STATE OF NEW YORK

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of	)	
Consolidated Edison Company's	)	Case 96-E-0897
Plans for Electric Rate Restructuring	)	
Pursuant to Opinion No. 96-12	)	

DIRECT TESTIMONY OF

PAUL CHERNICK

ON BEHALF OF

THE CITY OF NEW YORK

Resource Insight, Inc.

FEBRUARY 14, 1997

CONTAINS MATERIAL FOR WHICH
CONSOLIDATED EDISON HAS ASSERTED CONFIDENTIAL STATUS

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EXHIBITS

I. Identification and Qualifications

Q: State your name, occupation and business address.

A: I am Paul L. Chernick. I am President of Resource Insight, Inc., 347 Broadway, Cambridge, Massachusetts.

Q: Summarize your professional education and experience.

A: I received an SB degree from the Massachusetts Institute of Technology in June, 1974 from the Civil Engineering Department, and an SM degree from the Massachusetts Institute of Technology in February, 1978 in Technology and Policy. I have been elected to membership in the civil engineering honorary society Chi Epsilon, and the engineering honor society Tau Beta Pi, and to associate membership in the research honorary society Sigma Xi.

I was a utility analyst for the Massachusetts Attorney General for more than three years, and was involved in numerous aspects of utility rate design, costing, load forecasting, and the evaluation of power supply options. Since 1981, I have been a consultant in utility regulation and planning, first as a Research Associate at Analysis and Inference, after 1986 as President of PLC, Inc., and in my current position at Resource Insight, I have advised a variety of clients on utility matters. My work has considered, among other things, the cost-effectiveness of prospective new generation plants and transmission lines; retrospective review of generation planning decisions; ratemaking for plant under construction; ratemaking for excess and/or uneconomical plant entering service; conservation program design; cost recovery for utility efficiency programs; and the valuation of environmental externalities from energy production and use. My resume is appended to this testimony as Exhibit PLC-1.

Q: Have you testified previously in utility proceedings?

A: Yes. I have testified approximately one hundred and thirty times on utility issues before various regulatory, legislative, and judicial bodies, including the Massachusetts Department of Public Utilities, Massachusetts Energy Facilities Siting Council, Vermont Public Service Board, Maine Public Utilities Commission, Rhode Island Public Utilities Commission, Connecticut Department of Public Utility Control, New Hampshire Public Utilities Commission, Texas Public Utilities Commission, New Mexico Public Service Commission, District of Columbia Public Service Commission, Michigan Public Service Commission, Minnesota Public Utilities Commission, Public Utilities Commission of Ohio, South Carolina Public Service Commission, North Carolina Utilities Commission, Florida Public Service Commission, New Orleans City Council, Federal Energy Regulatory Commission, and the Atomic Safety and Licensing Board of the U.S. Nuclear Regulatory Commission. A detailed list of my previous testimony is contained in my resume.

Q: Have you testified previously on issues of electric industry restructuring and stranded-cost determination?

A: Yes. I testified in the rulemaking portion of New Hampshire PUC Case No. DR 96-150 on the definition and measurement of stranded costs, in the adjudicatory portion of the same docket on the market value of power and interim stranded costs, and in Massachusetts DPU Docket 96-100 on the measurement and mitigation of stranded costs. In addition, other pieces of my testimony have addressed options for industry restructuring and the implications for utility planning.

Q: Are you the author of any publications on utility planning and ratemaking issues?

A: Yes. I am the author of a number of publications on rate design, cost allocation, power-plant cost recovery, conservation program design and cost-benefit analysis, and other ratemaking issues. Several of my recent papers deal with issues in industry restructuring, including integrated resource planning, environmental considerations, and stranded-cost determination. These publications are listed in my resume.

II. Introduction and Summary

A. Scope of Testimony

Q: What is the purpose of your testimony?

A: My testimony covers the following topics:

- the differences between ConEd's narrow and self-serving rate plan and the City's more comprehensive restructuring plan,
- a review of ConEd's estimates of stranded costs,
- the City's estimate of ConEd's stranded costs,
- an initial restructuring-related rate decrease for 1998,
- the mitigation of ConEd's market power in generation energy and capacity, and
- other issues in implementing retail access and restructuring.

B. Summary of the City Restructuring Proposal

Q: How does the City's proposal in this proceeding differ from ConEd's approach?

A: ConEd offers a rate plan and a general offer to allow at least customers to purchase generation services from other suppliers, but no real plan for restructuring the company or its rates to reflect competition. Even the rate plan consists primarily of higher rates to accelerate depreciation of ConEd generation, rather than a transition to rates that reflect the competitive market. All customers would continue to pay conventional cost-of-service rates, with customers selecting direct access receiving a discount to reflect the short-term market price of power. The Company does not propose to revise its rates to reflect the sale or revaluation of any specific amount of generation, and ~~does~~ proposes to keep Indian Point 2 in cost-of-service ratemaking indefinitely.

In contrast, the City proposes to promptly restructure ConEd rates to reflect the restructuring of the industry, repricing virtually all generation at market value and recovering the resulting gain or loss over a ten- to twenty-year period. This restructuring would reduce rates to all customers, regardless of whether they immediately switch power supplier, and would ~~be~~ provide a pricing structure that could continue through ConEd's divestiture of its generation and emergence of a fully competitive market.

Q: Please summarize the City's approach to restructuring ConEd's electric services.

A: The City's proposal starts with the PSC's stated commitment to restructuring the generation portion of the electric industry to competitive market pricing on the fastest feasible schedule. If this transition is to benefit electricity consumers and the economy of New York, the restructuring must:

(1) Compensate ratepayers for the additional costs associated with giving up their claim to future benefits of existing resources, including below-market generation assets.

(2) Create an opportunity for increases in efficiency, and ensure that ratepayers capture some of the resulting benefits.

(3) Ensure that the resultant market operates competitively, without abuse of market power concentration. Truly competitive markets (as opposed to oligopolies) provide no opportunity for price manipulation.

Q: How would your proposed restructuring reduce rates?

A: Restructuring of the ownership of ConEd generation, as well as restructuring of the purchases, can reduce short-term ratepayer costs through three effects:

1. The timing of cost recovery changes, reducing the high above-market charges in the short term, and spreading them out over time.
2. The cost of the resources may be reduced, through improved operational and cost-control incentives.
3. The financing costs for above-market resources can be reduced, by reducing the risks to lenders.

These cost reductions are in addition to any traditional cost-of-service reductions and to any stranded costs absorbed by ConEd.

C. Summary of Stranded-Cost and Restructuring Rate Reductions

Q: What do you conclude about the magnitude of ConEd stranded costs?

A: I agree with ConEd that a substantial portion (at least $300 million), and perhaps all $500 million, of its investment in Indian Point 2 is stranded. I also agree with ConEd that the IPP contracts are above market value, but I estimate a loss of $1–2 billion, while ConEd claims $3–4.5 billion. While ConEd claims $700 million in stranded costs for its fossil units, I project a net restructuring gain (negative stranded costs) of $1.9–2.4 billion. Overall, I project a total stranded costs ranging from a $600 million loss to a $1 billion gain.

I do not independently estimate Indian Point 2 decommissioning costs. I have assumed that the bulk of these costs would be recovered on an annual basis from ConEd distribution customers.

Q: What do you conclude about the magnitude of achievable rate reductions from restructuring?

A: The magnitude of achievable rate reductions from restructuring will depend primarily on the market value of ConEd's plants, short-term market prices for energy and capacity, the extent to which IPPs accept lower present-value payments, and financing costs. I estimate that a 10% rate reduction in 1998, followed by a five-year rate freeze, could be achieved through restructuring, in addition to any rate reductions due to traditional cost-of-service issues.

Q: What level of stranded-cost recovery do you assume in these computations?

A: I include full recovery of estimated stranded costs in these calculations. Once the actual level of stranded cost is determined, and ConEd's success (or lack thereof) in mitigating stranded costs has been demonstrated, the Commission should revisit the issue of sharing stranded costs between shareholders and ratepayers.

D. Regulatory Actions to Promote Effective Competition

Q: What special considerations must be taken into account in ensuring that customers benefit from the transition to competition?

A: For ConEd, the market transition must also reflect three special circumstances. First, transmission capacity is seriously limited within the City and between the City and the rest of the New York Power Pool (NYPP), or to the PJM pool. Second, most of the generation within the City load pocket is owned or controlled by ConEd. Third, the bulk of the generation within the City is concentrated at a handful of large stations, and generation within sub-pockets is even more concentrated.

Q: What specific actions are required by the considerations you have just enumerated?

A: The appropriate actions are different in the short term—the next one to four years—than in the longer term. In the very short term, neither the Independent System Operator (ISO) nor the Power Exchange (PX) will be fully functional. Value-maximizing divestiture of generation will require that the ISO rules (especially for transmission pricing and requirements for ancillary services) be established and a complex auction process be designed and implemented, so ConEd will continue to own most generation in the City. In addition, not all customers are likely to be able to obtain retail access immediately, and some regulatory and legal changes that would reduce costs (such as securitization) may not be in place.

In this short term, ConEd's ownership of generation must be separated from control of market prices, so that a reasonable approximation of competitive prices can be developed. Transmission access must also be priced to reflect the difference in energy prices within and outside the City, without raising overall costs to customers. Simultaneously, ConEd's rates must be functionally unbundled, and the generation costs split into two parts (which may not add up to the current cost-of-service rate): market prices and recovery of the utility's losses (or gains) from restructuring.

Q: What additional actions are appropriate in the longer term, once the ISO is operating?

A: In longer term, the interim mechanisms of the short term can be replaced by real and permanent changes in market structure. The administrative measures to mitigate ConEd's market power can be largely replaced by diversification of ownership. The Commission should effect divestiture of the bulk of ConEd's capacity in the City, and establish rules to prevent reconcentration of ownership to levels that pose problems of market power.[1] Similarly, initial estimates of the market value of generation plants can be replaced with actual market prices, as generation is auctioned off. Additional cost reductions are likely as IPP purchase obligations are refinanced.

Q: What regulatory actions are necessary to create a competitive market in the longer term?

A: In addition to the elimination of market power, a competitive and efficient market will require a strong ISO, with authority for scheduling generation and transmission maintenance; dispatching generation and transmission; creating and clearing markets in energy, capacity, and ancillary; and ensuring the addition of economic transmission capacity.

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[1] If the Commission cannot order divestiture, it can encourage divestiture by ascribing high value to plants ConEd chooses to retain.

III. Estimate of Stranded Costs

Q: Please describe the development of estimates of stranded costs for ConEd.

A: Strandable costs can generally be divided into four types of liabilities:

1. above-market sunk costs of ConEd's own generation,
2. above-market costs of power-purchase obligations,
3. decommissioning costs of nuclear plants (in ConEd's case, Indian Point 2), and
4. regulatory assets.

ConEd does not report significant regulatory assets, so I do not discuss this category further.

Q: What are the important determinants of stranded costs?

A: Stranded costs are simply the difference between net book cost (gross investment minus accumulated depreciation and tax benefits) and market value. The market value of the unit is the present value of operating profits. Operating profit (which ConEd calls "cash flow") in each year is the difference between

- revenues (market energy and capacity, uplift, ancillary services, and steam revenues), and
- operating costs (fuel, O&M, A&G, property taxes, and capital additions).

Stranded costs—or regulatory gain, if market value exceeds net book—are thus sensitive to net book costs, market prices, and operating costs.

Q: How did you compare costs and benefits over time?

A: Following ConEd's approach, I use a 20% discount rate and a 20-year horizon in computing market value.[2]

A. Critique of ConEd Estimate

Q: What problems have you identified in ConEd's determination of stranded costs?

A: My review of ConEd's analysis has been complicated by ConEd's delay in providing stranded-cost analyses, and then only under burdensome restraints, such as limiting the number of staff members who can review or even enter the data. The Company has refused to provide most of the actual inputs to the analysis, such as O&M or energy revenues by unit, and instead has provided only various composites (such as "market revenues minus fuel," or "cash flow").[3]

Despite these limitations, I have identified problems both in ConEd's conceptual approach and methodology, and in ConEd's specific assumptions and inputs. I will first discuss the methodological errors ConEd makes in applying its basic estimates, and then proceed to the errors in the estimates.

[2] ConEd's plant sites (other than Indian Point 2, whose decommissioning is accounted for separately) are likely to have very considerable additional terminal value at the end of their lives, for the land, cooling systems, transmission equipment, and associated permits.

[3] I see no trade secrets in the stranded-cost analysis. Most of the projections are either rather standard estimates (such as the cost of a combined-cycle plant, or of gas prices) or are internally inconsistent (such as ConEd's estimates of market energy prices). The computations based on those projections are either obvious summations, or errors (such as ConEd's treatment of capacity bidding).

1. Errors in Approach and Methodology

Q: What problems have you identified in ConEd's stranded cost methodology?

A: There are at least three such errors:

- Omitting the restructuring gain it is likely to experience from the gas turbines.
- Constructing an unrealistic model of capacity sales that results in zero capacity value for many ConEd units in years when other units receive capacity payments.
- Assuming that ConEd units would not be retired, even once they become permanently uneconomic to operate, reducing the present value of those units.

