STATE OF NEW YORK

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of Consolidated Edison	)	
Company of New York, Inc.'s Plans for	)	**Case No. 00-E-1208**
Electric Rate Restructuring With Respect to	)	
Service Provided in Westchester County	)	

DIRECT TESTIMONY OF

PAUL CHERNICK

ON BEHALF OF

THE CITY OF NEW YORK

Resource Insight, Inc.

OCTOBER 15, 2001

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I. Identification and Qualifications

Q: State your name, occupation and business address.

A: I am Paul L. Chernick. I am the president of Resource Insight, Inc., 347 Broadway, Cambridge, Massachusetts 02139.

Q: Please summarize your professional education and experience.

A: I received a Bachelor's degree from the Massachusetts Institute of Technology in June, 1974 from the Civil Engineering Department, and a Master's 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. In these capacities, I have advised a variety of clients on utility matters. My work has considered, among other things, power supply planning, rate design, cost allocation, and utility industry restructuring. 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 seventy 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, 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, Pennsylvania Public Utilities Commission, New York Public Service Commission, Arizona Commerce Commission, New Orleans City Council, Federal Energy Regulatory Commission, and the Atomic Safety and Licensing Board of the U.S. Nuclear Regulatory Commission. My resume includes a detailed list of my previous testimony.

Q: Have you testified previously before this Commission?

A: Yes. I testified in

- Case No. 96-E-0897, on the electric restructuring plan of the Consolidated Edison Company of New York, Inc. ("Con Edison" or "the Company").
- Case No. 99-W-0658, on the rates of United Water New Rochelle.
- Case No. 99-S-1621, on the Con Edison's steam rates.

II. Introduction and Summary

Q: On whose behalf are you testifying in this proceeding?

A: I am testifying on behalf of the City of New York .

Q: What is the purpose of your testimony?

A: I have been asked to testify on the propriety of Con Edison's current practice for allocating its projected Monthly Adjustment Charge (MAC), which recovers the Company's stranded costs. As ordered by the Commission, the Company sets one value for the MAC for customers in New York City and a different value for Con Edison's customers in Westchester County.[1] Con Edison sets the MACs for the two regions so that the difference between MACs is equal to, and of opposite sign from, the difference in Con Edison's Market Supply Charge (MSC) for the two regions. Since the rest of Con Edison's rates are equal for customers across its territory, this policy produces equal total rates for the two regions.

Q: Please provide an overview of the scope of your testimony.

A: I start by considering the policy rationale for equal (or postage-stamp) total rates across Con Edison's service territory, and for using the stranded costs in the MAC to maintain equal total rates. I go on to respond to the Commission's decision that this:

> proceeding will examine whether stranded costs are higher for Westchester customers as a result of lower market values of energy and capacity in Westchester and whether a cost basis exists for different delivery rates in Westchester and New York City. (Case 96-E-0897, Order of November 30, 2000).

I discuss both the effect of market prices in the two regions on stranded costs, and the effect of the resources with stranded costs on market prices in the two regions.

Q: Please summarize your conclusions with regard to the policy issues.

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[1]Order Concerning Retail Access Implementation Plan-Phase 3, Case 96-E-0897, February 28, 2000. Those two areas make up all of Con Edison's service territory.

A: I conclude that Con Edison's current practice for allocating the MAC is appropriate for the following policy reasons:

- There is a strong historical preference for uniform pricing across a utility's service territory.
- The New York market for generation and transmission services is not yet "workably competitive," as defined in the Recommended Decision in Case 00-M-0504 (July 13, 2001) at 36, note 64.
- The differentials in regional market prices for energy and capacity are largely the legacy of regulation, in which average costs, not marginal costs, determined charges to ratepayers, and in which all customers paid the same average costs for generation services. Under this regulated regime, Con Edison did not receive adequate price signals to build new in-City generation or transmission lines into the City.
- Stranded costs are a legacy of the regulated generation market, and those costs may be reasonably used to offset regional differentials in market prices that result from regulation.
- Abandoning Con Edison's current practice of uniform generation rates across its service territory would shift roughly $100 million in annual electric costs onto New York City at a difficult time for the City, its residents and businesses.

Q: What factors should the Commission evaluate if it decides to allocate stranded costs equally throughout a service territory, without regard to locational market prices?

A: Such a potentially important policy change should be preceded by a careful analysis of the extent to which market prices in each region reduce stranded costs, and the extent to which the generation resources that produce stranded costs reduced market prices for energy and capacity in the various regions. As I discuss below, my analysis of these factors indicates that a detailed and equitable allocation of Con Edison's stranded costs by region would produce results very similar to those of the current practices.

The Commission should not arbitrarily reallocate one set of costs without considering whether other costs vary across portions of a utility's territory. For example, before imposing different total generation costs across regions, the Commission should revisit its 1982 finding that distribution investment per kilowatt-hour of sales is higher in Westchester than in New York City, and determine whether distribution rates should also be disaggregated across the service territory. In a slightly different situation, Baumol cautions (at 30):

> Over the whole…there looms most menacingly the injunction of the second best: Thou shalt not optimize piecemeal.…[O]ne should shun piecemeal ameliorative measures that have not been sanctioned by careful analysis and the liberal use of common sense.[2]

Q: Please summarize your analytical conclusions on the allocation of the MAC costs.

A: As described in §IV below, I conclude that the annual MAC, as projected by Con Edison over the last twelve months, was reduced about $164 million because market prices in the City are higher than those in Westchester. In addition, as I describe in §V below, Con Edison's base rates were reduced by approximately $120 million, due to the higher proceeds from the sale of the divested in-City plants that resulted from the higher in-City market prices. Of this total $284-million reduction in total stranded costs attributable to the

[2]Baumol, William. 1965. *Welfare Economics and the Theory of the State* 2nd Ed. Cambridge: Harvard University Press.

higher prices in the City, approximately $41 million in benefits flows annually to Westchester.

