the lack of real control over its implementation can have significant impacts on the Company. For example, the 18.5% increase in tax rates in the City forced the Company to pay almost $100 million in additional property taxes on an annual basis. The amount applicable to steam property taxes was approximately $6.1 million. Without a 100% reconciliation, the Company absorbs 14% of that increase or approximately $854 thousand each year until rates are reset in a rate proceeding. I do not think it is proper for the Company to be responsible for this type of an increase due to our inability to control it. I would also note that the Company's electric rate agreements have provided for a 100% reconciliation of property tax expenses and the basis for that provision applies

equally to the Company's steam department. Company witness Rasmussen discusses how any over-recoveries or under-recoveries would be reflected in rates.

Q. Why do you propose for the Company to retain 14 percent of any property tax refunds it receives?

A. Property tax refunds are not specifically addressed in our current steam rate agreement. However, consistent with its long-standing policy of allowing utilities to retain a percentage of tax refunds to encourage them to challenge questionably imposed taxes, the Company's current electric rate agreement allows the Company to retain 14 percent of any property tax refunds, with 86 percent of the refund to be deferred for the benefit of customers. The sound regulatory policy that is the basis for this provision in the Company's electric rate plan is equally applicable to the Company's steam rates. In addition, I believe that the clarification reflected at the end of the proposed policy is needed to address future tax reductions.

Q. Why is that clarification needed?

A. Although our efforts to seek tax refunds occasionally produce actual refunds, refunds are extremely difficult to obtain from governmental entities. A future reduction or credit (potentially over a number of years)

is often the solution to this problem because the Company obtains a property tax reduction in lieu of a refund and the governmental entity avoids the current capital demands of a refund. The language on sharing of refunds between the customer and the Company was created to provide an incentive for the Company to challenge its assessments. Without a change that allows the Company to receive the incentive it successfully negotiates during the term of this proposed policy, we have an incentive that is nearly impossible to attain.

Q. Does that conclude your testimony?

A. Yes, it does.

Q. Please state your name and business address.

A. My name is Frank C. Yaegel. My business address is 4 Irving Place, New York, New York 10003.

Q. By whom are you employed?

A. I am employed by Consolidated Edison Company of New York, Inc. ("Con Edison" or the "Company").

Q. Please state your work experience and education.

A. I have been employed by Con Edison since 1972. I have held various positions in the Energy Management organization. In March 1983, I was promoted to the position of Gas and Steam Forecast Manager. I received a Bachelor of Science degree in Economics from the City University of New York. I have also completed the Executive Education Program for the Gas Industry conducted by the University of Colorado, Boulder Graduate School of Business.

Q. What are your responsibilities in your present position?

A. Under the direction of the Company's Resource Planning Director, I supervise the Gas and Steam Forecasting section. I am responsible for forecasting Con Edison and Orange & Rockland gas sendout, Con Edison steam sendout, peak load, delivery volumes, sales, and resultant revenues. Additionally, I am responsible for

the collection, maintenance, and dissemination of weather data as well as the periodic updating of the Company's weather normals used to forecast electric, gas and steam sales and sendout.

Q. Have you previously testified before this Commission?

A. Yes. I submitted testimony in Con Edison Steam cases 93-S-0997, 96-S-1065, and 99-S-1621. I also submitted testimony for Phase II-A of the Con Edison gas case 28954, and the recent Orange and Rockland gas case 02-G-1553.

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

A. The purpose of my testimony is to present the Company's forecast of steam sales, sendout and revenues for the rate year, the twelve months ending September 30, 2005. My testimony addresses the development of these forecasts starting from the historic year, the twelve months ended June 30, 2003. My testimony also addresses the need for a real time steam weather normalization clause ("WNC") should the Commission, at the conclusion of this proceeding, determine not to implement the Company's proposed rate re-design.

Q. Please describe the sales forecast methodology.

A. The process begins with the weather normalization of

the historic year sales. This eliminates any deviations in sales due to warmer or colder than normal weather. Weather normalized sales are then adjusted to account for the impact on sales yet to be realized from customers added or lost during the historic year. It also recognizes the impact of reduced usage by existing customers who have already replaced their air conditioning equipment with more efficient equipment and the future impact of changes in employment during the historic year that has not been fully realized. These adjustments, together with a billing cycle adjustment, yield the base estimate that serves as the starting point for the future rate year sales forecast. The key components that are expected to affect the level of rate year sales include new business, lost business, reduced sales to air conditioning customers who are projected to install more energy efficient equipment, and projected changes in employment.

Q. Was Exhibit_(FCY-1), entitled "CONSOLIDATED EDISON COMPANY OF NEW YORK, INC. - DEVELOPMENT OF 12 MONTHS ENDING SEPTEMBER 30, 2005 - FORECASTED STEAM SALES (MMlbs)", prepared under your supervision and direction?

A. Yes, it was.

MARK FOR IDENTIFICATION AS EXHIBIT_(FCY-1)

Q. Please describe Exhibit_(FCY-1).

A. This exhibit sets forth, by service classification, the steam sales booked by the Company during the historic test year - 12 months ended June 2003 (line 1). It then details adjustments made to the historic year's sales as well as the key components that will affect the level of the rate year's sales. Lastly, it shows the forecasted sales for the rate year, the 12-month period ending September 30, 2005.

Q. Please describe the Weather Normalization adjustments shown on line 2 and 3.

A. Line 2 shows the Weather Normalization adjustment necessary to recognize that the historic year's sales were affected by the colder than normal weather experienced during the 2002/03 heating season. Total heating degree-days over the 2002/03 heating season were 18.7% greater than normal. The related impact on sales, by service classification, was calculated monthly by multiplying the "variation between normal and actual heating degree-days" times a "use per heating degree-day per average customer" factor times the number of customers. The factors, by service classification, were determined by regression analysis

of actual average monthly-billed sales per customer per billing day versus actual monthly billing period heating degree-days per billing day.

Line 3 shows the adjustment needed to recognize that the historic year's air conditioning sales were also affected by abnormal weather. Actual cooling degree-days over the historic year period were 4.8% greater than normal. The sales volume impact was calculated in a manner consistent with the calculation of the winter period impact. Line 4 shows the sum of the heating and cooling adjustments and line 5 shows the weather normalized sales for the historic year. The weather normalization adjustment represents a 7.7% adjustment to the actual booked sales during the historic year.

Q. Please explain the Annualization Adjustments shown on lines 6, 7, 8, 9, and 10.

A. Annualization Adjustments reflect the impact on sales expected from customers added (line 6) or lost (lines 7 and 8) during the historic year. It also recognizes the future impact of reduced usage by existing customers who have already replaced their air conditioning equipment (line 9), and the future impact of changes in employment during the historic year that has not been fully realized (line 10). For example, if

a customer was lost or added in the final month of the historic test year, a downward or upward adjustment equivalent to the sales to that customer in the preceding eleven months was made. On the other hand, if a customer was added or lost at the beginning of the historic year, then no adjustment would be necessary. Line 11 is the total of the annualization adjustments.

Q. Please explain the Billing Cycle adjustment shown on line 12.

A. The Billing Cycle adjustment recognizes the impact on future sales due to the difference in the actual number of billing days in the historic year and the projected number of billing days for the rate year.

Q. What does line 13, Base Estimate, represent?

A. The Base Estimate represents the historic year's sales adjusted to normal weather, known new and lost business, the projected rate year number of billing days, as well as the future impact of reduced usage by existing customers who have already replaced their air conditioning equipment and the future impact of changes in employment during the historic year which has not been fully realized. It serves as the starting point for the rate year's sales forecast.

Q. Please explain the development of the New Business

forecast shown on line 14.

A. The New Business forecast reflects the projected realized sales in the rate year associated with known service applications that have been filed with the Company.

Q. Please explain how the forecast of future lost business due to on-site generation shown on line 15 was developed.

A. This estimate was based on the historic average annual losses over the period January 1998 - December 2002. The air conditioning usage of those customers who have also discontinued their use of steam for heat and/or hot water was excluded in the development of the historic average.

Q. How was the estimate of Demolition and Other Lost Business shown on line 16 developed?

A. This estimate was based on the historic average annual losses over the period January 1998 - December 2002.

Q. Please explain the projection of A/C Lost Business (Efficiency Impact) shown on line 17.

A. This projection reflects the assumption that air conditioning customers totaling 25,000 tons of air conditioning requirements wi11 replace their existing equipment with new energy efficient equipment prior to

the summer of 2004 and that additional air conditioning customers totaling another 25,000 tons of air conditioning requirements will replace their existing equipment prior to the summer of 2005 under the company's air conditioning discount program. Based on the steam requirements per ton of old and new equipment, customers can expect an approximate 30% decrease in their steam usage for air conditioning by joining this program. In addition to the direct cost savings as a result of the decreased usage, customers receive a $2 per Mlb discount from the current tariff rates on their air conditioning usage for a period of two years. Under the current rate agreement provisions, the Company can provide these discounts for customers totaling 75,000 tons. Prior to the end of the historic year, customers totaling 32,600 tons have already replaced their equipment. The portion of the reduced air conditioning usage of those customers not realized prior to the end of the historic year is shown on line 9.

Q. Please explain the forecasted impact of Employment shown on line 18.

A. Employment is projected to grow, albeit modestly, throughout the forecast period. The projected change in

employment was converted to steam sales by use of an average consumption per employee factor.

Q. What is the forecasted sales level for the future rate year, i.e., the 12 months ending September 30, 2005?

A. As set forth on line 19, the forecasted sales level for the 12 months ending September 30, 2005 is 24,965 MMlbs.

Q. Mr. Yaegel, did you provide witness Northup with a forecast of Steam Sendout?

A. Yes.

Q. Please describe how the forecast of sendout was developed?

A. The forecast of sendout was developed in a two-step process. Starting with the sales forecast previously described and by recognizing the differences between monthly normal weather conditions on an "as billed" basis versus a "calendar" basis, as well as the number of average monthly billing days as opposed to calendar days, I restructured the projected billed sales to a calendar basis. I then provided witness Litkouhi with calendar sales for each month of the future rate year. The total for the future rate year being 24,874 MMlbs.

Q. By "calendar" sales, do you mean the level of monthly sales that would be reported if all customer meters

were read on the last day of each month?

A. That is correct.

Q. Please continue.

A. Witness Litkouhi then provided the estimated level of losses and unaccounted for (or variance between sendout and sales) equal to 4,430 MMlbs resulting in an estimated level of 29,304 MMlbs of sendout for the rate year.

Witness Litkouhi's testimony addresses how the estimated level of losses and unaccounted for was developed as well as how such losses should be treated at the conclusion of this proceeding.

Q. Was Exhibit_(FCY-2), entitled "CONSOLIDATED EDISON COMPANY OF NEW YORK, INC. - FORECASTED STEAM REVENUES - 12 MONTHS ENDING SEPTEMBER 30, 2005 AT CURRENT AND PROPOSED RATES" prepared under your supervision and direction?

A. Yes, it was.

MARK FOR IDENTIFICATION AS EXHIBIT_(FCY-2)

Q. Please describe what this exhibit shows.

A. Column (1), entitled Base, shows the projected tariff revenues (net of contractual and projected air conditioning rate discounts) on a per service classification and total basis, inclusive of the

current base cost of fuel, at current rates. Column (2) shows the Increase in Rates and Charges associated with Column (1). Column (3) shows the projected Statement of Fuel Adjustment revenues. Column (4) shows the Increase in Rates and Charges associated with Column (3). Column (5), which is the forecast of total revenue at current rates, sums Columns (1), (2), (3) and (4). Column (6) shows the proposed base rate revenue increase. Column (7) shows the forecast of total revenue at the proposed base rate revenue increase.

Q. Please explain how the projected base revenues at current rates shown in Column (1) were calculated.

A. Using regression analysis, pricing relationships were developed from the historic year's class sales and booked base revenue data. These relationships were then applied to the projected sales in the rate year.

Q. How was the estimate of the Statement of Fuel Adjustment revenue shown in Column (3) developed?

A. This information was provided to me by witness Northup. It is important to note that the projected Statement of Fuel Adjustment revenues shown in Column (3) and included in Total Revenue @ Current Rates shown in Column (5) reflects anticipated fuel cost savings totaling approximately $64,000,000 related to East

River Re-Powering Project, which significantly reduces the impact of the proposed base rate increase. These anticipated savings also reduced the Increase in Rates and Charges shown in Column (4) and included in Column (5) by approximately $1,600,000.

WEATHER NORMALIZATION CLAUSE

Q. Mr. Yaegel, earlier in your testimony you stated that absent Commission approval of the Company's proposed rate re-design, you believe a steam Weather Normalization Clause ("WNC") is needed. Is that correct? If so, why?

A. Yes, that is correct. The level of rate relief granted in this proceeding will in large part be based on the forecast of the rate year's sales, which assumes normal weather. Absent approval of the company's proposed rate re-design or a WNC, a milder than normal winter could substantially offset the level of rate relief granted. Conversely, a colder than normal winter could result in higher customer bills and higher Company revenues, assuming the current rate design remains in place. A real time steam WNC would protect steam customers from higher bills when abnormal weather causes higher usage, and it would protect the Company when abnormal weather results in lower customer use.

Billing adjustments, which handle variations from normal weather experienced on a real time basis, can be made on a real time basis. A real time WNC was first adopted for the Company's gas operations in October 1989. It is important to note that the Company's steam system's net revenues are more weather sensitive, on a relative basis, then its gas system. Steam customers should benefit from rate stability during both warmer and colder periods like the Company's gas customers. The Company and its steam customers should not continue to bear the full risk and impacts of abnormal weather.

Q. If the Commission were to conclude that a real time steam WNC is appropriate, how should normal and variations from normal weather be measured?

A. During the heating season, normal weather would be defined on a heating degree-day basis as the average number of degrees that the average daily dry-bulb temperatures during the most recent 30 calendar year period fell below a reference of 56 degrees. Actual weather and resulting variations should be measured using the same temperature reference used in the normal.

Q. Was the normal used in the sales projected for the rate year developed on the same basis?

A. Yes. It was based on the average weather conditions experienced over the 30 calendar years ended 2002.

Q. Is the use of a 30-year average appropriate to define normal weather conditions?

A. The 30-year average condition is used by the National Weather Service to define normal conditions and it is a widely accepted standard in the energy industry. The 30-year average condition is utilized in the Company's gas weather normalization clause and updated on an annual basis. The annual updating of the 30-year average condition captures any trend(s) in experienced weather conditions without placing overt emphasis on the most recently observed conditions. I would propose that a steam weather normalization clause would utilize a normal weather condition defined as the average condition over the most recent 30-years and be updated annually.

Q. Would a WNC add stability to the level of monthly bills that customers would expect to see?

A. Yes. It would result in a more predictable pattern in the month-to-month charges in the non-fuel component cost of customers' bills. While the Company has taken steps to mitigate swings in monthly unit fuel costs, such as leveling storage and handling costs, unit fuel

costs may fluctuate for reasons beyond the Company's control.

Q. Would a real time WNC apply to all steam customers?

A. No. It would apply only to those customers who use steam for space heating during the winter billing months of November through April, inclusive. It is important to note that the WNC would equally apply to small SC 1 heating customers as it would to the larger SC 2 and SC 3 customers. The small SC 1 customers are, on a relative basis, just as impacted by abnormal weather as the larger SC 2 and SC 3 customers.

Q. How would the impact of abnormal weather on revenues be quantified and treated?

A. For each billing trip where actual heating degree days during the billing trip varied from normal by more than plus or minus 2.2%, a unit credit or charge would be developed and included in the Statement of Fuel Adjustment.

Q. What is the basis for and the significance of the 2.2% bandwidth around normal?

A. A 2.2% bandwidth is applied in the Con Edison's gas WNC. It would be appropriate to apply the same 2.2% bandwidth to a steam clause since the relative impacts would be the same. The 2.2% bandwidth recognizes that

individual customer reaction to actual weather conditions cannot be precisely measured while equally limiting the potential revenue gain to the Company and the potential cost to its steam customers.

Q. How would the unit credits or charges be calculated?

A. Each billing trip's variation between actual and normal heating degree days after accounting for the 2.2% bandwidth around normal would be multiplied by the applicable service classification's average customer steam heating requirement per heating degree day and the applicable service classification's winter period penultimate block rate, exclusive of fuel, associated variance, water, chemical and electric costs embedded in it.

This product would then be divided by the estimate of the applicable service classification's average customer actual steam sales for that billing trip, resulting in a unit credit or charge.

Q. Why would it be necessary to develop unit credits or charges on a service classification basis?

A. The relationship of temperature sensitive sales to non-temperature sensitive sales differs by service classification. The Company's rates also vary by service classification. Therefore, customers in the

various service classes do not equally contribute to system revenue deficiencies or surpluses caused by abnormal weather.

Q. Why should winter penultimate block rates be used to develop unit credits or charges?

A. Rates charged per Mlb vary by service and the amount used. However, the incremental usage due to variations from normal weather for the majority of steam customers falls in the penultimate block rate.

Q. How would average customer actual sales estimates for the individual service classifications be determined?

A. The average customer actual sales estimates for the individual service classifications would consider: (1) the non-temperature sensitive requirements per day and the temperature sensitive requirements per heating degree day determined by regression analysis of actual sales data, (2) the actual number of billing days in the billing trip, and (3) the actual number of heating degree days in the billing trip.

Q. Regarding the sales forecast, are there factors that could significantly alter the projected level of future steam sales and revenues?

A. Yes. The levels of new business and lost business are subject to uncertainty. For example, the timing of new

business attachments may slip. Similarly, the level of lost business over the next several months may be lower or higher than currently projected. The level of future sales can also be affected by changes in the level of employment. These variables will be closely monitored, and if conditions change significantly, the changes will be reflected in the Company's update filing.

Q. Does this conclude your testimony?

A. Yes, it does.

Q. Please state your name and business address.
A. My name is John Ricco. My business address is 4 Irving Place, New York, New York 10003.
Q. By whom are your employed?
A. I am employed by Consolidated Edison Company of New York, Inc. (Con Edison).
Q. Please state your work experience and education.
A. I have been employed by Con Edison since June 1967. I held various positions of increasing responsibility in the Company's planning organization through June 1993. From that period through the present time, I have been assigned to the Corporate Accounting Department and I have held the positions of Section Manager Capital Budgeting, Section Manager Corporate Budgeting, and Group Leader, Financial Forecasting, my current position. I received a Bachelor of Science degree in Economics from the City University of New York and a Master of Science degree in Organizational Leadership from Mercy College.
Q. What are you responsibilities in your present position?
A. I am responsible for the preparation of the one-year construction budget, the five-year construction program and the projection of plant in service as a component of rate base. I also have responsibility for studies

of an economic nature including planned capital investments.

Q. Have you previously testified before this Commission?

A. Yes. I submitted testimony in Con Edison Steam Cases 93-S-0997 and 96-S-1065. I also submitted testimony for the Con Edison Gas Case 93-G-0996 and submitted and testified in Con Edison Electric Case 94-E-0334.

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

A. The purpose of my testimony is to appraise the impact of the current construction and retirement programs on the Steam Department's rate base.

Q. Have you prepared projections for the twelve months ending September 30, 2004 and September 30, 2005?

A. Yes, I have.

Q. I show you a two page tabulation, the first entitled "ESTIMATED NET PLANT - STEAM - TWELVE MONTH AVERAGE ENDING SEPTEMBER 30, 2005", and the second "ESTIMATED NET PLANT - STEAM - JUNE 30, 2003 - SEPTEMBER 30, 2004", and ask if it was prepared under your supervision and direction?

A. Yes.

MARK FOR IDENTIFICATION AS EXHIBIT_(JPR-1)

Q. What does this exhibit show?

A. Page 1 of this exhibit shows the projected average net plant for the twelve months ending September 30, 2005. Page 2 of the Exhibit shows the estimated monthly balances from July 1, 2003 through September 30, 2004 that served as a basis for my rate year projections. The first column shows the book cost of plant; the second column shows the accumulated provision for depreciation; and the third column shows the resulting net plant.

Q. I show you a two page tabulation, the first entitled "ESTIMATED CONSTRUCTION WORK IN PROGRESS - STEAM - TWELVE MONTH AVERAGE ENDING SEPTEMBER 30, 2005", and the second "ESTIMATED CONSTRUCTION WORK IN PROGRESS - STEAM - JUNE 30, 2003 - SEPTEMBER 30, 2004", and ask if it was prepared under your supervision and direction?

A. Yes.

MARK FOR IDENTIFICATION AS EXHIBIT_(JPR-2)

Q. What does this exhibit show?

A. Page 1 of this exhibit shows the projected construction work in progress balances for the twelve months ending September 30, 2005. Page 2 of the Exhibit shows the estimated monthly balances from July 1, 2003 through September 30, 2004 that served as a basis for my rate year projections.

The first column shows the construction work in progress balance for total steam plant; the second column shows the interest bearing construction work in progress; and the third column shows the resulting non-interest bearing construction work in progress.

Q. Please describe the development of the projections contained in your exhibits.

A. Using estimated capital expenditures provided to me by Company witness Bozgo and the Company's book and records for the construction work in progress balances through June 30, 2003, I developed estimated transfers to plant in service, and construction work in progress balances. I added the estimated transfers to plant in service to the actual plant in service accounts balances at June 30, 2003 and deducted the book cost of plant scheduled for retirement. In addition, I then calculated the accumulated provision for depreciation in order to develop net plant balances. Included in this calculation are the forecasted depreciation accruals based on the depreciation rates and net removal costs provided by Company witness Hutcheson. Estimates of plant in service and construction work in progress also include projections for the East River Repowering Project based on construction expenditures

included in Company witness Gonnella's testimony.

Q. In preparing your estimates, did you use the capital expenditures estimated in Company witness Bozgo's construction program shown on Exhibits RB-1 and RB-2?

A. No. Company witness Bozgo's Exhibits RB-1 and RB-2 detail the level of expenditures under a revised program. However, my estimates were prepared based upon the level of expenditures that were originally estimated, which were provided to me by Company witness Bozgo. I will update my estimates to reflect the expenditures included in Company witness Bozgo's testimony when preparing the Company's update, but I don't believe this update will produce significant changes to my estimates.

Q. Does this conclude your testimony?

A. Yes.

Q. Please state your name and business address.
A. My name is Edward J. Rasmussen. My business address is 4 Irving Place, New York, N.Y. 10003.
Q. By whom are you employed and in what capacity?
A. I am employed by Consolidated Edison Company of New York, Inc. ("Con Edison" or the "Company") and hold the position of Vice President and Controller.
Q. Briefly state your educational background.
A. I graduated from St. Francis College in June 1970, with a Bachelor's Degree in Business Administration. In 1977, I received a Masters Degree in Finance from Long Island University.
Q. Please explain your work experience with Con Edison and your current primary responsibilities.
A. From 1970 to 1987 I worked in the Rate Matters Section of Corporate Accounting in increasing levels of responsibility up to and including Director of the section. In 1987, I was promoted to Assistant Controller responsible for Accounting Research, Payroll and Stores Accounting. In 1990, I was transferred to Manhattan Customer Service as General Manager of Operations Service responsible for transportation, stores, budgets and personnel. In 1993, I returned to Corporate Accounting as Assistant Controller

responsible for various sections within the department. In December 2000, I was promoted to my current position of Vice President and Controller.

Q. Have you been involved in industry-wide utility issues?

A. Yes, for many years I have been an active member of both the EEI and AGA finance and accounting committees and I am currently a member of the Executive Accounting Committee of the EEI. In addition, I have written an article published in the Public Utility Fortnightly, and I have been a speaker at many industry forums on matters of concern to the electric and steam industries.

Q. Have you previously testified before this Commission?

A. Yes. I have testified before the Commission in numerous electric, gas and steam rate proceedings.

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

A. The purpose of my testimony in this proceeding will be to cover the following topics:

- Provide an overview of the items driving the Company's request for a steam rate increase for the rate year, the Twelve Months Ending September 30, 2005;
- Discuss how the projected fuel savings to be

generated from the operation of the East River Repowering Project ("ERRP") will result in benefits for steam customers that will exceed the associated carrying costs we are seeking to recover in this case;

- Set forth a proposal to expand this filing to include a three-year steam rate plan with staged increases in the 2nd and 3rd years;
- Outline the Company's request for permission to continue the use of deferred accounting for certain operating costs as previously authorized by the Commission and further request authorization to go back on the Commission's Statement of Policy and Order Concerning the Accounting and Ratemaking Treatment for Pensions and Other Post-employment Benefits Other Than Pensions, issued and effective September 7, 1993 ("Policy Statement"); and the Company's request to use deferred accounting for employee health benefit costs;
- Discuss the Company's proposal for the handling of costs related to the World Trade Center incident ("WTC");

- Outline the Company's proposal to implement a true-up mechanism for capital expenditures and modify the current true-up mechanism in place for property taxes;
- Provide background to the Company's request for permission to continue to receive reimbursements from the Electric Department for the cost of operating the 74th and 59th Street Plants;
- Outline reasons supporting the Company's request for the termination of the current steam line loss incentive mechanism; and, finally,
- Propose that the existing Fuel Adjustment Clause ("FAC") be modified in a manner so as to be fully reconciled in the same way as the electric market supply charge ("MSC") and gas cost factor ("GCF").

Overview of Rate Increase

Q. Mr. Rasmussen, please describe the steam Rate Agreement and Settlement that is currently in effect for Con Edison.

A. The Company is currently operating under an Agreement and Settlement that was adopted by the Commission in 2000, as a result of Case 99-S-1621. The agreement provided for a $16 million base rate increase and holds

base rates constant through September 30, 2004.

Q. Please describe the major components driving the Company's proposed rate increase request of approximately $129 million.

A. The Company's request for a base rate increase of approximately $129 million is made up of two components. The first component of the increase is a request for the recovery of items related to existing steam operating and construction requirements of approximately $91 million. The second component of the request is for approximately $38 million and is designed to reflect the carrying costs allocated to the Steam Business Unit for the ERRP project in rates. As I will discuss later in my testimony, the Company has projected that steam customers will realize approximately $64 million in fuel cost savings from ERRP during the rate year that will flow to them through the FAC. Thus, the net impact to customers from the requested base rate increase of $129 million and anticipated fuel savings of $64 million would be a net increase in customer bills of $65 million, or approximately 14.6%.

Q. Please outline the items that are included in the Company's proposed base rate increase of approximately

$91 million.

A. For the twelve months ending September 30, 2005, the Company is projecting that its sales revenues net of fuel recoveries will be approximately $25 million lower than the level reflected in rates. The Company's weather adjusted steam sales have been flat and in some instances declining over the last several years. Moreover, the Company lost its largest steam load - the World Trade Center - on September 11, 2001. Property taxes increases of $19 million are the second largest item driving the need for a rate increase. Other operation and maintenance expenses, excluding pension and insurance costs, ("O&M") are projected to be $18 million higher. The increase in O&M expenses reflects the actual cost of electricity used at the steam stations, which is $5 million higher due to the commodity price for this item; increased levels of environmental remediation account for another $5 million of the increase; and labor and steam plant operating costs make up the balance. The projected pension and insurance costs are $13 million higher due to the elimination of pension credits of $7 million that will not continue going forward, liability insurance premium increases of $4 million and higher

health benefit insurance costs.

The Company is continuing to upgrade, reinforce and replace its steam infrastructure and is planning to spend between $80-$90 million a year over the next two years on projects other than ERRP. The carrying cost on this investment has added approximately $13 million to the requested rate increase.

Increased depreciation expense due to plant additions, a change to the depreciation rates and the amortization of a reserve deficiency over 15 years, as discussed in Mr. Hutcheson's testimony, accounts for $11 million.

The Company is also seeking a minimum return of 12.0% for its Common Shareholders, which compared to a 10.5% return, the approximate equity return assumed in current rates, accounts for $5 million of the increase.