Q: How does ConEd omit the restructuring gain it is likely to experience from the gas turbines?

A: The Company simply does not value these plants. ConEd owns 2,090 MW of gas turbines, of which 2,032 MW are located in the high-value City load pocket. These plants are inexpensive to keep in operation (costing only about $12/kW-yr of O&M) and have a collective net book value of only $140 million, or $70/kW. Since new peaking capacity is likely to cost on the order of $300/kW, these older peakers would have a market value well in excess of their net plant.

Q: How does ConEd construct a model of capacity sales that results in zero capacity value for ConEd units, when other units receive capacity payments?

A: ConEd assumes that each generator annually bids a price in \$/kW-yr for installed capacity. The Power Exchange would select the lowest-cost bids, up to the amount of capacity needed to meet the Pool reliability criteria. This is a reasonable structure, as far as it goes. In application, generators would bid the minimum price they would accept to stay on line, and those that were not selected would be deactivated or retired. Units that were certain to remain in operation (for example, plants that would be expensive to mothball and that would be highly profitable in future years) would offer a capacity bid near zero to ensure that they would be selected.

Rather than implementing its assumed market structure in a consistent fashion, ConEd assumes all other generators price their capacity at or below the market-clearing price, to keep them on line, while ConEd prices at annual operating cost minus market energy revenues, and also keeps all plants on line. This treatment results in three problems:

1. ConEd assumes that all competitors keep all units on line, even if the market-clearing energy and capacity prices do not cover the plants' operating costs, in either the short or long term.[4] Keeping these uneconomic units on line depresses ConEd estimates of market prices for capacity and energy. The price situation ConEd assumes would result in closure of units with operating costs higher than market prices, either in the short term (through mothballing) or permanently (through

[4] ConEd explains that it was forced to make this assumption, since it does not have detailed information on other generators' costs. While ConEd would need to estimate the costs of keeping some marginal units on line (e.g., Nine Mile 1, and the fossil units identified as retirement candidates in the last State Energy Plan), and its estimates would only be approximately correct, ConEd's approach is precisely incorrect.

retirement). Those shutdowns would increase the market-clearing prices for energy and upstate capacity.

2. ConEd assumes that, unlike every other generator, it would place a capacity bid for each unit equal to total operating costs (O&M, A&G, property taxes, and capital additions averaged over the next five years) minus energy profits. If this net cost is higher than the market-clearing price, ConEd assumes that it would get no capacity revenue for the unit.[5] In those years, ConEd ignores both the capacity revenues and energy profit the unit could receive, but somewhat offsets that understatement of the benefits by ignoring all fixed operating costs other than property taxes, as if the plant were mothballed.[6] Except for Indian Point 2, this treatment generally overstates annual losses, since the capacity revenues would exceed the non-property-tax operating costs.

why IP2 ?

3. ConEd assumes that it would operate plants even if they are uneconomical throughout the analysis period (this is true for Indian Point 2, East River, Hudson Ave, and 74th St. in ConEd's analysis), or in later years with falling market capacity value (Astoria 3, 4, 5; Ravenswood 1, 2, 3; Arthur Kill 3). Shutting down these uneconomic

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[5] In ConEd's modeling, this situation occurs for Indian Point 2 in 1998-2003; Bowline 2 98-2001, and 2017; Astoria 3 2004-7, and 2013-2017; Astoria 4 in 2009-2017; Astoria 5 in 2010-2017; Arthur Kill 3 in 2011-2017; Ravenswood 1 in 2011-2015; and Ravenswood 2 in 2012-2016. It also occurs for East River, 74th Street, and Hudson Avenue for every (or nearly every) year.

[6] But ConEd does not reflect such shutdown in the modeling of energy costs, which would increase the value of other units.

plants would reduce ConEd's estimates of these units' stranded costs, and would thus increase market prices and the value of other units.

Q: You have explained how ConEd has miscalculated the annual operating profit. Does ConEd then properly compute the present value of those operating profits to determine the market value of each unit?

A: No. ConEd computes the present value of the operating profit separately for 1998-2007, and 2008-2017. If the present value is negative for either period, ConEd sets the present value for that period to zero instead. The Company estimates that the present value of operating profit is negative for the first ten years for Indian Point; for the second ten-year period for Astoria 3–5 and Arthur Kill 3; and for both periods for East River 6 and 7, Hudson Ave., and 74th St. Operating profit is thus set to zero for all these periods.

Q: Why is this treatment of operating costs problematic?

A: In zeroing out only these ten-year periods, rather than specific periods in which plants could be retired, ConEd

- eliminates profitable years that happen to fall into a ten-year period that is uneconomic overall;
- includes unprofitable late years, in which the unit should be retired, but which happen to fall into a ten-year period that is economic overall; and
- misstates the costs of keeping units (especially Indian Point 2) in service until their operating profits become positive.

Q: How much difference does ConEd's treatment of negative operating profits make?

A: For some units, it is substantial. For Astoria 3, ConEd projects a market value of $26 million, based on the first ten years. But given ConEd's projections, the units is uneconomic to operate past 2003; shutting it down then would avoid $6 million in PV losses, increasing ConEd's market-value result by 23%. For Arthur Kill 3, ConEd makes the opposite mistake, and shuts the plant down too soon. Again, ConEd includes only the first 10 years of operation, even though the plant is economic to operate for three more years, producing over $1 million in additional market value.[7]

Q: Did ConEd make any other modeling errors?

A: Yes. It appears that ConEd treated dual-fuel units as if they were required to burn gas for a fixed portion of the year, and oil the rest of the time. In fact, these units switch back and forth between fuels, based on price. The Company does not appear to have provided any opportunity for its units to select the lowest-cost fuel, or to avoid using gas on days with the highest costs. This rigid treatment of fuel choice, plus some arbitrary allocation of gas to Bowline 1 and oil to Bowline 2, results in Unit 1 operating 30 times as much as Unit 2. While the effect is most important for Bowline 2, ConEd has apparently overstated effective fuel costs for all the dual-fuel units, decreasing their generation and the energy profit per kWh of generation, and hence reducing operating profit and market value.

2. Implausible Projections of Market Prices

Q: What portions of ConEd's projections are implausible?

A: The problems are concentrated in ConEd's projections of market capacity value and energy value. As noted above, ConEd also overstated the fuel costs for its dual-fuel units by failing to recognize the benefits of fuel flexibility.

[7] It is important to remember that these results use ConEd's market prices for energy and capacity. Realistic market-price inputs would produce higher market values for the units.

The other major input category, fixed costs, is more difficult to analyze because ConEd has not provided O&M, property taxes, capital additions and overheads separately (or even combined).

Q: Please describe ConEd's projection of market capacity prices.

A: ConEd projects separate market capacity prices for in-city and upstate supply. Once ConEd projects a need for new capacity, starting in 1998 in-city and in 2005 upstate, the capacity price is set at ConEd's estimate of the annual cost of new combined-cycle capacity, net of energy profit.[8] In other words, ConEd estimates the capacity price that would be sufficient (combined with projected energy revenues) to finance a combined-cycle plant. The cost of the new combined-cycle, its O&M, and the offsetting energy profit, is higher in-city than upstate. Prior to 2005, the upstate capacity price is set by assuming that (as discussed above) all other generators in the NYPP bid arbitrarily low prices for capacity, and that ConEd bids its fixed cost net of energy profit.[9] The market capacity price is then set at the bid price of the most expensive ConEd unit needed to meet NYPP reserve targets.

Except for the asymmetrical treatment of ConEd capacity, this general approach is perfectly reasonable: using the market-clearing price for capacity until new capacity is required, and then using the cost of capacity net of energy profit.

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[8] ConEd produced capacity estimates for low, base and high combined-cycle costs; I discuss only the base case here.

[9] The fixed costs used in this particular computation are not all annual costs. ConEd uses a five-year forward average for capital additions for all plants, and a two-year average for O&M for Indian Point 2.

Q: What are the problems with ConEd's projections of market capacity prices?

A: There are four such problems. First, ConEd's projections of net combined-cycle capacity costs in the base case fall 5.03% annually in real terms (and 2.18% in nominal terms) for every year from 1996 to 2036. ConEd's projected capacity cost thus falls by two thirds in real terms from 1996 to 2017, and 87% by 2036. This dramatic decline in combined-cycle capacity cost is apparently due to the assumption that the cost of new combined-cycle units are fixed in nominal terms, but that the value of the energy offset rises with inflation.[10] Compared to nominal levelization, ConEd's approach requires higher capacity charges in the short run and lower capacity charges in the long term.

Second, ConEd failed to reflect any property taxes for the new combined-cycle units, even though property taxes are important costs for its existing units. ConEd's projection of combined-cycle fixed O&M is only about 2% of base-case plant cost; property taxes alone on ConEd plants are typically over 5% of plant.

Third, in computing the net cost of capacity, and hence market capacity revenues, ConEd assumed higher market energy prices than it used in computing market energy revenues in the stranded-cost analysis. This

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[10] ConEd computed this 2.18% annual nominal price decrease in net capacity cost from the difference between the present value of energy profits for a plant installed in 1996 and one installed in 1997, and then extrapolated the rate of decrease for 40 years. Actually, ConEd computed the rate for decrease for each case (base, low and high) and for in-city and upstate. The rates of decrease indicated by ConEd's base-case analyses are 2.18% for upstate and about 1.68% in-city. Yet ConEd used the higher upstate price decrease for in-city, further understating market prices.

inconsistency understates the combined market value for energy and capacity.

Fourth, ConEd assumes a combined-cycle heat rate that is very optimistic.

Q: What would be the effect of correcting the property-tax error?

A: Adding 5% property taxes to ConEd's assumed cost of a new combined-cycle plant would increase the present value of required capacity charges by about 50%. Using ConEd's methodology for estimating annual carrying charges, the upstate net cost of capacity would be increased 40% higher, to over $100/kW-yr in 1996$, and the rate of decrease due to rising market energy costs would fall to less than 0.5% per annum.

Q: Please expand on the inconsistency in market energy costs ConEd uses in different portions of its analysis.

A: For the upstate combined-cycle, ConEd assumed a "yearly average energy price" (apparently averaged over ConEd's load shape, or the load shape of upstate generation) of $28.50/MWh, and a market price during hours of combined-cycle operation of $28.30/MWh. The stranded-cost report (p. 72) provides summaries of the upstate energy prices used in computing operating profits; the annual average upstate energy price in that summary ranges from about $21/MWh to $23.43/MWh.[11]

Similar problems arise for in-city plants. The in-city market energy price is $30/MWh for average load and $29.8/MWh during combined-cycle

[11] All these prices are stated in the same 1996$ used in the combined-cycle cost analysis.

operation, while the stranded-cost summary reports that the market energy prices actually credited to ConEd plants that never exceed $25.2/MWh.[12]

Q: What is the effect of this inconsistency?

A: If the energy values ConEd actually used in its stranded-cost analysis were used in ConEd's capacity analysis, the present value of required capacity charges would increase by about 60%. Using ConEd's methodology for estimating annual carrying charges, the 1996 out-of-city rate would rise nearly 50%, to about $110/kW-yr, and the rate of decrease due to rising market energy costs would fall to about 0.2% per annum.

Q: Please expand on the problems with ConEd's assumed heat rate for new combined-cycle plants.

A: ConEd assumes a heat rate of 6,324 Btu/kWh, a lower heat rate (and hence a higher level of efficiency) than appears to have been demonstrated in practice.[13] While manufacturers have promised higher efficiencies in the future, many of the claimed heat rates use lower heat values (LHV) for the fuel—roughly 900 Btu/cf—rather than the higher heat values (HHV)—roughly 1000 Btu/cf—commonly used in US utility terminology.[14]

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[12] As discussed below, the summary values were not directly used in the stranded-cost analysis. The market energy prices actually used in valuing ConEd's plants and purchases were somewhat different from the summary values, but not overall higher.

[13] The Martin combined-cycle plant of Florida Power and Light, completed in 1994, had a 1995 heat rate of about 7,200 Btu/kWh.

[14] The difference between HHV and LHV is the 100 Btu/cf that is used in vaporizing the water formed by the combustion of the fuel. That heat is trapped in the water vapor and exhausted unless the vapor is condensed out, a process that is feasible for residential furnaces but not for power plants.

For example, the largest combined-cycle unit in *Gas Turbine World 1996 Handbook* (the KA13E2-3, at 728 MW and \$436/kW manufacturer price) is similar to the units ConEd assumes (760 MW and \$425/kW).[15] The LHV heat rate for this unit is listed as 6,380 Btu/kWh, very similar to ConEd's estimate of 6,324 Btu/kWh. In HHV terminology, the KA13E2-3 would have a claimed heat rate of about 7,089 BTU/kWh.[16]

These manufacturer-reported heat rates are for a brand-new turbine operating at full load. Heat rates will also vary with loading and cycling, and with the age and condition of the combustion turbine. After a few years of operation, several months after the last cleaning and maintenance, and operating at the 80%–83% capacity factor assumed by ConEd, the combined-cycle would have a significantly higher heat rate.