In addition, the presence of Con Edison's upstate generation, in excess of Westchester's load, reduces Westchester's costs relative to the City by about $20 million annually for energy costs and $38 million for capacity, for a total of $58 million of additional annual benefits to Westchester.

A detailed allocation of stranded costs through the MAC, recognizing (a) the role of New York City's market prices in reducing stranded costs and (b) the extra benefits to Westchester of Con Edison's upstate NUG capacity, would allocate about $100 million more to Westchester than a straight energy allocation. This value is approximately equal to the difference between Westchester's MAC charges under the current system and what it would pay under a uniform allocation of stranded costs. Consequently, the current system results in a fair allocation of stranded costs, without requiring the periodic detailed analyses entailed in a fully cost-based approach.

Q: What is your recommendation?

A: I recommend that the Commission retain the current mechanism for coordinating the recovery of stranded costs in the MAC with the market cost of power in the MSC. That approach is consistent with ratemaking practice in other areas of New York State and would produce approximately the same results as the detailed allocation of MAC costs I develop below. It also would maintain postage-stamp rates and provide rate stability for Con Edison customers, shielding them from the volatility in market prices in the initial development of a deregulated generation market that is still far from workably competitive.

In any case, the Commission should not authorize a change in the current MAC practice without recognizing the following:

- any difference in distribution costs that may be revealed in an update to the 1982 regional cost-of-service study;
- different contributions of the two regions to reducing stranded costs;
- the additional benefits to Westchester due to Con Edison's decisions (understandable under the circumstances) to locate so much of its capacity upstate, rather than in the City.

As I demonstrate in this testimony, the estimation of regional contributions and benefits would be more complex than the simpler existing approach, while probably yielding similar results.

As a competitive market emerges, including the construction of new generation and new transmission capacity, the MSC differentials should decline, phasing out the MAC differentials consistent with the development of a competitive market.

III. Policy Considerations

A. History of Regional Rate Design

Q: What has the practice of the New York Public Service Commission been regarding the pricing of utility service in different parts of a utility's service territory?

A: In general, regulators have set prices equal in different parts of a utility's territory within a jurisdiction, even if the costs of service or revenue requirements vary across the territory. The portions of a utility's territory in different jurisdictions may have different rates, and different subsidiaries of a holding company may have different rates, but the rates of a specific utility rarely vary with location. So far as I have been able to determine, the Commission has followed this practice.

Q: Has this been true for the Commission's treatment of Con Edison's rates?

A: Yes. Con Edison's rates by class have historically been the same for each type of customer, regardless of the density of the load or other factors that might make costs vary from Westchester, to Manhattan, to Queens, to Staten Island. Indeed, even when the Commission Staff found in a 1982 study that the costs of distribution plant per kWh of sales was significantly greater in Westchester than in the City, the Commission did not reduce in-City delivery rates. Instead, it continued equal total rates.[3]

Similarly, the Commission has applied postage-stamp rates in the more widely diverse service territories of Niagara Mohawk and New York State Electric & Gas ("NYSEG"), which serve multiple discontiguous districts scattered from Lake Erie to the Hudson. Customers in part of Westchester benefit from the Commission's decision to retain postage-stamp rates across NYSEG's service territory.

[3]The Commission rejected the conclusions of the study on the grounds that the load data used to allocate generation and transmission costs were based on single monthly peaks, rather than the average of four peaks used in the Company's other cost allocation studies. However, the Commission did not appear to be sufficiently interested in pursuing the large differences in distribution costs per unit of sales indicated by the study (and not affected by the load data) to order Con Edison to develop the additional load data needed to determine whether disparate locational delivery rates were appropriate.

Q: How has the Commission treated geographic differences in wholesale power supply costs created by its first steps towards a deregulated market?

A: The Commission has maintained the traditional postage-stamp pricing. For Con Edison, NYSEG and NiMo, the Commission has allowed power supply costs to vary between zones, while keeping the total tariff approximately the same for all customers in a rate class. The varying costs of power supply are offset by variations in recovery of other costs. In the Con Edison and NiMo tariffs, the recovery of stranded costs (in Con Edison's Monthly Adjustment Charge or NiMo's Competitive Transition Charge) is explicitly adjusted to maintain equalized rates between zones. NYSEG's tariffs are not unbundled; NYSEG simply charges all customers the same total rates, and ignores the differences in market prices across zones. NYSEG credits each customer purchasing from a third-party supplier with a retail-access credit reflecting the customer's zone, resulting in larger delivery charges for customers in low-cost zones than those in high-cost zones.[4]

This approach allows generation prices to be set at market prices, facilitating competition, without violating the historical preference for postage-stamp rates. It is also consistent with allocation of the MAC between classes. Each class pays the share of generation costs that regulation allocated (net of any subsequent rate reductions); each class's MSC is set by market prices, and its MAC is the difference between the class's total generation costs and the MSC.

[4]For NiMo and Con Edison, the total rates charged may vary somewhat across zones, due to different schedules for truing up the zonal power-supply and stranded-cost charges.

Q: What are your conclusions regarding the Commission's practice of maintaining equal total rates across its service territory?

A: The practice has provided rate stability for customers located throughout a utility's service territory and should not be discarded lightly. It would be incongruous to maintain this practice throughout New York State *except* in Con Edison's service territory.

B. Geographically Uniform Rates in the Transitional Market

Q: Does the current state of deregulation and competition in the electric industry in New York State justify abandonment of postage-stamp rates?