The projected reimbursement from the electric department for operating expenses and property taxes for the 74th and 59th Street generating stations mitigates the needed rate increase.

Q. Please detail the items that are included in the Company's proposed East River Repowering Project base rate increase of approximately $38 million.

A. The East River Repowering Project will become part of steam rate base. Approximately two-thirds of the

carrying costs for this plant will be allocated to the electric department as described in the testimony of Company witnesses Shansky and Gonnella. We anticipate the annual carrying cost of this investment will be $114 million in the rate year, the Twelve Months Ending September 30, 2005. The carrying cost is comprised of a return on investment amounting to $74 million, depreciation costs of $21 million and property tax expense of $19 million. The interdepartmental rent to be allocated to the electric department amounts to $76 million, leaving the steam customers with a balance of $38 million.

Q. At this time, are you aware of any potential delays in the timing of the ERRP project?

A. Yes, it has recently been brought to my attention by Mr. Gonnella that the Company now believes the commercial operation date for the project may slip from the October 1, 2004 date used to calculate the revenue requirement associated with this project.

Q. How would you propose to handle a delay in the commercial operation date for the ERRP units?

A. My proposal would be to pass back to customers through the fuel adjustment clause any overcollections in base rates for the plant until the unit is in commercial

operation.

Q. I show you a one-page document entitled, "Consolidated Company of New York, Inc. - East River Repowering Project - Monthly Revenue Requirements and Fuel Savings," and ask whether it was prepared under your supervision and direction?

A. Yes, it was.

MARK FOR IDENTIFICATION AS EXHIBIT___(ERJ-1)

Q. What does Exhibit ___(ERJ-1) show?

A. I have set forth in Exhibit ___ (EJR-1) the monthly carrying charges included in the Company's revenue requirement for EERP in the rate year, the Twelve Months Ending September 30, 2005. This Exhibit also includes the variable O&M costs for labor, water, chemicals and interdepartmental rents related to the operation of the ERRP units. The labor, water, chemical and interdepartmental rent expense is net of the costs for these items at stations that would be making up the steam for the ERRP plant. Under my proposal, the Company would pass back to customers through the fuel adjustment clause any overcollections in base rates for the plant until the unit is in commercial operation.

ERRP Fuel Savings

Q. Please describe the basis for fuel savings you are projecting from the East River Repowering Project and how these benefits will be reflected in the bills for steam customers.

A. The Company is installing a new steam/electric generating facility using state-of-the-art, high-efficiency equipment. The heat rate or efficiency of these units is far better than units currently in the system; accordingly, the units will require much less fuel to operate. As described in more detail by Company witness Northup, the Company ran a simulation using its "PROMOD" model to compare fuel costs with and without ERRP. The difference in fuel costs for the rate year amounted to approximately $64 million, which would be reflected in lower fuel adjustment costs. Thus, it is anticipated that the fuel savings to be achieved with ERRP will effectively reduce the bill impact of the Company's proposed rate increase to $65 million.

Three-Year Steam Rate Plan

Q. Mr. Rasmussen you indicated earlier in your testimony that you will be sponsoring a three-year rate proposal.

Can you explain how an agreement of this length would benefit both the Company's customers and shareholders?

A. Yes. Multi-year agreements provide the Company with the flexibility to schedule and execute critical programs in the most cost effective manner and place a greater responsibility on the Company to manage its resources over several years when there may be large swings in economic conditions. When the Company is successful in managing its resources, shareholders see the benefits in form of higher earnings during the rate plan period and any efficiencies the Company is able to achieve will be captured for consumers and reflected in future rates. By limiting the length of the agreement to three years, the Company and the Commission can review the results of the agreement and reset rates, if necessary, without allowing too much time to elapse should events cause the economic conditions on which the agreement is premised to be materially different from the economic conditions affecting the Company, its customers and its shareholders.

Q. Can you explain how your multi-year proposal would work?

A. The Company is essentially requesting that the rates set for the rate year, the Twelve Months Ending

September 30, 2005 ("RY1"), become the base from which projections would be developed for the 2nd and 3rd years of the rate plan. The Company is further requesting that the Commission adopt a series of staged rate changes for the Twelve Months Ending September 30, 2006 ("RY2") and the Twelve Months Ending September 30, 2007 ("RY3"). I would like to emphasize that, by proposing a three-year plan, the Company is not waiving its rights to file for new rates to take effect on October 1, 2005, if the Company views the rate change granted by the Commission for RY1 to be inadequate, or the terms for RY2 and/or RY3 under a multi-year rate plan to be unreasonable.

Q. I show you a one-page document entitled, "CONSOLIDATED EDISON COMPANY OF NEW YORK, INC. - THREE-YEAR STEAM PLAN" and ask whether it was prepared under your supervision and direction?

A. Yes, it was.

MARK FOR IDENTIFICATION AS EXHIBIT ___(EJR-2)

Q. Please explain your Exhibit ___ (EJR-2).

A. Exhibit ____ (EJR-2) highlights the items for which the Company is seeking recovery in RY2 and RY3. The first column represents the calculated increase in revenue requirement of $128.9 million for RY1, and was provided

to me by Company witness Muccilo. The increase in revenue requirement is supported by the testimony of various Company witnesses in this proceeding, including: Mr. Yaegel (sales forecast); Ms. Lee (operation, maintenance and administrative expenses, as well as other operating revenues and other taxes excluding property taxes); Mr. Bozgo (capital expenditures); Mr. Adinolfi (O&M); Mr. Muccilo (revenue requirement and rate base); Mr. Hutcheson (depreciation expense and property taxes); Mr. Fitzmartin (capital structure and overall rate of return); and Mr. Rosenberg (cost of equity capital). The second and third columns show the projected annual increases in costs that the Company would seek to recover in RY2 and RY3 and the categories of costs to be "trued up" on an annual basis; that is, property tax expense, book depreciation, labor and general escalations, pensions and Other Post Employment Benefits other than Pensions ("OPEB's"), health insurance and rate base additions. In addition, the Company is requesting the ability to recover/pass back to customers during the second and third rate years the over/under recoveries during the prior rate year of WTC costs, environmental, property tax, pension, OPEB and health insurance costs, as well

as interference charges.

Q. Do the dollar amounts included on Exhibit __(EJR-2) represent what the Company is seeking, or is it a placeholder for data that is to be updated at a latter point in time? Also, please explain how the amounts for RY2 and RY3 are calculated.

A. The amounts shown for RY2 and RY3 represent a combination of the amounts the Company is requesting and items that are placeholders. Property taxes, for example, represent the level of expense recovery the Company is seeking for this expense. This amount was calculated and provided to me by Company witness Hutcheson. The Company would propose to continue deferred accounting for this item, as I will discuss later, so the customer will be protected if there is any difference between the actual and projected expense. Book depreciation and rate base additions also represent the level of expense the Company is seeking; it is based on the Company's Capital Budget and was provided to me by Company witness Ricco. The Company is proposing a true-up for capital spending in this filing that I will discuss later, so, again, the customer will be protected if there is a shortfall. For the item labeled labor and general escalation, I

would propose to apply the labor increase rate to be negotiated in the Company's next union contract, that will replace the existing agreement which will expire in June 2004, to all labor and use the published GDP deflator to escalate other expenses subject to inflation. The labor and other costs base that would be subject to escalation are shown in Exhibit ___(HLL-7) and supported in the testimony of Company witness Lee. For pension and OPEB expense, the Company is requesting recovery of the annual expense to be calculated by its actuaries, Buck Consulting. The current projected increase in pension and OPEB expense is based on the May 2003 actuarial study. This study will be updated during the course of the proceeding to reflect the actual performance of Con Edison's pension and OPEB investments during 2003 and changes that may be made to the underlying actuarial assumptions to reflect the latest long-term view of economic conditions. Finally, for health insurance costs, the Company would propose to use the same health care trend rates that are developed and used by the Company's actuary in the OPEB projections. Again, the Company is proposing to true-up amounts recovered to its actual

experience.

Q. Can you provide some additional details as to how you would calculate the line item titled "Rate Base Additions?"

A. Yes, I would propose to start with the rate base approved in this proceeding for RY1. To this balance I would:

- add the Company's budgeted capital additions;
- make changes in working capital requirement related to property taxes, labor and general escalations; and
- subtract book depreciation accruals and related deferred income taxes.

Q. Please explain how you would propose to treat the category of expenses under the caption "Annual true-ups" on Exhibit ___ (EJR 2).

A. The Company is currently using and/or is proposing to use deferred accounting for WTC costs, MGP/Super Fund/Other environmental expenditures, property taxes, pensions, OPEBs, health insurance and interference. The Company would submit an annual reconciliation to the Commission for its review in order to reflect any prior-year over/under recoveries in the RY2 and RY3

rate changes. Due to the timing of the annual filings and proposed rate changes, the Company would propose to file the annual true-up based on nine months of actual data and three months of forecast data for the first year in order to give the Commission adequate time to review and approve the level of costs to be reflected in the 2nd stage. For the 3rd Stage, the Company would provide actual data for the three months that were estimated in the 2nd stage and provide nine months of actual data and three months of forecast data for RY2.

Q. What expense do you propose to recover under the category labeled World Trade Center Costs?

A. I will address the accounting for this item in more detail later in my testimony, but essentially the Company is requesting that all expended funds that are not recovered from governmental agencies or insurance carriers be included as part of the 2nd and 3rd stage updates.

Deferred Accounting

Q. Does the Company currently employ the use of deferred accounting as permitted under SFAS No. 71, Accounting for Regulated Businesses?

A. Yes, the Commission has authorized the Company to utilize deferred accounting to match the recognition of

expenditures with the recovery of those costs.

Q. Is the Company proposing to continue the use of deferral accounting for all costs that the Commission has previously authorized?

A. Yes, with the exception of the New York State Corporate Business Tax, the Company would request permission to continue utilizing deferred accounting for items previously authorized by the Commission. With regards to the NYS Corporate Business Tax, the use of deferral accounting was authorized as a temporary measure by the Commission in its Order dated June 28, 2001, until this cost could be reflected in base rates. Currently, this expense is being collected through a temporary surcharge included in customer bills. Mr. Muccilo's testimony discusses how this expense was rolled into his calculation of the Company's revenue requirement.

Q. You indicated earlier that the Company would like to go back on the Policy Statement, which allows the use of deferral accounting for pensions and OPEBs. Why is the Company proposing to make this change?

A. Over the last several years it has been very difficult to predict the Company's annual pension and OPEB expense. This is due to a number of factors, but the primary volatility in calculating this expense has come

from significant and dramatic swings in financial markets. While it is normal to expect cyclical changes in business activity, the unforeseen tragic events of September 11, 2001, the turmoil among nations and the resulting conflicts in the Middle East that followed have made it next to impossible to develop a long term view of economic and financial market conditions beyond the current year. Major swings in the financial markets significantly affect the value of the Company's pension and post-employment benefit funds and, therefore, the ability to accurately project a rate year allowance, even more so an allowance appropriate to a multi-year rate plan. As a result, the Company's experience over the past several years has been that the performance of the financial markets has had a great impact on its net income for shareholders. As a regulated utility, the Company's financial condition and performance should reflect the operation of the regulated business, not that of the financial markets. Reconciling these costs would ensure that customer rates reflect only the actual cost of pensions and OPEBs over time.

Q. Aside from the use of deferred accounting for current pension and OPEB expense accruals, do you have other

concerns with regards to the accounting related to the pension and OPEB liability recorded by the Company on it financials?

A. Yes, the Commission's Policy Statement on Pensions does not address all of the accounting requirements of SFAS No. 87, Accounting for Pensions. One specific test included in this Accounting Standard requires that companies like Con Edison compare their unfunded accumulated benefit obligation ("ABO") with the accrued benefit cost recorded on their books. The accrued benefit cost reflects accruals recorded over time less amounts funded into pension assets. If the ABO is higher than the accrued liability, then the excess is recorded as an additional minimum liability with the offset being recorded as a charge to Other Comprehensive Income ("OCI"). The ABO should reflect the Company liability that exists currently to discharge the pension obligation. Over the last few years, there have been sudden and sharp declines in the value of the Company's pension and OPEB assets that resulted from violent swings in the stock market. The Company has a serious concern that if this situation reoccurred, it could trigger the recording of a charge to OCI. A charge to OCI has the effect of reducing the

Company's shareholder equity, which can harm ratepayers. While this situation proved to be temporary, it nonetheless heightened the Company's awareness that this could very well happen again and cause needless harm to the Company's financial position through the application of accounting rules in periods of unusual economic circumstances. The overall impact of recording such a charge to OCI would ultimately be an adverse impact to ratepayers in the form of higher rates resulting from higher borrowing costs.

Q. What remedy for this situation are you proposing?

A. I am proposing authorization to treat any gap that would occur if the ABO were to exceed the accrued benefit cost caused by the application of SFAS 87 as a regulatory asset. We would defer this item as a regulatory asset as opposed to a charge to OCI. The creation of this regulatory asset would not affect the Company's operating results or what customers pay currently.

Q. Mr. Rasmussen, you indicated that the Company is seeking authorization to use deferral accounting for employee benefit (health insurance) costs. Can you please explain why you feel that this item should be subject to a true-up?

A. Over the last several years, the Company has continued to see increases in health insurance costs that have far exceeded the GDP deflator. The Company had to change the actuarial health care trend rates used by its actuaries in the OPEB calculation to reflect much higher than anticipated increases in health care costs. As testified by Company witness Reyes, these cost increases are occurring in spite of increases in the level of reimbursement we have required from employees in the form of deductibles and co-payments along with plan design changes made to try to control this cost and reduce the level of expense incurred. Since, the Company has projected increases in health benefits costs based on the current outlook for this expense, the Company would propose to use deferred accounting in order to true-up actual and projected costs and avoid a large divergence between the Company's actual and estimated expense levels.

Q. With regards to environmental spending for MGP/ Superfund/Other environmental expenditures, is the Company proposing to change the annual rate allowance or "bogey" in this case?

A. Yes, the Company's current rate plan allows it to defer environmental expenses in excess of the Steam

department's share of a $5 million Company-wide annual bogey. Steam operations represent approximately 5% of the Company total, or roughly $250,000 annually. In the current case, the Company is proposing to increase the level of environmental costs reflected in rates up to the level actually disbursed during the test year, the Twelve Months Ending June 30, 2003, escalated for inflation. For steam operations, this would amount to approximately $1.6 million. We would propose to utilize deferred accounting for any over/under expenditures and would collect or pass-through any variation in the 2nd and 3rd stage updates.

World Trade Center

Q. Please explain how the Company is accounting for costs related to the restoration of facilities in lower Manhattan that were damaged as a result of the attack on the World Trade Center ("WTC"), and how it is proposing to reflect these costs in the 2nd and 3rd Stage updates.

A. The Company has deferred and categorized actual spending related to the WTC incident as follows:

- Category 1 - Restoration and emergency response;
- Category 2 - Rebuilding of facilities; and

- Category 3 - Interference (relocation of Company facilities).

The Company has applied for recovery of these costs through the Lower Manhattan Development Corporation ("LMDC"), which, in partnership with the Empire State Development and New York City Economic Development Corporation, has prepared a partial action plan with regard to the $750 million federal appropriation for reimbursing utilities. The Company has recently received the first installment of approximately $30 million. It is the Company's proposal to apply funds received from LMDC and insurance carriers against the deferred expenditures. It appears unlikely, however, that federal funding and insurance reimbursements will be adequate to provide for recovery of all anticipated expenditures. Accordingly, in this current rate proceeding, the Company proposes a thirty-six month recovery for Category 3 expenditures incurred through September 30, 2003, as described in the testimony of Company witness Boyle. The Company would propose to update the WTC recovery as part of the 2nd and 3rd Stage filings.

Capital Expenditure True-up

Q. What is your proposal with regards to a capital spending true-up?

A. Con Edison's capital budget provides for amounts necessary for continued infrastructure reliability, safety and expansion. The Company proposes to true-up the level it spends for capital improvements to within +/- 5% of the annual rate allowance. The Company would maintain the ability to substitute and reschedule projects based upon system needs, but the overall level of spending would be reconciled to the annual rate allowance. I would propose that the Company defer a carrying charge equivalent to 16% on expenditures that vary by more than 5% from the capital budget. The 16% represents carrying costs equivalent to a before tax rate of return of 13% and an annual depreciation allowance of 3%.

The first 5% of any over/underrun would be excluded from the adjustment. This proposal would only apply to the rate year, if the Company does not enter into a multi-year agreement. If a multi-year rate plan is agreed to and approved by the Commission, the Company would defer a carrying charge on the average rate base variation greater than +/- 5% for the three-year

period.

Property Tax True-up

Q. What is your proposal with regards to property tax true-ups?

A. Currently the Company is allowed to true-up only 86% of all steam property tax changes and there is no provision in the rate plan for retention of a portion of property tax refunds. Under the currently effective electric rate plan, the Company is allowed to true-up 100% of tax changes and retains 14% of tax refunds. As discussed by Company witness Hutcheson, the Company proposes that it be allowed to defer 100% of all property tax expenses that are higher or lower than the amounts to be reflected in steam rates. Additionally, the Company proposes that it be allowed to retain 14% of all tax refunds, as further explained by Mr. Hutcheson. I would propose to collect/passback annual variations in property tax and the customers' share of tax refunds in the 2nd and 3rd stages.

74th & 59th Street Reimbursements

Q. Mr. Rasmussen, as a result of Case 99-S-1621, the Company was authorized to transfer the unrecovered plant cost for the 74th and 59th Street generating

stations to steam plant and allowed to continue to recover non-fuel operation and maintenance expenses, including property taxes related to these plants, from the electric department through the MAC until ERRP was in service. What is the Company proposal for these costs in this rate proceeding?

A. As discussed by Company witness Lee, the Company is requesting permission to continue the recovery of the ongoing operating costs and property taxes from the electric department through the MAC until the proceeds from the sale of the 1st Avenue properties are available and can be used to offset this cost.

Steam Line Losses

Q. Mr. Rasmussen what is the Company's proposal with regards to steam line losses?

A. Dr. Bahman Litkouhi's testimony addresses steam line losses, the inappropriateness of using the percentage variance to measure the Company's performance, and the inability of the Company to substantially control losses. As a result, we are requesting that the current incentive/penalty mechanism that is in place for Steam be eliminated going forward.

Steam Fuel Clause

Q. You indicated earlier in your testimony that the Company proposed to modify the existing steam FAC to be fully reconciled, similar to the MSC and GCF. Why are you proposing this change?

A. The Company does not believe that it should make or lose money from the operation of the FAC. An FAC should exist solely to allow the Company to be reimbursed for actual fuel and purchased steam costs incurred to provide service to customers. The way the current mechanism is structured, there are times when the Company can make or lose money depending on the price of energy and the time of year.

Q. I show you a one-page document entitled, "Consolidated Edison Company of New York, Inc. - Summary of Steam Fuel Cost and Purchased Steam (FAC) Over/(Under) Recoveries," and ask whether it was prepared under your direction and supervision?

A. Yes, it was.

MARK FOR IDENTIFICATION AS EXHIBIT___(EJR-3)

Q. What does Exhibit ___(EJR-3) show?

A. Exhibit ___ (EJR-3) shows the actual over and under collection of fuel and purchased steam costs by the Company over the last several years. This exhibit

indicates that there are wide variations on an annual basis. The Company would like to avoid this volatility all together by having a fully reconciled FAC.

Q. Does this conclude your testimony?

A. Yes, it does.

KEVIN BURKE

Q. Please state your name and business affiliation.

A. My name is Kevin Burke. I am President of the Consolidated Edison Company of New York, Inc. ("Con Edison" or the "Company").

Q. Please describe your educational background.

A. I have a Master of Science in Business Policy from Columbia University, a Juris Doctor from Fordham University, a Masters in Engineering from Rensselaer Polytechnic Institute and a Bachelors in Engineering from Cooper Union.

Q. Please discuss your employment history.

A. I have been with the Company for 30 years. From July 1999 to August 2000, I served as President of Orange and Rockland Utilities, Inc. Prior to that, I held various positions including Senior Vice President of Customer Service, Senior Vice President of Corporate Planning, Vice President of Brooklyn Customer Service and Vice President of Construction. In September 2000, I was named President of Con Edison.

Q. What are your current responsibilities as President of Con Edison?

A. As the Chief Operating Officer, I have overall responsibility for Con Edison's electric, gas and steam operations, including the Steam Business Unit.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to describe the need for ongoing infrastructure investments in Con Edison's service territory and the importance of maintaining the integrity of the steam system and reliable service to customers.

Q. Please describe the Steam System.

A. Con Edison's steam system comprises more than 100 miles of mains from 96th Street to downtown Manhattan. Con Edison's steam system is the largest district steam system in the world. It is a crucial part of New York City's energy infrastructure.

Q. How do Con Edison's investments affect the economy in your service territory?

A. New York City's dense population requires energy services that go well beyond what might be needed elsewhere. Because it enables the Company to provide extremely reliable service that customers can

routinely depend upon, Con Edison's infrastructure is a sound base on which the City's economy is built. Con Edison is constantly investing in its energy systems in order to maintain high levels of reliability. Our customers demand this, and deserve nothing less. In order to keep our systems operating at these exceedingly high standards, the investments we make must keep pace with both customer needs and with the natural obsolescence of aging equipment. The energy utility industry is very capital intensive and its financial strength, which allows it to continue to make large capital investments, is critical to the economic success of the City and the State—and to the quality of life enjoyed by our customers. Policies that encourage investment in energy infrastructure will generate jobs and create the energy platform that will allow businesses - and the employment they create - to flourish. Adequate cash flow through rates will allow the Company to access the capital markets as necessary to secure sufficient funding to make the investments required to maintain our energy systems.

Without sufficient cash flow from operations, the level of increased borrowings will result in pressure on Con Edison's key financial ratios, an increase in the cost of debt, and a weakening of our overall financial position. As Company witness Fetter explains in his testimony, New York City needs Con Edison to be financially strong, particularly in this post-Enron atmosphere, to backstop weaker participants in our various energy markets and to be able to continue investments that will support projects critical to New York City's future.

Con Edison's steam system represents the third component of Manhattan's energy supply, along with electricity and gas. Although smaller than our electric and gas businesses, the steam system is an integral part of the New York City economy. For example, the Real Estate sector has historically been a crucial financial driver in New York City and is a key foundation to future growth. Numerous major commercial buildings in the Midtown and Downtown Manhattan business districts use steam for space

heating, domestic hot water, air conditioning and other commercial uses. Major steam customers include large office buildings, hospitals, hotels, universities, important cultural institutions, the United Nations and numerous government buildings. Significantly, the vast majority of all new commercial buildings in Con Edison's steam territory choose to use steam for heating and hot water. This is a testament to the space and operating efficiency advantages of the steam system.

Q. What are the benefits that the steam system provides to the citizens of New York City?

A. The steam system enhances the quality of life of the City's residents in addition to providing many benefits to the New York City metropolitan area as a whole. Production of steam in central plants avoids the need for individual boiler plants at numerous customer locations and the problems attendant to such on-site plants, including increased air emissions at low elevations from smaller sources that are subject to less stringent regulations than are central plants,

and increased traffic congestion from deliveries of fuel oil when used to supplement natural gas. Moreover, the unavailability of steam service for air conditioning would result in sharply increased electric demand on the peak hot summer days, when the marginal generation used to meet such increased demand is generally in short supply, high-priced and the most polluting. Indeed, the steam system currently supplies the equivalent of 400 MW of air conditioning load, which otherwise would require another large power plant to generate. In addition, there would be a need for corresponding capability on the electric distribution system of approximately two electric area substations and associated delivery feeders. Significantly, under the demand side management programs conducted in the 1990's, one-fourth of the reductions in Con Edison's electric peak load were achieved through steam air conditioning installations.

Q. How old is the steam system's infrastructure?

A. Some of the boilers on the system date back to the 1930's and their repair costs are increasing and some

of the buildings and infrastructure supporting the operation of the boilers are almost 100 years old and are in need of significant structural repairs. The system has been maintained over the years, but, as the facilities are getting older, it is experiencing problems associated with age.

Q. Has the Company recently made any enhancements to its steam system?

A. Yes. The Company is constantly upgrading and maintaining the system. The Company recently completed a 10-year Steam Enhancement Program to upgrade the steam distribution system in order to improve its reliability, structural integrity and efficiency. The program, which cost about $200 million, included the replacement of thousands of components, such as expansion joints, anchors and cast-iron fittings, throughout the system. The Company has also focused on the aging steam production facilities, which are in need of continued refurbishment to assure system reliability, efficiency and safe operations. We have replaced pressure parts

in several of our boilers at East River, 60th Street, 59th Street and 74th Street Stations. However, the system is still aging and the availability of the production facilities is being impacted. There is a need to accelerate spending to maintain our equipment and to offset the defects of aging.

Q. Please discuss the East River Repowering Project ("ERRP") and its benefits to steam customers and other residents of the New York City metropolitan area.

A. To ensure that Con Edison's steam service will continue to be reliable and economic, a new steam/electric generating facility, using state-of-the-art technology and equipment, is being installed in an unused section of the East River Generating Station. The proven combined-cycle technology will offer a high degree of operating efficiency, reduced emissions and high reliability, thereby providing significant economic and environmental benefits to Con Edison's customers and the City of New York. The new facility will permit the retirement and replacement of aging generating units at the Waterside Generating

Station and, in the summer, will provide an additional 125 MW of electric generating capacity to help meet New York City's peak load. The new facility will also provide an additional 650,000 lbs/hr of steam capacity to the steam system, while reducing projected aggregate annual emissions by about 70 percent compared to emissions from the Waterside units it is replacing.

The retirement of the Waterside plant will also enable the sale of its site along with three other Company-owned sites along First Avenue and the net proceeds from the sale will benefit consumers.

Company witness Gonnella discusses the cost and schedule of the project and Company witness Shansky further discusses the anticipated benefits of ERRP for customers.

Q. Please discuss the importance of maintaining the steam system infrastructure.

A. An upgraded, reliable infrastructure is vital to customers, who require a reliable energy source for heating, air conditioning and other uses. The

continued integrity of the steam system and its service reliability are imperative not only for continuing to provide excellent service to existing customers, but also for continuing to attract new business and accommodate potential growth. Absent the necessary investment to repair and replace aged and deteriorating structures, equipment and facilities, as proposed in this rate filing, the Company's ability to continue to provide high-quality, reliable steam service -- which customers deserve and have come to expect -- will be seriously compromised.

Q. Please provide a brief description of the Company's plan to upgrade and enhance the steam system's infrastructure.

A. In order to maintain current levels of service reliability, Con Edison will have to spend substantially more capital and maintenance dollars than are covered by current rates to address the immediate and longer-term needs of its production-related facilities. As explained in more detail in Company witness Bozgo's testimony, the Company's five-

year steam capital plan includes expenditures to repair aging boilers and other major plant components, refurbish major structures, including various building roofs, facades, stacks and docks, and upgrade outdated or obsolete control systems and equipment.

Similarly, Company witness Adinolfi's testimony describes various expense programs for major repairs and maintenance of aged production plant equipment, structures and facilities necessary for equipment integrity, performance efficiency and operating reliability.

While we are continuing our ongoing efforts to reduce the cost of our operations and to retain the competitiveness of our steam service, we cannot continue to assure customers reliable service without investing in sorely-needed upgrades. We believe that the investments and level of spending that we propose in this rate filing accomplish these objectives and continue to assure customers reliable service.

Q. Does this conclude your testimony?

A. Yes, it does.

Q. Please state your name and business affiliation.

A. My name is Andrew L. Jacob. I am employed by the Consolidated Edison Company of New York, Inc. ("Con Edison" or the "Company") as Vice President of Steam Operations.

Q. Please describe your educational background.

A. I have a Bachelor of Engineering Degree in Mechanical Engineering from Manhattan College and a Masters of Business Administration Degree from Pace University.