Q: How does this optimistic estimate affect ConEd's market capacity price?

A: Increasing the combined-cycle heat rate would increase the combined-cycle fuel costs, reducing the operating profits and requiring higher capacity prices. A heat rate of 7,500 Btu/kWh would increase the present value of required capacity charges by about 40%. Using ConEd's methodology for estimating annual carrying charges, the 1996 out-of-city rate would rise over 30%, to nearly \$100/kW-yr, and the rate of decrease due to rising market energy costs would fall to about 0.7% per annum.

Q: What would be the effect of correcting these problems?

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[15] The *Gas Turbine World* capacities (and hence costs per kW) are based on performance at ISO standard conditions, including 59°F. Based on summer ratings, the capacity would be lower and the cost per kW higher.

[16] Whether BTUs are measured in LHV or HHV terms, about 7.09 cf of gas are required for each kWh.

A: Correcting all three of these problems (using 5% property taxes, the summary energy prices, and a 7,500 Btu/kWh heat rate) results in upstate capacity costs of $160/kW-yr (over twice ConEd's estimate), rising at nearly 1% annually.

Q: Please describe ConEd's projection of market energy prices.

A: According to the Stranded Cost Report, ConEd used the MAPS model to determine annual market energy prices by location on the transmission system, for each year through 2005. After 2005, ConEd simply inflated all energy prices at a constant rate.

ConEd properly recognizes that the market value of energy (in $/MWh, for example) will vary with the location of the plant, will increase over time, and will be higher for plants that are dispatched less.[17] Unfortunately, there are problems in the ways in which ConEd reflects these factors.

Q: Do any of the errors you discussed above in connection with market capacity prices also affect ConEd's estimates of market energy prices?

A: Yes. ConEd's projections of market energy prices are depressed by the assumption that all power plants in the state will remain on line throughout the analysis period, regardless of how much money their owners would lose from operating them. In addition, I have described the inconsistency between the market energy price ConEd used in determining the net capacity cost of new combined-cycle plants and that used in the stranded-cost analysis.

Q: Are there other problems in ConEd's projections of energy costs?

A: Yes. These include:

[17] Units with lower operating factors (i.e., that are used less often) will have higher values per kWh, since they will be used only when market energy prices are highest.

- inconsistencies between the market energy prices presented in the stranded-cost summary and those used for the individual units, even in the period for which ConEd explicitly models energy prices;
- use of a post-2005 inflation rate for the market energy prices received by ConEd units that is lower than the inflation rate assumed for virtually all other purposes;
- in-city energy prices that are lower than upstate energy prices.

Q: Please summarize the inconsistencies between the market energy prices ConEd uses and presents.

A: ConEd presents three sets of market energy prices: for the energy offset to combined-cycle capacity costs, in the stranded-cost summary, and for individual generation units.[18] In the period for which ConEd explicitly models energy prices, the projections are:

			Utility Units			IPPs			Overall average
	ConEd Capacity analysis	ConEd Summary	min	max	average	min	max	average	
Upstate									
1998	30.24	22.44	22.65	30.66	23.52	23.19	27.20	23.93	
1999	31.14	23.41	23.77	30.70	24.29	24.80	27.36	25.28	
2000	32.08	24.51	24.74	32.76	25.21	25.16	28.04	25.73	
2001	33.04	26.23	26.78	31.99	27.22	26.82	28.41	27.15	
2002	34.03	26.66	26.79	36.00	27.68	27.31	29.23	27.73	
2003	35.05	27.9	27.68	37.92	28.94	28.53	30.14	28.88	
2004	36.10	29.08	29.16	38.05	30.17	29.73	31.20	30.09	
2005	37.19	30.57	31.06	39.95	32.05	31.16	31.92	31.34	

[18] ConEd does not actually present the market prices used for individual units, but these prices can be backed out of the summary values ConEd does present.

In-City

1998	31.61	26.73	24.01	29.35	26.60	23.16	23.84	23.59	25.64
1999	32.56	26.92	24.92	28.90	26.62	23.58	24.32	24.04	25.82
2000	33.54	27.71	25.73	29.73	27.78	25.36	25.80	25.64	27.11
2001	34.55	28.57	26.77	29.12	28.50	26.46	26.63	26.57	27.93
2002	35.58	29.12	27.46	30.47	29.23	27.28	27.38	27.34	28.66
2003	36.65	30.41	28.59	31.26	30.45	28.49	28.59	28.55	29.91
2004	37.75	31.27	29.18	32.27	31.45	29.40	29.78	29.66	30.94
2005	38.88	32.89	30.78	34.65	33.11	31.23	31.24	31.23	32.62

Since the value used for the combined-cycle computation is intended to represent baseload operation, the market energy prices received by most other units should be higher than the combined-cycle value.[19] ConEd's results show the opposite. Except for the lowest-load-factor units, this is not true: all measures of the market energy prices ConEd attributes to existing units are far lower than those it attributes to new combined-cycle units.

Q: How does the escalation rate ConEd uses for market energy prices paid to its units after 2005 compare to the inflation rate ConEd assumed for other purposes?

A: ConEd assumes a 3% general inflation rate (xx cite), and uses that rate for the market energy prices (and O&M) used in offsetting combined-cycle capacity costs, and the market energy prices reported in the summary page of the stranded-cost report. However, for the actual energy revenues used in the stranded-cost report, ConEd used a 2.23% escalation rate, resulting in energy revenues in 2017 that are 28% lower than they would have been had ConEd simply assumed the 3% inflation rate it used for other purposes.

[19] The market energy prices received by Indian Point 2, Bowline 1, and the IPPs would be similar to, and sometimes lower than, the market energy price received by the combined-cycle.

Q: Is this 2.2% escalation rate for post-2005 market energy price consistent with the escalation of market energy prices in ConEd's modeling of pre-2005 energy markets?

A: No. From 2000 to 2005, ConEd's results show the market energy prices of various units rising at 2.5% to 4.9% per annum. The market energy prices for units with stable capacity factors (e.g., Indian Point 2 and Bowline 1) rise 4-5% per annum.[20] While this rate of increase may decline somewhat after 2005, it is not reasonable to assume that escalation of market prices will fall from over 1% above than inflation to almost 1% less than inflation.[21]

Q: Please amplify on your statement that ConEd's stranded-cost analysis uses in-city energy prices that are lower than upstate energy prices.

A: Exhibit (PLC-2) shows the market prices of energy (excluding uplift) that ConEd estimated for each reheat unit and IPP, for three representative years.

As expected, units with lower capacity factors have higher energy prices.[22] However, it is harder to explain the relationship between prices received by in-city and upstate units, with similar operating patterns. The upstate generators often receive higher prices than the in-city generators: for

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[20] Most units' market energy prices rise more slowly, because their capacity factors are projected to rise significantly in 2000-2005. As a plant's capacity factor rises, it operates in more low-price, off-peak hours, depressing the rate of increase of the average market price it receives.

[21] In contrast, ConEd's projected inflation in fossil fuel prices by unit show a much smaller decline after 2005. Those projections rise at roughly inflation to 2005 and at about 2.3% after 2005, slightly faster than market energy prices.

[22] Some variations from this general rule are expected. For example, Indian Point's capacity factor varies due to outages, but it always operates like a baseload unit, with an energy price similar to Sithe's (at over 100% capacity factor).

example, Bowline 1, Selkirk, and Indeck generally receive higher prices than the two in-city IPPs, even when the in-city units operate at lower capacity factors.[23] Similarly, in 2003 and 2008, Bowline 1 receives higher energy prices than Arthur Kill 3, even though Bowline 1 consistently has a much higher capacity factor. Roseton receives higher energy payments than any of the in-city plants, even those that operate less than half as much as Roseton.

Q: **Has ConEd offered any explanation of this anomaly?**

A: Yes. ConEd points out that market energy prices plus uplift are generally higher for in-city plants than upstate plants. ConEd is correct that in-city plants would be expected to receive higher uplift payments (compensating the units for times when ramp-up, minimum load, and other costs are not covered by market energy price) than upstate units. Of course, this does not address the issue of whether market energy prices are properly being modeled as being higher in the city than outside. It is conceivable that the MAPS runs produce in-city market energy prices that are higher in each hour than the upstate prices, but that in-city plants prices are dragged down by significant amounts of power generated at low-value periods to provide services compensated by uplift.[24]

Since ConEd has refused to provide any data on the hourly market energy prices produced by its MAPS runs, the amount of energy associated with the uplift, or any other detail on its assumptions or results, I cannot test

[23] Since Cogen Tech is not fully dispatchable, the market value of its energy would be lower than a fully dispatchable plant with the same capacity factor, but certainly no lower than a plant dispatched as baseload.

[24] It is difficult to believe that this effect could reduce the $/MWh value of Arthur Kill 3 (at a 48% capacity factor) below that of Bowline 1 (at 73%), as ConEd's results indicate for 2001.

this explanation further.[25] In any case, since ConEd assumed that IPPs would not receive any uplift revenues (or be operated in a manner that would justify those revenues), ConEd's explanation of the anomalies does not explain why the in-city IPPs receive lower market energy prices than upstate IPPs, or the essentially baseload Bowline 1.

B. RII Estimate

1. Approach and Assumptions

Q: How did you estimate market prices for energy and capacity?

A: To the extent possible, I relied on ConEd's approach and assumptions. Unlike ConEd, I combined these assumptions in a consistent manner.

- Like ConEd, I use separate values for energy and capacity, and for power delivered in the City and outside, and reduce energy prices as operating factors increase.
- I compute the market value of each ConEd station as the present value of the difference between its annual market revenues and operating costs, and stranded cost as the difference between market value and ConEd's net investment.
- I compute the stranded cost for each IPP as the present value of the difference between ConEd's projected payments to the IPP and the market revenues that IPP's capacity and energy could earn.
- I use ConEd's assumptions regarding

[25] Indeed, ConEd did not even provide average annual market energy price by unit; I had to back those values out of more aggregate results.

- gas prices delivered to New York power plants ($2.68/MMBTu upstate and $2.73 in-city, in 1996$)
- combined-cycle capacity costs ($565/kW and $11.33/kW-yr of O&M upstate, 18% more in-city)
- cost of capital for competitive power producers (20% pre-tax), used to present-value ConEd plant costs
- 10 % discount rate for present-valuing above-market IPP costs
- annualization of combined-cycle costs based on a twenty-year planning period
- upstate baseload market energy price for 1998 (from ConEd's estimate for Indian Point 2)
- short-term out-of-city market capacity price for 1998

Q: Which of ConEd's market-price assumptions did you change?

A: As discussed above, ConEd failed to reflect property taxes, and used inconsistent projections of energy costs. To correct these problems, I

- Included a 5% property tax rate for new capacity.
- Set the post-2005 out-of-city capacity cost at $66/kW-yr, which is the cost of a CT at $300/kW, $3.25/kW-yr O&M, 5% property taxes, and ConEd's competitive capital costs.[26]
- Set the in-city capacity cost 18% higher than upstate, following ConEd's assumption about the difference between in-city and upstate costs of capacity.

[26] While ConEd calculates market capacity price as the difference between total combined-cycle cost and market energy price, I compute market energy price as the difference between total combined-cycle cost and market capacity price. I thus avoid the ConEd's inconsistency in market energy prices.

- Derived baseload market energy prices as the costs of combined-cycle (using ConEd estimates, except for a 7,500 Btu/kWh heat rate, 5% property taxes, and the use of real-levelized carrying charge), minus the CT capacity value, starting when ConEd expects new combined-cycles to be cost-effective—1998 in-city and 2005 upstate.[27]
- Interpolated short-term out-of-city capacity and energy costs linearly from 1998 to 2005.
- Interpolated the effect of operating factor on market energy price from ConEd's upstate estimates, as shown in Exhibit (PLC-3).

The resulting market prices are shown on page 1 of Exhibit (PLC-4).

As a sensitivity, I also derived a set of market prices more closely from ConEd's basic assumptions in its capacity-cost calculation—market energy prices and net capacity costs in and out—and ConEd's short-term upstate energy and capacity estimates. I set the long-term market capacity prices equal to ConEd's estimates for 1996, and held them constant in over time.[28] I also used ConEd's long-term estimates of the 2.83¢/kWh and 2.98¢/kWh for upstate and in-city market energy prices. For the upstate market, I interpolated from ConEd's estimates for 1998 to the combined-cycle-based costs in 2005. The resulting market energy prices are much lower, but capacity costs somewhat higher, than in the RII case. These results are shown on page 2 of Exhibit (PLC-4).

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[27] These market energy prices ($33/MWh upstate and $36/MWh in-city in 1996$) are very close to the baseload market energy prices in the UK pool, which in the year ending 3/96 averaged 2.39p/kWh, or roughly $36/MWh.

[28] Including a 5% property tax rate produces real-levelized capacity costs comparable to the starting capacity prices ConEd uses.