A: No. The restructuring of the industry to date is only the beginning of a process that can lead to a competitive market that may operate under different rules. The end of that process would entail the following:

- A workably competitive market for generation supply, including the construction and operation of new generation (particularly in New York City) in response to price signals that did not exist under regulation.
- Transmission infrastructure that has adapted to the competitive market, including the addition of capacity in response to generation market prices, either through competitive development or market-responsive regulation.
- The limitation of retail rates to competitive charges for generation service, and regulated charges for distribution services and related system benefit charges. Since stranded costs are a legacy of regulation, they will disappear in a fully competitive market.

Until the market is fully competitive, there is no basis for deviating from postage-stamp rates. The current situation is still far removed from full competition, since

- the generation market is not yet competitive.
- the transmission market is not yet competitive.
- locational market costs still reflect decisions made over a period of decades, under regulation, in the absence of locational price signals.
- Con Edison is still recovering stranded costs, which are legacies of the regulated generation market.

Q: Is there any regulatory support for your conclusion that New York's electric market is not yet workably competitive?

A: Yes. The Recommended Decision in the Commission's competition proceeding found that New York does not meet the criteria for "workably competitive markets," defined as "retail and wholesale markets, uninfluenced by the exercise of market power, where customers have a variety of supplier choices and the choice of a number of different products" (Case 00-M-0504, July 13, 2001, at 36, note 64). The Recommended Decision attributes the lack of workable competition to a variety of problems:

> The existing flaws in the operation of the wholesale market, the inadequacy of transmission (gas and electric), and the lack of adequate generation reserves must be solved before robust retail competition can be expected. On the electric side, more generation must be built, more aggressive action needs to be taken to reinforce the transmission system, and demand side market creation and numerous other issues at the ISO need to be resolved. (Case 00-M-0504, Recommended Decision, July 13, 2001, at 32–33)

In implementing the various bid-cap and price-cap mechanisms that are in place currently, FERC has also concluded that competition in the New York electric market is not yet sufficient to maintain just and reasonable prices.

1. Absence of Workable Competition

Q: Why do you say that the generation markets are not yet workably competitive?

A: Several considerations indicate that the NY ISO generation markets have not yet become fully competitive.

- The Federal Energy Regulatory Commission has found in particular that a competitive generation market does not exist in New York City, and, in general, that regulating market power in the newly deregulated market is a serious concern that requires further investigation.[5]
- The electric market in New York City is still operating with a continuously effective cap on capacity bids and a frequently binding cap on energy bids.
- Energy prices in the entire state market are subject to less frequent but occasional price controls.
- Notwithstanding these controls, prices still substantially exceed marginal costs during many hours of the year, demonstrating that the limited price controls in effect do not prevent above market pricing.
- No major merchant plants have been added since restructuring. The first such plants, Athens (located near Albany) and the 250-MW Ravenswood cogeneration plant in New York City, are scheduled for operation in 2003; several new projects would enter service in 2004.
- Once a sufficient amount of new generation is completed in New York City and on Long Island (which currently has higher market energy

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[5](Con Edison, 96 FERC ¶ 61,095 (2001)); untitled FERC Market Based Rate Options Paper, (October 2, 2001) available from FERC's web page www.ferc.gov/Public.pdf (October 12, 2001).

prices than New York City and is a net importer from the City, further increasing in-City market-clearing prices), the differentials in capacity and energy costs between Westchester and the City will tend to decrease or disappear.

Q: Why do you say that the transmission market is not yet competitive?

A: As I discuss above, the economics of transmission constraints have changed dramatically from the average-cost world of regulated generation charges to the marginal-cost world of the restructured generation market. Constraints that had little effect on average costs can have large effects on marginal costs. The transmission owners have not yet expanded transmission capacity to reflect the new realities.[6]

In addition to competition in the generation market, restructuring of electric utilities has created the possibility of competition in construction of new transmission lines. Much of the interest in merchant transmission has focused on transmission into New York City and Long Island, with proposed projects totaling about 8,000 MW:

- 600 MW of transmission from Linden, New Jersey, to the Farragut Station in New York City (Neptune Phase 1, 2003).
- 600 MW of transmission from Red Bank, New Jersey, to Long Island (Neptune Phase 1, 2003).
- 600 MW from New Haven to Long Island (TransÉnergie's Cross-Sound Cable, 2004)
- 990 MW HVDC connection from PJM to West 49th Street and/or Farragut (TransÉnergie, 2003)

[6]This inaction is not surprising, considering how little time has passed since the beginning of the transition to competition, and continuing uncertainties regarding cost recovery.

- 330 to 660 MW from Norwalk to Shore Road on Long Island (Northeast Utilities' Connecticut–Long Island DC Cable, May 2004).
- Replacement of the existing Northeast cable from Connecticut to Long Island, to restore the design capacity of 283 MW.[7]
- As much as 1,200 MW of transmission from Bergen Station in Ridgefield, New Jersey, to West 49th Street (PSEG Power's Cross-Hudson project, 2003 or 2004).[8]
- 1,200 MW of transmission from New Brunswick, Canada to the Farragut Station in New York City (Neptune Phase 2, 2004).
- 1,200 MW of transmission from Linden to West 49th Street (PG&E National Energy's Jupiter line, 2004).
- 1,200 MW of Neptune transmission from Nova Scotia to Long Island and Boston to Long Island (Neptune Phase 3, 2005).
- 2,400 MW HVDC connection from NYPA's upstate Marcy station to West 49th Street (Arcadian's East Coast HVDC, 2005)
- Connections from Maine and Connecticut to the remainder of the Neptune system, allowing further transfers from New England to New York City and Long Island.