Q. Please discuss your employment history.

A. I have 34 years of experience in the electric utility and related industries, including American Electric Power, Columbia University and Con Edison. For most of that time, I was involved in various aspects of planning, design, construction, operation and maintenance of electric and steam generating plants. On August 1, 1999, I was promoted to Vice President of Steam Operations.

Q. What are your current responsibilities as Vice President of Steam Operations?

A. I have overall responsibility for Con Edison's steam business including production, distribution, delivery and customer service.

Q. Have you previously testified in rate cases before the New York Public Service Commission ("Commission")?

A. Yes. I testified as a witness for the Company in Commission Case Nos. 90-S-0938, 91-E-0462, 93-S-0997, 94-E-0334, 96-E-0897, 96-S-1065 and 99-S-1621.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to discuss:

1) the proposed new steam rate design, which is intended to recover the fixed costs of the steam system through fixed charges. I also discuss the alternative real-time weather normalization clause ("WNC") proposal;

2) the proposed elimination of the steam variance incentive/penalty mechanism; and

3) a number of proposed changes to existing tariffs and a new negotiated price fuel service for customers.

STEAM RATE DESIGN

Q. Explain why Con Edison is proposing a steam rate re-design.

A. The Agreement and Settlement approved in Opinion No. 00-15 was based upon an anticipated annual return on steam equity in the range of 10-11% (with an earnings sharing threshold of 11% in the first rate year and

10.5% in subsequent rate years). However, experience has shown that the rate plan under that agreement has not enabled the Company to earn anything close to the returns envisioned. For the first rate year (i.e., 12 months ending September 30, 2001), the actual steam return on equity was 6.68%, despite winter weather that was colder than normal. For the second rate year (i.e., 12 months ending September 30, 2002), due in large part to abnormally warm winter weather, the actual steam return on equity was 0.72%, which is grossly inadequate by any measure. For the third rate year, notwithstanding the colder than normal weather, the actual steam return on equity reached only 9.17%. These rates of equity returns are clearly inadequate to allow the Company to maintain current levels of investment, let alone meet the increasing investment needs of the steam system. In addition to the rate relief requested in this filing, the proposed rate re-design is necessary in order to permit the Company to realize the revenue increase granted by the Commission to enable the Company to recover its costs of providing service and make the necessary investments in steam infrastructure.

Q. Please describe the rate re-design.

A. The Company proposes re-designed steam rates in SC 2 and SC 3 that will collect fixed steam system costs through fixed charges and, thus, more accurately align rates with system costs. The re-designed rates would be based on normal weather, would be revenue-neutral (for customers and Company shareholders), and would take potential bill impacts into consideration. A more detailed description of the re-designed rates, which are not only more cost-based, but also mitigate the effects of weather variations on the Company's steam revenues, is provided in the testimony of the Steam Rate Panel.

In conjunction with the re-designed steam rates, the Company proposes a program to install state-of-the-art metering at the sites of our larger SC 2 and SC 3 steam customers, as described in the testimony of Company witness Bozgo, and to phase-in charges in these customers' bills based on the demand measured by these new steam meters, as more fully discussed by the Steam Rate Panel.

The Commission has long recognized that using fixed charges to recover fixed costs is the best way to ensure that utilities have sufficient revenues to invest in their systems, and that they provide

consumers with the proper price signal concerning their peak consumption. Other utility services uniformly have both fixed and variable cost designs, and the implementation of this rational rate design for the steam system is long overdue.

Q. How does the proposed rate re-design differ from a weather normalization clause, which also neutralizes the effects of weather on steam earnings?

A. The proposed rate re-design more closely aligns rates with system costs, provides more predictable monthly bills for customers and revenues for the Company, and addresses the effects of abnormal weather year-round. As a second-choice alternative, the Company proposes a standard weather normalization clause ("WNC").

Q. Please generally describe the proposed WNC.

A. The proposed WNC provides that the non-fuel component of customers' bills will reflect normal weather and that steam heating customers will be charged or credited monthly based on unit charges that quantify the impact of abnormal weather on revenues. The WNC will mitigate higher bills to steam customers when abnormal weather causes higher usage, and it will protect the Company when abnormal weather results in lower customer use. The weather normalization clause

proposal is explained in more detail in Company witness Yaegel's testimony.

ELIMINATION OF STEAM VARIANCE INCENTIVE/PENALTY MECHANISM

Q. Please explain the current steam variance incentive/penalty mechanism.

A. Steam base rates currently assume a 10.9% factor for the steam variance or line losses. The fuel costs associated with losses above that amount are collected through the steam fuel adjustment clause. However, to the extent that losses exceed 13.5% in any rate year, the associated fuel costs are to be refunded to customers through the fuel adjustment clause in the following rate year. The Company is not required to refund avoided fuel costs associated with line losses less than 10.9%.

Q. What has been the Company's experience under this mechanism?

A. Over the previous six years, since the inception of the steam variance penalty target of 13.5%, the percentage loss has ranged from 13.4% to 17.2%; therefore, the Company has only incurred penalties and has had no opportunity to receive a benefit from this mechanism. The results of this mechanism have been closely tied to weather. In the current rate plan's

Rate Year 2 (ending September 30, 2002), the northeast region experienced record mild weather, the steam flow rate through the steam system piping was, for reasons of mild weather and sales shortfalls, significantly lower than normal, driving the steam loss percentage to an unprecedented 17.2%. In direct contrast, during Rate Year 3 (ending September 30, 2003), when the New York area experienced colder-than-normal weather, the steam loss percentage was 13.5%, which demonstrates that the 13.5% penalty target is barely achieved even when a colder-than-normal weather pattern is experienced. The incentive target of 10.9%, below which the Company starts to realize a benefit, is clearly not achievable.

Q. Please explain why the Company proposes to eliminate the steam variance incentive/penalty mechanism.

A. As explained in the testimony of Company witness Litkouhi, the steam system's losses are primarily thermal losses that are largely fixed regardless of total sendout. However, the current mechanism penalizes the Company for steam losses on a percentage basis relative to the total recorded sendout. Losses expressed in percentage terms tend to vary primarily as a result of changes in sales volumes. As a result,

the percentage steam variance is significantly higher during warmer-than-normal periods simply because of reduced sales, while the absolute losses are much more stable.

This pattern has had a particularly deleterious effect on the steam system's financial condition, because it exacerbates the effect of warm weather. Thus, when the weather is unusually warm, not only have the steam system's revenues fallen short of expectations because of less customer usage, but the steam variance incentive/penalty mechanism has worked to further erode steam system earnings, resulting in unacceptably low returns to the Company.

The Company should not continue to be subject to an incentive/penalty mechanism that is based on a measure of steam losses over which the Company has no reasonable control. Moreover, the incentive/penalty mechanism should be eliminated in its entirety because, as discussed in the testimony of Company witness Litkouhi and others, the Company has little control even over the absolute variance.

Q. Notwithstanding its proposal to eliminate the steam variance penalty/incentive, is the Company continuing to work at reducing steam line losses?

A. Yes. As discussed in the testimony of Company witness Bozgo, the Company has various capital programs to help reduce leaks, which constitute but a small part of the losses. In addition, a manhole insulation program has recently been completed, which only marginally reduced the steam variance. Finally, Company witness Codner discusses some R&D programs that the Company is pursuing to further reduce losses. It must be emphasized, however, that the steam losses are primarily related to weather conditions that the Company cannot control. The additional initiatives, while they may show themselves to be cost effective, will not have a substantial effect on steam losses.

Q. Without an incentive/penalty mechanism for line losses, what incentive does Con Edison have to control fuel costs?

A. Controlling fuel costs is an essential part of keeping steam competitive with other energy sources because fuel costs are a major component of steam rates. As described in the testimony of Company witness Northup, Con Edison is taking a number of steps to manage the volatility of fuel costs, in addition to the significant reduction in fuel costs that will be provided by the East River Repowering Project.

TARIFF CHANGES

Q. What other changes to the steam tariffs do you propose?

A. The Company proposes to, among other tariff changes:

i) withdraw the SC 6 Transportation Service since there have been no subscribers to this service since its inception during the current rate plan period, and no subscribers are expected in the foreseeable future. Furthermore, given that the cost of providing this service is highly dependent on site-specific circumstances, the SC-6 rate may, in many instances, not be cost-based;

ii) modify the tariff to require prepayment for extension or reinforcement of steam mains if estimated revenue over a two-year period (rather than a one-year period) is insufficient to justify the expenditure. This would encourage new steam business while continuing to ensure that the cost of service extensions is covered;

iii) modify the terms of the Steam Repair Service (Special Services Performed by the Company for Customers at a Charge as described below); and

iv) add the opportunity for the Company and its customers to negotiate the price of the fuel

portion of the steam service rate for a fixed amount of the customer's requirements.

Q. Please describe the Steam Repair Program.

A. The Steam Repair program offers customers leak repair services on a voluntary basis. Con Edison assists in repairing leaks on the customer's side of the meter, including requests in emergency situations or at times of the day when the firms that normally may be able to provide these services to customers are unavailable.

Q. What changes are being proposed?

A. To ensure recovery of the cost to provide steam repairs and to reduce the cost of collection, the Company proposes the collection of the estimated labor and materials charges from the customer in advance of performing a steam repair job, with a subsequent charge/credit to customers if actual charges are higher/lower than the estimate. In addition, the Company proposes that the basis for the materials charge be the fair market value of the materials.

Q. Please elaborate on the proposal for a new tariff to provide the opportunity for the Company and its customers to negotiate the price of the fuel portion of the cost of steam service?

A. The addition of this new service addresses the informal requests by certain steam customers to have the fuel adjustment clause portion of their bills fixed or stabilized, at least during the seasons in which fuel prices are traditionally most volatile. The negotiated fuel price would be set forth in a written agreement between the Company and the customer. The customer would pay an agreed upon amount for fuel in lieu of the average cost of fuel. That amount would be charged or credited as an increment or decrement to the base cost of fuel. This is further discussed in the testimony of Company witness Northup.

Q. Does this conclude your testimony?

A. Yes.

Q. Please state your name and business address.

A. My name is Rick Shansky. My business address is 4 Irving Place, New York, New York 10003.

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

A. I am employed by Consolidated Edison Company of New York, Inc. ("Con Edison" or the "Company") as Section Manager, Steam Resource Planning, in Energy Management.

Q. Please state briefly your education and professional background.

A. I graduated from Rensselaer Polytechnic Institute with a Bachelor of Science degree in Electrical Engineering in 1981. I also earned a Master of Science degree in Energy Management from New York Institute of Technology in 1988. I am licensed as a Professional Engineer in the State of New York.

From 1981 to 1984 I was employed by the Long Island Lighting Company in the Planning Department. I joined Con Edison in 1984 as an Associate Engineer in Generation Planning and have since been promoted to increasing levels of responsibility. Since 1995, I have been responsible for steam system planning, including preparation of Con Edison's Steam System Plans.

Q. Have you previously testified before the New York State

Public Service Commission ("Commission")?

A. Yes. I have been a witness for Con Edison in Cases 92-E-0814, 93-E-1075, 94-E-0334, and 99-S-1621. In addition, I testified in the East River Repowering Article X proceeding (Case 99-F-1314). I also appeared before the Commission in Case 93-E-0912 as a witness for the Member Electric Systems of the New York Power Pool.

Q. What is the purpose of your testimony?

A. First, I will discuss Con Edison's steam resource plan, which will include a presentation of the results of a study of potential future generating options at the 59th Street, 74th Street, and Hudson Avenue stations. Second, I will address the methodology for allocating costs between steam and electric operations at joint facilities including the East River Repowering Project ("ERRP"). Third, I will present an analysis of the benefits of ERRP. Fourth, I will explain the basis for the incremental usage adder to be included in the proposed Usage Charge as described in the testimony of the Steam Rate Panel.

STEAM RESOURCE PLAN

Q. Please describe Con Edison's steam resource plan.

A. The primary objective of the plan is to enable Con Edison

to continue to provide reliable steam service at a reasonable cost. Con Edison intends to meet this objective by replacing Waterside with ERRP and continuing to maintain other steam and steam-electric generating plants in order to maintain the integrity and reliability of the steam production infrastructure. Company witnesses Burke and Bozgo provide greater details on the need for these infrastructure investments.

Q. Does the Company's resource plan provide sufficient steam generating capacity to meet customer needs?

A. Yes. Con Edison plans its steam generating capacity to meet forecasted peak loads and to maintain a reserve in the event of equipment outages. The steam system has been planned so as to limit the risk of occurrence of low pressure (i.e., capacity shortages) to no more than one day per year, on average. In addition to this long-standing criterion, I recommend that sufficient capacity be maintained to allow for loss of the largest steam generating unit during the peak winter season. A reserve of 1.5 million lbs/hr (equal to the steam capacity of one ERRP unit) would be sufficient to meet these two criteria. When ERRP is placed in commercial service, Con Edison will have approximately 12.8 million lb/hr of

generating capacity. The forecasted peak load for the 2004/2005 winter is 10.5 million lb/hr. Therefore, Con Edison will have sufficient capacity to satisfy its reliability criteria.

Q. Company witnesses Jacob and Bozgo and the Steam Rate Panel describe the planned introduction of demand metering. How will this be incorporated into the steam resource plan?

A. With demand metering, it is expected that customers will have both the information and the appropriate price signals to manage their peak loads so as to minimize the total need for steam generating capacity. Con Edison plans to monitor changes in the peak load and adjust its program for steam plant maintenance according to changes in the need for capacity.

Q. In developing its steam resource plan, did Con Edison consider installing new steam or steam-electric generation?

A. Yes. Pursuant to the Agreement and Settlement adopted by the Commission in Case 99-S-1621, Con Edison performed a study of new steam and steam-electric generation at the 74th Street, 59th Street, and Hudson Avenue Stations.

Q. What was the objective of the study?

A. The objective of the study was to determine if new steam or steam-electric generation at these sites could help to minimize steam rates. Working in consultation with the staff of the Department of Public Service and other interested parties to Case 99-S-1621 ("Study Group"), Con Edison examined the following generation options: new boilers at each of the three plants; gas turbine cogeneration with supplemental boilers at each of the three plants; and combined-cycle with supplemental boilers at Hudson Avenue.

Q. Why was combined-cycle considered for Hudson Avenue only and not at 59th Street or 74th Street?

A. Only the Hudson Avenue site was judged to be a feasible potential location for installing a combined-cycle plant on account of the space needed for a steam turbine and air-cooled condenser.

Q. Please describe the methodology underlying the study.

A. The study compared the cost of steam for each generation option with the cost of maintaining the existing boilers at each station over a 20-year period. All options were assumed to be in service in 2007. Included in the cost projections were capital costs, O&M costs, property taxes, and fuel costs. In the case of steam-electric

options, the value of the electric generation was also considered.

Q. How were the cost projections developed?

A. The capital cost estimates for new generation were obtained from an engineering consultant. Capital costs for site preparation and system reinforcements were estimated internally. Avoided capital costs associated with the existing boilers were based on Company witness Bozgo's 5-year construction forecast and projections of other capital requirements over a 20-year period. O&M cost estimates were also developed internally. Fuel and electricity costs were based on a forecast developed in consultation with the Study Group.

Q. Please describe the results of the study.

A. The study concluded that installing new steam or steam-electric generation would further increase steam rates and would not be preferable to Con Edison's plan to maintain the existing steam generation.

Q. Did you prepare an Exhibit, entitled "ECONOMIC IMPACT OF NEW STEAM GENERATION", that compares the various scenarios that were studied?

A. Yes.

MARK FOR IDENTIFICATION AS EXHIBIT __(RS-1)

Q. Please describe what Exhibit __(RS-1) shows.

A. Exhibit _____(RS-1) shows the estimated economic impacts of the various scenarios studied for the three stations.

Q. Please explain why property taxes are reduced for the new boiler options.

A. The property tax calculations include an assumed reduction in taxes if existing boilers are retired. They also include an increase in taxes resulting from future capital spending, whether for existing or new boilers. Depending on the balance among these increases and decreases, the resulting taxes could be higher or lower.

Q. Certain of the options result in annual cost increases of a few million dollars. Could impacts of this magnitude be justified to replace older steam generation?

A. I urge caution in interpreting the study results. This is a screening analysis which was intended to provide "order-of-magnitude" results. It lacks the benefit of detailed site-specific estimates for installation costs, site preparation, and demolition costs. It also assumes that increased fuel burning as a result of electric generation would not require any mitigation (e.g., operational limitation). Similarly, the gas turbine cogeneration option was assumed to operate in a base load

fashion, although it is likely in practice that such units would be shut down during light load periods. In summary, I believe the cost impacts determined in this study are likely to be understated.

Q. Did the study consider the possibility of shifting generation from one site to another?

A. Yes, this concept was initially considered. However, the Study Group decided to limit consideration to shifting that would not result in the need to reinforce the steam distribution system. The result of this limitation was that only small shifts in generation could be considered. Therefore, Con Edison concluded that shifting generation would not materially affect the results of the study.

Q. Did the study consider ways to extract real estate value from the sites?

A. No. Although the Study Group had contemplated this as an element of the study, Con Edison concluded that there is little opportunity to extract such value from an operating generation site.

Q. Do the study's conclusions regarding cogeneration have any implications for the ERRP?

A. No. The study concluded that cogeneration would produce more expensive steam than the existing boilers. The

economics of ERRP, as I will explain in more detail below, are based on the comparison of new cogeneration technology at East River to old cogeneration technology at Waterside. Moreover, ERRP will take advantage of the remaining base load cogeneration opportunity in the steam system. Therefore, any additional cogeneration projects would show diminishing returns.

ALLOCATION OF JOINT COSTS

Q. Please describe the methodology used to allocate costs associated with jointly used facilities among the Electric, Steam, and Gas Departments.

A. The allocation of these costs is in accordance with the Commission's determination in Case No. 27276. In general, the cost of facilities that are jointly used by the Steam and Electric Departments are carried in the Electric Department accounts and only the incremental costs related to steam production are allocated to the Steam Department. This approach is used for the Waterside Station and the current East River Station. The Ravenswood Tunnel is carried in the Gas Department plant accounts and is jointly used for electric, steam, and gas operations. Annual charges are computed by applying carrying charge rates to the book cost of each

facility. The specific computations are described in the testimony of Company witness Lee.

Q. What approach do you recommend for allocating the ERRP costs?

A. I propose that the same incremental costing method be applied to ERRP as is currently used for Waterside.

Q. Please explain how the methodology would be employed with regard to the capital cost of ERRP.

A. Only those components that are associated with steam production or delivery would be allocated to steam. Therefore, the capital cost of the heat recovery steam generators ("HRSGs") and their associated piping; the capital cost of the water treatment plant; and the capital cost of the steam interconnection would all be allocated to steam. All other costs would be allocated to electric.

Q. How would the fuel consumed by ERRP be allocated between electric and steam?

A. As proposed by the Company and reflected in the Agreement and Settlement adopted by the Commission in Case 99-S-1621, all of the fuel consumed in the gas turbines would be allocated to electric production since the gas turbines would have to be operated to produce electricity

even if no steam were produced. The fuel used for supplemental firing in the HRSGs to increase steam production would be allocated to steam.

Q. How would other costs be allocated?

A. Processing costs, consisting of the costs of water, water chemicals, and water treatment plant labor, would be allocated to steam. All other O&M costs would be allocated to electric production.

ERRP BENEFITS

Q. Have you prepared an analysis of the anticipated benefits of ERRP for both the steam and electric ratepayers?

A. Yes. I have prepared an exhibit entitled "ERRP ECONOMIC BENEFITS."

MARK FOR IDENTIFICATION AS EXHIBIT __ (RS-2)

Q. Could you please explain this exhibit.

A. Exhibit___(RS-2) compares the various cost elements associated with ERRP with the costs associated with keeping Waterside in service, if ERRP were not built. These costs are expressed as levelized annual costs over the next 20 years. The results show that the overall savings are estimated to be approximately $60 million per year.

Q. How will these benefits be shared by steam and electric

customers?

A. The benefits will be shared in relation to the allocation of ERRP costs as determined by the Commission; the current allocation of costs at Waterside; the allocation of net gains from the sale of the First Avenue Properties as will be determined by the Commission; and the customers who would otherwise have incurred avoided costs such as electricity purchases.

Q. Please explain the cost element entitled "Recovery of Investment".

A. Recovery of Investment consists of the carrying charges needed to recover the capital investment (including return, depreciation and income taxes) in ERRP or, alternatively, the future capital costs associated with maintaining Waterside and other boilers on the steam system that would no longer be needed once ERRP is completed.

Q. Which boilers, aside from Waterside, would not be needed?

A. For this analysis, consistent with the ERRP Article X analysis, credit was taken for avoiding future costs associated with five of the ten boilers at the East River South Steam Station.

Q. Please explain the Real Estate Benefits item.

A. The real estate benefits are the annual equivalent of a portion of the proceeds anticipated from the sale of the First Avenue Properties. The portion consists of the net proceeds available to offset the remaining book cost of the Waterside plant, plus those net gains on the properties attributed to the construction of ERRP and the sale of Waterside.

Q. Aside from the savings shown in your Exhibit, are there any other benefits that ratepayers will derive from ERRP?

A. Yes. The addition of approximately 125 MW of in-City electric capacity (based on summer ratings) would lower the cost of capacity that is priced according to the demand curve. It is estimated that the annual savings for Con Edison's electric customers would be in excess of $50 million. ERRP's higher electric output should also help to reduce the price of electric energy.

USAGE CHARGE

Q. Turning to the last area of your testimony, did you provide the Steam Rate Panel with an incremental cost adder of $0.85/Mlb to be included in the proposed Usage Charge?

A. Yes.

Q. Please explain the basis of the adder.

A. While the Access Charge is meant to recover fixed costs and the Usage Charge is meant to recover variable costs, there are certain costs that are neither solely fixed nor solely variable. For example, while labor and maintenance costs are considered fixed costs, these costs can vary somewhat with large enough variations in steam plant operation. However, such variability is difficult to estimate. Therefore, as a proxy for these "semi-variable" costs, an incremental cost was derived from the current discounted steam air conditioning rate. This rate is assumed to recover none of the purely fixed costs. The difference between this rate and the total variable cost in rates is assumed to be the incremental O&M cost.

Q. Did you prepare an exhibit entitled "USAGE CHARGE ABOVE BASE FUEL COST AND ELECTRIC, WATER, AND CHEMICAL COST " Exhibit ___ (RS-3)?

A. Yes.

MARK FOR IDENTIFICATION AS EXHIBIT __ (RS-3)

Q. Why was the discounted air conditioning rate used to derive this adder?

A. The discounted air conditioning rate represents a price for steam during an "off-peak" season, i.e., where the

costs of production are not driven by fixed plant costs. Since such discounted rates are always greater than or equal to marginal costs, it follows that the discounted air conditioning rate covers marginal variable costs (fuel, water, chemicals, and electricity). The extent to which the rate exceeds these variable costs must reflect a contribution to "fixed" costs other than fixed plant costs, i.e., the "semi-variable" costs. It is appropriate to recover these costs through a variable charge because they vary with usage, albeit less directly than fuel or water costs.

Q. Does this conclude your testimony?

A. Yes.

Q. Please state your name and business address.

A. My name is Victor Gonnella and my business address is 801 E 14th Street, New York, New York, 10009.

Q. Who is your employer and what is your job title?

A. I am employed by Consolidated Edison Company of New York, Inc ("Con Edison" or the "Company") as a General Manager in the Steam Business Unit. I am the Project Manager for the East River Repowering Project ("ERRP").

Q. How long have you been employed by Con Edison and what positions have you held?

A. I have been employed by Con Edison for over 37 years and have held many different positions throughout the company including General Manager in Construction Management (where, for six years, I was responsible for a 400 person engineering and construction organization), General Manager in Transportation and Stores and Director in Purchasing.

Q. Briefly describe your educational background.

A. I received a Bachelor of Civil Engineering Degree from Manhattan College in 1965. I am a registered Professional Engineer in the State of New York.

Q. What is the purpose of your testimony?

A. My testimony will address the capital construction costs associated with ERRP.

Q. What is the purpose of ERRP?

A. The primary purpose of ERRP is to ensure that Con Edison can continue to supply reliable, reasonably priced steam by replacing the Waterside Generating Station with highly efficient, low emission, combustion technology.

Q. What is the projected capital cost of ERRP?

A. The projected capital cost is $670 million.

Q. Could you please explain the major components that comprise the $670 million?

A. The $670 million covers the following eight major activities:

1. $45 million to alter the existing, original East River power plant facility to create the space for the new equipment. This work consists of modifying existing building structural steel framing, as well as relocating electrical and mechanical systems to provide the required space.
2. $134 million for the purchase of the new ERRP equipment. This includes $70 million for the General Electric Combustion Turbines, $22 million for the Vogt Nem Heat Recovery Steam Generators, and $10 million for the US Filter Water Treatment Equipment.

3. $201 million for the construction contract to install the new equipment including the requisite foundation work.
4. $76 million for the engineering, construction management, start up, legal and outreach costs associated with the plant work.
5. $77 million for the engineering, design, and construction of a 30 inch steam main that takes the 3.0 Million pounds per hour of steam output from ERRP and delivers it to 40th Street and 1st Avenue, the location of the existing output from Waterside Station. Included in this cost is the construction of a tunnel, 10 feet in diameter, 4100 feet long, under 1st Avenue from 20th Street to 36th Street.
6. $27 million for the engineering, design and construction of a 30,000 foot long, high pressure gas main from East River Station to a tie in point at 75th Street and West End Avenue.
7. $14 million for the electrical construction work required to connect the output of Combustion Turbine Generator # 1 to the 138KV Substation at 14th Street and Avenue C, and to connect the output of Combustion Turbine Generator # 2 to the 69KV substation on 15th Street.

8. $96 million for corporate overheads ($3 million), construction contingency ($18 million) and allowance for funds during construction (AFUDC -- $75 million).

Q. Could you please explain how much has been expended on this project to date - by year - and how much is required to complete the project?

A. Actual expenditures from 1999 through the 3rd quarter, 2003, are $ 419.8 million. The cost breakdown on an annual basis is as follows:

1999 -- $ 4.9 million

2000 -- $ 44.1 million

2001 -- $ 105.3 million

2002 -- $ 118.3 million

2003 -- $ 147.3 million

Future expenditures are forecasted as follows:

4th qtr 2003 - $ 67.7 million

2004 -------- $ 182.4 million

Q. Could you please explain some of the cost increases since submission of the Article X application?

A. At the time the Company submitted its Article X application, the Company estimated the cost of the ERRP to be $406 million (including $ 46 million for the gas main). In several instances the full extent of the

eight project components described in my prior answer above were not known at the time of the Article X application, and in other instances there have been work scope and scheduling effects that could not have been anticipated previously, prior to the completion of detailed design work and subsequent vendor bidding. It bears mention that ERRP is unique in that the Company is retrofitting ERRP into an operating power plant, coupled with the gas and steam work in the streets, the latter involving two different tunnel elements.

The significant cost increases include:

- $110 million in the cost of construction contracts, resulting from the completion of the detailed design after the Article X cost estimates were made and the limited competition in the market for construction of large projects such as ERRP.
- $36 million in pre-construction structural alterations following detailed engineering and complete examination of field conditions.
- $28 million in the costs of steam main due to final analysis of field/environmental conditions which required design and route changes.
- $55 million increase in AFUDC due to 18 months change in service date and increase in project cost.

Q. What is the current schedule for the completion of the project?
A. The project is expected to be completed in the fourth quarter of 2004.
Q. What are the benefits of ERRP?
A. Company witness Shansky presents an analysis of the benefits of ERRP to ratepayers.
Q. Have you determined which capital costs should be allocated to steam vs. electric customers?
A. Yes.
Q. I show you a one-page table entitled, "East River Repowering Project - Current Working Estimate," and ask you whether it was prepared under your supervision and direction?
A. Yes.