Q: Other than the projected market energy and capacity prices, how does your estimation of stranded costs compare to ConEd's?

A: My approach is similar to ConEd's in terms of the analysis period (20 years, except for Indian Point 2, retired in 2013) and discount rate. The important differences include:

- I included the costs and capacity value of ConEd's combustion turbines.
- I excluded the cogeneration units serving the steam system (East River, Hudson Ave., 74th St., and Waterside).
- I attributed the market capacity value to all units.
- I reduced the fuel cost of dual-fuel reheat steam units by 12% to reflect their ability to select the lower-cost fuel on a weekly basis. This estimate is supported by the analysis in Exhibit (PLC-5), which shows that the average fuel cost for a dual-fuel unit in 1994-96 would be 12% lower than the fuel cost for a gas-only unit.
- Rather than use a production-costing model to estimate market energy revenues for each unit, I interpolated from the baseload market energy price and assumed that the average capacity factor of each plant in the 1998-2007 period would be the same as in the period 1988-89.[29]

[29] These values are generally not very different from ConEd's average projected capacity factors for 1998–2017, which understate future reheat capacity factors by ignoring the flexibility of dual-fuel plants, including generation from non-economic steam plants and other utilities, and the use of market prices that are lower than the prices necessary to justify addition of required capacity, as discussed below. Since ConEd only modeled six relevant years (1998–2005), most of the ConEd capacity factors are also simple projections.

- I reflected the return of Roseton to Central Hudson G&E in 2005, which ConEd ignores.[30]

Q: How did you estimate non-fuel operating costs for ConEd's plants?

A: In general, I started with its average O&M and capital additions in 1992-95, with minor variations as listed in Exhibit PLC-6. For the base case, I assumed a 25% performance improvement under competition, and added 30% overheads. I also included property taxes for each unit at the value reported by ConEd in the 1994 electric cost-of-service study, and escalated those taxes as suggested by ConEd in xx (cite). Both low and high O&M and capital additions values are listed in Exhibit (PLC-6), with other operational inputs.

Q: How do your projections of non-fuel operating costs compare to ConEd's projections?

A: Since ConEd has not provided O&M, property taxes, capital additions and overheads, I backed out the total of these fixed operating costs for each unit, as the difference between ConEd's reported *Market Revenues minus Fuel* (which also eliminated variable O&M) and *Cash Flow*. This computation appears to produce ConEd's estimate of fixed operating costs, except in years in which the unit does not receive capacity credits, in which case ConEd's *Cash Flow* contains only property taxes.

Exhibit (PLC-7) compares the average of ConEd's projected fixed costs with my low and high estimates. ConEd's estimates are lower than my

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[30] It is my understanding that, in exercising this option, Central Hudson would be required to pay ConEd for some approximation of the net book value of the plant. I do not include this value, which would reduce stranded costs, for lack of detail on the arrangement.

low estimates for the upstate plants, while ConEd's estimates for the in-city reheat plants are higher than my high case. ConEd's estimate of total fixed costs for its reheat and nuclear plants lies between my low and high assumptions.

Q: Does this include all of ConEd's projected non-fuel costs?

A: No. ConEd also included variable O&M.

Q: How did ConEd estimate variable O&M?

A: According to the stranded-cost report, each unit—nuclear, fossil reheat, or steam-electric, regardless of size or vintage—was assumed to have variable O&M of $1/MWh in nominal dollars for every year of operation.[31]

Q: Can you break the fixed costs into components?

A: I have been able to extract the property taxes ConEd projected for some units for some years. It appears that our initial projections are quite close, which is not surprising, since I attempted to apply ConEd's assumed escalation rates to recent actual tax assessments. However, ConEd's stranded-cost analysis appears to assume 1%–1.5% annual escalation in property taxes through the forecast period, which is not supported by xx (cite).

Q: What is the basis for your assumed performance improvement and overhead levels?

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[31] This assumption is obviously rather arbitrary, as are some other assumptions in the stranded-cost analysis, such pricing ancillary services at ConEd's current proposed tariff, also in nominal terms. Other equally odd assumptions may be embedded in the MAPS inputs and cost assumptions that ConEd has refused to provide. Under these circumstances, ConEd's detailed MAPS modeling may not produce any significant improvement in accuracy over my simpler approach.

A: The cost reduction is based on the assumption that competitive market incentives will improve productivity, especially under new management.[32] This specific adjustment is judgmental, reflecting the amount by which potential owners may believe they can reduce costs compared to the level under competition. For comparison,

- Bellucci, et al., ("Potential Cost Savings in Electric Utility Non-Fuel Operating Costs Under Deregulation," *Deregulation of Energy: Intersecting Business, Economics, and Policy*, United States Association for Energy Economics, 1996, pp. 450-459) found that efficient operation of Midwestern could reduce non-fuel O&M costs by about 50% compared to 1994.
- British Electric, the new competitive owner of the nuclear capacity previously operated in a cost-plus environment, has announced plans to reduce staffing by 23% over the next three years.
- KWU-Siemens has reduced the costs and prices for its nuclear engineering services by as much as 40%.

Equivalent savings or benefits could be achieved through improved heat rates, lower fuel costs, increased capacity, additional generation at the sites, or other uses of the site.

The overhead values are based on a review of overhead ratios (A&G to non-fuel O&M) for utilities that have little or no non-generation activities.

[32] Actually, the sale price of the plants will depend on bidders *expectations* of the improvements in performance they can achieve. Buyers who over-perform on their expectations will earn higher returns, while those who under-perform will earn less. In terms of the computation of stranded costs, the final outcome of operating costs (or market prices) is less important than buyers' expectations.

For fossil plants, overhead ratios range from under 10% to around 35%. For nuclear utilities that are part of a holding company, the overhead ratios range from 20% to 30%.[33] The 30% overhead rate is probably at the high end of the reasonable range for large-scale generation owners.

Q: How did you estimate ConEd's net investment in each station?

A: At the time we structured our analysis, ConEd had not yet provided its projection of net plant by station as of 1/1/98. I therefore used the gross plant and accumulated depreciation shown in the 1994 cost-of-service study, and assumed that additions in 1995–1997 would roughly equal depreciation in the same period. ConEd's stranded-cost study includes estimates of 1/1/98 net book, but no derivation of those estimates. My estimates are within 3% of ConEd's for the reheat plants (higher in-city and lower upstate) and within 2% of ConEd's total for the sum of the reheat and nuclear stations.

2. Stranded-Cost Results

Q: What are the results of the base-case stranded-cost analysis you described above?

A: These base-case assumptions produce the following results:

- All the modeled plants are cost-effective to continue operating.
- The in-city reheat units produce a restructuring gain of $1.7 billion.
- The gas turbines produce a restructuring gain of $0.6 billion, and Bowline another $0.1billion.
- Stranded costs from Indian Point 2 are about $0.3 billion.
- Stranded costs from IPPs are $1.5 billion.

[33] The Maine and Vermont Yankee plants, and in some years, Great Bay Power, have considerably higher ratios.

- Net restructuring gain is $600 million.

These results are presented in more detail in Exhibit (PLC-8).

Q: Have you conducted any sensitivity analyses on these results?

A: Yes. I conducted five such analyses:

- Sensitivity 1 uses lower capacity factors, similar to those used by ConEd.
- Sensitivity 2 assumes that no improvement in O&M is possible, compared to historical values.
- Sensitivity 3 combines the low capacity factors with market prices that use lower energy prices.
- Sensitivity 4 (most pessimistic) combines the high O&M, low capacity factors, and low ConEd-based market prices.
- Sensitivity 5 determines the additional potential value of increasing the dispatch of the Cogen Tech IPP, assuming that the additional energy is available at prices equal to the energy prices of the Selkirk contract.

Q: What were the results of these sensitivity cases?

A: The detailed results are presented in Exhibit (PLC-8). The general pattern of results for Sensitivities 1-4 is similar to those of the base case, with lower restructuring gain and higher stranded costs. In the high O&M cases—Sensitivities 2 and 4, as for the assumptions in ConEd's stranded-cost report—operation of Indian Point 2 is not cost-effective. In other words, significant reduction in O&M would be required to make Indian Point 2 economically viable. In contrast to ConEd's proposal that Indian Point 2 should be ConEd's only major plant to remain under cost-of-service regulation, the importance of cost reduction argues especially for

restructuring the ownership and regulation seeking a more experienced nuclear operator to run the plant.

Lower capacity factors (Sensitivity 1) market prices reduces the value of ConEd's plant (and hence total restructuring gain) by $300 million. Higher O&M (Sensitivity 2) reduces restructuring gain by $450 million. The combination of low capacity factors and low market prices (Sensitivity 2) increases the loss on the IPPs by $500 million, producing a total stranded cost of $250 million.[34] Adding in higher O&M in Sensitivity 4 increases those stranded costs by about $400 million.[35]

In Sensitivity 5, increasing the dispatch of Cogen Tech would reduce its net cost by $350 million.

Q: Are there other factors that you have not explicitly modeled that could further reduce ConEd's stranded costs?

A: Yes. First, I have not included any revenues from the sale of Roseton to Central Hudson G&E. Second, any surplus in the portion of ConEd's pension and other post-retirement benefits funds attributable to generation would offset stranded costs. Third, I do not include any benefits of securitization. Fourth, my stranded-cost calculations assume that the IPPs would not accept

[34] The value of Indian Point 2 and the reheat plants also fall, by about $250 million, compared to Sensitivity 1, but this is counterbalanced by $200 million in increased value for the CTs.

[35] High O&M has a smaller effect going from Sensitivity 3 to Sensitivity 4, than from the Base Case to Sensitivity 2. In either case, the higher O&M makes operation of Indian Point 2 uneconomic, eliminating whatever market value Indian Point 2 had with lower O&M. Since the value of Indian Point 2 is lower in Sensitivity 3 than in the Base Case, the effect of high O&M is reduced.

any restructuring of their contracts—such as front-loading payments in exchange for lower present-value payments.[36]

This last point is especially important. The IPP payments have a present value of about $8 billion; even a small percentage reduction in prices could save hundreds of millions of dollars.

Q: How does your range of estimates compare to ConEd's estimates?

A: ConEd estimates a total stranded cost of $4.7–6.2 billion, compared to my range of a stranded cost of $0.6 billion to a gain of as much as $1.0 billion. The differences in stranded cost (in millions of dollars) break down as:

	ConEd Estimate	RII Favorable	RII Unfavorable
Indian Point	$495	$314	$467
Upstate Reheat	$146	($103)[37]	($72)
In-City Reheat	$148	($1,696)	($1,122)
Steam Plants	$358	Excluded	Excluded
Gas Turbines	Excluded	($591)	($717)
IPPs	$3,421[38]	$1,114[39]	$2,038
Total[40]	$4,568	($962)	$640

The differences between my estimates and ConEd's are mostly due to ConEd's modeling errors and differences in projections of market prices

[36] If the IPP's discount rate (reflecting financing, operating risks, and regulatory and legal risks) is higher than the securitization interest rate, front-loading may produce a higher present value for the IPP, but lower annual payments for ConEd.

[37] Minus the sale price of Roseton.

[38] The Company's filing (p. 70) reports stranded NUG costs of $3.0–$4.5 billion, reflecting a range of capacity-price assumptions.

[39] Minus any effect of contract restructuring and securitization.

[40] This total does not include nuclear decommissioning (which ConEd estimates at $550 million) or regulatory assets and liabilities.

(including ConEd's inconsistencies).[41] Significant differences also result from ConEd's inclusion of the steam plant costs, and exclusion of gas turbine value.

Q: Given this wide range of estimates, how should ConEd's stranded costs or restructuring gain be determined?

A: In the long term, the loss or gain from restructuring should be determined through divestiture to the highest bidder of all generation assets, through properly structured auctions. The value of ConEd's resources does not depend on my expectations, or ConEd's, or the Commission's, but on the expectations and value of the highest potential bidder. If ConEd wishes to retain ownership of some capacity, consistent with market-power mitigation concerns described below, it should be willing to pay more than other bidders.

In the short term, the Commission should set rates based on my Base Case. If ConEd believes that the stranded cost is higher than I estimate, the Company will have every incentive to foster the prompt resolution of the ISO and other issues, so that sales can go forward and the stranded-cost recovery can be reconciled to the sales price.

IV. Effect of Restructuring on the Rate Plan

Q: What form of restructuring did you assume for the purposes of this testimony?

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[41] All these estimates use ConEd's 20% discount rate for market valuation of power plants, and would be lower if operating profits were discounted at a lower rate.

A: I assumed that all ConEd's generation resources, except for the steam-system cogeneration plants, would be repriced in 1998 as though they were sold at market value.[42] Any difference between the net book value of the plant (or the present value of IPP payments) and its sales price would be spread out over many years.

A. Nature of the Effect on Rates

Q: Please outline the effect of restructuring of ConEd generation resources on the rate plan.