These transmission projects would have been of much less interest to the regulated, vertically integrated utilities, which lacked locational marginal-cost price signals.[9] Also, as the FERC has recognized, the lack of regional

[7]This is a regulated line.

[8]PSEG Power has asked the NY ISO to conduct an interconnection study for up to 2,500 MW.

[9]In recent years, the uncertainties surrounding the development of competitive markets and regional rules for recovery of transmission costs may also have discouraged development of this type of project, by utilities or merchant developers.

transmission planning also perpetuated transmission constraints that spanned more than one service territory. Once a regional merchant transmission market is fully functional, addition of these lines, or similar connections, will help produce a workably competitive market in New York City and will reduce the differential between energy prices in the City and those in Westchester.

Q: **How should the absence of workably competitive generation and transmission markets affect the Commission's determination here?**

A: Workably competitive markets will reduce the magnitude of the differences between market prices in New York City and those in Westchester. Until reasonably robust competition exists, supply options for Con Edison and its customers are essentially limited to the facilities developed under average-cost regulation. Discarding historical ratemaking before the supply markets are workably competitive would expose customers to variations in locational prices without either the old protection (averaging of total costs) or the new protection (competitive incentives to expand service in high-cost areas).

2. Differences in Market Supply Costs are Legacies of the Regulated Market

Q: Why do market supply costs vary between portions of Con Edison's service territory?

A: Prices are lower in Zones H and I (Westchester County) than in Zone J (New York City) due to historical decisions about construction of power plants and transmission lines. There is a large amount of generation in Zone H (mostly the Indian Point nuclear units) and further north, and transmission connections from upstate to Zone H, and Zone H to Zone I, are relatively robust. Hence, relatively inexpensive energy tends to be available to set the locational-based marginal price (LBMP) in Westchester, and Westchester's capacity requirements can be met by generation anywhere in the New York ISO region.[10]

The situation in New York City is significantly different. The City does not have enough generation to serve its load, and the installed transmission equipment is able to import only a fraction of the City's load. The zonal loads, generation capacity, and import capabilities are summarized in the following table.[11]

Zone	Capacity (Summer MW)	Load (MW)	Import Capability (MW)	Ratio to Load	
				Capacity	*Capacity + Imports*
A	5,001	3,184	3,300	1.57	2.61
B	823	1,564	3,900	0.53	3.02
C	6,111	2,975	3,770	2.05	3.32
D	1,361	1,053	3,950	1.29	5.04
E	279	1,735	10,770	0.16	6.37
F	2,421	2,555	6,070	0.95	3.32
G	3,553	2,408	9,370	1.48	5.37
H	1,948	188	7,600	10.36	50.79
I	2	1,196	10,950	0.00	9.16
Westchester	1,950	1,384	7,600	1.41	6.90
J—NYC	7,808	10,340	5,200	0.76	1.26
K—Long Island	4,363	4,500	1,650	0.97	1.34

[10]Due to the large amount of transmission connecting them, energy prices in Zone H and Zone I are very similar, and capacity prices are identical. Capacity in the City has increased since this report, due to the addition of the NYPA combustion turbines and Con Edison's reactivation of the Hudson Avenue generator.

[11]The data are taken from "Locational Requirements Study Covering the New York Control Area for the 2000–2001 Capability Year," New York ISO, May 22, 2000.

Relative to load, Westchester has both more internal generation and better access to upstate generation than does the City. In addition, Long Island has insufficient local capacity and little import capability from upstate or New England, and tends to draw power from the City, further increasing in-City prices.

The table does not show that the generation available to Westchester includes much of the lowest-cost energy in New York State, including the Indian Point nuclear plant, other nuclear and coal-fired generation, and coal-fired imports from Pennsylvania and the Midwest. New York City, on the other hand, is more dependent on its local generation, much of which is older boiler plants burning oil and gas, and old combustion turbines.

Q: How does this disparity of supply affect the MSCs for Westchester and New York City?

A: In at least two ways. First, Westchester's capacity requirements are entirely supplied by the statewide market, in which there are many participants and adequate supply. Statewide generation capacity prices have generally been about $1–2/kW-month, although for a couple months in 2001 they increased to $5–7/kW-month as supply tightened. Due to the inadequacy of transmission capacity, entities serving loads in the City must provide 80% of peak load from in-City generation resources; that market is very tight, and the price has consistently been pegged to the regulated maximum of $8.75/kW-month.

Second, Westchester loads are met by local generation with low fuel cost, and by imports from other zones. At many times, transmission limits prevent enough of that lower-cost energy from flowing into the City to serve the City's load economically, and the market-clearing price in the City is set by higher-cost local oil and gas plants.

Q: Why did the regulatory structure allow these vast disparities in access to generation and transmission?

A: Under regulation, the disparity of access was not important. All of Con Edison's customers were charged for the same generation energy and capacity, and the same distribution equipment, regardless of location. And generation prices were based on average costs, not on marginal market-clearing prices. In planning its system, Con Edison considered only total costs of providing services, not the effect of locational decisions on market price.

The average costs of generation supply to Westchester and New York City are not nearly so different as the marginal costs. With regulated generation supply, if 90% of the energy flowing into the City in an hour cost \$20/MWh, and the remainder cost \$50/MWh, customers paid \$23/MWh; with LBMP, they pay \$50/MWh for the same energy supply.

Consequently, when Con Edison as an integrated company compared options to upstate generation, such as participating in Roseton and Bowline, or purchasing power from Sithe and Selkirk, to adding its own new units in the City, or encouraging further in-City NUG development, the location of the units made little difference. And so long as power supply was reliable, the inability of the transmission system to carry all the low-cost power available in Westchester on into the City was not particularly important.