MARK FOR IDENTIFICATION AS EXHIBIT ___ (VG-1)

Q. What does the exhibit show?
A. Exhibit ___ (VG-1) shows the elements of the project costs and their allocation between steam and electric using the methodology described in Company witness Shansky's testimony. Under that methodology, the water treatment plant, steam interconnection, heat recovery steam generators (HRSGs) and their associated piping would be charged to steam and all other components

would be charged to electric. In addition, a pro rata share of overheads and AFUDC were applied to all the capital costs. As shown on Exhibit ___ (VG-1), the result is that approximately two-thirds of the project cost is allocable to electric and one-third to steam.

Q. Does this conclude your testimony?

A. Yes.

Q. Please state your name and business address.

A. My name is Ronald Bozgo and my business address is 4 Irving Place, New York, New York 10003.

Q. Who is your employer and what is your job title?

A. I am employed by Consolidated Edison Company of New York, Inc. ("Con Edison" or the "Company") as the Chief Engineer in the Civil Mechanical Engineering Department.

Q. How long have you been employed by Con Edison and what positions have you held?

A. I have over 33 years experience in the utility business, of which the last 20 years have been with Con Edison. I was first employed by Con Edison in January 1984 and held various engineering and engineering support positions in Central Engineering. In September 1998, I transferred to Con Edison Development, an affiliate of Con Edison, where I held the position of Vice President of Engineering. On November 1, 2002, I rejoined Con Edison as the Chief Civil Mechanical Engineer in Central Engineering, my current position.

Q. What are your current responsibilities as Chief Civil Mechanical Engineer?

A. My primary responsibility is to provide senior technical authority and management oversight to ensure the safe and sustained operation and maintenance of

specific systems within their design basis. These systems include: the steam distribution and transmission systems, the mechanical and structural systems and equipment that support the Steam Business Unit power plants, and the system and transmission operations infrastructure.

Q. Briefly discuss your educational background.

A. I received a Bachelor of Engineering Degree in Electrical Engineering from Pratt Institute in 1968. I also received a Masters of Science Degree in Management Engineering from Columbia University in 1972. I am a senior member of IEEE and a Professional Engineer in the state of New York.

Q. What is the purpose of your testimony?

A. My testimony will address the Steam Plant Construction and Steam Distribution Construction Programs. These programs comprise the Company's capital expenditure plan for maintaining the steam generating plants and distribution infrastructure.

Q. Please describe what is meant by Steam Plant Construction.

A. Steam plant construction includes short and long-term capital improvements to the generating stations that are needed to provide safe, reliable and efficient steam service.

Q. Please describe what is meant by steam distribution construction.

A. Similar to plant construction, Steam Distribution Construction includes capital improvements to the piping and support systems that that are needed to provide safe, reliable and efficient steam delivery to our customers.

Q. How is the construction budget prepared?

A. Each year, Con Edison goes through a rigorous process in preparing its budget and 5 year capital program. A list of projects is developed with proposed priorities based on current needs. These projects are prioritized in the annual capital budget process and are evaluated by senior management. Priorities are assigned based on meeting the Company's objectives of providing reliable service at a reasonable cost.

Q. Did you provide Mr. Ricco with the construction expenditure estimates shown on your exhibits?

A. No, these estimates were not yet available. I provided him with estimates for 2004 and 2005 based on the initial construction program, which was subsequently revised.

STEAM PLANT CONSTRUCTION PROGRAM

Q. Please identify and describe Con Edison's Steam Plant Construction Program.

A. Con Edison's Steam Plant Construction Program supports the Company's steam generating stations by providing funding for projects needed for operational purposes. This funding is used to maintain the existing stations so that they can operate safely, reliably, and efficiently. This capital program consists of five major classifications of expenditures, namely, 1) Environmental, Health and Safety ("EH&S"), 2) Capacity, 3) Reliability, 4) Regulatory Compliance, and 5) Small Capital.

Q. Mr. Bozgo, have you prepared an exhibit entitled "CONSOLIDATED EDISON COMPANY OF NEW YORK, INC., STEAM PLANT CONSTRUCTION PROGRAM, ESTIMATED 2004-2008", set forth as Exhibit __ (RB-1) that shows the Company's steam plant five-year capital program?

A. Yes.

MARK FOR IDENTIFICATION AS EXHIBIT __ (RB-1)

Q. What does this exhibit show?

A. This exhibit shows Con Edison's projected Steam Plant Construction program for each of the years 2004 to 2008 by major program category: EH&S, Capacity, Reliability, Regulatory, and Small Capital.

Q. How much does the Company expect to spend in the Steam Plant Construction Program during 2005, the major part of the rate year?

A. The Company projects to spend nearly $32 million for these projects. While the descriptions below indicate that the funding is currently allocated for certain programs, the Company re-evaluates its capital budget frequently and if, at a later date, there is a higher priority need, the Company may reallocate the funding.

Q. Please describe what is covered under construction expenditures for EH&S.

A. Con Edison's EH&S Program requires periodic environmental and safety assessments of each generating station. During these assessments, projects are developed to address plant conditions that may impose an EH&S risk. These assessments are important as they ensure the Company's continued compliance with environmental regulations. Currently, some of the EH&S projects include the installation of containment under the boilers and replacement of oil-filled transformers at the 74th Street station. During 2005, the Company plans to spend about $2.3 million on this category. About $1.2 million is allocated for environmental-related projects identified by the environmental assessments. In addition, the Company expects to continue installing emissions reduction technology ($1 million) and fire suppression systems at various steam production plants. This emissions technology includes

the installation of nitrous oxide emissions monitoring and control equipment. The steam system currently provides an important environmental benefit to the New York City metropolitan area because the Company's steam production units generally have less air emissions than on-site oil boilers. These proposed programs will further improve the Company's environmental performance.

Q. Please describe what is covered under construction expenditures for Capacity.

A. Capacity projects are those that are needed to maintain generating capacity to meet customer demands and service requirements. Capital expenditures for these projects will be required over the next five years to maintain boilers, major structures, and related balance of plant systems.

Q. Please describe what is covered under the category entitled Reliability.

A. Plant reliability is a program category that seeks to maintain and improve the reliability of the steam supply to our customers. Plant components that fail or degrade and contribute to plant unavailability need to be replaced or upgraded. The Company has budgeted $15.7 million for these types of projects in 2005. Under this category, the Company currently expects to

fund the following projects:

- East 60/74th Street ($5.3 million) - various reliability related programs have been funded for these two plants. These projects include, but are not limited to, the replacement of tubes on the package boilers because their condition is beyond economic repair; replacement of breakers throughout the station; replacement of an economizer and the upgrade of existing control systems technology.
- York Steam Line Upgrade ($1.5 million) - this is to mitigate potential leaks and cracks currently found on the steam transmission line coming from the Brooklyn Navy Yard Steam Facility to Hudson Avenue. These major alterations, including the installation of new piping, are intended to assure the long-term service of the line.
- Hudson Avenue ($3.3 million) - major repairs will be performed on the steam row headers and the branch feed piping, repair of the deaerators, which have degraded over time; and the repair of the boiler components.
- Obsolescence Program ($1.5 million) - this program is to replace obsolete parts and equipment throughout the plants.

Other projects have been funded in this reliability category.

Q. Please describe what is included under the category entitled Regulatory.

A. This category includes projects to address plant conditions that may affect the Company's ability to comply with regulatory requirements (e.g., OSHA and NYC Building Codes). In order to comply with these various regulatory requirements, the Company periodically inspects structures such as building roofs, facades, stacks, and docks, to determine the facility refurbishments projects that are needed for the safety of employees, to protect the Company's assets, and for the continuity of operations of the generation system. During 2005, the Company intends to spend $11.9 million on this category of projects. Some of the specific projects include the roof replacements at the various stations ($3 million); refurbishment of facilities and infrastructure at various stations ($2 million); repair of deteriorating steel and concrete at Hudson Avenue and other stations ($2.5 million); repairing the main pier and dock at the W. 59th Street Station ($1 million); and repairs to stacks at various locations ($1 million).

Q. Please describe what is included under construction expenditures for Small Capital.

A. The Small Capital Program is used to fund short-term smaller projects. This category is mainly used to address low cost emerging issues that require a quick resolution to ensure these issues do not create larger problems. The Company has allocated $2 million for these types of projects, which covers the replacement of various equipment on the steam generation system. Since it is not practical to anticipate the specific jobs that will be addressed, I have included the total dollar amount based on our past experience with this type of work. Examples of typical projects are the: (1) replacement of degraded water supply pipes; (2) installation of a ventilation system in the battery room at the West 59th Street Station, and (3) replacement of a desuperheater valve at East 74th Street Station.

STEAM DISTRIBUTION CONSTRUCTION PLAN

Q. Turning now to the Steam Distribution construction program, Mr. Bozgo, have you prepared an exhibit entitled "CONSOLIDATED EDISON COMPANY OF NEW YORK, INC., STEAM DISTRIBUTION CONSTRUCTION PROGRAM, ESTIMATED 2004-2008", set forth as Exhibit __ (RB-2).

A. Yes.

MARK FOR IDENTIFICATION AS EXHIBIT __ (RB-2).

Q. What does this exhibit show?

A. This exhibit shows Con Edison's steam distribution construction program for 2004 through 2008, by major program category: 1) New Business, 2) Interference, 3) System Reinforcement, 4) Meter Installations and 5) Meter Purchases.

Q. Please describe the New Business Program.

A: The New Business Program involves the installation of steam service connections to accommodate new steam customers and/or additional steam load. The Company has allocated $1.2 million in 2005 for its New Business Program.

Q: Please describe the Interference Program.

A: The Interference Program involves the relocation of underground steam facilities that are in the vicinity of the City's roadway reconstruction and public improvement projects as described in the testimony of Company witness Boyle, for which $500,000 has been allocated in the capital budget in 2005. While Company witness Boyle's testimony addresses the interference process in general, his forecast only includes operation and maintenance expenses for steam interference.

Q: Please describe the System Reinforcement Program.

A: The System Reinforcement Program is designed to maintain and upgrade the steam distribution and transmission system, in order to provide safe and reliable service to steam customers. Listed below are some of the System Reinforcement Programs, which comprise the $10.75 million allocated to that category in 2005:

- The Expansion Joint Replacement Program is a 10-year program (initiated in 2003) that is designed to systematically remove internally pressurized expansion joints from the steam system, in order to reduce the consequences of expansion joint failure.
- The Flange Removal Program is designed to replace flanges with welded straight pipe. Flanges were installed in the steam system prior to the commercial use of welding and, over time, the flange gaskets deteriorate due to pipe movements and exposure to moisture. This program is intended to proactively remove flanges in areas where the City will be doing roadway reconstruction, in order to avoid future excavations after the roadways are repaved.

- Steam leak repair activity, which includes repairs to services, valves, slip joints, traps, cooling chambers and mains.
- The Manhole Rebuild Program is designed to evaluate and rebuild deteriorated steam manholes. Steam manholes may contain base anchors, expansion joints, slip joints, main valves, service valves, by-pass and blow-off valves. Deterioration of the manhole structure can place these components at risk of damage. In addition, deterioration of the manhole structure can lead to hazards to employees, and roadway and pedestrian traffic.
- The Telemetry Program is designed to replace the thirteen (13) pressure monitoring stations and five (5) valve control stations that are used to monitor and operate the steam system. All pressure monitoring and valve control stations will be replaced with new equipment that will be designed to an open-standards architecture. In addition, five new temperature telemetric stations will be installed to monitor steam send out temperature, which will enable the Company to optimize the steam send out temperature at the operating pressure.

Q. Please describe the Meter Installation Program.

A. The Meter Installation Program, for which $3.75 million has been allocated in 2005, involves the installation of steam meters and associated metering equipment. Listed below are some of the Meter Installation Programs:

- The Vortex Meter Conversion Program was initiated in 1999 for the purpose of replacing 500 Shuntflo meters (out of an estimated total of approximately 3600 Shuntflo meters) with Vortex meters at approximately 170 customer locations. The Shuntflo meter is a mechanical steam-metering device that contains moving parts that are subject to wear and tear. In addition, the manufacturer of this meter went out of business ten years ago and replacement parts are costly to reproduce. The Vortex meters are also more accurate (+/- 1% uncertainty for Vortex meters vs. +/- 2% uncertainty for Shuntflo meters) and have a wider measuring range than the Shuntflo meters (5% to 100% of maximum flow for Vortex meters vs. 10% to 100% of maximum flow for Shuntflo meters). By the end of 2003, the Company anticipates that all 500 Shuntflo meters that were originally targeted for removal will be replaced with Vortex meters.
- The Remote Metering Program is designed to install

remote steam metering capability at customer locations where Vortex meter conversions have been completed. Remote steam metering involves the installation of flow computers, electrical conduit, telephone cable and modems at customer locations. These installations will provide instantaneous customer load information, which will enable the Company to remotely diagnose and repair malfunctioning metering equipment in a timelier manner.

- Demand Metering Program - As described in the testimonies of the Steam Rate Panel and Company witnesses Jacob and Shansky, the Company plans to implement a Demand Metering Program at selected large customer locations by October 2004. This will involve the installation of Vortex meters with remote metering capability at approximately 35 new locations. In addition, approximately 50 existing Vortex meter locations will be retrofitted with telephone modems for data transmission. The selection of these large customers may be subject to technical constraints. As a result of the above-mentioned Vortex Meter and Remote Metering Programs, there are currently 96 large customers that already have demand

metering capability. Therefore, by October 2004, a total of approximately 181 customer accounts/locations will have demand metering capability. Also included in this program is the procurement of the necessary computer systems to implement demand billing.

- The Load Study Program is conducted in compliance with Commission requirements. The Load Study Program involves the installation of power supply, data loggers, and computer hardware at customer locations. These installations provide information that can be utilized for cost of service studies, rate design, system planning, load forecasting, and customer studies.
- The Meter Regulating Valve Replacement Program is designed to replace the existing meter regulating valve with the more reliable motor-operated ball valve at various customer locations.

Q. Please describe the Meter Purchase Program.

A. The Meter Purchase Program, for which $1.425 million has been allocated in 2005, involves the purchase of steam meters for the New Business Program, the Vortex Meter Conversion Program, and the Demand Metering Program.

Q. Does either budget include any expenditure for reducing the portion of the steam variance that results from thermal losses?

A. No. The Company's prior program of insulating steam manholes has been completed. The Company's analysis found that this program had a marginal impact on the steam variance. At this time, there are no other programs to reduce the portion of the steam variance that results from thermal losses. The R&D programs described by Company witness Codner will demonstrate whether additional capital programs to reduce thermal losses will be cost effective. While some capital programs will help to reduce steam leaks, as discussed in the testimony of Company witness Litkouhi, leaks account for a small portion of the overall steam variance.

Q. Mr. Bozgo, does this conclude your testimony?

A. Yes.

Q. Please state your name and business address.

A. My name is Anthony Adinolfi. I am employed by the Consolidated Edison Company of New York, Inc. ("Con Edison" or the "Company") at the East River generating station, New York, New York.

Q. What is your present title at Con Edison?

A. I am the Plant Manager of the East River generating station.

Q. Please state your education and professional background.

A. I graduated from Long Island University in 1976 with a Bachelor of Science degree in Marine Science. I also earned a Master of Business Administration degree from Rensselaer Polytechnic Institute in 1998.

From 1977 to 1982, I served in the United States Navy in the Nuclear Submarine program. I joined Con Edison as an Engineer in 1982 at its Indian Point station. Since then, I have held various management positions of increasing responsibility in the Company, including General Manager for Business Services for the Steam Business Unit when it was first formed in 1999. In 2000, I assumed my present position as Plant Manager of the East River generating station ("East River").

Q. Have you testified previously?

A. Yes. I submitted testimony in the Company's last Steam

Rate Case 99-S-1621 before the New York State Public Service Commission ("Commission").

Q. Briefly describe your current responsibilities.

A. I am responsible for the management of all activities required to safely and reliably produce steam and electricity at East River. This includes managing the annual operation and maintenance ("O&M") and Capital budget for East River and developing forecasts for future expenditures required to maintain and improve station performance.

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

A. I will address the Company's rate year forecast for steam production and O&M expenses other than fuel.

O&M EXPENSES

Q. Have you supervised the preparation of a schedule entitled "CONSOLIDATED EDISON COMPANY OF NEW YORK, INC., STEAM OPERATIONS, SUMMARY OF STEAM OPERATIONS EXPENSES FOR THE RATE YEAR ENDED SEPTEMBER 30, 2005," Exhibit__(AA-1)?

A. Yes.

MARK FOR IDENTIFICATION AS EXHIBIT__(AA-1).

Q. Please describe this exhibit.

A. The exhibit shows the rate year steam plant and distribution O&M expense forecast for various elements of expense. Each element is shown at the historic year level

with normalizing adjustments and program changes. This exhibit does not reflect any escalation to calculate the rate year forecasts for these items. The escalation is calculated in Exhibit__(HLL-7), Schedule 9.

Q. Please explain steam plant.

A. Steam plant is the generating stations and ancillary equipment required to provide reliable steam service.

Q. Please explain steam distribution.

A. Steam distribution is the piping and support systems that deliver steam to our customers.

Q. Please describe the first line on the exhibit, Company Labor.

A. Company Labor is comprised of both the labor costs incurred at the Company's steam-only stations and the labor portion of the steam processing charges, which are applicable to steam-electric stations. All labor costs are escalated to the rate year amounts by the factor of 4.99 percent as discussed by Company witness Muccilo, and this escalation is calculated and included in Exhibit__(HLL-7), Schedule 1, Page 3 of 4. It is not reflected in my Exhibit__(AA-1).

Q. Please discuss the program change decrease of $439,000 shown for Company Labor.

A. The decrease reflects primarily the net impact of three changes. The first change is a $1,471,000 decrease

resulting from the Waterside Station shutdown, currently scheduled for December 2004. This decrease represents the elimination of the labor component of the steam processing charges applicable to steam sendout from this combination electric-steam station. The second change is a $400,000 increase reflecting the commercial operation of the East River Repowering Project ("ERRP"), currently scheduled in the fourth quarter of 2004, which requires an additional five (5) employees to operate the demineralization plant. The ERRP demineralization plant requires these additional employees to cover all operating shifts. The third change is a $632,000 increase as a result of a correction in the allocation to steam operations of the Environmental and Financial groups in the Steam Business Unit. The labor and non-labor expenses incurred by these sections were previously charged principally to electric operations. A review of the work of these groups determined that more of their costs should be allocated to steam operations, and an adjustment was recorded in July 2003 to correctly allocate these costs to each service.

Q. Please discuss the Plant Inspection and Repair program increase of $1,443,000 shown in your exhibit.

A. The Plant Inspection and Repair program represents a plan to maintain and improve reliability and operating

efficiency. These costs are associated with the enhancement of the life of a turbine/generator or boiler. Routine inspections are conducted at the older plants to identify equipment that, due to "normal wear and tear," must be repaired and maintained. For example, at the 59th Street station, the Company will conduct a condition assessment inspection of boilers 114 and 115, where the condition of floor tubes and superheater elements have deteriorated and will be repaired to ensure future reliable operation. Also at the 59th Street station, Stack #3 repairs will be performed as recommended by Engineering during its routine plant inspection. At the Hudson Avenue station, a Flow Accelerated Corrosion inspection and feedwater riser inspection will be performed to improve plant equipment availability.

Q. Please explain the element of expense referred to as Water.

A. The Water expense for the steam-only stations is based on the cubic feet of water used per pound of steam sendout for the rate year. The quantity of water required can be obtained by applying the water used per pound of sendout in the historic year to the rate year steam sendout at the steam stations. The rate year steam sendout was provided to me by Company witness Northup in Exhibit__(IN-1). Water costs for the rate year were obtained by multiplying the

quantity of water required for generation by $16.036 per MCF.

Q. Please explain how Water is calculated at the steam-electric stations.

A. As in the case of labor expenses at these stations, the water component of the processing charge at the steam-electric stations, as developed by Company witness Northup, was multiplied by the rate year steam sendout for the steam-electric stations.

Q. Please explain the program change increase of $834,000 for Water.

A. Based on the above calculations for water at the steam and steam-electric stations, the requirement for water for steam sendout in the future rate year shows a decrease of $421,000. This is due to the scheduled shutdown of the Waterside Station at the end of 2004 and decreased sendout at the other steam and steam-electric stations, which will be offset in part by the startup of the East River Repowering Project.

Water costs were escalated to the 2005 rate year by the escalation factor of 5.5 percent at the start of the New York City fiscal year, which begins in the month of July. This amounts to a projected increase of $1,255,000. The $834,000 program change reflects the net of the $1,255,000

water cost escalation and the $421,000 decrease attributable to the requirement for water for steam sendout.

Q. Please explain the basis for the 5.5 percent escalation factor.

A. The New York City Water Board announced, in a public notice dated May 29, 2003, a 5.5 percent increase in water rates (from $14.40 per MCF to $15.20 per MCF) effective July 1, 2003. I applied that 5.5 percent increase to the $15.20 per MCF rate effective July 1, 2003 to develop the projected rate of $16.036 per MCF for the rate year. I believe it is reasonable to assume that increases in water rates will continue at the 5.5 percent level, given the City's need to continually improve its water infrastructure.

Q. Are the Water expenses on your exhibit the sum of the expenses you just mentioned?

A. Yes.

Q. How is the forecast for Water Chemicals developed?

A. Water Chemicals use for each steam-only station is developed on the basis of chemical usage in cents per pound of steam sendout. To obtain the cost of chemicals required, I applied the average chemical rate in units per pound of steam sendout in effect during the historic period

to the rate year 2005 steam sendout as forecasted for each station.

Q. How is the Water Chemicals cost developed for the steam-electric stations?

A. The Water Chemicals component of the steam processing charge is multiplied by the rate year sendout for the steam-electric stations.

Q. Please discuss the negative program change of $523,000 for Water Chemicals.

A. The decrease in spending reflects the Waterside Station's shutdown and forecasted lower sendout at the other stations, offset partially by the East River Repowering Project.

Q. Are the rate year Water Chemicals expenses the sum of the expenses for the steam and steam-electric stations?

A. Yes.

Q. Please explain the program change increase of $660,000 for Plant Component Upgrade.

A. The Company developed programs to upgrade certain plant equipment as a result of an engineering effort to improve plant equipment. Some of the types of work that will be performed include replacement of 7&8 Row ID fans wiring, upgrading the data highway controls and other technological advancement programs at the Hudson Avenue station.

Q. Please describe the security related programs.

A. In response to the World Trade Center event and to the Commission's directives in Case 02-M-0953, the proceeding instituted to review the physical and cyber security at major New York utilities, the Company is implementing security enhancements to detect, deter, respond to, and recover from physical and cyber intrusion and damage at Company facilities, including steam generating stations. For the steam stations, these enhancements consist of (1) capital improvements for intrusion detection and perimeter protection, such as closed circuit television monitoring and recording, card access systems, new guard posts, alarms, gates, fences and barriers, and (2) O&M improvements associated with guard service and with increased manning and security requirements at generating stations during periods of heightened Homeland Security Alert response levels (e. g., condition Orange and condition Red alerts). In addition, as required by the Commission's September 30, 2003 Order Directing Further Action in Case 02-M-0953, Con Edison is evaluating physical and cyber security recommendations made by security consultants retained pursuant to the Commission's earlier order in that case. Upon completion of that evaluation, the Company may propose additional security enhancements

and will reflect these in the update filing in this proceeding.

Q. Please explain the program change increase of $600,000 for Guard Service expense.

A. This represents the increased vendor costs for Guard Service at the stations. Following the WTC event, the Company's Specification for Guard Services was revised to identify additional skill levels and duties required of the guards, such as the skills to monitor intrusion prevention systems, use of communication systems and vehicle inspection systems. The role and training experience requirements of the Lead Guard/Captain title was also revised. The program change reflects both an increase in incremental guard service and an increase in the contract rates for services provided, in addition to increased costs related to the Homeland Security Alert Response program mentioned above. The program includes the costs of maintaining facilities during condition Orange and Red alerts, such as food, cots, and other supplies.

Q. What is the basis for the element of expense Electric and Gas Used?

A. Electricity used by steam stations is used to operate auxiliary equipment at the steam-only stations. General Accounting develops the rate per kwhr annually.

Q. What is the basis of the $6,508,000 change for Electric and Gas Used?

A. This increase is based on the most recent General Accounting calculation of the electricity rate and a normalizing adjustment. This adjustment is discussed further in Company witness Lee's testimony.

Q. Please explain the element of expense of Water/Sewer program and the program change increase of $262,000.

A. The New York City Water Board charges Con Edison a fee for steam system discharges of steam condensate wastewater into the New York City sewer system. These charges are computed in accordance with Part III, Section 7, of the New York City Water Board Water and Wastewater Schedule based on information provided by the Con Edison Steam Business Unit with respect to the sales of steam to the various classes of Con Edison's customers. These costs were allocated previously between electric and steam operations, and the increase is the result of charging these costs to steam operations only.

Q. Please explain the element of expense Other.

A. The normalizing adjustment of $545,000 is the result of the correction in the allocation of the non-labor expenses of the Environmental and Financial groups in the Steam Business Unit to steam. As I mentioned in the discussion

of Company Labor, a review of the work of these groups determined that more of their costs should be allocated to steam operations rather than electric operations. Therefore, an adjustment was recorded in July 2003 to allocate both the labor and non-labor costs of these sections to each service.

Q. Does this conclude your testimony?

A. Yes.

Q. Please state your name and business address.

A. My name is Irina Northup. My business address is 4 Irving Place, New York, New York 10003.

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

A. I am employed by Consolidated Edison Company of New York, Inc. ("Con Edison" or the "Company") as Manager, Steam Operations Planning section in the Steam Distribution department.

Q. What is your educational and professional background?

A. I graduated from the Polytechnic Institute of Bucharest, Romania with a Bachelor of Science degree in Mechanical Engineering in 1981 and with a Master's of Science degree in Mechanical Engineering in 1982. In 1993, I received a Master of Business Administration degree from New York University. I joined Con Edison in 1986 and held various positions of increasing responsibility in the Mechanical Engineering, Fossil Power, System Operations, Energy Management and Treasury departments. In 2003, I joined the Steam Distribution department in my current position as the Manager, Steam Operations Planning section.

Q. Please describe your current responsibilities in the Steam Operations Services area.

A. My responsibilities include, among others, preparing estimates of fuel requirements for the Company's generating facilities; preparing budgets for fuel and purchased steam expenditures; and preparing the operating and outage plans for the generating units for the near term.

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

A. My testimony will cover several areas. First, I will provide estimates of fuel costs for steam production and describe how the estimates were prepared, including the Company's projections of the fuel savings due to the operation of the East River Repowering Project ("ERRP"). Second, I will present Con Edison's estimates of future fuel prices. Third, I will describe the allocation of heat rate and processing charges between steam and electric operations. Fourth, I will discuss the fuel oil storage capability and needs. Last, I will discuss a tariff change that will provide the Company the opportunity to explore with customers a negotiated price option, such as fixed prices, for a portion of the fuel costs of its steam service.

ESTIMATED FUEL COSTS

Q. Turning to the first area of your testimony, have you prepared an exhibit showing your estimated fuel costs for steam production?

A. Yes. I have prepared a one-page exhibit entitled "STEAM SYSTEM FUEL REQUIREMENT AND COSTS", set forth as Exhibit (IN-1).

MARK FOR IDENTIFICATION AS EXHIBIT __ (IN-1).