A: Restructuring of power-plant cost recovery can reduce rates in three ways. First, changing the ownership of generation resources, through divestiture or the equivalent, effectively reprices the resources. Under traditional ratemaking, charges for utility-owned generation are front-loaded and fall over time. Since market power prices are lower in the short term, customers pay much more than market prices in the short term. Over time, this differential shrinks or reverses. Similar timing problems arise for IPPs. Restructuring allows for spreading the above-market cost, or the savings, evenly over the life of the resource.

Second, restructuring is likely to increase the value of generation. Competitive-market incentives are likely to increase the efficiency of the operation. The high bidder for sold generation is likely to be a party that believes it can reduce costs, increase output, and otherwise increase the value of the plant. That high bid would thus be higher than the value of the plant to ConEd.

[42] Some of the actual sales might occur later, with a true-up.

Third, restructuring of above-market plant eliminates a portion of the plant's cost from the utility's books and converts the remainder to a regulatory asset that should have much lower risks and carrying costs.

Q: Please outline the effect of restructuring of ConEd generation purchases on the rate plan.

A: Restructuring of power purchases can reduce also rates in three ways. First, levelizing the above-market portion of the purchases has the same timing effects as restructuring of plant ownership. Second, if IPPs are interested in a higher degree of assurance of payment, in earlier payment, or other features with little or no cost to ConEd, contract renegotiation in combination with refinancing can reduce total costs to ratepayers. Third, lower-cost financing, particularly in the form of securitization, can further reduce costs.

Q: How does the City's Rate Plan differ from that of ConEd?

A: ConEd's rate plan does not reflect any rate reduction from restructuring, due to retiming, refinancing, increased efficiency, or mitigation. Instead, ConEd proposes to accelerate depreciation on its fossil generation, purportedly to reduce its stranded costs.

The City Plan does not include any acceleration of depreciation in current rates. If ConEd has strandable generation costs to recover, that recovery should coincide with market access, so that customers can benefit from competitive generation at the same time that they pay for the stranded costs. ConEd's proposal would give the Company stranded costs before the ratepayers receive any benefits.

In any case, I do not believe that ConEd has any net stranded investment in the generation it owns, and certainly not in the fossil plants.

Q: Is it realistic to assume that ConEd will be able to sell Indian Point 2, or that any utility will be able to sell any nuclear power plant in a competitive market?

A: Yes. There are at least three recent examples of sales of nuclear capacity in a competitive market.

- In 1994, investors purchased a 60% ownership interest in Great Bay Power, which owns 140 MW of the Seabrook nuclear plant and sells into the competitive wholesale market without long-term commitments. This purchase implied a value of $400/kW, without management control of the plant or economies of scale, and at a time of low prices in the energy markets.
- In the U.K., British Energy, the newly privatized owner of eight nuclear power plants, has a market value of about £2.4 billion. British Energy assumed about £3.7 billion of debt and present-value liabilities for decommissioning and waste disposal, offset by about £429 million in cash and other assets. The value of the power plants must be about £6.1 billion, or roughly $10 billion. Divided over BE's total capacity of 9,600 MW, this is about $1,000/kW.[43]

[43] Market values of nuclear capacity in the US may vary from those in the UK, due to differences in reactor technology, financial structures, tax rates and regulations, and regulatory requirements. British Energy's capacity consists of one new 1,200 MW PWR (expected to operate until 2035), and 14 advanced gas-cooled reactor (AGR) units built in 1978–1989 and currently projected for retirement in 2006–2018 period, with an average retirement date of 2011. The British Energy shareholders appear to be exposed to greater decommissioning-cost risks than the purchaser of Indian Point 2, and average projected remaining life of the capacity is very similar. The UK experience is suggestive, rather than predictive for the US.

- Illinois Power has recently agreed to purchase the 13% share of the Clinton nuclear plant owned by the Soyland Power Cooperative, for sale at market-based rates. The price of the purchase has not been announced.

Q: Does your ratemaking proposal simply trade off lower electricity prices in the near future for higher prices in longer term?

A: No. Most of the benefits of the transition to competition result from cost reductions, rather than redistributing over time:

- In the competitive market, the owners of generation will have incentives to operate plants at low cost and high availability, to improve plants and add capacity, and to retire or repower plants when those actions reduce costs.
- Purchases can be renegotiated to reduce total costs and utility payments, while improving cash flow and security for the generators.
- Above-market costs of plants and purchases can be refinanced at lower costs. Hence, the total cost that electricity consumers pay for power is likely to be lower in a properly designed competitive market than in the status quo.

In addition, the PSC has indicated a desire to move toward competitive market pricing of generation. ConEd has generally committed itself to the divestiture of at least a portion of its generation. Hence, in the long term (say, 10 to 15 years from now) customers will pay market prices. Those future market prices are likely to be higher than the price ratepayers would have paid under traditional ratemaking for many existing units. Thus, the ratepayers have effectively been committed to pay more for generation in the future. If electricity consumers are to pay these higher prices in the future, they should pay prices in the near term that are lower than the current ratemaking costs of those units.

Q: Will customers necessarily be exposed to increased cost risks as a result of restructuring?

A: No. Short-term market spot prices are likely to be more volatile than ConEd's current generation costs, but customers will not be limited to purchasing from the spot market. Customers should be able to purchase power from various producers at prices that are fixed for various periods, or indexed to fuel costs.[44]

Q: Would restructuring produce the same market prices and stranded costs for all ConEd customers?

A: No. If the restructuring results in locational pricing, market prices for energy and capacity will be higher in the city than outside, since all power sold in the City will be at in-city prices, including the power brought in from lower-cost markets outside the city.[45] The transition to competition must be structured to avoid windfalls to the owners of generation in the City, upstate generation owners, or to transmission owners. Different solutions are appropriate for upstate and in-city generation.

For upstate generation, the transmission pricing rules must provide for the difference in market-clearing prices across the interfaces of the city load pocket being captured in transmission charges, rather than by upstate

[44] Producers should prefer such contracts, which would better match the producers' costs than would spot prices.

[45] In-city customers should be able to hedge (e.g., lock in fixed prices) through purchase of capacity entitlements in the City, as discussed below.

generation owners.[46] That excess should be used to benefit in-city customers, through rebates against ConEd access fees, or financing of measures to mitigate the transmission constraints, such as transmission upgrades, energy efficiency, and distributed generation.

For in-city generation, the portion of the market value that is due to the in-city location should similarly be credited to city ratepayers, as plant is divested.

Hence, it will be necessary to establish separate stranded-cost rates for customers within and outside City.

B. Rate Effects of Restructuring

Q: How did you model the rate effects of restructuring?

A: I started by estimating base case revenue requirements for 1998–2003 from 1994 revenue requirements, from the 1994 cost-of-service study, plus fuel inflation and the costs of NUGs added. For this limited purpose, I assumed other inflation and depreciation offset one another.[47]

I then removed the costs of all ConEd generation (nuclear, fossil reheat, and combustion turbines) except for cogeneration, and also all costs related to the IPPs. I replace that generation with market purchases of capacity and energy. Since I had the ConEd generation costs for 1994 in the base case

[46] When the transmission lines into the City are fully loaded, the transmission charge across each interface would equal the difference between the market-clearing prices in the City pocket and outside.

[47] I am more interested in the difference between revenue levels than in the base-case revenues themselves. The actual base-case revenue level will depend on cost-of-service issues currently in dispute.

(adjusted for fuel prices), I removed those 1994 costs and replaced them with market at 1994 generation levels. For the IPPs, I used the capacity factors xx.

I spread the gain or loss on ConEd plants over time by amortizing the cost over 10 years.[48] The above-market portion of IPP costs was spread over 20 years (still much shorter than the lives of the contracts), financed at ConEd's cost of capital; I separately compute the annual cost with 7.5% securitized debt financing. I computed the annual rate effect of restructuring, and then computed the 1998 rate reduction that could be followed by a five-year rate freeze. This rate reduction would be additional to any due to cost-of-service adjustments.

Q: What share of estimated stranded costs have you included in your proposed cost recovery?

A: I have assumed full recovery of post-mitigation stranded costs. Once the actual level of stranded cost is determined, and ConEd's success (or lack thereof) in mitigating stranded costs has been demonstrated, the Commission should revisit the issue of sharing stranded costs between shareholders and ratepayers.

Q: What restructuring rate reduction does your stranded-cost analysis imply?

[48] Plants that are uneconomic to operate (none are identified in my base case, but many are identified in ConEd's analysis, including Indian Point 2 and all the steam units) are not used and useful and should be amortized without return. If ConEd is correct that Indian Point 2 is not economic to operate, the prudence of the $190 million or so that ConEd expects to have invested in the plant in 1995-97 must be highly suspect. If Indian Point 2 is shut down before the steam generators are replaced, the unused replacement steam generators may have significant salvage value.

A: The results of the computations I described above are shown in Exhibit (PLC-9). For the Base Case, restructuring would reduce 1998 revenue requirements by 14% and allow a five-year rate freeze at 9.3% below the rates that would otherwise be required in 1998. Any cost-of-service adjustments that would reduce 1998 revenue requirements would be added to this rate decrease.

Most of the Sensitivity cases reduce the magnitude of the rate decrease, but do not eliminate it. Even the pessimistic case (page 2 of Exhibit (PLC-9)) would support a 5% rate decrease and freeze.

Including any significant amount of IPP contract restructuring (either to allow more efficient dispatching of Cogen Tech or to reduce the present value of payments) would push the allowable rate reduction past 10%.

Q: Are these reductions solely the result of your stranded-cost estimates, or would ConEd's stranded-cost estimates also support a rate decrease and freeze?

A: While the reduction would be smaller, restructuring would allow for a rate reduction, even with ConEd's estimates of stranded costs, which (among other things) assume very low market prices and no improvement in efficiency due to competition. Page 3 of Exhibit (PLC-9) summarizes the rate reduction that could be achieved with ConEd's stranded-cost estimates, for the same set of plants included in my analyses. I removed the stranded costs of the steam-electric plants, and added in the gain on the gas turbines, using ConEd's estimates of market capacity prices. Revenue requirements would be reduced about 2%, allowing a 0.8% rate decrease and five-year rate freeze.

C. Implementation Issues

Q: How do you envision the Commission implementing these restructuring-related rate reductions?

A: The City's estimates of restructuring gains and losses would be used to set rates during the rate freeze, subject to reconciliation based on actual sale prices or an administrative repricing when the generation is transferred to an affiliate of the ConEd distribution company (Disco). All customers would receive the benefits of the restructuring, regardless of whether they immediately participated in retail access. Customers who continue purchasing bundled service from ConEd would pay a delivery charges (for T&D, customer service, and societal benefits), pay a stranded-cost charge, and pay ConEd for power at a proxy of market prices. Customers who opt for direct access would pay ConEd for the delivery charge and receive the restructuring gain, and pay their power provider for capacity and energy under a separate agreement.[49]

Class cost allocation and rate design would be determined in a separate proceeding later in 1997, with the intent of avoiding any substantial shift in revenues.

Q: Would the stranded-cost charge be the same for all customers?

A: The stranded-cost charge could be differentiated by class, location, or both.

The stranded-cost charge should generally not be differentiated across classes, but should be a constant ¢/kWh charge for all classes. The stranded costs result from commitments related to obtaining large amounts of energy—the baseload IPP contracts and Indian Point 2—rather than

[49] Provisions for consumer protection and billing arrangements must still be worked out.

investments primarily to meet peak demand, such as the gas turbines (which produce a large restructuring gain).

On the other hand, ConEd's stranded-cost charge should be geographically differentiated. The stranded-cost charge is driven by the difference between ConEd's costs and the market value of the resources. Higher market values result in lower stranded-cost charges, and vice versa. To the extent that customers expect to pay high market prices for energy and capacity, they are entitled to low stranded-cost charges. This basic relationship is equitable, to the extent that the same customers are paying the stranded-cost charges and the market power prices.

ConEd customers, unlike those of other utilities, will face two very different sets of market prices. Market energy and capacity prices in the city will be higher than those outside. If ConEd's system were split into two separate companies, with each owning a load-proportional share of each generation resource, the in-city customers would face higher market prices and lower stranded-cost charges than those in Westchester. Post-restructuring electric bills would not be very different for the two companies. The same approach should be used in the two parts of ConEd's territory: Westchester customers should pay the stranded-cost charge that would apply if all generation were valued at upstate market energy and capacity prices, and the in-city customers would pay a lower stranded-cost charge reflecting the higher prices those customers will pay for power.

The basic principle here is quite simple: the customer in areas with higher costs should be compensated from the revenues generated by the fact that they are paying those costs. For generation in the City, the in-city customers who pay the higher in-city prices should get the additional revenues from the sales of in-city generation.

Similarly, the in-city customers will pay congestion charges (the difference between in-city and upstate prices) for the use of the transmission interfaces into the city. The NYPP ISO proposal effectively provides for flowing these congestion charges back to customers. More specifically, the congestion revenues should flow to the customers in the area paying for the congestion, in this case, the City.

V. Market Power Mitigation

Q: What is the scope of the City's analysis of market power?

A: The City analysis of mitigation of market power focuses on the total in-City load pocket, with special considerations for subpockets. Similar analysis should be conducted, and ownership rules should be developed, for the entire pool.