Using locational market prices without offsetting differences in locational stranded costs charges would now impose additional costs on New York City customers as a result of past siting decisions that were made in a different world with different incentives. This approach would be fundamentally unfair.

Q: Were there other considerations that led to the current situation?

A: Yes. It is my understanding that opposition to new power lines by residents and governments in Westchester also discouraged Con Edison from expanding transmission capacity into the City. Westchester County is opposing the proposed Millennium pipeline, which would bring gas through Westchester County to, among other things, power the new in-City generation that would reduce the differential in market prices. The more-visible transmission lines usually provoke more opposition than do gas pipelines. Even now, when many transmission projects have been put forth, no company is proposing to build a new transmission line through Westchester to New York City.[12] As I explain above, those transmission limitations had much smaller economic consequences prior to restructuring.

Q: How should the Commission take the historical legacy of geographical variation in market supply costs into account in this proceeding?

A: The Commission should not change the allocation of stranded-cost recovery until the market supply costs have been able to respond to the changes in market structure, which will take at least four years, according to the Recommended Decision in the competition proceeding (Case 00-M-0504, op. cit., at 66). Even after that, the Commission should not reallocate the MAC without incorporating the cost-based considerations in that are discussed in the second half of my testimony.

[12] I have not been able to determine the proposed routing of the Arcadia line from Marcy.

3. Stranded Costs Are Legacies of the Regulated Market

Q: Why does Con Edison have stranded costs to recover from ratepayers?

A: The stranded costs result primarily from long-term power-supply commitments (construction and purchases) made to serve customers under regulation. Power-supply commitments made since restructuring have been short-term and low-risk from the perspective of Con Edison; long-term commitments are made by developers and other parties in the competitive generation market. If those commitments turn out to be above market price in the longer term, the costs will not be borne by ratepayers. On the other hand, if today's commitments are below future market prices, ratepayers will not get the benefits of the low-cost resources, either.

C. Allocation of Stranded Costs

Q: You discussed above the historical preference for equal pricing of utility services across the territory of a particular utility, and the geographic variation of market costs for generation services. Is the allocation of stranded costs driven by the factors affecting either of these standards?

A: No. Stranded costs are not costs of providing service, and are not caused by any current user. They are legacies of past decisions and historical events, such as the decline in the costs of new generation. Unlike total utility-service costs, there is no long history of ratemaking for stranded costs, and no tradition of geographic uniformity. Unlike market costs of generation, stranded costs are not created by the loads of particular customers.

Q: How should stranded costs be allocated across geographical regions within a utility?

A: The simplest approach to cost allocation is to maintain postage-stamp total rates, so long as stranded costs remain to be collected. Any difference in market prices across regions would be offset by a counterbalancing difference in stranded-cost recovery. This is the approach taken to date for all three New York utilities with service territories that span ISO zones with significantly different market prices.

IV. New York City's Extra Contribution to Reducing Stranded Costs

Q: If the Commission chose to abandon the current method of setting regional values for the MAC, what principles should it follow in allocating stranded costs between regions?

A: If stranded costs are to be allocated to geographic regions, the allocation must reflect differences in how much various areas contribute to reducing stranded costs by paying higher market prices, and to reflect the differential regional benefits of the resources with stranded costs. This process would include the allocation of the benefits of high market prices (i.e., reduction in stranded costs) to the areas that pay those higher market prices. It would allocate to the beneficiaries the stranded costs of resources that contribute to the disparity in market prices. This alternative would result in total rates that would be more uniform across regions than those produced by an equal energy allocation of stranded costs, but would not necessarily result in equal rates across regions.

Q: Please describe the possible allocation of stranded costs in more detail.

A: Many stranded costs, including the bulk of Con Edison's stranded costs, are associated with operating generation resources, either utility-owned plants or NUGs. The resources may still be owned or controlled by the utility, or they may have been transferred to a third party. The stranded cost of such a resource is the difference between its total cost and the value of the associated energy and capacity in the market. Two cost-based allocations can be applied to these resources, as follows:

First, the customers and loads who pay the market prices that reduce stranded costs should receive the benefits of those reductions.

Second, to the extent that these resources result in lower market prices of generation services for one group of customers or loads than another, the group that receives the benefit of the lower market prices should pay the stranded costs.

Q: Why should the customers who pay the market prices that reduce stranded costs receive the benefits of those reductions?

A: Such a matching of costs and benefits would ensure that no group of customers should suffer or benefit perversely from the market conditions born by another group of customers.

For example, suppose that there are two groups of customers, each of equal load, who would have been allocated the same cost of a Resource X, say, 8¢/kWh. This resource is located in Area A, as is customer Group A, and provides half of the energy required by the utility's customers. The remaining energy is purchased from the market. Under regulation, if market prices were 5¢/kWh, all customers would pay 6.5¢/kWh for power.

In the restructured market, not much changes, so long as market prices remain 5¢/kWh for all customers. Stranded costs would be 3¢/kWh from resource X, or 1.5¢/kWh of customer use (since resource X generates half as much energy as the customers use). Both groups pay the market price of 5¢, plus the stranded cost of 1.5¢, or 6.5¢/kWh. This is the expected result with restructuring; so long as the cost or operation of the resource does not change, the total cost power supply to customers does not change.[13] Restructuring does not harm either group of customers.

Now suppose that market prices in Area A for the output of resource X, and the market prices paid by Group A rise to 7¢/kWh, while market prices paid by Group B remain at 5¢/kWh. Stranded costs would be reduced to 1¢/kWh generated, or 0.5¢/kWh of customer usage. If the stranded costs were allocated equally across the groups, Group A would pay 7.5¢/kWh, while Group B would pay just 5.5¢/kWh.