Q. Please describe the information contained in this exhibit.

A. This exhibit shows actual steam sendouts, fuel consumption and total fuel and purchased steam costs for the historic year, i.e., the twelve-month period ended June 30, 2003. These quantities are shown separately for steam-electric and steam-only stations. Total fuel and purchased steam expenses for the Rate Year ending September 2005 are estimated to be approximately $186 million, which reflect the fuel savings associated with the ERRP and a lower fuel price forecast as compared with the historic year. This compares with actual fuel expenses of approximately $292 million for the twelve-month period ending on June 30, 2003.

Q. Please explain the terms included under the heading "Steam Sendout" in your exhibit.

A. "Steam Sendout" is the actual or estimated steam supplied from the steam-electric stations, steam-only stations, and from steam purchased from the Brooklyn Navy Yard cogeneration plant ("BNYCP"). The total estimated steam sendout for the Rate Year ending September 2005 is 29,304 million pounds of steam.

Q. How was the total estimated steam sendout for the Rate Year determined?

A. Projections of the total monthly steam sendout were developed by Company witness Yaegel.

Q. How were steam sendout requirements from various stations determined?

A. The steam sendouts for the generating stations are estimated based on PROMOD simulations.

Q. Please discuss the PROMOD analysis.

A. PROMOD is a multi-area production cost computer model, which has been widely used in conducting planning studies and in rate proceedings. For rate case purposes, and as has been done in the past, PROMOD was also employed to simulate the least-cost reliable dispatch of the steam system.

Q. What data is used to simulate the forecast year?

A. The assumptions include inputs such as forecasts of unit maintenance schedules, heat rates, fuel prices, availability of natural gas, and volume and prices of steam purchases.

Q. Please describe the next two items on Exhibit __ (IN-1) entitled "Heat Rate" and "Fuel Consumption by Type".

A. "Heat Rate" is a measure of plant or system efficiency. For steam-only stations, "Heat Rate" is calculated from recorded heat input and steam sendout. For steam-electric stations, the "Heat Rate" includes only the portion of heat input allocated to steam sendout, which allocation I will describe in the Heat Rates and Processing Charges section of my testimony. "Fuel Consumption by Type" is the actual or estimated oil and gas consumption for the steam-electric stations and steam-only stations during each of the periods.

Q. How did you estimate the quantity of fuel and consumption by type that would be used for steam production?

A. The quantity of fuel and consumption by type for steam production was taken from the results of the PROMOD simulations of forecasted operations as described above.

Q. Please describe the next item on Exhibit __ (IN-1) entitled "Total Fuel & Purchased Steam Costs".

A. Fuel cost is the actual or estimated cost of fuel for each period for steam-electric and steam-only stations. Steam purchased costs are described below.

Q. How were total fuel and purchased steam costs determined?

A. I used actual fuel and purchased steam costs through September 30, 2003. Thereafter, the fuel and purchased steam cost estimates were based on the PROMOD analysis and the fuel price forecasts I describe later in my testimony.

Q. Please explain the item entitled "Oil-Storage and Handling" shown in your exhibit.

A. "Oil-Storage and Handling" costs are the costs for storing fuel oil and withdrawing it from storage when required. The storage and handling cost estimates shown in the exhibit are based on the allocation methodology approved by the Commission in Case 99-S-1621.

Q. Does your estimate of the total cost of fuel include any other components?

A. Yes. My estimate includes the energy portion of the steam purchases from BNYCP.

Q. How was the BNYCP estimate for energy developed?

A. The amounts of energy are based on simulations from PROMOD. The pricing of the energy is equal to the sum of (1) ninety-five percent (95%) of the product of the NYMEX natural gas price for such month ($/DT) and 2.45 (DT/Thousands of Pounds) and (2) one hundred percent (100%) of the Steam Processing Charges for such month ($/Thousands of Pounds).

Q. What is your estimate of the capacity charge associated with steam purchases from BNYCP?

A. For the Rate Year ending September 2005, the capacity charge is estimated to be $2.75 million based on the base price set forth in the contract, escalated according to an inflation index and adjusted for the plant's expected equivalent availability.

Q. Have you estimated the fuel savings resulting from the operation of ERRP?

A. Yes. The estimated fuel savings associated with ERRP operation and projected for the Rate Year ending September 2005 amount to approximately $64 million.

Q. Please explain how you arrived at these savings.

A. PROMOD simulated the operation and resulting fuel costs of the system assuming operation of ERRP during the Rate

Year. Those costs amounted to approximately $136.6 million. Also PROMOD simulated the fuel costs of the system assuming Waterside's continued operation through the end of the Rate Year instead of ERRP. Those costs amounted to approximately $200.7 million. The difference of approximately $64 million represents the estimated fuel savings.

FORECASTED FUEL PRICES

Q. Did you prepare or have an exhibit prepared relating to the development of oil and gas prices entitled "CONSOLIDATED EDISON COMPANY OF NEW YORK, INC., FORECAST OF FUEL PRICES, OCTOBER 2003 TO AUGUST 2006."

A. Yes, I did.

MARK FOR IDENTIFICATION AS EXHIBIT __ (IN-2).

Q. Please explain how the forecast of gas and residual fuel oil prices was developed.

A. The forecast of gas and residual oil prices as reflected in Exhibit __ (IN-2), which was used as an input in the PROMOD runs previously described, was developed as follows:

Determination of the Natural Gas Prices:

Column A - the last NYMEX natural gas futures trade by month at the time this exhibit was generated.

Column B - Current market basis for delivery on TRANSCO to Con Edison's system; basis beyond the first month or two is normally traded in summer (April-October) and winter (November- March) blocks.

Column C applies weighting to the winter and summer basis blocks to arrive at a monthly basis valuation; weightings are derived from history and by indications from the broker market.

Column D - The monthly basis calculation (Column B times Column C)

Column E - The delivered cost of gas to Con Edison's gate, which is the sum of Column A and Column D.

Column F - The delivered gas cost to Con Edison's gate plus 4% NYC sales/use tax.

Determination of the New York Harbor (NYH) 0.3% sulfur ("S") high pour (HP) No. 6 Fuel Oil prices:

Column G - is the forward price for 1%S NYH No. 6 fuel oil as indicated by the broker market.

Column H - the 0.3%S No. 6 fuel oil forward market is very thin and forward prices are not readily available. Where possible, the 1%S forward price is adjusted by a historical basis/difference to 0.3%S HP fuel oil (Column H) to arrive at a 0.3%S HP forward price. If 1%S

forward prices are not available, the 1%S forward price is derived as a percentage of the current NYMEX WTI crude futures price. The percentage is based on historical relationships between 1%S spot market and NYMEX WTI crude futures.

Column I - is the 0.3%S HP No. 6 fuel oil cost derived from the sum of Column G and Column H.

Column J - is 4% NYC sales/use tax

Column K - $0.1225/bbl NYS spill tax

Column L- NYS PBT (Petroleum Business Tax) on No.6 fuel oil.

Column M - Delivered cost of 0.3%S HP No.6 fuel oil excluding taxes.

Column N - Delivered cost of 0.3%S HP No.6 fuel oil including taxes, calculated as the sum of Columns I, J, K, and L and expressed on a $/MMBTU basis.

Q. Does the gas price forecast as described above account for the change in methodology for purchasing and recording interdepartmental gas as recently approved by the Commission?

A. The PROMOD runs in support of this testimony were prepared prior to Commission approval. However, since NYMEX pricing is also the basis of the Gas Department's

gas price forecast, no change is required to the PROMOD runs.

Q. What is the nature of these forecasts?

A. These forecasts are based on the market expectations at a point in time. History has demonstrated that fuel prices can and will repeatedly deviate substantially from forecasted levels. Changes in market prices are generally outside of the Company's control, notwithstanding the Company's efforts to mitigate price volatility.

HEAT RATES/PROCESSING CHARGES

Q. Turning now to the third area of your testimony, please explain how the Company allocates heat rates and processing charges at the steam-electric stations.

A. To this end I prepared an exhibit titled "RECOMMENDED CHARGES FOR STEAM SENDOUT FROM STEAM-ELECTRIC STATIONS EFFECTIVE OCTOBER 1, 2004" and set forth as Exhibit __ (IN-3).

MARK FOR IDENTIFICATION AS EXHIBIT __ (IN-3)

Heat rates for live steam sendout are determined by dividing the heat output, in BTU/lb (steam enthalpy less make-up water enthalpy), by the boiler efficiency and then making adjustments to reflect the energy used by

electrical auxiliaries for steam generation. The boiler efficiency is the ratio of the heat captured in the boiler to the heat available in the fuel. This heat rate is also adjusted for the steam and electric auxiliaries used in the production of live steam.

Q. Please explain the items included in processing charges shown in this exhibit.

A. The processing charges include water, chemical, and labor costs. Water costs at the steam-electric stations consist of three components, namely, sendout, treatment plant use, and boiler blowdown, all determined directly from the current New York City water price. The chemical costs are for chemicals used to remove or neutralize impurities in the water. With the exception of Waterside, where a portion of the boiler labor is allocated directly to steam in accordance with the PSC's decision in Case No. 27276, labor costs include those costs that are associated with the additional manpower required for steam system operations.

Q. What was done with the steam heat rates and the unit processing charges after they were prepared?

A. The heat rates were used to apportion fuel usage between electric and steam production for the combined electric-

steam stations. The processing charge rates for steam production were supplied to Company witness Adinolfi.

FUEL OIL STORAGE CAPABILITY

Q. Turning now to fuel oil storage capability, how are your estimates utilized?

A. The estimates of fuel inventories are used as inputs to the estimation of total system fuel costs. Company witness Muccilo also uses these costs in determining the Company's rate base and working capital requirements.

Q. What are the factors you consider in estimating fuel oil inventories?

A. We consider a number of factors, including the Company's storage capacity, target inventory levels, and other practical operational considerations.

Q. How are target inventory levels arrived at?

A. The target inventory levels are based on the PROMOD forecasted oil burn, fuel availability and constant monitoring of weather and market conditions. To mitigate the risk of disruptions in fuel burn, supply and price, the Company's fuel oil contracts contain minimum and maximum requirements with the option to buy from the spot market.

Q. What are the projected residual oil inventory levels for the steam system for years 2004 and 2005?

A. The projections of residual oil inventory are done for Company-owned electric and steam generation, and the steam system's share is based on the relative amount of fuel to be burned for steam and electric. The estimates of the residual oil inventory for the steam system for 2004 and 2005 are approximately 2.7 million barrels and 2.1 million barrels, respectively.

Q. What is the Company's current storage capability?

A. Con Edison has about 250,000 barrels of its own residual oil storage capacity, and about 800,000 barrels of leased storage capacity.

Q. What is the storage capacity requirement as mandated by the Commission?

A. In PSC Case 26200, the Commission ordered the Company to have available storage capacity at least equal to the amount of such oil to be consumed by its generating plants in the 45 consecutive days of maximum use in a year. Such fuel oil consumption during recent history amounted to approximately 1,000,000 barrels.

Q. Will fuel oil needs be reduced once ERRP is on line?

A. Yes. Fuel oil needs will be reduced as a result of ERRP coming on line and displacing a portion of the oil-fired generation as well as due to the projected conversion of the East River South package boilers to natural gas.

Q. Please explain the basis used for estimating other fuel-related expenses.

A. There are three fuel-related expenses that we estimate: system oil storage rents, demurrage charges, and fuel testing charges. The system oil storage rents are estimated based on storage commitments under long-term contracts that are required to supplement Company-owned storage in meeting the PSC minimum storage capacity requirement. Demurrage charges and fuel testing charges are estimated based on our best judgment that takes into consideration historic costs and the forecasted oil burn.

NEGOTIATED FUEL COST SERVICE

Q. Turning now to the last area of your testimony, please state whether you are supporting any tariff changes?

A. Yes. The Company is proposing to permit customers to negotiate the fuel costs for a fixed volume portion of their steam requirement. I will explain how this would work and why it is important.

Q. Please explain the Company's proposal.

A. Base steam rates include a base cost of fuel. When the cost of fuel to the Company changes, the Company passes the difference in cost through to steam customers on an average cost basis in the monthly fuel adjustment clause. I have been informed that some customers have complained that steam rates are unacceptably volatile because of the impact of the changes in fuel cost each month. Under this proposal, the customer and the Company could agree to fix the fuel cost component of the Company's charges to the customer for a fixed volume of the customer's steam requirements for the term of the agreement. This would reduce the volatility of the customer's steam bills.

Q. How does the Company plan to fix the fuel cost component under a negotiated fuel cost agreement?

A. The Company could purchase either sufficient fuel in the market to generate the agreed upon volume of the customer's steam requirements at a price that would meet the agreed upon fuel cost amount or a hedge for the required volume of fuel that would lock-in the agreed upon cost. The costs of procurement, including any

hedging costs, would be part of the negotiated fuel cost to be paid by the customer.

Q. Would the customer be permitted to establish a negotiated cost for its entire steam requirements?

A. No, the customer would have to designate a fixed volume of steam requirements for which the fuel cost would be established. Because the Company would be incurring costs for the calculated volume of fuel, the Company would have to charge the customer for any fuel not used to satisfy the customer's requirements. The customer would be expected to designate a steam requirements volume that would ensure that all fuel covered by the agreement would be used in order to avoid having to pay for unused fuel.

Q. What would customers with negotiated fuel cost agreements pay for steam service in excess of the volume subject to the agreement?

A. Such customers would pay standard tariff rates in the service classifications under which they take service for any steam requirements in excess of the agreed-upon volume.

Q. Would non-participating customers be affected by any negotiated fuel cost agreement?

A. No, other customers would not be affected. The full cost of the fuel supply and any hedging would be borne by the participating customers.

Q. Does the Company hedge its fuel supply costs for steam service?

A. Under the recent Commission decision in Case 03-G-0759, the Steam department will be provided gas from the Company's gas portfolio at a cost that reflects the gas hedging activities undertaken by the Gas Department. However, while these activities will reduce the volatility of fuel costs to steam customers generally, the negotiated fuel cost service will allow individual customers to establish a price that meets their individual needs.

Q. Does the Company provide any similar service to gas customers?

A. I am informed that the Company may arrange to supply natural gas to customers taking transportation service at rates negotiated between the Company and the customer.

Q. Do both participating and nonparticipating customers benefit from this new steam service?

A. Yes. Fixing the fuel cost component of customers' steam charges will reduce the fluctuation in steam rates from month to month for the customers opting for this service. As a result, the Company may retain or attract customers to the steam system for the benefit of all steam customers.

Q. Have the terms and conditions for the negotiated fuel cost service been reflected on tariff leaves filed in this proceeding?

A. Yes. The tariff leaves reflecting the new service are part of the exhibit sponsored by the Steam Rate Panel.

Q. Does this conclude your testimony?

A. Yes.

Q. Please state your name and business address.

A. My name is Dr. Bahman Litkouhi. My business address is Mechanical Engineering Department, Manhattan College, Riverdale, New York 10471.

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

A. I am employed by Manhattan College as a full-time Professor of Mechanical Engineering and also employed by Consolidated Edison Company of New York, Inc. ("Con Edison or the Company") as a consultant.

Q. Please state briefly your education and professional background.

A. I earned a Master of Science and a Ph.D. in Mechanical Engineering from Michigan State University in 1978 and 1982, respectively. I have been licensed as a Professional Engineer in the State of New York since 1991. I am a member of the American Society of Mechanical Engineers (ASME), the American Society of Engineering Education (ASEE), and the American Society of Heating, Refrigeration, and Air-Conditioning Engineers (ASHRAE). I joined Manhattan College in 1983 as an Assistant Professor of Mechanical Engineering. I was promoted to an Associate Professor rank in 1988 and to a Full Professor rank in 1993. Since 1999, I have been the Chairman of the Mechanical Engineering

Department. I have been involved in consulting for a number of companies since 1991. I have provided a number of technical studies on the steam variance to Con Edison since 1999.

Q. What is your specific field of expertise?

A. My specific expertise is in the Thermal/Fluid area. I have been teaching a variety of courses in this field. I have also published several technical papers and a book in this field.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is:

1) to define steam system losses (or steam variance) and the factors affecting these losses; 2) to provide a historical comparison between the relative loss (percentage variance) and the absolute loss for the steam system and to demonstrate why the percentage variance is an inappropriate measure of the system losses; 3) to present an economic analysis concerning the cost-effectiveness of re-insulating pipes to reduce the steam variance; and 4) to show how I estimated the level of line losses that Company witness Yaegel used in his testimony to estimate steam sendout.

STEAM VARIANCE AND FACTORS AFFECTING THE VARIANCE

Q. Please describe the steam system losses (or steam variance) and the factors affecting these losses.

A. Steam variance is the disparity between the total recorded steam sendout and sales. The steam variance results from line losses. The major part of line losses is due to condensation; steam leaks are a minor part of line losses.

Q. How much is the leak component?

A. Con Edison has previously estimated that the leak component is in the range of 0.5% to 1.5% of the total recorded sendout, which makes leaks, on average, approximately 7% of the absolute steam loss, which historically is equivalent to 15% of total sendout (1%/15% ≅ 7%).

Q. How much is the condensate component?

A. The rest is due to condensation. This is reasonable to assume because there are no other factors materially affecting line losses, although I note that metering error can affect the evaluation of lines losses.

Q. How can metering error affect line losses?

A. Metering error does not represent an actual loss of steam; however, it creates uncertainty in the evaluation of line losses.

Q. Please explain how condensate is formed.

A. Condensate is formed due to thermal energy losses from different segments of the piping network to the surrounding environment. The greater the thermal losses from the steam lines and components, the more condensate will form.

Q. What are the factors that affect the thermal losses?

A. In general, the thermal losses are affected by the surrounding soil temperature, its moisture content, the steam flow rate and the thermal properties of the existing insulation. Both soil temperature and its moisture content are uncontrollable factors that depend on the ambient temperature and the precipitation. In addition, the steam flow rate generally depends on the demand of the customers on the system, which in turn is affected by variations in ambient temperature.

Q. Are you sponsoring Exhibit __ (BL-1) entitled "FACTORS AFFECTING THERMAL LOSSES" displays the factors affecting the thermal losses?

A. Yes. It was prepared under my direction and supervision.

Mark for Identification as Exhibit __ (BL-1)

Q. How does the flow rate affect condensation?

A. A lower steam flow rate causes a greater increase in heat loss per pound of steam sendout, which in turn causes a larger steam variance.

Q. Have you prepared an exhibit that shows the effect of a low steam flow rate on steam variance?

A. Yes. I have prepared an Exhibit __ (BL-2) entitled "EFFECT OF LOW STEAM FLOW RATE," with two pages.

Mark for Identification as Exhibit __ (BL-2)

Q. How did you prepare this exhibit?

A. I wanted to show graphically how flow rate affects the variance using an accepted mathematical model that governs the loss of steam in a typical insulated main. In order to construct this graph, I also needed typical sendout temperature and pressure. I decided to use Con Edison's Avenue D main for these inputs, which is why the exhibits show how this mathematical model applied for that main.

Q. Are the results applicable to the Avenue D main only?

A. No. As I stated, I am merely using the Avenue D main as an example to demonstrate the steam loss at various flow rates. The results presented here would be similar to any comparable steam pipe operating at comparable conditions.

Q. Please explain the results in the exhibits.

A. Exhibit __ (BL-2), page one, shows the percentage variance (or line losses) versus pipe length for different cases of sendout flow rates, ranging between 50,000 to 500,000 Mlb/hr, along 4,800 feet of the Avenue D main. This exhibit shows that for a low steam flow rate, condensation starts earlier in the pipe and accumulates more as compared to a higher flow rate. For example, for the case of 50,000 lb/hr flow rate, condensation starts at approximately 400 feet along the main and increases to more than 16% at the end of the main, while for the case of 500,000 lb/hr flow rate, condensation starts much later at approximately 3,200 feet along the main and increases to less than 1% by the end of the main. Similar behavior can be observed in Exhibit __ (BL-2), page two. This exhibit shows the line loss for 2,800 feet of the same Avenue D main (presented in both percentage and lb/hr) versus percentage of maximum flow rate (or load factor) for the main. Again, it can be seen that as the flow rate decreases from 30% to 5% of the maximum flow rate, the condensate buildup rises substantially to more than 5,000 lb/hr.

Q. Does this show that lower sale levels result in lower flow rates through the piping network and consequently higher line losses?

A. Yes. As stated above, similar results would be obtained for any other steam system pipe with respect to line losses.

HISTORICAL ANALYSIS SHOWS THAT THE PERCENTAGE VARIANCE IS AN INAPPROPRIATE MEASURE

Q. What has the steam system loss been in the past?

A. Despite some fluctuations due to the aforementioned environmental factors, a long-term history of absolute steam system losses shows a relatively stable trend, notwithstanding the Company's efforts to reduce the variance.

Q. Have you prepared an exhibit that shows this trend?

A. Yes. I have prepared an exhibit entitled "SENDOUT AND SALES HISTORY," Exhibit __(BL-3).

Mark for Identification as Exhibit __ (BL-3)

Q. How did you obtain the information for this exhibit?

A. The data used for this exhibit were obtained from the Company's books and records.

Q. Please explain this exhibit.

A. Exhibit __(BL-3) presents a 21-year history of the actual total annual rolling average of steam sendout and sales on a calendar year basis. It also shows the

difference between sendout and sales (or the line losses) for the same period. It can be seen from this exhibit that even though both steam sendout and sales vary considerably from year to year, their absolute difference (or line losses) is relatively steady over these years. Since line losses are primarily due to thermal losses, one can also conclude that the thermal losses have also been relatively stable.

Q. Please explain why the percentage variance fluctuates considerably from year to year.

A. If the sendout materially changes from year to year but the absolute line losses remain relatively the same, then the percentage variance (or the ratio of the "absolute line losses" to the "sendout") will also vary considerably. This behavior is demonstrated in Exhibit __ (BL-4) entitled "SENDOUT & PERCENTAGE VARIANCE COMPARISON" and Exhibit __ (BL-5) entitled "COMPARISON OF PERCENTAGE & ABSOLUTE STEAM VARIANCE."

Q. Have you prepared these exhibits?

A. I have, based upon the information that I obtained from the Company's books and records.

Mark for Identification as Exhibit __ (BL-4) and Exhibit __ (BL-5), respectively.

Q. Please explain these exhibits.

A. Exhibit __(BL-4) shows the history of the annual rolling average steam sendout and the percentage variance over the past twenty-one years. It can be seen that the percentage variance tends to move in the opposite direction of the steam sendout. As the sendout decreases (less sendout due to less sales), the percentage losses (or percentage variance) increases, even though the absolute loss remains relatively unchanged. Therefore, since the percentage variance is based on the total recorded steam sendout, which varies seasonally and from year to year, the percentage variance does not give an accurate picture of the system losses in an absolute sense.

Q. What is Con Edison's current steam variance allowance?

A. The steam variance allowance is 13.5 percent. This allowance was set in 1997 based on the historic three-year average ending June 1996.

Q. What is the three-year average absolute variance for the same period, ending June 1996?

A. The historic three-year average absolute variance (or actual line losses) for the same period is 4608 MMlb/yr.

Q. Please continue.

A. Exhibit __(BL-5) shows a comparison between percentage variance and absolute variance (or actual line losses)

for the past nine years from 1994 through 2002. This exhibit also shows the percentage variance allowance cap of 13.5 percent as well as the corresponding three-year average absolute variance (or actual line losses) of 4608 MMlb/yr. If one reasonably sets this average absolute loss of 4608 MMlb/yr as the allowable system loss, then to maintain the corresponding percentage variance of 13.5% requires a minimum of 34,133 MMlb/yr of sendout, which corresponds to 29,525 MMlb/yr of sales. The actual sales, however, for the past five years did not meet the minimum requirement of 29,525 MMlb/yr. From Exhibit __ (BL-5), one can also observe that, for the past five years, the absolute variance (or the actual line losses) stayed relatively stable and below the three-year absolute allowance of 4,608 MMlb/yr. For the same period, the percentage variance exceeded the corresponding allowance of 13.5% and had a more erratic behavior. For example, from 2001 to 2002, the percentage variance changed considerably from 14% to 16.3%, an increase of 16.4%, while the absolute variance (or the actual losses) had only a minor increase of 2.2% from approximately 4,400 to 4,500 MMlb/yr.

Q. What can you conclude?

A. From these observations, one can conclude that the percentage variance is highly affected by sales that vary from year to year depending on the steam consumption and, therefore, it is an inappropriate measure of steam system losses.

ECONOMIC ANALYSIS CONCERNING COST-EFFECTIVENESS OF RE-INSULATING THE PIPES TO REDUCE THE STEAM VARIANCE.

Q. Given your discussion of the factors affecting thermal losses, is there a scientific explanation why absolute thermal losses stay relatively the same notwithstanding the changes in steam sendout?

A. Yes, because the different factors affecting thermal losses can relatively balance each other. For example, in a year that is cold, thermal losses will increase on an annual basis from lower soil and ambient temperatures. At the same time, a higher steam flow rate resulting from higher customer consumption will lower the loss per pound of sendout. As a result, the absolute variance can relatively stay the same regardless of sendout.

Q. What can the Company do to control the absolute variance?

A. As described above, all of the factors that affect condensation, the primary cause of the steam variance,

are generally beyond the Company's control except for pipe insulation.

Q. How does pipe insulation affect the thermal losses?

A. As insulation ages, it loses its effectiveness due to deterioration and damages caused by pipe expansion, thermal cycling, shrinkage, and penetration of moisture and dirt. Another factor that greatly affects the integrity of thermal insulation is the infiltration of groundwater into the weather barrier jacketing.

Q. Has the Company taken steps to improve steam system insulation?

A. Yes. As discussed in the testimony of Company witness Bozgo, the Company recently completed the manhole insulation project that marginally improved the steam variance.

Q. Were you involved in any studies to determine the cost-effectiveness of other measures?

A. Yes. Based upon the information provided to me by the Steam Business Unit, I estimated that it is generally not cost-effective to re-insulate pipes, except possibly for specific locations in low tide areas (approximately 10,000 ft) such as the Avenue D main, which are exposed to higher moisture penetration and flooding than the rest of the steam distribution network.

Q. Has this re-insulation been implemented?

A No. As a first step, the R&D group is conducting a project to develop a method for insulating the Avenue D main, as discussed in the testimony of Company witness Codner.

Q. Have you prepared an Exhibit to show the results of your estimation?

A. Yes. Exhibit __ (BL-6) entitled "COST ESTIMATION FOR PIPE RE-INSULATION" displays the results of my estimation.

Mark for Identification as Exhibit __ (BL-6)

Q. Please explain this exhibit.

A. The estimation provided in Exhibit __ (BL-6) is based on an infrared survey of 26 miles of steam mains performed in 1997. About 50,000 feet of piping were identified by the Company as areas of concern. This includes 10,000 feet in the low tide areas, such as Avenue D, that had earlier been identified by the Company as an area of primary concern. As shown in this exhibit, four classes of insulation were considered and a simple payback method was employed in the estimation process.

STEAM SYSTEM LOSS AMOUNT PROVIDED TO COMPANY WITNESS YAEGEL

Q. Did you provide an estimate of absolute steam system line losses for Company witness Yaegel to use in his steam sendout forecast?

A. Yes. I developed a mathematical model based on the conservation of energy principle, which provides an energy balance between sendout energy and sales, condensate and leak energies, and thermal losses. I then used in this model the historic 5-year rolling average value for the thermal losses and the calendar sales forecast provided by Company witness Yaegel for each month of the future calendar year to estimate the absolute line losses provided to him. Leaks were assumed to be 1% of the sendout. Since the thermal losses are relatively stable, this approach provides a reasonable estimation of the absolute variance as well as the percentage variance and the sendout. This model showed 4,430 MMlbs for the annual steam variance for the calendar year forecast provided to me by Company witness Yaegel.