As demonstrated in the testimony of Mr. Biewald, the concentration of in-City generation ownership by ConEd creates virtually unlimited opportunity for market power abuse, greatly increasing prices to consumers. In addition, market power varies dramatically with changes in fuel prices, unit availability, transmission capacity, and load level, making impractical exhaustive analysis of potential abuse. The restructuring of ConEd, and the development of the ISO, should provide multiple mechanisms for mitigating market power.

A. Market Structure

Q: What market structure do you recommend?

A: Successful mitigation of ConEd's market power in the City will require extensive diversification of the ownership of in-city generation; independent and efficient control and pricing of transmission; and a truly independent ISO able to prevent market abuse.

1. Truly Independent ISO

Q: What characteristics should the PSC seek in the New York ISO?

A: The ISO should

- be closely linked to the power exchange(s), to coordinate pricing with economic decisions in the presence of varying transmission constraints, ensure that services are appropriately priced, and clear markets;
- ensure merit-order dispatch, considering the closely-linked economic and reliability concerns;
- the transparent measurement and availability of ancillary services;
- price transmission efficiently, reflecting the difference in market-clearing energy prices in various load pockets; and
- authorize the addition of economic transmission, with appropriate PSC oversight of construction decisions.

Q: Why are transparent measurement and availability of ancillary services important in the mitigation of market power?

A: The market valuation of generation is an essential portion of divestiture of generation. In order to determine the value of capacity, purchasers will need to know how much of each ancillary service—which might include reactive power, black start, load following (regulation), spinning and operating reserve, planning reserve—will be required, how the service will be measured, and how that requirement will be allocated and priced.[50]

Q: Why is it important that the ISO be able to effect addition of economic transmission?

A: The ConEd distribution company may have little incentive to improve interconnections. Indeed, if it is affiliated with the owner of a significant amount of in-city capacity, it will have an incentive to restrict access to alternative supplies. Even if the ConEd Disco were acting in its customers' interests, the total benefits to the state may greatly exceed those to the service territory. The benefits of increased capacity to New Jersey, for example, may include reduced energy and capacity costs for in-city consumers, similar benefits for LILCo and upstate consumers, and increased ability to make economy sales from New York to the PJM pool and beyond. Some central decision-making capability is needed to aggregate these benefits and select cost-effective projects. The ISO, which will work around transmission constraints in its daily operations, is the logical locus for capacity planning.[51]

2. Ownership Rules

Q: What limits should be imposed on the ownership or control of capacity in the City?

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[50] For example, the ISO may charge for the service and compensate providers, or require each participant to provide or purchase the service in a secondary market. The service requirement may be allocated to participants on load or generation, and by the minute, day, year. Prices may be set by zones, or on a postage-stamp rate for the entire state.

[51] Actual construction and maintenance can be performed by the local utility, or if the utility is not interested in the project, another entity selected by the ISO on the basis of bid price and capabilities. The PSC should retain its current oversight responsibility

A: As demonstrated in the testimony of Mr. Biewald, the current concentration of ownership in the city must be diversified. With its current control of generation, ConEd would be able to increase energy prices almost without limit, earning vast monopoly profits at the expense of energy consumers.

Sale or long-term lease of in-City generation capacity to diverse entities not affiliated with ConEd would greatly reduce market power. As Mr. Biewald demonstrates, if each in-City plant were owned by a different entity, even the largest participant (the owner of Ravenswood) would have much less market power than ConEd has currently. The Ravenswood owner would still be able to profitably increase prices by as much as 5¢/kWh when load exceeds about 9,000 MW (or when load plus outages reach similar levels). The annual cost to consumers of this exercise of market power would be in the tens of millions of dollars.

While this level of non-competitive behavior would not be catastrophic, Mr. Biewald's results suggest that, even with divestiture to the plant level, modest additional mitigation measures—sales of capacity entitlements, controls on fluctuations in bid prices, investigation of claimed outages—may be required for the largest in-city generation owners, to eliminate market power and reasonably approximate a truly competitive market. This determination would depend on the results of additional modeling, as well as the success of other approaches. Certainly, the ISO will need broad powers to mitigate market power.

Q: How should ownership be diversified?

A: To maximize the sale prices of existing capacity, the entire unit or station should be sold as a unit. In addition to selling off each of the major in-city plants (Astoria, Arthur Kill, Ravenswood, Gowanus, and Narrows) individually, some sale of capacity contracts by owners of the larger power plants may be required.[52] Auctioning off capacity entitlements on an annual basis should not reduce the value of plants to their owners, except by reducing market power abuse.

Q: Would this divestiture be inconsistent with ConEd's obligation to serve?

A: No. ConEd's obligation would be to provide delivery capability, and to ensure that power is delivered from pool generation to end users. The financial arrangements for paying for that power will be worked out between users and their power suppliers. For end users who do have a designated power suppliers, ConEd would act as a broker or merchant between the Power Exchange and the customers, to settle accounts. Those unaffiliated customers would end up paying market-clearing prices, plus any transaction costs. ConEd's role would not be very different from any utility that purchases power at wholesale, on an all-requirements basis.

So long as capacity in the pool is adequate to meet load, all customers in the pool will be served. That is the situation today and it will not change with restructuring.

3. Control of ConEd generation sites

Q: Why is it important to diversify control of ConEd generation sites?

A: While other generation sites can certainly be found in the City (as demonstrated by the Brooklyn Navy Yard and Kennedy Airport IPPs), the

[52] ConEd has recognized that it would have to sell off capacity rights to allow out-of-city energy suppliers to sell in the city. In principal, the capacity value of a plant for reliability purposes could be sold separately from the ability to obtain energy from the plant. Normal practice in the industry sells joint entitlements for both services, but this is not necessary.

existing ConEd sites offer significant parcels with appropriate zoning and historical usage patterns. The ability of a number of parties to expand generation will help to restrain abuse of market power.

Q: Is there significant potential for increasing capacity at ConEd-owned sites?

A: It certainly appears so. Existing ConEd generation sites once held over 1600 MW of additional generation, now retired.[53] ConEd is also holding land at the Sherman Creek and Hudson Avenue sites for future generating plants; at the 100 MW/acre capacity density of the Waterside plant, these two sites could accommodate 650 MW. Finally, significant amounts of additional land for generation facilities appear to exist at Astoria and Arthur Kill, potentially accommodating thousands of additional MWs. The market for future generation in the city is likely to be much more competitive if these sites are distributed among several parties.

B. Reducing the Need for In-City Central Generation

Q: Other than changing the market structure through creation of a powerful ISO and diversification of ownership of generation and sites in the City, how can the market-power problem be mitigated?

A: Both the Disco and the ISO have potentially important roles in reducing the market power of central generation, through distributed generation, load management, and energy efficiency.

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[53] These include Astoria 1&2, Arthur Kill 1, East River 5, Hudson Ave 3-8, and several units at Waterside, 59th Street and 74th Street.

Distributed Generation: Development of distributed generation, on the scale of a few kW to a few MW, could save environmental, distribution-capacity, power-quality, transmission, and generation costs. The most promising distributed-generation technologies are gas-fired fuel cells (especially where they can be used for cogenerating hot water) and photovoltaic cells. The Disco is an appropriate agent for distributed-generation planning.

Load Management: The ISO should develop mechanisms for rewarding interruptible or dispatchable loads for reliability and ancillary services. In particular, dispatchable loads could provide in-City operating reserves to support higher levels of transmission imports. The City's initial estimate is that load management of lighting intensity and chiller settings at large buildings would provide approximately xx MW of operating reserves.

Energy Efficiency: Reducing peak loads (especially air conditioning and lighting in conditioned space) will help keep in-City generation and transmission capacity far enough above load to maintain competition, while decreasing generation, transmission, and distribution costs. Some energy efficiency will be achieved by better pricing signals, or by marketers bundling efficiency with power supply. The Disco should take responsibility for promoting cost-effective efficiency that is not otherwise pursued, and for targeting efficiency efforts in areas with transmission and distribution constraints.

C. *Short-term Mitigation in the In-City Pocket*

Q: Can the establishment of the ISO, divestiture, and diversification in the capacity and site holdings in the City be accomplished immediately?

A: No. Establishment of the ISO and its rules will take some time. Once those rules are in place and tested, sales of capacity can start. Since auctions will need to be designed, approved, and implemented (probably on a staggered schedule), the sale of capacity may take some time. The City therefore proposes a combination of mitigation measures in the short term, to diversify control and limit ConEd's ability to game the system, combining long-term measures with auctioning off substantially all the capacity in contracts of roughly one year.

- ConEd could continue to own and operate its in-city power plants, but would be required to auction off substantially all the capacity in contracts of roughly one year. The energy produced by the plants can either be auctioned with the capacity entitlement, or auctioned separately as annual contracts for differences. ConEd would have inherent incentives to maximize the auction prices (by improving reliability and heat rate) and to minimize fixed operating costs. The form of the contracts could provide additional incentives, such as by fixing variable O&M in advance.
- No party would be allowed to own capacity entitlements of more than 10% (800 MW) of in-City generation.
- It is especially important that ConEd-operated resources be bid at cost. The owners of the ConEd capacity entitlements would receive the market clearing price in the City pocket. Withdrawal of capacity from dispatch can affect markets much as price changes do; if ConEd appears

to be manipulating market prices by withdrawing capacity at particular load levels, the ISO or the PSC might need to apply sanctions.

Marketers or customers can mitigate congestion price risk by buying in-city capacity entitlements or contracts for differences with entitlement owners.

Q: How long should these short-term measures remain in place?

A: The rate at which the short-term market-power mitigation measures can be phased out depends on the rate at which the ISO, power exchange, and markets for generation capacity develop. The PSC should particularly encourage ConEd to divest in-City generation when that becomes feasible, by setting assumptions (market value of power, capacity factor, O&M) for ConEd-owned generation at optimistic levels, when determining initial stranded-cost recovery levels.

Q: Should the steam plants also be divested as soon as possible?

A: The ConEd Disco should retain ownership of the steam cogeneration capacity until the costs of that capacity can be allocated between electric ratepayers, steam users, and shareholders. This capacity is very expensive, with a net book value of $750/kW, even though some of the units are quite old. Most of the 535 MW of steam capacity, including the East River units, are over 40 years old, and only one unit (Waterside 6, at 72 MW) is under 35 years old. ConEd's stranded-cost report finds that East River 6, Hudson Ave., and 74th St. each has fuel costs higher than the value of their output, even including the costs of new package steam boilers.[54] East River 7 produces

[54] In ConEd's analysis, Hudson Ave operates only in 1996, 74th St. only in 1996-99.

modest energy benefits, but its fixed O&M costs are much higher, so even this unit also does appear to be worth continuing to run.

This 535 MW of steam plant produces over half the stranded cost ConEd estimates for the entire 5,500 MW fossil system included in the stranded-cost study. It is not at all certain that all investment in the steam-electric units was prudent and recoverable from either electric or steam customers.

D. Mitigation in Sub-pockets

Q: How should market power in the sub-pockets within the City be mitigated?

A: The small number of power plants in each of the sub-pockets identified in ConEd's load pocket study will make any reasonable approximation of a competitive market in these areas particularly difficult. Operating electricity markets with five pricing areas in the City alone (Astoria, Greenwood-Staten Island, Vernon, East River, and the rest of the City) would greatly complicate the development of these markets. Hence, the City proposes a different short-term mitigation strategy for these sub-pockets.

The City proposes that the generators be paid the market-clearing price in the City load pocket. In addition, if out-of-order generation is required for local transmission support, the ISO would compensate the affected generators at cost, rather than at a sub-market market-clearing price. Units in the sub-pocket that are running at the same time may thus be paid different prices. Thus, transmission support in the sub-pockets will be priced as an uplift charge, similar to spinning reserve and other ancillary services.

VI. Retail Access

Q: How fast should ConEd move toward retail access?

A: Direct retail access should start by 1998 and be available to all customers by 2001. The phase-in of access should be proportional across classes.

Q: Are there any special problems that must be resolved before all customers can receive direct access service?

A: Mechanisms must be developed to allow small customers full access to the competitive market, through some combination of low-cost hourly meters, a reliable and transparent algorithm for allocating ConEd hourly load to individual customers, and/or geographic aggregation of loads (by neighborhood or large building). This issue must be addressed promptly if small customers are to participate in direct access.

Q: During this transition period, when some but not all customers have direct access, how should ConEd's services to customers taking ConEd generation services be priced?

A: ConEd should be charging the same delivery charge and the same stranded-cost charge (or giving the same restructuring credit) to all customers, regardless of their power supply source. In addition, customers served by ConEd power supply would pay a price for that supply based on market prices.

Q: How would those rates be structured?

A: ConEd's rates would consist of

1. A cost-of-service-based distribution charge, with customer, energy (time-differentiated where feasible), and (where feasible) demand components varying by class, covering

a) metering, billing, and customer services,

b) distribution equipment, and

c) transmission costs (net of charges and revenues from the ISO).