Conversely, if market prices in Area A fall to 3¢/kWh, stranded costs rise to 2.5¢/kWh of customer use. If the stranded costs were allocated equally across the groups, Group A would pay 5.5¢/kWh, while Group B would pay 7.5¢/kWh.

These results would be highly unfair. Group B would benefit from the misfortune of Group A, when prices in Area A rise, and would suffer when Group A is lucky enough to have market prices fall.

Q: How can this problem be avoided?

A: The decrease in stranded costs due to higher market prices can be directly assigned to the group that bears the costs of those prices. In this example, if market prices in Area A increased 2¢/kWh, the change in stranded costs could be allocated as a 2¢/kWh decrease to Group A (which just happens to use the same amount of energy generated by resource X). This would result in total charges of 6.5¢/kWh (7¢ market price offset by a negative 0.5¢ stranded cost), while Group B costs would remain unchanged, at the same 6.5¢/kWh (5¢ market price plus 1.5¢ stranded cost). A 2¢/kWh decrease in Area A

[13]Competition in the generation markets can result in reduction in costs for plants that are divested, and in entry of lower-cost new generation. It does not make fixed costs go away.

market prices would result in a 2¢/kWh increase in stranded costs to Group A, again leaving Group B unaffected.

This outcome is entirely equitable: Group B is neither helped nor harmed by changes in the Area A market prices, which they do not bear. Changes in market prices for Group A are offset by changes in stranded costs.[14]

The current MAC ratemaking treatment of the retained generation and NUG purchases was set up to ensure that increases in market prices would be offset by reductions in stranded costs due to the higher market prices received by the retained resource. To the extent that market prices paid by consumers differ between zones, the recovery of stranded costs should also vary.

Q: Why should the stranded costs of resources that result in lower market prices for one group of customers be charged to that group?

A: A generation resource can have two types of benefits for electric customers. It can produce energy and capacity to sell into the market, directly offsetting stranded costs. It can also reduce market energy and capacity prices by increasing the amount of supply in a region. Where a resource has stranded costs yet contributes to pushing the market price for power for one group of a utility's customers below another's, those extra benefits should be applied to reducing the stranded costs, before they are split between the two groups of customers.

As noted above, geographical price disparities can be the legacy of decisions made under regulation. These price disparities should be mitigated, not exaggerated, by the allocation of stranded costs.

[14]Total rates just happen to be equal across regions in this example, due to my choice of the amount of generation from the resources associated with the stranded costs.

A. Non-Utility Generators and Retained Generation

Q: How does your first allocation principle apply to Con Edison's stranded costs?

A: Electricity customers in the New York City load pocket pay higher market prices for energy and capacity than customers in Westchester, whether through Con Edison's MSC or through a third-party load-serving entity purchasing power at market prices. The higher market prices that drive the MSC also increase revenues from Con Edison resources in New York City, reducing stranded costs compared to the levels that would apply if all of Con Edison's retained generation were upstate. This differential should be reflected in the allocation of stranded costs.

Q: What are the components of that differential?

A: The market prices of both energy and capacity are higher in New York City than in Westchester. Stranded costs are lower than they would be without the NYC load pocket by the difference between Zone J and Zones H & I prices for the units that deliver their power into the load pocket.

For energy, this value is the difference in the zonal energy prices times the energy delivered by the in-City generators. For capacity, it is the difference in the capacity price between the City and upstate, times the Company's capacity entitlement. Stranded costs of the in-City retained generation and NUGs are reduced by both of these differentials.

Q: What is the extent of the reduction in stranded costs due to higher market energy prices in New York City than in Westchester?

A: The exact value of the reduction varies by month, and is different between the projections used in establishing Con Edison's MAC and the historical results for the same month. Con Edison's responses to discovery have not provided all the detail necessary to estimate the reduction in stranded costs due to the higher New York City market prices for all periods.

Con Edison has provided its projection of energy generation and market energy prices by region used in setting the MSC and MAC for May–October 2001. This projection probably understates the market value of the energy generated by the in-City retained generation, since it uses the same energy value per kWh for the peaking and intermediate retained generation as for the baseload NUGs. The projected differentials between the energy prices in New York City and Westchester vary from $5/MWh to $9/MWh. The difference in energy revenues due to the higher New York City prices range from $2.3 to $5.3 million per year, with a six-month total of $23.7 million; see Exhibit____PLC-2

Con Edison has not provided a similar summary of projected generation by unit for the period November 2000 to April 2001, but has provided projected market energy costs for that period (Response to City Question 13). Con Edison projected that in-City market prices would be $5/MWh greater than upstate prices throughout that period. Assuming the in-City generation provided the same 3,257 GWh of energy in that period as in the following summer period, the fact that in-City prices were higher than upstate prices reduced stranded costs by another $16.3 million, for an annual total of $40 million.

Q: What is the extent of the reduction in stranded costs due to higher market capacity prices in New York City than in Westchester?

A: The price of capacity in the City has been stuck at the $8.75/kW-month regulated cap throughout the period November 2000 through October 2001. For the MSC and MAC projections, Con Edison projected that the upstate price of capacity would be \$1.10/kW-month from November 2000 through April 2001, and \$2/kW-month from May 2001 through October 2001.[15] Thus, I estimate that the higher value of the capacity in New York City reduced stranded costs by \$124 million; see Exhibit____PLC-3.

B. Divested Generation

Q: Did the higher market energy and capacity costs in New York City affect the value of the divested plants in the City?

A: Yes. Con Edison undoubtedly received higher prices for the divested in-City generation (Arthur Kill, Astoria, Ravenswood, and most of the in-City combustion turbines), due to the higher market energy and capacity prices in the City. Con Edison's profit on these sales was reflected in rates for all electric customers in the recent rate settlement. It is important to recall that the in-City customers did not receive any greater rate reductions (to reflect the fact that the proceeds from the divestiture resulted from the high market prices in the City).