Q. Have you prepared an example to demonstrate the accuracy of your mathematical model?

A. Yes. As an example, the model was employed to estimate the monthly percentage variance for the year 2000 using

the actual sales for the same year. The results were compared with the actual experienced monthly percentage variance for the same year. This is demonstrated in Exhibit ___ (BL-7) entitled "MONTHLY PERCENTAGE VARIANCE FOR THE YEAR 2000 - ACTUAL VERSUS MODEL" which I prepared.

Mark for Identification as Exhibit __ (BL-7)

It can be seen from this exhibit that for the case where the actual sales were used, the estimated percent variance closely matches the actual percent variance.

Q. Does this conclude your testimony?

A. Yes, it does.

Q. Please state your name and business address.
A. My name is Robert S. Boyle. My business address is: Consolidated Edison Company of New York 1610 Matthews Avenue, Bronx, NY 10462.
Q. By whom are you employed and in what capacity?
A. I am employed by Consolidated Edison Company of New York, Inc. ("Con Edison" or the "Company") in the capacity of General Manager of Public Improvement.
Q. How long have you been employed by Con Edison and what positions have you held while at Con Edison?
A. I have been employed by Consolidated Edison Company of New York since 1986 and have held the positions of Operating Supervisor, Chief Construction Inspector, Field Engineer, Engineering Section Manager and Project Manager. I currently hold the position of General Manager for the Public Improvement Department within the Maintenance and Construction Services organization.
Q. Please explain your educational background.
A. I graduated from Manhattan College with a Bachelor's Degree in Civil Engineering in 1986. I also received an MBA from Manhattan College in 1989. I have been a member of the American Society of Civil Engineers since 1986.
Q. Explain your work experience with Con Edison and your

current responsibilities.

A. During my career at Con Edison I have held positions in Engineering and Construction and have worked extensively on the design and construction of utility and municipal facilities in the heavily congested streets throughout New York City and Westchester County. My current responsibilities are to maintain the integrity of Con Edison's electric, gas and steam systems during the course of municipal construction projects in a cost effective-manner. This requires planning, coordinating, engineering and negotiating with municipalities and the contractors assigned to work for them to ensure the timely completion of their projects.

Q. What is the purpose of your testimony?

A. In my testimony, I explain the program changes for Operation and Maintenance (O&M) interference costs associated with the Company Steam facilities for the rate year, twelve months ending September 30, 2005, the forecast for the years 2005-2007, the methodology we used in forecasting these costs, the issues associated with Lower Manhattan, and a proposal for full reconciliation of these costs and expenses.

Q. Please explain interference.

A. Con Edison has more than 100 miles of Steam mains under the streets of Manhattan. These mains and associated appurtenances share the space under the street with other facilities such as telephone and cable TV owned by private utility companies and sewer, water and traffic facilities owned by New York City. When the City plans to perform work within these streets and is prevented from completing the proposed plan due to other facilities being in the way, the term "interference" is used. Interference can be direct or indirect. A direct interference means that the existing facility needs to be moved to accommodate and provide space for the new facility. An indirect interference means that the new facility can go above, under or around the existing facility. Either way, the proposed job becomes more difficult when working around other facilities.

Q. Please explain interference expenses as they relate to Steam Operations.

A. If a private entity performs work in the vicinity of our facilities, for example the telephone company installing a new structure around a Com Edison steam main, and Con Edison determines that the steam main needs to be supported, protected, adjusted or relocated

to accommodate the work of the private entity, then the private entity is required to bear this cost. However, if the City of New York performs work, such as repairs being made to a sewer around Con Edison's steam mains, then Con Edison must bear the cost to move, replace, support and protect Con Edison's steam facilities affected by the City's construction activity. In addition, steam facilities that need to be repaired or modified during the course of a City public improvement project are also a component of interference expense. For example, when a City street is repaved, raising the castings of steam manhole covers, or modifying the pavement around these structures, are considered an interference. The cost that the Company incurs when these proposed activities interfere with the Company's Steam facilities is considered to be a Steam Interference Expense.

Q. What type of City construction activities cause interference with steam facilities?

A. The typical public improvement activities that affect Company facilities are the installation of water, sewer and drainage facilities, reconstruction of bridges, roads, curbs and sidewalks, and the repaving of roadways.

Q. How often does the Company have to support, protect and/or relocate its Steam facilities?

A. On any given day, there are hundreds of City projects being planned, engineered, or constructed within our service area. These projects are initiated by such organizations as the Department of Transportation, Department of Environmental Protection, Department of Parks, Bureau of Bridges and the Economic Development Corporation. The projects may be planned or may be emergency activities such as a response to a water main break. Since the Steam system is only in certain portions of Manhattan, not every public improvement project will affect the steam facilities. However, any excavation that is required to perform public improvement work within the steam areas can potentially impact the steam facilities and therefore may present an interference. The Company's Engineering groups work with these agencies to try to minimize the impact to the steam facilities, but in many cases, there is simply no way to avoid the interference due to the heavy congestion of utilities within the streets.

INTERFERENCE FORECAST FOR THE RATE YEAR

Q. Have you prepared an exhibit entitled "Steam Interference Expenses Twelve Months Ending September

30, 2005."

A. Yes, it was prepared under my supervision and direction.

MARK FOR IDENTIFICATION EXHIBIT ___ (RSB-1)

Q. Please explain your program change.

A. As shown on Exhibit ___ (RSB-1), the Company's forecast for the rate year, twelve months ending September 30, 2005, is $1,894,219, which is lower than the historic year by $38,627. Steam Interference Expenses have two categories of work: Steam Interference and Steam Operations Interference. Steam Interference includes the expenses associated with supporting, protecting or accommodating the steam facilities to facilitate the construction of a public improvement project. Steam Operations Interference includes the expenses associated with modifying and repairing the steam facilities that are affected as a result of a public improvement project. The rate year forecast is developed utilizing two methodologies for the following two periods of time: (a) October through December 2004 and; (b) January through September 2005. The 2004 expenditure forecast is developed by using a zero based budget process. The 2005 expenditure forecast is developed by taking the Company's gross interference

forecast for year 2005 and multiplying it by a factor of 1.09% to derive the Steam Interference forecast number and by a factor of 2.44% to derive the Steam Operations Interference forecast. These factors are the three-year average of Steam interference expenditures to the Company's total interference expenditure.

Q. Please explain your zero based budget process?

A. The interference budget is developed four to six months prior to the start of a calendar year. As I mentioned earlier, the Company works closely with all of the City agencies that generate the infrastructure projects that may result in interference situations. The City provides the Company with construction schedules for current projects and commitment plans for the projects that the City plans to put out for bid in the upcoming fiscal year. The Company's Construction and Engineering groups then analyze each of these projects and determine the potential impact on Company facilities from these projects. Interference cost estimates for the projects are developed and the projects are grouped into one of four categories. A description of each of these categories follows:

a) Working Projects - This category is comprised of

multi-year projects that are currently in progress and will continue into the next budget year.

b) Awarded/Bid Projects - This category is comprised of projects that have been bid and awarded to contractors with definite start dates in the budget year and also City projects that have been bid, not yet awarded, but still with a start date in the budget year.

c) New Projects - This category is comprised of projects published by various agencies proposed to be engineered, bid and awarded in the budget year.

d) Annual Projects - This category is comprised of contracts awarded on a yearly basis to contractors to handle emergency type projects, such as water main breaks, sewer breaks and other repair projects, including restoration of curbs, sidewalks, pedestrian ramps and roadway repaving projects.

The cost estimate for the first three categories is developed based on the Company's Engineering analysis of the potential impact on the Company's facilities from these projects. The cost for the Annual project category is based on an average of the prior three-years' level of expenditures. After the total cost is

determined for each category, a weighted factor is applied to each category. These factors have been developed and adjusted over the past eight years and are based on the tendency for projects and their expected expenditures to actually materialize. Over the past three years, the actual expenditures have varied an average of 2.0% from the forecasted budget.

Q. Have you prepared an exhibit entitled "New York City Capital Commitment and Expenditures and Con Edison Interference Forecast for 2005-2007".

A. Yes, it was prepared under my supervision and direction.

MARK FOR IDENTIFICATION EXHIBIT ___ (RSB-2)

Q. Explain your methodology in developing your Steam O&M interference forecast for 2005-2007.

A. As mentioned before, Con Edison's gross interference expenditure is proportional to the City infrastructure improvement expenditure forecast. Three times a year, New York City publishes its five-year capital commitment plan. This plan includes all projects that are anticipated to be committed in each of the upcoming fiscal years. A commitment occurs after a project has been awarded to a contractor and the City registers a project with the City Comptroller. The proposed

commitment forecast for the categories defined as Water, Sewer, Highway and Highway Bridge projects are then extracted from the commitment plan. The commitment plan includes a commitment target. Commitment targets are set because the City realizes that not all planned projects will actually proceed. As a result, there are projects proposed in excess of the target number. For the current plan, the target is 68%. This commitment target forecast reflects the projects that are expected to be engineered, bid, awarded and registered for each fiscal year. From previous analysis, the Company has determined that there is a relationship between the City's commitment target and the City's actual expenditures the following year. For the years 2000-2003, 96% of commitments have resulted in expenditures the next year. The Company has also found a correlation between the City expenditures and the Company interference costs. The Company actual and forecasted interference costs as a percentage of the City expenditures average approximately 13%. To arrive at the interference expenditure forecast for future years, the following steps are taken. The City commitment target is multiplied by a factor of 96% to determine the City

expenditure forecast for infrastructure improvement in the following year. The City expenditure forecast is then multiplied by a factor of 13% to derive the Company's gross interference expenditure forecast. Finally, the Company's gross interference expenditure forecast is multiplied by a factor of 1.09% to derive the Steam Interference forecast number and by a factor of 2.44% to derive the Steam Operations Interference forecast. As mentioned previously, this factor is the historical relationship of Steam interference expenditures to the Company's gross interference expenditures. This process is demonstrated in Exhibit __ (RSB-2).

INTERFERENCE EXPENSE IN PRIOR YEARS

Q. What was the actual interference expenditure for the first three rate years covered by the current rate agreement (rate years ending September 2001, 2002 and 2003, respectively) and how does it compare to the target for the corresponding rate years in the agreement?

A. The Company's actual non-labor interference expenditures for the rate year ending September 2001 were $6.508 million versus the target of $2.438 million; for the rate year ending September 2002 and

2003, the expenditures were $3.629 and $1.619 million versus the annual target of $1.937 million. The increased expenditure for the first two rate years can be attributed to some specific City public improvement projects that occurred within the steam service areas where there is a heavy concentration of steam facilities. The most noteworthy of these projects were Mulry Square, 6th Avenue and Union Square. These projects involved a significant amount of activities that required excavations that were wide and deep. For example, the 6th Avenue Project was performed by the City to remove enormous amounts of unsuitable soil that was causing the roadway to settle. Mitigating Steam interference is difficult, because it is often too difficult, expensive and time consuming to relocate and move the Company's facilities to accommodate the City public improvement project. Therefore, steam facilities are often supported and maintained in place during public improvement projects. In addition, once steam facilities are exposed by the City excavation activities, they often require repairs since the soil around them has been disturbed.

Q. Explain the lower Steam interference expenditures in the rate year ending September 2003.

A. The lower expenditures in the third rate year can be attributed to two specific reasons. The first reason is that the major projects mentioned previously were primarily completed in 2002, while the major City infrastructure project in the steam service area for 2003 provided the Company an opportunity to move a major portion of the steam main rather than supporting it. The second reason is attributable to the after effects of the World Trade Center events. Shortly after the terrorist attacks at the World Trade Center, the Company was notified that there would be numerous municipal projects planned to rebuild the streets in the World Trade Center/lower Manhattan area. The funding to perform the municipal work would be provided by the Federal Government. In 2003, the Lower Manhattan Development Corporation announced its Partial Action Plan for allocating $750 million to restore and rebuild damaged properties, including utility infrastructure, affected by the attacks. While the utility companies are eligible to submit claims for these funds, to date, the Company has not received any reimbursement for its interference expenditures related to the September 11, 2001 attacks. At this juncture, it is unclear whether all or any of the Company's

interference expenses in Lower Manhattan will be reimbursed. The Company considered all interference expenditures resulting from the public improvement work funded by this Federal program as a special case and created special accounts for this work so that these costs can be accumulated and submitted for reimbursement from Federal funds or reflected in rates as proposed by Company witness Rasmussen. These interference costs have been termed "WTC expenses" or "Lower Manhattan" expenses and were not included in the figures mentioned previously.

Q. What are the steam interference costs associated with Lower Manhattan for 2002-2004?

A. For 2002, the Company spent $1.8 million. In 2003, the current estimate is $4.8 million and for 2004 the forecast is $3.3 million.

Q. Does the Company envision any additional work in the Lower Manhattan area?

A. Yes. After the attack, the New York City Department of Design and Construction in conjunction with the Lower Manhattan Development Corporation embarked on a five-year project for the reconstruction of roadways south of Canal Street in Manhattan. These projects are being funded by the Federal government and are being

performed to rebuild the infrastructure in order to revitalize the area known as Lower Manhattan. In addition, other infrastructure projects are planned by New York State Department of Transportation, Port Authority of NYNJ, Economic Development Corporation and NYC Transit. Con Edison estimates that total interference costs affecting all of its energy systems as a result of these activities could exceed $400 million.

Q. What are the forecasted interference costs associated with the Lower Manhattan work for 2005-2007?

A. A detailed analysis was performed for each of the blocks proposed to be reconstructed in years 2005-2007. An estimate was derived for steam interference based on the historical expenditures that have occurred on similar blocks in this area. It is estimated that an average of $8.5 million a year will be expended in Lower Manhattan for 2005 to 2007 as a result of this program.

RECONCILIATION

Q. Does the Company propose to update the forecast of interference expenses?

A. Yes. The New York City Capital Commitment Plan will be updated and released again in 2004 and will

provide an updated forecast of projects for 2005. In addition, the Company continually monitors the ongoing projects to develop and modify the Company's project estimates as the City scope of work on a project changes and develops.

Q. Is the Company looking for any other reconciliation mechanism related to interference?

A. Yes. Since these expenses are outside of the Company's control, the Company proposes to update and reconcile its interference expenditures if a multi year rate plan, as described by Company witness Rasmussen, is adopted.

Q. Does this conclude your testimony?

A. Yes, it does.

Q. Please state your name and business address.
A. My name is Hector J. Reyes. My business address is Consolidated Edison Company of New York, Inc., 4 Irving Place, New York, NY 10003.
Q. By whom are you employed and in what capacity?
A. I am employed by Consolidated Edison Company of New York, Inc. ("Con Edison" or the "Company") as Director of Benefits and Compensation.
Q. How long have you been employed by Con Edison?
A. I have been employed since June 1976.
Q. Please state briefly your educational and professional background.
A. I graduated from Fordham University with a Bachelor of Science Degree in Accounting in 1976. In 1982, I earned a Master of Science Degree in Taxation from Pace University. I joined Con Edison in 1976 as a Staff Accountant in Corporate Accounting. Between 1979 and 1981, I was promoted to different supervisory positions in Corporate Accounting. In 1983, I was promoted to Assistant Manager, Accounting Research and Procedures. My responsibilities as Assistant Manager included accounting for the Company's health and welfare expenses. In 1988, I was promoted to the position of Manager, Retirement and Insurance Benefits and in 1989, I was

promoted to the position of Manager of Employee Benefits. In September 1999, I was promoted to Director of Benefits and Compensation.

Q. What are your general responsibilities and duties?

A. My responsibilities as Director of Benefits and Compensation include the development, implementation, communication, and administration of the Company's employee benefit programs. I am also responsible for management compensation, executive compensation and compensation planning.

Q. Are you a member of any professional organizations in the benefits or healthcare industries?

A. Yes. I am a member of the Board of Directors of the New York Business Group on Health (NYBGH). NYBGH is a not-for-profit coalition of 150 health plan sponsors and health-related organizations whose mission is to find practical solutions to contemporary healthcare issues in the New York metropolitan area.

Q. Have you previously testified before this Commission?

A. Yes, I testified in PSC Case 99-S-1621.

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

A. My testimony will address the Company's forecast of employee welfare expenses and executive compensation.

EMPLOYEE WELFARE EXPENSES

Q. Did you prepare an exhibit entitled "Consolidated Edison Company of New York, Inc., Administrative and General Expenses - Major Account Group 49, Employee Welfare Expenses - PSC Account 926.2"?

A. Yes.

MARK FOR IDENTIFICATION AS EXHIBIT__(HJR-1)

Q. What does this exhibit show?

A. Page 1 of this exhibit is a summary table of the Company's forecast of employee welfare expenses for the rate year ending September 30, 2005. This forecast is based on historical costs for the test year ending June 30, 2003. Lines 1 through 18 show costs for the Company's employee benefit programs and lines 19 to 23 show costs for the Company's health insurance programs net of employee deductions. Total employee welfare expenses are shown on line 24. Line 25 shows the capitalized portion of group life insurance (line 2) and health insurance net of employee deductions (line 23). Total employee welfare expenses net of capitalized amounts are shown on line 26. Page 2 of this exhibit is a summary table of the rate year forecast for health insurance costs and employee deductions.

Q. Please explain the common split normalization adjustments

on page 1 of your exhibit.

A. As discussed in Company witness Lee's testimony, these adjustments to the historic year reflect changes in common cost allocations resulting from the sale of electric generating assets. For steam operations, a common cost allocation of 5.10% is used to derive the rate year forecasts for employee welfare expenses.

Q. What is the basis for the normalization adjustments on page 1 of your exhibit?

A. On line 2, the $80,717 normalization adjustment for group life insurance is required to reconcile historic year costs to actual premiums paid. The normalization adjustments on lines 5, 7 and 14 are required to capture expenses that relate to the historic year, but are reflected in the accounting records of a prior or subsequent period.

Q. Please describe the program changes on page 1 of your exhibit.

A. The program changes on lines 19 through 22 represent forecasted increases in health insurance premiums, health service utilization, and employee contribution amounts.

Q. How is the escalation developed as shown on page 1 of your exhibit?

A. Three different methods are used to escalate historic

year costs to the rate year. First, a labor factor of 4.99% is used to escalate employee welfare costs that are a function of salaries and wages. The development of this labor factor is discussed in Company witness Muccilo's testimony. Second, a non-labor factor of 3.53% is used to escalate employee welfare costs that are unrelated to salaries and wages. Company witness Lee provided this non-labor factor, which is based on the GDP deflator. Third, projected healthcare cost trend rates of 8.75% for the rate year ending September 30, 2004 and 8.25% for the rate year ending September 30, 2005 are used to escalate health insurance premiums and health service utilization costs. The Company and its actuaries, Buck Consultants, developed these trend rates, which are also used in forecasting costs for other post-employment benefits. Escalation for health insurance costs is included on lines 19 to 22.

Q. Please explain the increase in the Thrift Savings Plan shown on page 1, line 1 of your exhibit.

A. The two types of costs associated with the Thrift Savings Plan are Company contributions on behalf of plan participants and administrative fees associated with the operations of the plan. For management employees, Thrift Savings Plan contributions up to 6% of base salary

qualify for a 50% Company match. For employees who are members of Local 1-2, a 50% Company match is applied to Thrift Savings Plan contributions of up to $1.22 per hour (maximum 40 hours). This maximum rate is an estimate based on the last collective bargaining agreement reached with Local 3, the Company's other union. For both management and Local 1-2 employees, the contribution rates are applied to the employee participation levels at July 31, 2003 to arrive at an estimate of total employee participating contributions. The Company match represents 50% of this amount. The labor factor is used to escalate the Company match for management employees only. For plan administration expenses, the non-labor factor is applied to the historic cost to arrive at the rate year cost. Finally, the common cost factor for steam is then applied to the Company match and administrative expenses to arrive at the rate year forecast.

Q. Please discuss group life insurance shown on page 1, line 2 of your exhibit.

A. For management employees, the Company provides group term life insurance equal to base annual salary. For weekly employees who are members of Local 1-2, the Company provides $20,000 of group term life insurance in

accordance with the labor agreement. Rate year amounts for both management and Local 1-2 employees are calculated using year 2003 premium costs and employee participation levels. Total management employee costs are escalated using the labor factor. Local 1-2 employee costs are escalated by the non-labor factor since the value of this life insurance benefit does not increase with base salary.

Q. Please explain the increase shown for health insurance.

A. The increase for health insurance includes costs associated with healthcare premiums and claims, long-term disability, and benefits administration and reflects the Company's cost containment programs. Projected healthcare costs for the rate year are developed by applying the number of employee contracts at August 31, 2003 to forecasted contract rates that reflect premium increases through the rate year. The forecasted contract rates are based on year 2003 premiums that have been escalated using healthcare cost trend rates developed in cooperation with our actuaries, Buck Consultants. Historic year costs for long-term disability are escalated using the labor factor. Historic year costs for benefits administration and cost containment programs are escalated using the non-labor factor. The common

cost factor for steam was applied to total projected health insurance costs to arrive at the rate year forecast.

Q. Please discuss the Company's cost containment initiatives related to healthcare expenses.

A. Cost containment programs such as Value Options and Managed Care are designed to protect the Company and plan participants from the effects of rising hospital and medical costs. These programs use accepted healthcare standards to determine the medical necessity of hospital and surgical procedures for benefit purposes. The Managed Care program also coordinates second opinions before surgical procedures are performed.

Q. Does page 2 of your exhibit detail the components of rate year forecasts for health insurance costs?

A. Yes. This exhibit shows the rate year forecast for each of the Company's various health insurance plans applicable to steam operations.

Q. Page 1, line 22 of your exhibit shows a $143,266 increase for the rate year in the amount of employee deductions for health insurance. Please explain.

A. Projected employee deductions for healthcare expenses are based on the number of employee contracts at August 31, 2003 and negotiated employee contribution rates for the

year 2004. This amount is then escalated using the non-labor factor. Forecasted employee contributions for the long-term disability plans are calculated by applying the labor factor to the historic amounts. The common cost factor for steam is then applied to the total employee deduction amount to arrive at the rate year forecast. The Company has been able to offset some of the recent escalation in healthcare expenses through various employee cost-sharing mechanisms such as increased deductibles and co-payments.

Q. Has the Company taken any other measures to control the recent growth in health insurance?

A. Yes. For certain employee benefit programs, the Company has switched to a self-insured funding arrangement in an effort to reduce the costs associated with insurance underwriting. Furthermore, the Company has negotiated cost savings for the prescription drug plan in the form of formulary rebates.

Q. Do you plan to update this exhibit during the course of this proceeding?

A. Yes. Con Edison plans to update this exhibit as actual rates and changes in employee benefits become known. For example, in February 2004, the actual 2004 premiums will be finalized for various health insurance coverages.

EXECUTIVE COMPENSATION

Q. Have you reviewed the Company's executive compensation?

A. Yes. I have reviewed the executive compensation data of other U.S. utilities in Con Edison's peer group. These peer group companies are similar to Con Edison in terms of workforce size and revenue dollars. The data indicates that Con Edison's executive compensation is reasonable.

Q. Does this conclude your testimony?

A. Yes.

Q. Please state your name and business address.

A. My name is Anthony Codner and my business address is 4 Irving Place, New York, New York 10003.

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

A. I am employed by Consolidated Edison Company of New York, Inc. ("Con Edison" or the "Company") as the Department Manager of Gas and Steam Research.

Q. How long have you been employed by Con Edison, and what positions have you held?

A. I have been employed by Con Edison for 29 years and held various Engineering and Managerial positions in gas and steam. I was the Chief Steam Engineer in 1983, General Manager of Bronx Gas in 1995, Chief Gas Engineer in 1997, and became the Department Manager of Research and Development in 2001.

Q. Briefly discuss your educational background.

A. I graduated with a Bachelor of Engineering Degree from City College of New York in 1974, and with a Masters in Engineering Degree from Columbia University in 1976.

Q. Are you a member of any professional societies or organizations?

A. Yes. I am a licensed Professional Engineer in New York State.

Q. With what industry committees and task forces are you associated?

A. I am associated with various industry committees in the American Gas Association, the Gas Technology Institute and the International District Energy Association. These committees are focused on research activities.

Q. Would you briefly state your responsibilities as gas and steam research manager?

A. As the Department Manager of Gas and Steam Research, I am responsible for developing products to enhance the safety, productivity, and the operations of both the Con Edison Gas and Steam organizations. I oversee two engineers dedicated to gas and one to steam project management. I oversee the projects, guide their development and manage the research and development ("R&D") budget.

Q. What is the purpose of your testimony?

A. My testimony will cover the current and planned levels of steam R&D expenditures through the Rate Year, specifically identifying the forecasted level of expenditures for the Rate Year.

Q. Does Con Edison have a steam R&D program?

A. Yes.

Q. What are the purposes of Con Edison's steam R&D program?

A. The purposes of Con Edison's Steam R&D program are to develop and demonstrate new processes/methods or technologies that will improve operations and meet business needs:

- To reduce or minimize operation and maintenance ("O&M) costs with new technologies or alternate procedures.
- To enhance reliability of generation and distribution of steam to customers in a safe manner
- To improve steam plant boiler fuel efficiencies and optimize combustion processes to improve environmental performance and lower costs.

Q. Please describe how projects are identified, researched and deployed into operations?

A. The Steam Research group consists of one employee and myself, who work very closely with the present Steam Operations employees to identify needs. Intimate knowledge of the steam business and the cooperation of operating personnel is essential for a successful R&D program. The R&D employees also stay in contact with other utilities, universities and technology

developments to bring in new ideas. Once a potential product is identified, we obtain a sponsor from the user organization who must complete a full cost/benefit justification for the research. The organization must agree to provide support as the project progresses through its employees' time and funds for field demonstrations. The user organization must also agree to implement use of the developed product if it is successfully developed. The close working relationship and cooperation between R&D and user organization are key to developing successful programs.

Q. Please describe some recent successful steam projects?

A. Recent successful Steam R&D projects include the following:

- Installation of the Performance Indicator ("PI") system at the steam generating stations and at the Energy Control Center to improve tracking of vital plant output data as it relates to the steam system as a whole.
- The demonstration of sensors and wireless technology, SmartWatch®, to remotely monitor the operability of indoor customer steam traps from a centralized engineering or operations homebase.

- The installation and demonstration of a steam microturbine for a commercial customer to generate its own electricity.
- The successful use of sleeves to repair leaking boiler feedwater tubes resulting from corrosion and stress cracking.

Q. Does Steam R&D currently have any ongoing projects?

A. Yes. The current steam projects include the following:

- The evaluation and testing of lighter, non-metallic materials in the design and fabrication of steam manhole covers.
- The development of a system to remotely monitor operation of steam traps in manholes in the street.
- The field assessment of existing smart pigging technologies to be demonstrated on steam distribution pipelines as a means to evaluate pipewall thickness.

Q. Does Con Edison coordinate steam research projects with other outside organizations and steam utilities?

A. At present, there is no vehicle for formal coordination of steam research with other utilities. While Con Edison is presently working to initiate a collaborative research funding mechanism through the International

District Energy Association ("IDEA"), because our steam system is so much larger and different than others, the Company takes a leadership position in R&D. Collaboration may become valuable, but will not substitute for an internal program focused on our specific company needs. It is hoped that cooperation will provide some new perspectives and ideas from others with knowledge in the field. It will not replace the years of internal experience that our R&D staff, working closely with operating engineers, bring to our current process.

Q. Has the Company changed its focus regarding Steam R&D?

A. Yes. The Company believes that the formerly modest program does not adequately meet the needs of Steam Operations. Additional spending is needed to address new opportunities and develop improvements for the Company's steam system.

The Con Edison steam business is unique. We need to operate it, with high reliability in one of the world's most densely populated cities. We strive to continuously find new and innovative ways to keep costs competitive to ensure that our customers are satisfied with our service.

Q. What was the Historic Rate Year Spending?

A. In the Historic Rate Year, July 2002 to June 2003, the total expenditure was $239,000. This is an anomaly. This uncharacteristically low spending level was attributable to the unexpected death of the only engineer devoted full-time to steam R&D. I have since replaced that engineer and the Company is ready to move forward with its program.