2. A systems benefits charge, probably as energy charges varying by class, covering

a) low income discounts

b) energy efficiency programs

c) R&D expenditures (other than those related to the distribution function).

3. A stranded-cost charge, set as an equal energy price for all classes, but varying between the City load pocket and Westchester.

4. A power-supply charge, with energy (time-differentiated where feasible) and (where feasible) demand components reflecting the current market price of power for each class's load shape.

Customers who select direct access would not pay item (4) to ConEd.

Q: Would this rate structure be consistent with performance-based ratemaking?

A: Yes. The Commission could either establish performance targets for specific cost in item (1), or establish a budget for items (1) and (4) combined.[55]

Q: Should metering and billing services be unbundled from the distribution service?

[55] The Company should be rewarded to reduce the total of customer bills for distribution and generation services, and not skimp on measures that increase distribution costs while reducing losses.

A: I recommend deferring consideration of those issues. There will be advantages to providing customers with metering options, especially linked to options for pricing power supply and for monitoring and controlling load. The distribution company may or may not be the best entity to provide a wide range of metering services. Access to billing data and control of the space in the billing envelope may also be important issues in competition.

Whether competition in metering and billing proves to be feasible and desirable will be determined by a number of considerations, including:

- provision of an appropriate range of metering, billing, information, and control options;
- avoiding premature and uneconomic investments in new metering technology;
- maintaining the consistency of distribution billing, power-supply billing, and power-exchange reconciliation functions;
- maintaining reliability of data collection and transfer;
- protecting customer privacy;
- ensuring fair use of space in the billing envelope; and
- avoiding unnecessary cost.

This are important and complex issues, some involving rapidly-evolving technologies and others closely related to the Commission's disposition of issues related to competition in generation services, such as vertical market power. They can be taken up at a later date, when the Commission and the parties can give them the level of attention they deserve.

VII. Summary of Recommendations

Q: Please summarize your recommendations.

A: In the near term, the PSC should take short-term actions and provide general direction for restructuring ConEd, including

- Requiring ConEd to file a restructuring plan that reduces rates at least 10% (in addition to any reductions justified by traditional cost-of-service considerations), followed by a five-year rate freeze, by reflecting actual or anticipated
  - repricing of ConEd owned generation at competitive market prices
  - refinancing of ConEd IPP obligations

  This value is optimistic, but reasonable, given the stranded-cost estimates developed above, and is intended to encourage ConEd to complete the transition and mitigate costs as soon as possible.
- Committing to reconciliation of stranded-cost charges as generation is divested or otherwise subjected to market valuation.
- Committing to divestiture of the vast majority of ConEd's in-City capacity.
- Providing general direction on the features required of the ISO rules to support divestiture, market valuation of ConEd assets, and market-power mitigation.

In addition, the PSC should identify the matters that should be dealt with over the coming months and years, including

- specifics on the stranded-cost mitigation plan, including divestiture schedules, auction structure, and refinancing
- specifics on the in-City market power mitigation plan, both short- and long-term

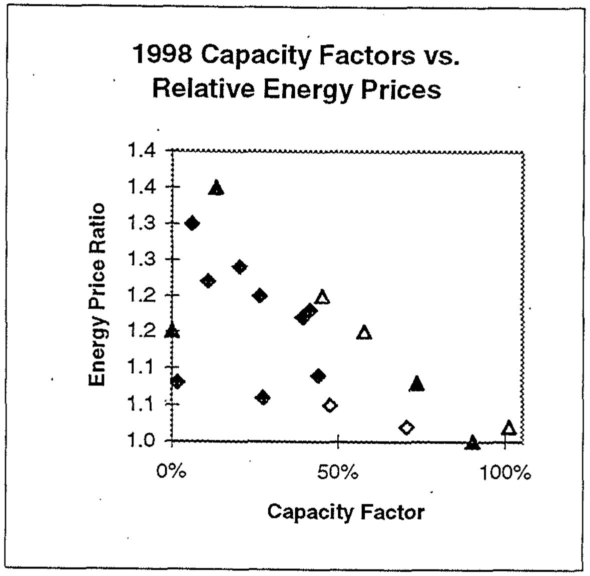
- unbundling of ConEd's expenses, investments, assets, and liabilities into generation costs (to be removed from rates), transmission costs, distribution costs, components of social benefits charges, and interim stranded costs
- analysis of market power within the NYPP
- cost allocation and rate design
- small customer access
- relationships between distribution companies and affiliated marketers and generators, including cost accounting and restrictions on power marketing in the service territory
- provisions for consumer protection
- metering and billing arrangements, including potential for competitive services

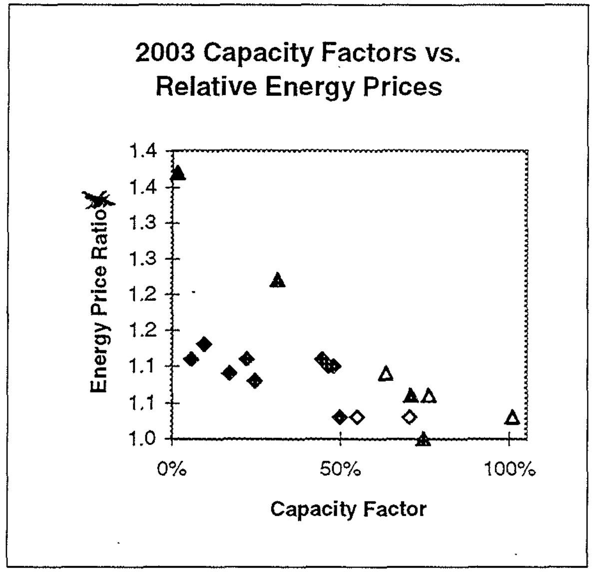
The PSC has started on the path to fundamental restructuring, which will change virtually every portion of the operation and regulation of electric utilities in New York. The revision of a century of practice cannot be completed overnight. Many details remain to be worked out.

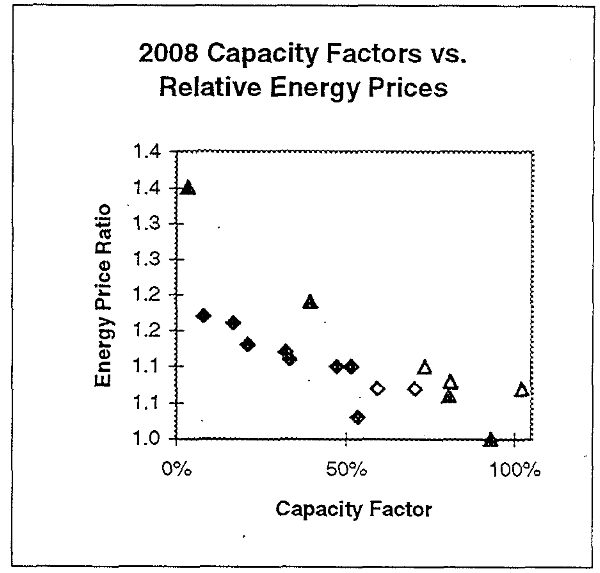
Q: Does this conclude your testimony?

A: Yes.

Exhibit ____ PLC-2
ConEd's Estimates of Relative Energy Prices for Reheat Units and IPPs







◆ ConEd In-City ▲ ConEd Out-of-City
◇ IPP In-City △ IPP Out-of-City

Note: In order to avoid divulging allegedly confidential data, each unit's energy price is expressed as a ratio to the lowest energy price of all units in each year. Each ratio is calculated as follows:

Energy Profit ($1,000)
\+ Fuel ($1,000)
\- Uplift ($1,000)
\+ Variable O&M ($1,000)
= Energy Revenue ($1,000)
÷ GWh
= Energy Price ($/MWh)
÷ Energy Price of the Low-Priced Unit ($/MWh)
= Energy Price Ratio

Exhibit ____ PLC-3
Effect of Operating Factor on Market Energy Price

Operating Factor	Multiplier to Market Energy Price
0%	0.00
5%	1.39
10%	1.32
15%	1.28
20%	1.25
25%	1.22
30%	1.20
35%	1.17
40%	1.15
45%	1.14
50%	1.12
55%	1.10
60%	1.09
65%	1.07
70%	1.06
75%	1.04
80%	1.03
85%	1.01
90%	1.00
95%	0.99
100%	0.97

Note: Values are rounded. Actual modeling uses ratios of greater precision.

Contains ~~data~~ Material ~~that~~ for which ConEd has asserted confidential status.

Exhibit ____ PLC-4
Market Prices of Power and Energy
(1998 dollars)

	Base Case				Low Energy-Price Case			
	Capacity ($/kWyr)		Energy ($/MWh)		Capacity ($/kWyr)		Energy ($/MWh)	
	In-City	Out-of-City	In-City	Out-of-City	In-City	Out-of-City	In-City	Out-of-City
1998	83.23	26.55	38.13	23.27	99.38	26.55	31.61	23.27
1999	83.23	32.83	38.13	24.72	99.38	33.97	31.61	24.11
2000	83.23	39.12	38.13	26.17	99.38	41.38	31.61	24.96
2001	83.23	45.40	38.13	27.62	99.38	48.80	31.61	25.80
2002	83.23	51.68	38.13	29.06	99.38	56.22	31.61	26.65
2003	83.23	57.97	38.13	30.51	99.38	63.63	31.61	27.49
2004	83.23	64.25	38.13	31.96	99.38	71.05	31.61	28.34
2005	83.23	70.53	38.13	34.86	99.38	78.47	31.61	30.02

Note: All prices are constant in real terms (i.e., rise with inflation) after 2005.

Exhibit ____ PLC-4 - REDACTED VERSION
Market Prices of Power and Energy
(1998 dollars)

	Base Case				Low Energy-Price Case			
	Capacity ($/kWyr)		Energy ($/MWh)		Capacity ($/kWyr)		Energy ($/MWh)	
	In-City	Out-of-City	In-City	Out-of-City	In-City	Out-of-City	In-City	Out-of-City
1998								
1999								
2000								
2001								
2002								
2003								
2004								
2005	83.23	70.53	38.13	34.86				

Note: All prices are constant in real terms (i.e., rise with inflation) after 2005.

Exhibit PLC-5: Effect of Dual-Fuel Capability on Average Fuel Cost

Annual Average Price $/MMBtu

	weeks of data	New York City-Gate Gas Price	New York City 0.3%S #6 Oil Price	Lower of Oil or Gas Price by Week	Ratio of Minimum Price to Gas Price	Ratio of Minimum Price to Oil Price
1996	34	$3.74	$3.19	$2.90	78%	91%
1995	51	$2.17	$2.62	$2.05	94%	78%
1994	49	$2.36	$2.50	$2.17	92%	87%
Total Period	134	$2.64	$2.72	$2.31	89%	84%

All Data from *Natural Gas Week*

Exhibit ____ PLC-6
Base Case Input Assumptions and Derivations

Name	Arthur Kill	Astoria	Bowline	Ravenswood	Roseton	Indian Point 2	GTs
Capacity (MW)	826	1,075	803	1,742	480	931	2,059
Last Year of Service	2017	2017	2017	2017	2004	2013	2017
Capacity Factor	35%	44%	44%	40%	56%	80%	0%
Operating Factor	40%	50%	50%	45%	65%	100%	0%
O&M (w/o overheads, 1998$/kW)	12	18.75	11.25	16.5	10.5	93.75	9.75
Annual Real Growth in O&M	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Capital Additions (1998$/kW)	2.25	6	3	3.75	5.25	30	5.25
Annual Real Growth in Additions	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Property Tax (million $ in '98)	14.8	19.5	15.2	24.0	6.5	25.1	15.6
Fuel	Gas	Gas	Gas	Gas	Gas	Nuclear	#N/A
Dual Fuel Adjustment	12%	12%	12%	12%	12%	0%	0%
Heat Rate (Btu/kWh)	10,500	10,200	10,000	10,200	9,800	10,000	#N/A
In City?	100%	100%	0%	100%	0%	0%	98%

See following pages for the derivation of these inputs.

Exh6&7.

Exhibit ____ PLC- 6

Page 2: Detailed notes on the development of base case cost and performance inputs

Capacity Factor

For the fossil plants, we have used the average of the capacity factors in 1988-89 from net generation reported in the FERC Form 1. For Indian Point 2 the 80% capacity factor is consistent with operation in 1992-95.

Operating Factor

All of the fossil units' operating factors are calculated as (capacity factor) ÷ (90% availability), and then rounded to the nearest 5% (for ease in later computating market energy values). Indian Point is assumed to run whenever available, and thus has an operating factor of 100%.

O&M and Capital Additions

For each plant, we based annual O&M and capital expenditures on the average, in constant dollars, of several recent years' expenses. Non-fuel O&M costs were calculated as total production costs, less fuel, less steam transfer. Capital additions were calculated as the difference between each year's gross plant and the previous year's gross plant (in nominal dollars). The number of years of data contributing to each plant's estimate varied with the plant, so as to avoid anomolous data (e.g., negative values, data distorted by unit retirements or non-recurring capital additions, etc.).

In the base case, these averages were reduced by 25%. In the high-expenses case, these averages were used as is.