Q: How did you quantify the additional value of the in-City divested capacity, due to its location?

A: I assumed that the in-City reheat plants would have sold for the same price as the younger Bowline plant, and the in-City CTs for the same price as JCP&L's mostly CT capacity, except for the higher market prices in the City

[15]The actual market prices have been close to these projections in most months. The average upstate price averaged about \$2/kW-month from May 2000 to June 2001, even though prices in May and June 2001 were much higher. Upstate prices have returned to the \$2/kW-month range since June.

and for certain quantifiable cost differences.[16] The Bowline, JCP&L, and in-City sales were all announced within a four-month period, from 11/9/98 (JCP&L) to 3/3/99 (Astoria, the last of the in-City generation). In this approach, the load-pocket-related gain would be the difference in sales prices, plus the present value of the excess of O&M for the in-City reheat plants over the O&M for a like amount of Bowline.

I performed these computations, assuming that

- The 900 MW of JCP&L combustion turbines were as valuable per kilowatt as the 517 MW of steam and combined-cycle units sold in the same bundle. This is unlikely, since the steam and combined-cycle units are more expensive to build than CTs, have lower heat rates, and (for the steam units) burn much less expensive fuel.[17]
- There is no difference in property taxes between the City and adjacent regions.
- The difference between Bowline O&M reported by Con Edison and by O&R (the operator) represented overheads charged by O&R to Con Edison.[18]
- Overheads (to cover pensions, benefits, payroll taxes, insurance, legal expenses and the like) are 15% of O&M.
- The market valuation of the plants is based on twenty years of cash flow, and a discount rate of 10% real.

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[16]There were no sales in New York or New England that were dominated by combustion-turbine capacity.

[17]The table uses the average 1997 and 1998 O&M for the JCP&L combustion turbines.

[18]The table uses Bowline O&M reported by O&R, to make it comparable to the O&M reported for the Con Edison in-City plants.

The below table summarizes the results of these calculations.

	In-City Sales				
	Steam	*CTs*	*Total*	**Bowline**	**JCP&L**
MW	3,638	1,829	5,466	1,215	1,418
Price			$1,652M	$203M	$187M
$/kW			$302/kW	$167/kW	$132/kW
Out-of-City Comparables	$608M	$241M	$849M		
O&M ($/kW-yr.)	16.85	13.17		10.23	5.66
Difference ($/kW-yr.)	6.63	7.51			
Difference $M PV	$236 M	$135 M	$371 M		
Out-of-City Adjusted			$478 M		

The in-City generation sold for $1.65 billion; the price based on contemporaneous sales outside the City load pocket, for a like amount of capacity with the same high O&M, would be about $480 million. The $1,170-million difference in prices is attributable to the higher prices in the in-City load pocket. The $1,170 million in lost proceeds might equate to $120 million annually, depending on the ratemaking used, including the number of years over which the gain is amortized.

Q: Is this $1.17 billion in added value from Con Edison's in-City divestitures reasonable?

A: Yes. There is no way of knowing how the bidders evaluated future costs of operating the plants and future market prices. However, assuming a 20-year evaluation period and a 10% discount rate, a difference in market prices as small as $2.10/kW-month would produce a difference in value for these plants of about $1.17 billion.

C. Summary

Q: What is the total effect of the higher market prices in New York City on Con Edison's stranded costs?

A: The annual differences in stranded costs is roughly $284 million, comprising

- $40 million from the energy value of the retained generation and NUGs in the City.
- $124 million from the capacity value of the retained generation and NUGs in the City.
- $120 million from the value of the divested in-City generation, reflected in base rate reductions.

Q: What portion of this reduction in stranded costs flows to Con Edison's Westchester customers?

A: Westchester customers represent approximately 14.5% of Con Edison full-service sales.[19] Assuming that ratio holds for all customers, approximately $41 million of the annual reduction in stranded costs flows to Westchester.

Q: How does this compare to the amount of stranded costs that Westchester has been paying through the MAC, above the average Con Edison MAC?

A: In the period May–October 2001, for residential customers, the average difference between the Westchester MAC and the average MAC was about $15.8/MWh. Assuming that this differential was typical and that Westchester used 6.7 million MWh (14.5% of Con Edison 2000 sales and choice delivery), Westchester paid about $105 million more than the average MAC

[19] I computed this ratio from the sales in Con Edison file MSCMACMay00-Aug01.xls, provided in discovery. Other data that Con Edison has provided imply other ratios of Westchester load to total Con Edison load. In general, both the MAC charges to Westchester and the benefits to Westchester of higher in-City prices and extra upstate capacity scale with Westchester load. Consequently, the conclusions reached in my testimony should not be sensitive to the exact share of Con Edison load that is in Westchester.

value. The $41 million in reduced stranded costs was about 40% of the extra MAC charges to Westchester.

V. Extra Value of Up-State Generation to Westchester

Q: How does Con Edison's upstate generation capacity compare to its upstate load?

A: Con Edison has much more capacity upstate than it needs to meet the Westchester load, including roughly 1,139 MW of upstate combined-cycle cogeneration from Sithe, Selkirk, and Indeck, and 931 MW of baseload capacity in Westchester at Indian Point 2.[20] Con Edison also built 480 MW at Roseton and 800 MW at Bowline, which it has now sold.

When Con Edison made the decision to add these facilities, it reasonably anticipated that their location would have little effect on the prices paid by Con Edison customers. As I describe above, restructuring has changed all that. Each MW of capacity that Con Edison located upstate rather than in the City reduces capacity and energy prices in Westchester, while raising prices in New York City. This is true even though the generation Con Edison located upstate far exceeds Westchester load, and is true regardless of whether Con Edison still owns the generation.