Q. What has been the annual level of spending for steam research in recent years?

A. Over the last five years, the average level of annual spending has been nearly $400,000.

Q. What is the level of expenditures proposed for the Rate Year?

A. The proposed level of expenditures is $567,000.

Q. Have you prepared an exhibit entitled, "CONSOLIDATED EDISON COMPANY OF NEW YORK, INC - ANALYSIS OF RESEARCH AND DEVELOPMENT COSTS -- ALLOCABLE TO STEAM"?

A. Yes.

Q. Was this exhibit prepared under your supervision and direction?

A. Yes.

MARK FOR IDENTIFICATION EXHIBIT __ (AC-1)

Q. Please explain this exhibit.

A. This exhibit shows current R&D projects, including some that are being conducted jointly with other departments but the expenses shown on the exhibit are all related to steam.

Q. Please explain the reason for the proposed increase.

A. This increase reflects input from various Steam Operation employees who have identified several dozen ideas where research could help improve their work performance. Using an outside research organization, we further developed these ideas and identified the top 24 for detailed specification preparation. Funding to pursue all 24 ideas would have been cost prohibitive. However, our Rate Year projection of $567,000 reflects a modest increase in steam-related R&D spending to start some of these projects and begin the process of steadily introducing new technology into Steam Operations. The proposed increase is only $167,000 greater than average spending for the past five years.

Q. Which ideas will be pursued in the Rate Year?

A. The Company plans to pursue the development of a digital leak detector, an advanced SOMIS (Steam Operations Mapping and Information System) to

incorporate GPS (Global Positioning System) and thermal imaging, and an improved pavement breaking tool because they show the greatest potential for improving the efficiency of the Company's steam system.

Q. Please describe these initiatives in more detail.

A. DIGITAL LEAK DETECTOR ("DLD"): The DLD is a modified version of a gas leak detection device to be designed and fabricated by Gas Technology Institute of Des Plaines, IL. Current leak pinpointing devices require the steam mechanic to be specially trained in identifying steam leaks by listening to steam "roars" through headphones and by using analog measuring techniques. While this method is successful most of the time, the listening process can have problems, especially in Manhattan where there are many other noise sources. With the DLD, the hardware and software in the prototype device are modified to distinguish steam frequencies from other stray noises during the pinpointing process and allow a steam mechanic to more readily and accurately identify steam leaks. The anticipated duration of the project is approximately 18 months and requires funding of $65,000.

OVERLAY OF THERMAL IMAGING ON STEAM OPERATIONS MAPPING

AND INFORMATION SYSTEMS (SOMIS): Steam Distribution currently contracts the services of Ergonomy Infrared Inspections to collect images of steam main locations using infrared technology. Steam Distribution is searching for a method to import these images into their mapping database, SOMIS, and create a visual layer that may be turned on/off as an overlay. The goal is to build a historical, pictorial archive to document specific locations throughout the steam main distribution system where areas exhibit significant heat loss and possibly target these areas for future insulation work. The anticipated duration of the project is approximately 18 months and requires $75,000 funding.

IMPROVED PAVEMENT BREAKING TOOL: The Steam Operations Group is interested in exploring the use of a pavement breaking tool that is ergonomically safe and breaks quietly and efficiently. Currently, Gas R&D is funding the design and development of such a tool for approximately $100,000. If field demonstrations show success with Gas Operations, it makes logical sense to extend the field demonstrations to Steam Operations. The anticipated duration of the project is

approximately 36 months and Steam funding of $73,000 is required. Combined with the Gas Department funding, the total Con Edison amount would be $173,000.

Q. Does R&D pursue projects aimed at reducing the steam variance?

A. Yes. We have a number of early-stage projects that will help to marginally improve the steam variance if the initiatives are successful. For example, as described in the testimony of Company witness Litkouhi, we have already identified our Avenue D main as one area having more significant heat loss from exposure to higher moisture penetration than the rest of the steam distribution network and therefore having the potential for cost-effective reinsulation. We have accordingly challenged several research organizations to develop a means to effectively reinsulate this main without the need to completely excavate it. If they can demonstrate such a method, we have budgeted $100,000 in the Rate Year to begin the Avenue D reinsulation. Other programs include the demonstration of sensors and wireless technology, SmartWatch®, to remotely monitor the operability of indoor customer steam traps from a centralized engineering or operations homebase.

This early detection of leaks will mean faster repair and reduced steam loss. Finally, our project to overlay thermal images on SOMIS will help in identifying areas of high heat loss and could potentially identify additional areas for reinsulation beyond the Avenue D location.

Q. Mr. Codner, does this conclude your testimony?

A. Yes.

Q. Please state your name and business address.

A. Randolph S. Price, 4 Irving Place, New York, NY 10003.

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

A. I have been employed by Consolidated Edison Company of New York, Inc. ("Con Edison" or the "Company") since August 2001, as Vice President for Environment, Health and Safety.

Q. By whom were you employed prior to joining Con Edison, and what positions have you held?

A. From 1982 until 1994, I worked for the DuPont Company. I started as a plant environmental coordinator and subsequently worked in various positions of increasing responsibility before leaving DuPont in 1994. In 1994, I joined J.M. Huber Corp. as corporate director of Environment, Health and Safety, where I stayed until 1996, when I joined Honeywell International as Director of Environmental Affairs & Six Sigma.

Q. Would you please briefly discuss your educational background?

A. I received a Bachelor of Science degree in Biology from the State University of New York at Cortland in 1975, and a Master of Science degree in Sanitary Science from Syracuse University in 1982.

Q. Do you belong to any professional organizations?

A. Yes. I am one of Con Edison's representatives to the Edison Electric Institute ("EEI"), serving as a member of EEI's Environment Executive Advisory Committee and Chairman of its Environmental Excellence Workgroup.

Q. Mr. Price, would you briefly describe the purpose of your testimony?

A. My testimony focuses on the following two environmental matters that are expected to result in increased expenditures by Con Edison:

- Con Edison's investigation and remediation of the former manufactured gas plant and manufactured gas storage holder sites ("MGP Sites") and Superfund sites for which it is responsible;
- The projected increase in hazardous waste generation fees that the Company will have to pay to the State of New York as a result of recently enacted State legislation.

MGP SITES

Q. Before turning to Con Edison's MGP Site investigation and remediation program, please provide a brief background on the Company's and its predecessors' former manufactured gas plants and manufactured gas storage holder facilities.

A. Manufactured gas plants ("MGPs") provided energy in the

form of combustible gases of varying composition to municipal street lighting systems and to homes and businesses in cities and towns across the more densely populated regions of the United States. In the case of the areas served by Con Edison and its predecessor companies, manufactured gas plants operated from the late 1820s through the early 1960s. The earliest of these plants produced illuminating gases from whale oil and rosin. The plants constructed during and after the 1830s converted coal (oven gas) or a combination of coke, oil and water (carbureted water gas) into a gas product that could be used for lighting, cooking and heating. There were about 200 MGPs in New York State and an estimated 3,000 to 5,000 in the United States, mostly in the Northeast and Midwest, prior to the plants becoming obsolete due to the construction of natural gas pipelines and large power plants. Holder stations consisted of large masonry, brick or steel tanks that were used to store manufactured gas after it had been produced at MGPs.

Q. What are the environmental concerns related to MGP Sites?

A. Manufactured gas production was a complex process that entailed the handling and storage of significant

quantities of feedstock materials, by-products, and residuals that contain organic and inorganic chemical constituents that are now considered to be hazardous substances under Federal and New York State laws and regulations and that when released to soil, groundwater, or waterways may pose a threat to human health or the environment. The materials of primary concern at MGP sites include carbureting oils, scrubber oils, coal tar, coal tar-related emulsions and sludges, and gas purification wastes. At gas storage holder sites, these materials include oils (which were used in hydraulic systems, as lubricants, or to maintain airtight seals between holder tank bases and shells) and coal tar (which at times condensed out of stored gas or was used to maintain airtight seals between holder tank bases and shells).

Q. Has the New York State Department of Environmental Conservation ("DEC") increased its activities regarding MGP Sites?

A. The DEC has pressured New York State's investor-owned gas utilities to investigate and, when necessary to protect public health and the environment, to undertake remedial response measures for the sites of their former manufactured gas plants. The DEC has now reached

agreements with most New York State gas utilities (including Con Edison) under which they will address their MGP Sites pursuant to comprehensive consent orders or cleanup agreements that cover multiple sites. Under the DEC's MGP program, investigations and/or remedial work have been undertaken or are planned at more than 160 former MGP sites across the State. DEC's MGP program is grounded in a Federal initiative to ensure that former MGP sites are addressed throughout the country. The New York State Department of Health ("DOH"), which works with the DEC in evaluating the results of MGP site investigations and determining the need for remedial response measures for them, views the primary goal of these investigations as assessing potential public exposure to MGP-related contaminants.

Q. Turning to Con Edison's MGP Site investigation and remediation program, can you provide the background for the program?

A. Yes. Con Edison and its predecessors formerly manufactured gas and maintained storage holders for manufactured gas at MGP Sites located throughout Manhattan, the Bronx, Westchester County, and western Queens, New York. Many of these sites are now owned by parties other than Con Edison and have been redeveloped

by their new owners for other uses, including schools, residential and commercial developments, public parks, and hospitals. The DEC is requiring the Company to investigate and, if necessary, to develop and implement remedial action plans for all of its and its predecessor companies' MGP Sites, which include 33 manufactured gas plant sites and 17 storage holder sites. Of these 50 sites, only 16 are still owned in whole or in part by the Company.

Q. Have you prepared a listing of Con Edison's MGP Sites?

A. Yes, the table entitled "MGP Site Listing" and labeled Exhibit __ (RSP-1) is a listing of all former manufactured gas plants and manufactured gas storage holder facilities that DEC is requiring Con Edison to investigate and, if necessary, to develop and implement remedial action plans.

Q. What has contributed to the significant recent increase in activities in this area for Con Edison?

A. On August 15, 2002, Con Edison entered into a cleanup agreement ("Agreement") with the DEC to conduct investigations and, if necessary, remediation at 45 of these 50 sites. The remaining five sites were already covered by either existing agreements (the Tarrytown Gas Works and White Plains Gas Works Sites), consent orders

(the East River Gas Works and Farrington Street Gas Holder Sites), or the federally-mandated RCRA corrective action requirements of a DEC-issued hazardous waste storage facility permit (Astoria).

Con Edison's execution of the Agreement began a period of significant increased activity in the Company's MGP program. Due to the large number of sites involved, the Company and the DEC agreed on a prioritization strategy under which MGP sites that are now the location of schools or residential properties would be investigated first. Other priority sites besides schools and residential properties can and have already surfaced primarily as a result of redevelopment projects by present property owners (W. 45th Street Gas Works and W. 58th Street Holder Station Sites) or infrastructure construction activities that have unearthed MGP-related contamination (E. 173rd Street Gas Works Site). The investigation of all 50 former MGP Sites could take up to ten years to complete. The remediation work for sites at which such action is deemed necessary by the DEC and DOH could extend beyond ten years. At some sites, the remediation may not be completed until well into the future until the structures and buildings present on the sites are retired and demolished.

Q. What is the required process for the investigation and remediation of Con Edison's MGP sites, and how long can this process be expected to take for a typical site?

A. The first step of the process required by the Agreement is to conduct a DEC-approved subsurface investigation to identify the nature and extent of any soil, groundwater, and sediment contamination that may be present at a site due to past MGP-related operations. More than one round of on-site investigation and, in some cases, off-site investigation may be necessary to ensure that the contamination has been characterized and delineated with a sufficient degree of certainty to support the development of an effective remedial action plan. If MGP-related contamination that DEC and/or DOH determine requires remediation is detected, a comprehensive remedial action plan must be developed and implemented by Con Edison with input from the community and affected property owners and approval by the DEC and DOH. It is not uncommon for the investigation/remediation process to take three to five years to complete. Recently enacted New York State legislation (A. 9120, signed into law on October 7, 2003), which extends to investigation work plans and reports the same opportunity for public comment now required for remedial action plans, could

increase the time needed to complete the process.

Q. What is the current status of Con Edison's MGP Program?

A. The Company has completed the required investigation and remedial action for the Farrington Street Gas Holder Site. The investigation work for the Tarrytown Gas Works Site has also been completed. DEC has approved a site remedial action plan that will be executed by the developer that now owns the Tarrytown Gas Works Site. That plan will be conducted pursuant to a $17.2 million fixed price remediation liability transfer contract under which the developer (with adequate remediation cost cap and pollution liability insurance backing) has assumed Con Edison's obligation to clean up the MGP-related contamination and released Con Edison from all future liability for MGP-related cleanup work at and around the site. Implementation of the remedial action plan will begin during 2004. The Company has also conducted an investigation and supplemental investigation at the White Plains Gas Works Site. The remediation of the MGP-related contamination that has been detected on and around the site will be carried out in phases to ensure that the work does not interfere with the operation of the Company's White Plains Substation, which occupies a significant portion of the

site. The first phase of the remedial action work is expected to begin during the second half of 2004.

Since entering into the Agreement with the DEC, the Company has developed site characterization study work plans and remedial investigation work plans[1] for sites with schools, residential properties, and parks, as well as those where current property owners are planning redevelopment projects. The Company has implemented nine of those work plans since August 2002. The Company has also developed, for DEC's review and approval, remedial investigation work plans for the East River Gas Works Site and for the Astoria Site, including the former manufactured gas plant portion of the Astoria Site.

Of the nine completed investigations it has conducted since entering into the August 15, 2002 Agreement, the Company has found MGP-related contamination requiring at least some level of remedial action at six of the sites. These six sites are the E. 115th Street Gas Works Site, Mount Vernon Gas Works Site, W. 42nd Street Gas Works Site, a portion of W. 45th

[1] Site characterization studies ("SCS") involve intrusive sampling work including the collection and analyses of soil, groundwater, and sediment samples. They are typically not as comprehensive in scope as a full-blown remedial investigation and, under the Agreement, may be conducted only for sites at which MGP-contamination has not yet been detected.

Street Gas Works Site, E. 173rd Street Gas Works Site, and the Con Edison gas compressor station portion of Hunts Point Gas Works Site. As for the other three sites, they appear to have minimal MGP impact and the Company will work with the DEC and DOH to determine whether additional action is necessary at these locations. For the remainder of 2003 into 2004, the Company's plan is to conduct site characterization studies at the remaining eleven high priority sites and to move into the remediation phase for those sites where investigations have found that remedial action is warranted. The Company also plans to carry out the remedial investigation work plans for the East River and Astoria Sites after those plans are approved by the DEC.

Q. When does the Company plan to initiate remediation on the six recently investigated sites mentioned above?

A. The required remedial action for the gas compressor station portion of the Hunts Point Gas Works Site has already been completed. The five remaining sites are at different stages of the investigation/remediation process.

Con Edison recently submitted a draft Remedial Action Work Plan for the E. 173rd Street Gas Works Site to the DEC. Depending upon the length of the public

comment period that the DEC sets for the plan and the nature of the comments that the DEC receives on it, the Company could receive approval of that or a modified work plan as early as the first quarter of 2004 and begin cleanup activities at some point during the second half of next year.

A full-blown remedial investigation ("RI") was conducted for the E. 115th Gas Works Site. However, the Company is still in the process of analyzing the results of the investigation and preparing the detailed RI report called for in the Agreement. Moreover, the development and implementation of the remedial action plan for the E. 115th Street Site will need to be carried out in phases with input from the New York City Department of Education, because the site is a public high school that must remain open during the school year, thereby limiting the implementation of those activities to summer months.

For the other three sites, the Company has only recently completed the investigation and is in the process of analyzing the sampling data and preparing reports presenting the study findings. Remediation at these sites will likely not take place until 2005, after any required additional investigation activities are

completed and the Company's proposed remedial action plans have been evaluated and approved by the DEC and DOH.

Q. Apart from the investigations discussed above, what other activities have taken place at Con Edison's MGP Sites?

A. At three of the sites no longer owned by Con Edison, investigation and/or remediation work was been conducted by the present property owners under cleanup agreements between the owners and the DEC.

At the Woodworth Avenue Gas Works Site in Yonkers, the owner of the parcel comprising the western portion of the grounds of the former manufactured gas plant has completed both the investigation and implementation of the DEC required remedial action plan for the MGP-related contamination that was present on the property. The parcel was redeveloped as a commercial bakery facility that opened this fall. In December 2001, Con Edison and the owner of this property entered into an agreement under which Con Edison agreed to contribute $900,000 towards the costs of the required investigation and remediation work.

In 1995, Con Edison entered into an investigation/ remediation cost sharing agreement with the owner of the

commercial shopping center located on the Pelham Manor Gas Works Site. The owner recently completed a comprehensive DEC-approved supplemental investigation program. The results of the supplemental investigation indicate that extensive remediation will be required for the site. Off-site investigation work, which would be carried out by Con Edison under its Agreement with the DEC, may also be necessary. The property owner intends to redevelop substantial portions of the site and to seek expedited DEC approval of a site remedial action plan, so that the required remediation work can be started next year.

The ground lessee of a portion of the W. 18th Street Gas Works Site has completed a DEC-approved investigation for its leasehold property under a DEC cleanup agreement and has received DEC approval of a remedial action plan for the MGP-related contamination on the property. The ground lessee intends to conduct the remediation work next year in conjunction with the construction work for a new high-rise office building that is planned for the property. Implementation of the remediation work in this manner is expected to result in significant cost savings. Con Edison and the ground lessee are in the process of finalizing a cost sharing

agreement for the investigation and remediation work.

SUPERFUND SITES

Q. What types of sites does Con Edison include in its Superfund Sites investigation and remediation program?

A. Con Edison's Superfund Program covers the following categories of sites:

- Third party-owned sites to which Con Edison has shipped hazardous substances for treatment, storage or disposal and has formally been designated a potentially responsible party ("PRP") for the investigation and remediation of site contamination by the United States Environmental Protection Agency ("EPA"), DEC, or other government environmental agency pursuant to the Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA") or comparable state statutes, including statutes that impose liability for the costs of investigating and cleaning up oil spills;
- Sites that were formerly owned by Con Edison and for which the current site owners assert claims against Con Edison for investigation and remediation costs pursuant to CERCLA or comparable state statutes;
- Fuel oil and dielectric fluid spill sites covered under Appendix B of the Consent Order that Con Edison

entered into with the DEC in 1994; and

- Sites (whether or not owned by the Company) at which Con Edison is required to conduct cleanup work because of releases of oil, dielectric fluid, PCBs, or other hazardous substances from its equipment, facilities, or operations.

PROJECTED EXPENDITURES FOR MGP AND SUPERFUND SITES

Q. How much does the Company expect to spend during the rate year on investigating and performing remediation work at MGP Sites and Superfund Sites?

A. For the rate year ending September 2005, an expenditure of $31.9 million is projected for the Company's combined MGP and Superfund programs. This projection is based on actual expenditures in the MGP and Superfund programs for the period from July 1, 2002 through June 30, 2003, escalated to the rate year. Of the $31.9 million, $1.6 million is allocable to steam. Company witness Lee's testimony explains the basis for the allocation.

Q. Could actual expenditures differ from these estimates?

A. Yes. The projected cost is the minimum that the Company expects to spend on these programs during the rate year. Because the MGP Program is ramping up, it is likely that expenditures for the MGP and Superfund Programs in the rate year will exceed $40 million. It is important to

note that each site is different due to various factors (e.g., nature of site, level of contamination, and site usage). Remediation on one site may require $100,000 in expenditures, whereas another location could require $15 million. The Company's estimates will become firmer as site investigations and remediation work proceed.

Q. Please describe the Company's experience with the remediation of MGP Sites?

A. Although the Company has conducted site characterization studies and remedial investigations at several of its MGP Sites, it has not yet carried out a major remediation program at any of them. The Company does have remediation cost estimates for some of the sites based on the investigation findings. For example, our consultants have provided us with cost estimates of $11.5 million for remediating the E. 173rd Street site and at least $9 million for remediating a portion of the W. 45th Street site.

In addition to our experience with these Con Edison sites, we are cognizant of a study that was conducted by the Gas Research Institute (GRI) where it was estimated that for those MGP sites that did require some level of remediation, the cost could range from approximately $5 million to $10 million per site. But,

as I mentioned earlier, remediation cost is site dependent.

Q. Do you propose a true-up or reconciliation of these costs?

A. Yes, as I mentioned before, the Company is still in the early stages of the investigation/remediation process for its MGP Sites. In most cases, until we complete the actual site characterization work to fully delineate the nature and extent of any MGP related contamination at a particular site, the actual remediation cost can widely vary. Therefore, as addressed by Company witness Rasmussen, the Company proposes to reconcile these costs annually.

Q. What steps has Con Edison taken to minimize its Superfund and MGP costs?

A. In an effort to keep its costs as low as possible, Con Edison diligently pursues reimbursement of its Superfund and MGP expenditures from other PRPs and from its liability insurers. Con Edison joins and plays an active role in Superfund site PRP groups to ensure that they negotiate with the government consent decrees and orders that equitably allocate liability for site investigation and remediation costs amongst all site PRPs and, when warranted, institute CERCLA cost

contribution actions against recalcitrant PRPs. Con Edison also files claims for the Superfund investigation/remediation costs it incurs with its liability insurance carriers and pursues litigation against its carriers when they fail to indemnify Con Edison against such losses.

Con Edison has been successful in these efforts for its Superfund sites. For example, the Company instituted breach of contract actions against its insurance carriers in connection with its liability for investigation and remediation costs for the Curcio Scrap Metal Superfund Site in New Jersey and the for PCB Treatment Inc. Superfund Sites in Kansas City, Kansas and Missouri. Con Edison settled the Curcio litigation with its carriers for $4.65 million and the PCB Treatment litigation for $1.67 million. Con Edison received an additional $350,000 settlement from the liability insurance carrier for the defunct scrap metal broker that delivered the Company's transformers to the Curcio Site.

Con Edison has litigated against its liability insurance carriers and continues to pursue such litigation against them for MGP Site related investigation and remediation costs. In 1999, the

Company received an adverse jury verdict in its insurance litigation for the Tarrytown Gas Works Site. The Company appealed the trial court's rulings on the allocation of damages and the burden of proof on the issue of whether the site MGP contamination constituted an "accident" or "occurrence" within the meaning of the Con Edison's liability insurance policies. The Court of Appeals upheld both rulings, making litigation against insurance carriers for MGP sites an uphill battle for Con Edison. Nevertheless, Con Edison has commenced litigation against its liability insurance carriers for the investigation and remediation costs it is incurring for the W. 18th Street Gas Works, Hunts Point Gas Works, Pelham Gas Works, and Astoria Sites.

HAZARDOUS WASTE GENERATION FEES

Q. Turning to your second subject, why are the State fees on hazardous waste increasing?

A. In 2005-2007, the Company will experience an increase of approximately $594,000 annually in hazardous waste fees payable to the State of New York due to recently enacted State legislation that imposes a surcharge on the generation of hazardous waste (A. 9120, signed into law on October 7, 2003).

Q. How was this projected increase in hazardous waste fees

calculated by Con Edison?

A. The projected fee increase was calculated by applying the surcharge rates imposed by the new legislation to total quantity of hazardous waste generated by the Company during 2002, which was the last complete year for which such data are available. This produced an estimated annual surcharge for the Company of $865,000.

Q. Should any adjustments be made to this amount?

A. Yes. The DEC recently approved the Company's lead stabilization program for Queens and Manhattan and partially approved it for the Bronx, Brooklyn, and Westchester County. Under this program, hazardous waste containing lead is stabilized by a chemical process, so that the waste is no longer considered hazardous. This will reduce the quantity of hazardous waste that the Company generates, which, in turn will reduce the Company's estimated annual liability for the hazardous waste surcharge to $594,000. Of the $594,000, $212,000 is allocable to steam. Company witness Lee's testimony explains the basis for the allocation. Further reductions in hazardous waste generation and the surcharge will be achievable if the DEC fully approves the Company's lead stabilization program for treated or stabilized wastes from underground structures in

Brooklyn, the Bronx and Westchester. I also note that the reduction in hazardous waste generation due to the lead stabilization program will result in a reduction in the base fee for hazardous waste generation and in the quarterly Superfund tax that Con Edison pays to the State. I have not yet had an opportunity to calculate these reductions, but I will provide them in the updates.

Q. Does this conclude your testimony?

A. Yes.

Q. Would the members of the Rate Panel please state your names and business address?

A. Joel H. Charkow, Christine Colletti and Allan S. Cohen, 4 Irving Place, New York, New York 10003.

Q. By whom are you employed, in what capacity, and what are your professional backgrounds and qualifications?

A. (Charkow). I will act as chairman of the Panel. We are employed by Consolidated Edison Company of New York "Con Edison" or the "Company"). I am Director of the Rate Engineering Department. The Rate Engineering Department is responsible for designing rates and performing cost-of-service studies for the electric, gas and steam systems. My background is as follows: I received a Bachelor of Electrical Engineering Degree and a Master of Electrical Engineering Degree from Rensselaer Polytechnic Institute in 1964 and 1965, respectively, and a Master of Business Administration Degree from New York University in 1968. I am a Registered Professional Engineer in New York State, served on the Load Research Committee of the Association of Edison Illuminating Companies, and am a member of several engineering and business honorary societies. In 1977, I was employed by Con Edison as a Division Analyst responsible for preparing electric,

gas, and steam demand analysis studies and electric marginal cost-of-service studies. In 1986, I was promoted to Department Manager - Cost Analysis and Load Research. In 1996, I was promoted to my present position. Prior to joining Con Edison, I was employed as a research engineer and as a computer systems analyst. I have previously testified before this Commission regarding electric and steam cost of service, unbundling and rate design.

(Colletti). I am Director of Electric and Steam Rate Design in the Rate Engineering Department. My background is as follows: I received a Bachelor of Arts Degree in Economics from the University of Massachusetts in 1977 and a Master of Arts Degree in Economics from the State University of New York at Binghamton in 1978. In 1979, I began my employment with Con Edison in the Electric Rate Division of the Rate Engineering Department. Between 1981 and 1991, I worked in positions of increasing responsibility in the Electric Rate Division and was promoted to the position of Division Analyst in 1989. Between 1992 and 1994, I worked as a Division Analyst in charge of the Rate Adjustments Division of the Rate Engineering Department. Between 1994 and 1995, I worked as a

Project Manager in the Corporate Planning Department working on industry restructuring issues. In 1996, I was promoted to Department Manger of Electric and Steam Rate Design in the Rate Engineering Department and in October of this year I was promoted to my current position. I have previously testified before this Commission.

(Cohen) I am Section Manager of the Cost Analysis Section of the Rate Engineering Department. My background is as follows: I received an Associate of Applied Science Degree from New York University in 1974. From 1973 to 1980 I was employed by National Utility Service in the dual capacity of Rate Analyst and Tariff Administrator. From 1980 to the present, I have been employed by Con Edison in the Cost Analysis Section of the Rate Engineering Department. Since joining Con Edison, I have been assigned increasing responsibilities in the Cost Analysis Section. In 1982, I was promoted to Senior Rate Analyst, and in 1992 I was promoted to Staff Analyst. In 1996, I was promoted to Manager and I was placed in charge of the Cost Analysis Section, and in 2001 I was promoted to my current position. I have previously testified on behalf of Con Edison, in various cases before the New

York State Public Service Commission and the Federal Energy Regulatory Commission. I have also testified on behalf of Rockland Electric Company before the New Jersey Board of Public Utilities.

Q. What is the purpose of the Steam Rate Panel's testimony?

A. The Panel will present the Company's proposals for revenue allocation and rate design. We will also present an embedded cost-of-service study (ECOS) and will propose several tariff changes.