The years contributing to each average are shown below:

	O&M	*Capital Additions*
Arthur Kill	1992-95	1992-95
Astoria	1994-95	1994-95
Bowline Point	1992-95	1992-95
Ravenswood	1991-95	1991-93, 1995
Roseton	1992-95	1991-92, 1994-95
Indian Point 2	1992-95 (approx.)	1993-95 (approx.)
GTs	1992-95	XX

Heat Rate

Heat rates were developed from the 1991 LRAC projections for the years 1992, 1997, 2002 and 2007. Capacity-weighted averages were developed for multi-unit plants for each of those years, and then a straight average was taken across the four years.

Exhibit ____ PLC-7
Comparison of ConEd and Resource Insight Non-Fuel Operating Cost Projections

Operating Expenses Implied By ConEd's Analysis (1998$million)
Calculated as: MR-Fuel - Cash Flow + VarO&M
Years in which there are no capacity revenues for any of a plant's units are omitted.

	Arthur Kill	Astoria	Bowline	Ravenswood	Roseton	Indian Point 2	TOTAL
1998	52	85		100			
1999	45	80		98	18		
2000	44	79		89			
2001	42	76		86	17		
2002	51	72	31	89	16		
2003	50	71	30	90	16		
2004	49		30	89	16	149	
2005	49		29	85	16	193	
2006	48		29	92	16	145	
2007	47		29	83	15	188	
2008	47	66	28	82	15	141	
2009	46		28	80	15	182	
2010	50		27	79	15	134	
2011			27		15	173	
2012			26		14	126	
2013			26		14	121	
2014			26		14		
2015			25		14		
2016			25		13		
2017					13		
Average	48	76	28	88	15	155	409

Operating Expenses Used in Resource Insight's Analysis (1998$million)
Calculated as: Property Tax + O&M + Overheads + Capital Additions

	Arthur Kill	Astoria	Bowline	Ravenswood	Roseton	Indian Point 2	TOTAL
High Expenses Case	28	50	28	65	15	164	350
Base Expenses Case	24	42	24	54	13	129	286

Exhibit ____ PLC-8
Summary of Stranded Investment Estimates

	Source of Input Assumptions			Stranded Inestment
	Expenses	CF	Market Price	(PV $ Million)
Base Case	Base	Historical	RII	(532)
Sensitivity 1	Base	ConEd	RII	(264)
Sensitivity 2	High	Historical	RII	(80)
Sensitivity 3	Base	ConEd	Low Energy-Price	252
Sensitivity 4	High	ConEd	Low Energy-Price	637
Sensitivity 5	Base	Historical + optimal CogenTech	RII	(879)

Exhibit ____ PLC-8
Summary of ConEd Stranded Investment
Base Case: Base Expenses, Historical CF, RII Market Price

	Net Book	Present Value Operating Profit	Stranded Investment
In-City Reheat	$ 704,235,630	$ 2,373,699,108	$ (1,669,463,478)
Bowline	114,072,290	226,490,778	(112,418,488)
Roseton	74,919,618	61,112,194	13,807,424
GTs	140,519,623	732,078,051	(591,558,428)
Total Fossil			**(2,359,632,970)**
Indian Point 2	466,931,946	147,481,038	319,450,908
Total Owned Plant			**(2,040,182,063)**
IPPs			1,508,618,586
TOTAL			$ (531,563,477)

Exhibit ____ PLC-8
Summary of ConEd Stranded Investment
Sensitivity 1: Base Expenses, ConEd CF, and RII Market Price

	Net Book	Present Value Operating Profit	Stranded Investment
In-City Reheat	$ 704,235,630	$ 2,110,778,636	$ (1,406,543,006)
Bowline	114,072,290	231,511,491	(117,439,201)
Roseton	74,919,618	51,399,376	23,520,242
GTs	140,519,623	732,078,051	(591,558,428)
Total Fossil			**(2,092,020,392)**
Indian Point 2	466,931,946	147,481,038	319,450,908
Total Owned Plant			**(1,772,569,485)**
IPPs			1,508,618,586
TOTAL			$ (263,950,899)

Exhibit ____ PLC-8

Summary of ConEd Stranded Investment
Sensitivity 2: High Expenses, Historical CF, and RII Market Price

	Net Book	Present Value Operating Profit	Stranded Investment
In-City Reheat	$ 704,235,630	$ 2,186,840,606	$ (1,482,604,976)
Bowline	114,072,290	197,523,508	(83,451,218)
Roseton	74,919,618	48,314,453	26,605,165
GTs	140,519,623	656,537,803	(516,018,180)
Total Fossil			**(2,055,469,209)**
Indian Point 2	466,931,946	(129,866,687)	466,931,946
Total Owned Plant			**(1,588,537,263)**
IPPs			1,508,618,586
TOTAL			$ (79,918,677)

Exhibit ____ PLC-8
Summary of ConEd Stranded Investment
Sensitivity 3: Base Expenses, ConEd CF, and Low Market Energy Price

	Net Book	Present Value Operating Profit	Stranded Investment
In-City Reheat	$ 704,235,630	$ 2,020,168,119	$ (1,315,932,489)
Bowline	114,072,290	202,967,833	(88,895,543)
Roseton	74,919,618	49,719,088	25,200,530
GTs	140,519,623	933,239,576	(792,719,953)
Total Fossil			**(2,172,347,454)**
Indian Point 2	466,931,946	80,711,214	386,220,732
Total Owned Plant			**(1,786,126,723)**
IPPs			2,038,397,340
TOTAL			$ 252,270,617

Exhibit ____ PLC-8

Summary of ConEd Stranded Investment

Sensitivity 4: High Expenses, ConEd CF, and Low Market Energy Price

	Net Book	Present Value Operating Profit	Stranded Investment
In-City Reheat	$ 704,235,630	$ 1,833,309,617	$ (1,129,073,987)
Bowline	114,072,290	174,000,563	(59,928,273)
Roseton	74,919,618	36,921,346	37,998,272
GTs	140,519,623	857,699,328	(717,179,705)
Total Fossil			**(1,868,183,693)**
Indian Point 2	466,931,946	(196,636,512)	466,931,946
Total Owned Plant			**(1,401,251,747)**
IPPs			2,038,397,340
TOTAL			$ 637,145,593

Exhibit ____ PLC-8
Summary of ConEd Stranded Investment
Sensitivity 5: Base Expns., Hist. CF but Optimal CogenTech, & RII Mkt. Price

	Net Book	Present Value Operating Profit	Stranded Investment
In-City Reheat	$ 704,235,630	$ 2,373,699,108	$ (1,669,463,478)
Bowline	114,072,290	226,490,778	(112,418,488)
Roseton	74,919,618	61,112,194	13,807,424
GTs	140,519,623	732,078,051	(591,558,428)
Total Fossil			**(2,359,632,970)**
Indian Point 2	466,931,946	147,481,038	319,450,908
Total Owned Plant			**(2,040,182,063)**
IPPs			1,161,332,422
TOTAL			$ (878,849,640)

Exhibit ____ PLC-9

Achievable Reductions to Electric Revenue Requirements
Under Base Case: Base Expenses, Historical CF, RII Market Price Case

Millions of Dollars

	1998	1999	2000	2001	2002
ConEd Retail Revenue Requirements	5,062	5,100	5,079	5,122	5,159
Reductions to Revenue Requirements					
Market Valuation and Amortization of Fossil / GT Restructuring Gain					
Remove assets from ratebase	(859)	(869)	(880)	(891)	(902)
Re-price output at market price	922	963	1,005	1,049	1,095
Amortize restructuring gain at ConEd COC	(510)	(481)	(452)	(423)	(395)
Subtotal	(447)	(388)	(327)	(265)	(201)
Market Valuation and Amortization of Indian Point 2 Stranded Cost					
Remove asset from ratebase	(315)	(316)	(318)	(319)	(320)
Re-price output at market price	197	220	244	270	297
Amortize stranded cost at ConEd COC	69	65	61	57	53
Subtotal	(49)	(31)	(12)	8	30
Market Valuation and Refinancing of IPP Stranded Cost					
Eliminate annual payments with buyout @ full cost	(855)	(878)	(841)	(868)	(887)
Re-price deliveries at market price	491	527	572	614	657
Finance stranded cost at ConEd COC	193	193	193	193	193
Subtotal	(172)	(158)	(77)	(61)	(38)
Additional Reduction from Securitization of IPP Stranded Cost	(48)	(48)	(48)	(48)	(48)
Total Reduction to Revenue Requirement	(716)	(624)	(463)	(365)	(257)
Revised Revenue Requirement	4,347	4,476	4,616	4,757	4,902
Percentage Reduction	(14.1%)	(12.2%)	(9.1%)	(7.1%)	(5.0%)
Levelized Revenue Requirement	4,593				
First-Year Rate Reduction	(9.3%)				

Exhibit _____ PLC-9
Achievable Reductions to Electric Revenue Requirements
Under Sensitivity 4: High Expenses, ConEd CF, and Low Market Energy Price Case
Millions of Dollars

	1998	1999	2000	2001	2002
ConEd Retail Revenue Requirements	5,062	5,100	5,079	5,122	5,159
Reductions to Revenue Requirements					
Market Valuation and Amortization of Fossil / GT Restructuring Gain					
Remove assets from ratebase	(859)	(869)	(880)	(891)	(902)
Re-price output at market price	975	1,025	1,101	1,164	1,238
Amortize restructuring gain at ConEd COC	(404)	(381)	(358)	(335)	(312)
Subtotal	(287)	(225)	(137)	(62)	24
Market Valuation and Amortization of Indian Point 2 Stranded Cost					
Remove asset from ratebase	(315)	(316)	(318)	(319)	(320)
Re-price output at market price	197	217	237	259	281
Amortize stranded cost at ConEd COC	101	95	89	84	78
Subtotal	(17)	(4)	9	24	39
Market Valuation and Refinancing of IPP Stranded Cost					
Eliminate annual payments with buyout @ full cost	(855)	(878)	(841)	(868)	(887)
Re-price deliveries at market price	476	508	546	582	619
Finance stranded cost at ConEd COC	260	260	260	260	260
Subtotal	(119)	(110)	(35)	(25)	(8)
Additional Reduction from Securitization of IPP Stranded Cost	(64)	(64)	(64)	(64)	(64)
Total Reduction to Revenue Requirement	(488)	(404)	(227)	(128)	(10)
Revised Revenue Requirement	4,574	4,696	4,852	4,994	5,149
Percentage Reduction	(9.6%)	(7.9%)	(4.5%)	(2.5%)	(0.2%)
Levelized Revenue Requirement	4,826				
First-Year Rate Reduction	(4.7%)				

Exhibit ____ PLC-9
Achievable Reductions to Electric Revenue Requirements Using ConEd's Straned Cost Estimates
Millions of Dollars

	1998	1999	2000	2001	2002
ConEd Retail Revenue Requirements	5,031	5,070	5,052	5,099	5,138
Reductions to Revenue Requirements					
Market Valuation and Amortization of Fossil / GT Restructuring Gain					
Remove assets from ratebase	(859)	(869)	(880)	(891)	(902)
Re-price output at market price	893	889	886	887	888
Amortize restructuring gain at ConEd COC	(30)	(28)	(26)	(25)	(23)
Subtotal	4	(8)	(21)	(28)	(36)
Market Valuation and Amortization of Indian Point 2 Stranded Cost					
Remove asset from ratebase	(315)	(316)	(318)	(319)	(320)
Re-price output at market price	197	211	219	234	240
Amortize stranded cost at ConEd COC	107	101	95	89	83
Subtotal	(11)	(4)	(4)	4	3
Market Valuation and Refinancing of IPP Stranded Cost					
Eliminate annual payments with buyout @ full cost	(825)	(848)	(814)	(844)	(867)
Re-price deliveries at market price	410	431	448	469	487
Finance stranded cost at ConEd COC	437	437	437	437	437
Subtotal	23	20	71	61	58
Additional Reduction from Securitization of IPP Stranded Cost	(108)	(108)	(108)	(108)	(108)
Total Reduction to Revenue Requirement	(92)	(101)	(61)	(71)	(84)
Revised Revenue Requirement	4,939	4,969	4,991	5,028	5,054
Percentage Reduction	(1.8%)	(2.0%)	(1.2%)	(1.4%)	(1.6%)
Levelized Revenue Requirement	4,991				
First-Year Rate Reduction	(0.8%)				

Exhibit ____ PLC-9
ConEd's Stranded Cost Estimates

	Net Book	Present Value Operating Profit	Stranded Investment
In-City Reheat	$ 684,019,167	$ 538,382,167	$ 145,637,000
Bowline	117,999,401	31,446,401	86,553,000
Roseton	77,500,539	15,684,539	61,816,000
GTs	140,519,623	571,298,254	(430,778,631)
Total Fossil			**(136,772,631)**
Indian Point 2	508,999,982	14,214,982	494,785,000
Total Owned Plant			**358,012,369**
IPPs			3,421,000,000
TOTAL			$ 3,779,012,369