Q. Do you have any exhibits to present?

A. Yes, we are presenting 9 exhibits, Exhibit No.__(SRP-1) through Exhibit No.__(SRP-9). We will describe these in the course of our testimony.

Q. How is Panel's testimony organized?

A. The testimony is divided into the following seven sections: (1) Revenue Allocation, (2) Rate Design Phase 1, (3) Rate Design Phase 2, (4) Rate Design Phase 3, (5) Billing Analysis, (6) Embedded Cost-of-Service Study, and (7) Tariff Changes.

(1) REVENUE ALLOCATION

Q. Did Company witness Muccilo identify the increased revenue requirement for the twelve months ending September 30, 2005 ("Rate Year")?

A. Yes. The increased revenue requirement for the Rate Year is $128,899,000, including gross receipts taxes of $3,171,000. The increased revenue requirement, excluding gross receipt taxes, is therefore $125,728,000.

Q. Please describe how the increased revenue requirement was allocated to the classes.

A. An overall pure base rate percentage increase was developed by dividing the Rate Year revenue increase by the total Rate Year pure base revenues. The overall pure base rate percentage increase was then applied to the SC 1, 2, 3, and 4 Rate Year pure base revenues to determine the increased revenue requirement for each class.

Q. How do you propose to recover State Income Taxes ("SIT") in the Rate Year?

A. SIT, as well as Gross Receipts Taxes, are currently recovered from steam customers through the "Percentage Increase in Rates and Charges". In accordance with the Commission's **Order Implementing Tax Law Changes On a Permanent Basis,** dated June 28, 2001, we are proposing to eliminate SIT from the Percentage Increase in Rates and Charges and provide for recovery of state income taxes through base rates. The $125,728,000 increase

includes $7,904,000 of state income taxes related to the increased revenue requirement. As explained in Mr. Muccilo's testimony, the balance of the SIT of ($1,510,000) that would have been credited as a separate percentage increase in rates and charges was reflected as an adjustment to sales revenue before the rate increase. This amount will be reflected in rates at the proposed revenue level. It should be noted, however, that the effect of this change is neutral to customers and will not affect Con Edison's overall revenues, although it will reduce base revenues with a corresponding increase in the amounts collected through the Gross Receipts Taxes included in the Percentage Increase in Rates and Charges.

Q. How do you propose to allocate the current level of state income taxes to each service class?

A. The ($1,510,000) of State Income Tax was first reduced by ($37,000) of gross receipts tax. The remaining ($1,473,000) of SIT revenue was allocated to each service class based on the ratio of Rate Year pure base revenues in each class to the total Rate Year pure base revenues.

Q. Will SIT amounts formerly collected through the Percentage Increase in Rates and Charges be reconciled?

A. The Company will continue to recover any under or over-collections of SIT expenses related to periods prior to October 1, 2004 through the Percentage Increase in Rates and Charges.

Q. Please discuss how the proposed increases were developed for the historical period.

A. First, "revenue ratios" were developed for each class by dividing the Rate Year pure base revenues by the pure base revenues for the historical period, i.e., the twelve months ended June 30, 2003, the period for which detailed billing data were available. The Rate Year pure base rate increases assigned to each class, including the SIT portion of the current revenue requirement, were then divided by each class' revenue ratio to determine each class' pure base rate increase for the historical period.

Q. Why didn't you allocate any of the increased revenue requirement to SC 5?

A. SC 5 is a Negotiated Rate Agreement Service. This service is offered by the Company to retain and attract customers with competitive alternatives to the Company's steam service. No increase was allocated to SC 5 since SC 5 customers are charged based upon fixed contractual terms.

(2) RATE DESIGN PHASE 1

Q. Please describe the rate design process that you used to develop the proposed rates in this case.

A. The Company is proposing that rates be designed and implemented in three phases - Phase 1, Phase 2, and Phase 3. In Phase 1, which we will describe in this section, the revenue requirement, including the increase, is collected through rates that are identical to existing rate structures. In Phase 2 and Phase 3, to be described in the next sections of our testimony, we will propose a change to rate structures.

Q. Which of the rate designs is the panel recommending be adopted at the conclusion of this case?

A. The rates developed in Phase 1 would apply to SC 1 and SC 4.

However, for SC 2 and SC 3, the Phase 1 rate design is an intermediate step in arriving at final rate designs developed in Phase 2 and Phase 3.

Q. Have you prepared an exhibit that describes the rate design phases that you are proposing be implemented in this case?

A. YES, MARK FOR IDENTIFICATION AS EXHIBIT__(SRP-1).

Q. Please describe this exhibit.

A. The far left column lists each of the main service

classifications (SC 5 is not shown in this exhibit for the reason provided above). The next three columns briefly describe each of the phases. SC 1 and SC 4 customers would be subject to the rates developed in Phase 1, which have the same design as existing rates. Small SC 2 and SC 3 customers would be subject to the Phase 2 rates, which include an access charge, but these customers would not be subject to demand metering. Large SC 2 and SC 3 customers would be subject to the Phase 2 rates at the conclusion of this case, and further, would be subject to the Phase 3 rates, which include demand metering and demand billing, under the schedule described below.

Q. Let us turn to the Phase 1 rates. After determining the historical period base revenue increases for each class, how did you design the proposed Phase 1 rates?

A. The SC 1, SC 2, and SC 3 historical period increases were recovered by increasing the customer charges and block rates, excluding the base cost of fuel, by a uniform percentage increase.

Q. How did you design the proposed SC No. 4 Back-Up/Supplementary Service rates?

A. SC No. 4 consists of a rate for customers who would otherwise be served under the SC No. 2 (Annual Power

Service) and SC No. 3 (Apartment House Service) service classifications if they did not require back-up/ supplementary service. SC No. 4 - Rate I is applicable to customers who would otherwise be served under SC No. 2, and SC No. 4 - Rate II is applicable to customers who would otherwise be served under SC No. 3. The Rate I and Rate II customer charges were set equal to the proposed SC 2 and SC 3 customer charges, respectively. The Rate I and Rate II On-Peak and Off-Peak Contract Demand Charges and On-Peak and Off-Peak Usage Charges excluding the base cost of fuel were increased by a uniform percentage increase as described above.

(3) RATE DESIGN PHASE 2

Q. Is the Panel proposing changes to existing steam rate designs developed in Phase 1 for SC 2 and SC 3 customers?

A. Yes. Before proceeding with a description of the changes, however, we would like to briefly review existing rate designs and underlying cost structures. In general, the main rate classes -- SC 1, SC 2, and SC 3 -- contain two basic charges -- a customer charge, which is imposed regardless of Mlb usage, and a per/Mlb charge. As described later in our ECOS study testimony, however, the underlying costs that are collected

through this rate structure have an additional dimension - demand (Mlb/Hr.) In order to better reflect underlying cost structures, we are recommending that SC 2 and SC 3 rates be redesigned to better reflect demand-related costs through the addition of a demand-based charge. Mr. Jacob further elaborates on the need for the rate design changes we are proposing.

Q. Please continue.

A. We are proposing that rates applicable to SC 2 and SC 3 customers be redesigned in Phase 2 to include demand-based charges. Since the metering required to bill customers on the basis of their maximum demand is not currently in place, we are proposing that demand billing be implemented in two phases - Phase 2 and Phase 3. Phase 2, which would not require demand meters, would be implemented on or about October 1, 2004, and Phase 3 would be implemented commencing October 2005 after demand metering is in place.

Q. Would all SC 2 and SC 3 customers be subject to both phases of the demand-based billing proposal?

A. No, only larger SC 2 and SC 3 customers would be subject to the Phase 3 demand charge. Smaller SC 2 and SC 3 customers would be subject to the Phase 2 rate design, which includes a rate form that has demand

billing aspects, but does not require demand metering.

Q. Before continuing with the discussion of the Phase 2 rate design, please explain why only large SC 2 and SC 3 customers would be subject to Phase 3, which requires demand metering.

A. As a general principle, demand metering would be cost-justified only for larger customers. We note that this principle is followed in the Company's electric rate schedule. Since the Company already has a program to install upgraded meters, which have the capability to record load profiles, we relied on this program to select larger customers that would be subject to demand billing. (The metering program is described by Mr. Bozgo.) By October 2004, we expect to have demand metering capability for approximately 180 of our largest steam customers, a group that accounts for about 50% of annual steam sales. This is the group we are recommending be subject to demand billing. We would, however, periodically review the demand billing program to determine if additional customers should be added or if other changes to the program may be warranted.

Q. Please explain why SC 1 customers are not subject to the Phase 2 demand billing rate form, which does not

require demand metering?

A. SC 1 is a residential class with approximately 1/3 of all customers, but which accounts for about only 3% of total system sales. To avoid administrative difficulties required to develop and administer capacity reservations for such a relatively large number of customers with such a small amount of sales, we are not recommending that the Phase 2 rate form be applicable to this class.

Q. Let us continue with the discussion of demand charges. You previously testified that demand charges are appropriate for the collection of fixed costs. How would other cost components, i.e., customer costs and usage-related costs such as fuel, water, and chemicals be collected in the proposed Phase 2 and Phase 3 rate designs.

A. These costs would be collected in the same way they are now, either on a per customer basis or on a per Mlb basis.

Q. Let us turn to the Phase 2 rate design that you are recommending in this case. Please describe Phase 2.

A. Phase 2 would be based on existing metering and would not require that demand metering be in place. In this phase, revenues associated with fixed costs, currently

collected through usage-based charges, would instead be collected through fixed charges. The fixed charges would be calculated such that each customer's seasonal bill would be essentially unchanged under the new rate structure as compared to the old rate structure, assuming normal weather.

Q. Please explain, in general, how fixed demand charges would be developed in Phase 2.

A. In Phase 2, fixed costs that are currently collected through usage-based charges would instead be collected by a customer-by-customer access charge. The fixed cost collection would be equal to the class access charge, expressed in $/Mlb/hr, times the customer's assigned demand or capacity reservation, expressed in Mlb/hr. The customer's capacity reservation, in turn, would be based on the customer's contribution to fixed costs in the Rate Year under the Phase 1 rate design.

Q. Please explain the purpose of the class access charge.

A. The class access charge is a surrogate for a demand charge. Under the access charge, a customer's bill for demand-related costs would equal the customer's capacity reservation times the class' access charge. In this calculation, the capacity reservation is equivalent to metered demand.

Q. Please explain why Phase 2 is required.

A. Phase 2 is a step in the direction of full demand metering and will serve three purposes: (i) it will better reflect cost causation than existing rate structures because charges related to fixed costs will not depend on Mlb sales, (ii) it will introduce customers to a rate form that has a fixed cost component, and (iii) it can be implemented immediately. Also, as noted above, Phase 2 will apply demand-related charges to smaller SC 2 and SC 3 customers, for which demand metering is not justified.

Q. Let us continue with your description of Phase 2. Have you prepared an exhibit that illustrates the Phase 2 rate design process?

A. YES, MARK FOR IDENTIFICATION AS EXHIBIT__(SRP-2).

Q. Please explain this exhibit.

A. Exhibit__(SRP-2) illustrates the development of the SC 2 winter monthly access charge. The access charges for SC 2 summer and SC 3 summer and winter are developed in the same manner. Column (1) shows the SC 2 winter Rate Year base revenues at the proposed revenue level. Column (2) shows the winter customer charge revenues at the proposed revenue level for SC 2. Column (3) shows the revenues to be collected through the usage charge.

Column (4) shows the revenues to be recovered through the access charge. Column (5) shows the system capacity in Mlbs/hr allocated to SC 2. Column (6) shows the monthly steam access charge applicable to SC 2 customers during the winter.

Q. Please explain how you developed the proposed usage charges.

A. The proposed usage charge in SC 2 and SC 3 was developed by adding (1) the base cost of fuel of $5.049 per Mlb, (2) the Rate Year forecasted cost of electric, water, and chemicals of $0.809 per Mlb, and (3) an incremental charge of $0.85 per Mlb. The total usage charge is $6.708 per Mlb.

Q. Why are you proposing that these costs be recovered through a usage charge?

A. Fuel and electric, water, and chemical costs vary with usage and are appropriately recovered through a usage charge.

Q. What is the basis for the incremental charge of $0.85 proposed to be recovered through the usage charge?

A. The basis for this charge is described by Company witness Shansky in his testimony.

Q. Please summarize how customers bills would be computed under this proposed new rate form.

A. Customers will be billed for the following: (1) a customer charge, (2) a usage charge stated on a $/Mlb basis, and (3) an access charge stated on a $/Mlb/hr basis. In addition, customers would continue to be billed a fuel adjustment and applicable taxes.

Q. How was the Capacity Reservation, Mlb/hr, to which the access charge applies, determined for each customer?

A. The Mlb/hr or Capacity Reservation was determined seasonally for each customer in the following manner:

(1) First, actual monthly pure base revenues were determined for each customer in each service classification for the 12-month period ending June 30, 2003. The monthly pure base revenues are the revenues that recover the steam system fixed costs other than those collected through the customer charge.

(2) Next, " historical period adjusted monthly pure base revenues" were developed. Historical period adjusted monthly pure base revenues are equal to the actual monthly total revenues less the sum of the actual monthly customer charges, monthly base fuel charge, monthly fuel adjustment charge, monthly gross receipts tax, monthly electric, water, and chemical costs, and monthly

revenues associated with the incremental usage rate of $0.85 per Mlb. Finally, Rate Year adjusted pure base revenues were developed by multiplying the historical period adjusted pure base revenues for each customer by the ratio of the class Rate Year adjusted pure base revenues at current rates to the class historical period adjusted pure base revenues at current rates.

(3) A seasonal steam access rate ($/Mlb/hr.) was developed for each service classification by dividing (i) the sum of the Rate Year adjusted pure base revenues (as defined in (2) above) for all customers served under a service classification by (ii) the steam system capacity allocated to that service classification. The steam system capacity was allocated to the service classifications by employing the demand allocation factors from the embedded cost-of-service study. A monthly steam access rate applicable to each season was determined for each service classification by dividing the seasonal steam access rate by six.

(4) A monthly steam access reservation (Mlbs/hr) was developed for each customer in each service

classification by dividing (i) the adjusted monthly pure base revenues of that customer for the 12-month period ending June 30, 2003 adjusted to the Rate Year, by (ii) the monthly steam access rate for the customer's service classification.

(5) A monthly steam access capacity reservation (Mlb/hr) was developed seasonally for each customer by adding the monthly steam access reservations determined in (4) for each season and dividing by the six months/season.

Q. Have you verified that the proposed rates will produce the revenue increases proposed by Company witness Muccilo when applied to the Rate Year forecast?

A. We provided the proposed rates to Company witness Yaegel and he has performed that verification.

(4) RATE DESIGN PHASE 3

Q. Please describe Phase 3 of your rate design proposal in this case.

A. Phase 3 would involve demand metering for large SC 2 and SC 3 customers. The implementation of Phase 3 would begin with dummy billing in October 2004. Prior to that date the Company would develop proposed demand charges based on data available from existing metering, supplemented by load research data. Customers would be

subject to these demand rates on a dummy-billing basis for one year - from October 2004 to October 2005. Under dummy billing, customers would be provided two bills: the bill under the then-current rate payable by the customer and a dummy-bill based on the proposed demand rates for informational purposes only. During the year that dummy bills are being issued, the Company would analyze the results and develop a new set of demand rates that would be revenue neutral, i.e., would yield the same total annual revenue for demand-billed customers, on a class-by-class basis, as then existing rates, giving consideration to customer impacts. The Company would file those rates with the Commission to become effective in October 2005.

Q. Please define the term "revenue neutral."

A. Revenue neutral means that revenues, measured over a specific period, are the same with or without the rate change, both for ratepayers as a whole and stockholders.

Q. Under demand billing, please explain how a customer's billing demand would be determined and how the demand component of the bill would be calculated.

A. There would be two contract demand charges - an on-peak charge and an off-peak charge. We will first discuss

the on-peak charge.

Q. Please continue.

A. The steam system peak demand generally occurs on winter mornings between 6 AM and 11 AM. Therefore, the customer's maximum demand occurring from 6 AM to 11 AM during the winter months (November through April) would be the basis for the on-peak contract demand charge. A customer's annual bill for peak demand would be based on the customer's peak winter demand, allocated to the months in a pattern similar to existing collections. In addition, the billing demand would be ratcheted based on the highest peak demand recorded.

Q. Please describe the off-peak contract demand charge.

A. To cover the cost of local facilities associated with the customer's own peak demand, there would be an off-peak contract demand charge. Off-peak contract demand would be the difference between the highest maximum demand registered on the meter at any time any day and the highest maximum on-peak demand. The Off-peak Contract Demand Charge would be assessed if the off-peak contract demand exceeded the on-peak contract demand. However, if the off-peak demand were less than the on-peak demand there would be no off-peak demand charge. The off-peak demand charge would be equal to

10% of the on-peak demand charge times the difference between the off-peak and on-peak demands.

Q. Have you prepared an exhibit entitled "Proposal for Demand Metering in Service Classification Nos. 2 and 3"?

A. YES. MARK FOR IDENTIFICATION AS EXHIBIT__(SRP-3).

Q. Please describe this exhibit.

A. This exhibit shows sample tariff language for demand metering in Service Classification Nos. 2 and 3. The new rates will have a charge for Contract Demand, a Customer Charge, and a Usage Charge applicable to each Mlb of steam used.

Q. Have you prepared tariff language for this proposal?

A. Sample tariff language is shown in Exhibit__(SRP-3). Actual tariff leaves have not been submitted since demand-billing rates will be developed at a later date.

(5) BILLING ANALYSIS

Q. Has an exhibit been prepared showing steam sales and revenues for the historical period, i.e., the twelve months ended June 30, 2003, reflecting the present rate level, entitled "Steam Sales and Revenues for the Twelve Months Ended June 30, 2003, Reflecting the December 8, 2000 Rates."

A. YES, MARK FOR IDENTIFICATION AS EXHIBIT__(SRP-4).

Q. Please describe this exhibit.

A. This exhibit sets forth, by service classification, the number of monthly bills rendered, Mlbs of steam sold, and the revenues for the twelve months ended June 30, 2003 that would have been derived at the current rates, i.e., the rates effective December 8, 2000.

Q. Has an exhibit been prepared comparing the present December 8, 2000 rates and charges and the proposed rates and charges, entitled "Steam-Comparison of the Rates and Charges Effective December 8, 2000 with the Proposed Rates and Charges"

A. YES. MARK FOR IDENTIFICATION AS EXHIBIT NO.__(SRP-5).

Q. Please describe this exhibit.

A. This exhibit consists of an index sheet and four tables showing each service classification. Each table consists of two columns. The left-hand column shows the present rates at the December 8, 2000 rate level and the right-hand column shows the proposed rates.

Q. Have you prepared an exhibit showing monthly bill comparisons at the present rates and at the proposed rates, entitled "Steam-Typical Monthly Bill Comparisons at Present Rates Effective December 8, 2000 and at the Proposed Rates"

A. YES. MARK FOR IDENTIFICATION AS EXHIBIT NO.__(SRP-6).

Q. Please describe this exhibit.

A. This exhibit consists of five tables headed by an index sheet.

The tables show comparisons of bills applicable to consumers at various monthly consumption levels under the present and proposed rates for each of the existing firm service classifications. These comparisons cover the reasonable ranges of monthly use under the rates shown.

Q. Has an exhibit been prepared showing what the estimated annual impact on customers' bills would be under the proposed rates, entitled "Steam-Summary of the Estimated Annual Impact on Customers' Bills Under the Proposed Rates Based on Billing Data for the 12 Months Ended June 30, 2003"?

A. YES. MARK FOR IDENTIFICATION AS EXHIBIT NO.__(SRP-7).

Q. Please describe this exhibit.

A. This exhibit sets forth, by service classification, the annual percentage increases, by the ranges shown, in Con Edison customers' bills under the proposed rates based on the customers' consumption for the 12-month period ended June 30, 2003. These percentage increases were derived by pricing each customer's monthly usage during the historical period at the current December 8,

2000 rates and at the proposed rates.

Q. Have you prepared an exhibit entitled "Steam-Estimated Effect on Customers' Bills and Company Revenues Resulting from Proposed Steam Rates - Based on Sales and Revenues for the Twelve Months Ended June 30, 2003."

A. YES. MARK FOR IDENTIFICATION AS EXHIBIT NO.__(SRP-8).

Q. Please describe this exhibit.

A. This exhibit sets forth for SC Nos. 1, 2, 3, and 4, the proposed annual revenue increases, the percentage increases and the number of customers' bills increased, decreased or unchanged.

(6) EMBEDDED COST-OF-SERVICE STUDY

Q. Did the Panel prepare an embedded cost-of-service ("ECOS") study for Con Edison's Steam system?

A. Yes. The ECOS study for the Steam Department was prepared under our supervision.

Q. Is the study to which you refer a document entitled "Cost Of Service Study - Steam Department Year 2002 Adjusted for Known Changes in Costs and Rates Effective December 8, 2000?"

A. YES. MARK FOR IDENTIFICATION AS EXHIBIT NO.__(SRP-9)

Q. Are you recommending that the results of the ECOS study be used to allocate revenues among the classes in this

case?

A. No, we are not. We concluded that, in order not to exacerbate already relatively large customer impacts, the increase should be allocated on an equal percentage basis to all classes.

Q. What time period does the ECOS study include?

A. It covers Steam Operations for the calendar year 2002.

Q. What steam revenues are reflected in the ECOS study?

A. Steam revenues reflect current rates, which were effective December 8, 2000.

Q. What customer classes are analyzed in the ECOS study?

A. The ECOS study analyzes the following customer classes shown on each Table, starting in column (2): SC No. 1 - General Service, SC No. 2 - Annual Power Service and SC No. 3 - Apartment House Service. A description of the type of customers served under each classification is shown on page 10 of the ECOS explanatory notes. In addition to these customer classes, costs and revenues (interdepartmental rents) have been assigned to the Electric Department, representing its use of the Hudson Avenue Tunnel.

Q. Let us now turn to the methodology used in developing the ECOS study. Please describe the procedures followed in the preparation of this study.

A. There are two main steps in the preparation of the ECOS study: (1) functionalization and classification of costs to operating functions, such as production, distribution, customer accounting and customer service (with further division into sub-functions such as production demand, production energy-fuel, distribution demand, distribution customer, services, etc.), and (2) allocation of these functionalized costs to customer classes.

Q. Please describe the functionalization and classification step.

A. The functionalization and classification step assigns the broad accounting-based cost categories to the more detailed categories employed in the ECOS study. This level of detail is required to differentiate production demand related costs from production energy-fuel, and production energy-other.

Q. Why is this necessary?

A. This data allows the proper allocation to the classes of the fixed, fuel, and other variable costs, i.e., water and chemicals, based on cost causation.

Q. Please continue.

A. During the process of functionalization, all costs are classified as being demand-related, energy-related or

customer-related. Demand-related costs are fixed costs created by the on-peak hourly loads placed on the various components of the steam system. Energy-related costs are variable costs resulting from the total quantities of steam delivered during the year. Customer-related costs are fixed costs, which are caused by the presence of customers connected to the system, regardless of the amounts of their demand or energy usage.

Q. Please describe the allocation step.

A. The allocation step allocates the functionalized and classified costs to the customer classes based on the appropriate demand, energy or customer allocation factors, which are shown on Table 7 of the ECOS study.

Q. Where in the ECOS study did you include the State Income Tax calculation?

A. The State Income Tax calculation at 7.5%, including SIT Adjustments, are shown on Table 5, Income Taxes, Pages 1 and 2.

Q. Please explain the general organization of the ECOS study.

A. The ECOS study begins with 28 pages of explanatory notes detailing sources of data and methods used in the preparation of the ECOS study followed by seven tables

of cost data, which was described earlier.

Q. Will you please briefly describe the explanatory notes?

A. The text material is an explanation of the tables that follow. Section I, on page 3 of the explanatory notes, is a summary of the organization of the ECOS study's, objectives. Section II, starting on page 4, describes the operating functions analyzed in the ECOS study. Section III, starting on page 7, describes the allocation factors used in the ECOS study. Section IV, on page 10, describes the Customer Classes used in the study. Section V, starting on page 10, explains the Rate of Return Statement. Section VI, starting on page 12, Rate Base, refers to the functionalization of plant costs, depreciation reserve, non-interest bearing construction work in progress, net plant, rate base adjustments, working capital, and total rate base. Section VII, Operating Expenses, which starts on page 18, describes the functionalization of Operating Expenses into fixed and variable components. Section VIII, Operating Revenues, starting on page 23, lists the various Steam Department operating revenues. Section IX, starting on page 24, describes the State and Federal Income Taxes. Section X, starting on page 25, itemizes the customer costs by class of service.

Section XI, starting on page 27, describes the allocation factors and the development of the Demand allocation factors used to allocate the functionalized costs for the production-demand and distribution-demand functions.

(7) TARIFF CHARGES

Q. Is the Company proposing elimination of SC 6 - Transportation Service?

A. Yes. The Company proposes to eliminate SC 6, because, as stated in the testimony of Company witness Jacob, there has been no customer interest in this rate, and no customers are taking service under SC 6. In addition, an appropriate cost-based transportation rate is too dependent on site-specific circumstances to lend itself to a uniform rate.

Q. Does the Company propose a change to its provision of Steam Repair Service?

A. Yes. As discussed in the testimony of Mr. Jacob, the Company proposes to require prepayment of estimated labor and material charges, instead of payment upon completion of the repair, and to price materials based on fair market price, instead of average storeroom prices, plus 12 percent for handling. Following the repair, estimated and actual charges for labor and

materials will be reconciled. If the estimate was higher than actual charges, the customer will receive a refund for the difference; if the estimate was lower than actual charges, the customer will be billed for the difference.

Q. Is the Company proposing additional tariff changes?

A. Yes. As discussed by Mr. Jacob, we are proposing the following: (1) changes to General Information Section VII "Adjustment of Rates Related to Changes in the Cost of Fuel" to eliminate Paragraph F entitled "Annual Credit Adjustment" dealing with the existing cap on fuel cost recovery associated with steam system variance. This provision will be replaced with an annual adjustment provision dealing with reconciling actual expenses incurred for fuel used by the Company plus the contractual variable cost of steam purchased from others for resale and the Special Monthly Adjustment to actual recoveries for the annual period. Any under-collection or over-collection will be reflected in the monthly fuel adjustment over a subsequent 12-month period; (2) the addition of a component to the Special Monthly Adjustment to the Fuel Adjustment to credit customers for overcollections of East River Repowering Project(ERRP) costs included in

base rates for any month in which ERRP is not in commercial operation on or after October 1, 2004 and elimination of components of the Special Monthly Adjustment that are no longer applicable; and (3) changes to "Prepayment for Extension or Reinforcement of Mains" to require prepayment if estimated revenue over a two-year period, rather than the current one-year period, is insufficient to justify the expenditure.

Q. Please continue.

A. As described in the testimony of Company witness Northup, we are adding a new Rider "E" in SC 2 and SC 3, which would allow the Company to charge the customer, in lieu of the average cost of fuel, an agreed upon amount, for a fixed volume of the Customer's steam requirements. This amount would be charged as an increment or decrement to the base cost of fuel. The negotiated price would be set forth in a written agreement between the Company and the customer. The customer would pay all rates and charges applicable under the service classification, plus the Special Monthly Adjustment of the Fuel Adjustment. Any steam usage in excess of the agreed upon quantity will be served under the rates and charges of the customer's

Service Classification, inclusive of the Fuel Adjustment.

Q. If there were a multi-year settlement in this case, how would you propose to collect the increased revenue requirement in years subsequent to the first rate year?

A. In rate years two, three, etc., the increased revenue requirement would be recovered by increasing customer charges and demand charges by a uniform percentage increase, subject to the rate design proposals that we have discussed.

Q. Does this conclude the testimony?

A. Yes, it does.