These resources benefit Westchester electricity consumers much more than New York City electricity consumers, and the allocation of their stranded costs should recognize that fact. The existence of the transmission constraint disadvantages in-City electricity consumers, and benefits Westchester con-

[20]Indian Point 2 was treated as utility-owned in Con Edison's projections of the MAC differentials through October 2001, but has been sold to Entergy. Con Edison continues to pay for the plant's output, and Indian Point's costs are still in Con Edison's MAC computation.

sumers; it would not be reasonable to further disadvantage in-City consumers by charging them equally for upstate resources that they cannot fully utilize, due to that same transmission constraint.

Q: How much does the excess upstate generation capacity benefit Westchester consumers, compared to New York City consumers?

A: There are at least two ways to answer this question. First, in terms of the capacity markets, had even a relatively small fraction of Con Edison's excess upstate capacity not been built, the market would be deficient and the market value of upstate capacity would rise to whatever cap was imposed administratively. Assuming that cap was set at the in-City cap of $8.75/kW-month, Con Edison's total power supply costs would rise about $200 million.

Since Westchester uses about a third of the upstate capacity required for the Con Edison system, compared to about 14.5% of energy consumption, the excess upstate generation capacity disproportionately benefits Westchester customers. Without the extra upstate capacity, the MSC would rise in both Con Edison regions, but about 19% of the added costs would fall on Westchester, above the increase in the New York City MSC. So the excess upstate capacity saves Westchester about $38 million.

Another approach is to consider how much lower the City capacity price would have been had Con Edison built 1,000 MW of the upstate generation in the City. The Company might well have done so had it somehow foreseen restructuring and LBMP at the time it made its commitments to, for example, the upstate NUGs. The addition of 1,000 MW of generation in the City would increase capacity in excess of the 80% in-City capacity requirement, allowing the capacity market to clear at less than the regulatory cap. If the market price fell by just $3/kW-month, the capacity bill for City customers would fall by more than $200 million.

Q: What about energy benefits?

A: The magnitude of the benefits to Westchester of the upstate generation can be estimated from a couple of sources. First, a study performed by General Electric for the NY ISO estimated zonal market-clearing energy prices in 2003, 2005, and 2008 for several levels and geographical patterns of capacity additions.[21] Exhibit____PLC-4 summarizes General Electric's results for market-clearing energy prices for Westchester and New York City as a function of the net load growth in the City, on Long Island, and in the rest of the state.

For each additional 1,000 MW upstate, the City-Westchester price differential rises by $0.38/MWh, while each additional 1,000 MW in the City reduces the differential by $0.53/MWh. Under General Electric's assumptions, locating an extra 1,000 MW upstate, rather than in the City, reduces Westchester market energy costs, compared to City costs, by about $6 million annually.

A study for the proposed 1,000-MW Astoria Project, also using the MAPS model, estimated that the addition of the plant would reduce the differential in energy costs from New York City to Westchester from $1.1/MWh to $0.3/MWh, a decrease of $0.8/MWh.[22] This reduction is about

[21]Sanford, Mark, Venkat Banunarayan, and Kim Wirgau. 2000. "Implications of Capacity Additions in New York on Transmission System Adequacy, A MAPS study performed for New York Independent System Operator" Report performed by General Electric for the NY ISO, December 27, 2000.

[22]Tierney, Susan, and John Farr. 2000."Production Modeling for the Astoria Project: Report on Results." Cambridge, Mass.: Lexecon, Inc. June 14, 2000.

50% larger than the average relationship in the General Electric study, and may be more typical of the effect of the first new units in the City.

These results can be compared to the difference in zonal prices for the period in which Indian Point 2 was out of service—most of 2000—with the differences in 2001, when Indian Point 2 was back in service. From February to July 2000, the average differential was $1.73/MWh; from February to July 2001, the differential averaged $4.35/MWh, almost $3/MWh more. This is a much larger effect than in the ISO analysis, which assumes lower fuel prices and higher statewide reserve margins.

The comparison of market energy prices with and without Indian Point 2 indicates that having an extra 1,000 MW available upstate reduces Westchester energy costs about $20 million, in addition to any increase in City energy costs from failing to locate the generation in the City.

Q: What is the aggregate effect of the extra upstate capacity on the allocation of stranded costs to Westchester?

A: The reallocation of stranded costs to reflect the benefits of the extra upstate generation capacity would add about $38 million to Westchester's share for capacity, plus $20 million for energy, for a total of $58 million. Recognizing the increases in New York City costs due to the location of so much of Con Edison's capacity outside the City would justify shifting much greater costs to Westchester.

Adding in the $41 million of the City's extra contribution to reducing stranded costs (as I describe and quantify above), the differential in the allocation of stranded costs should be about $99 million. This result is essentially the same as my estimate of $105 million in Westchester's MAC payments in excess of the average MAC charges.

VI. Duration of the Differences in Market Service Charge

Q: Are the differences between the MSC in Westchester and in the City likely to persist?

A: No. They are likely to decline over time. The ISO study shows the energy-cost differentials dropping dramatically with higher reserve margins. With a 22% reserve margin, and 2,000 MW constructed in the City, the ISO study projects that the cost differentials would disappear. The Astoria analysis shows the energy-cost differentials falling to $0.3/MWh by 2004 with the addition of that one plant, even with the addition of about 5,000 MW of proposed upstate combined-cycle generation.

Addition of the proposed merchant transmission would also decrease the differentials.

Q: Does this conclude your testimony?

A: Yes.

Exhibit____PLC-1

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SUMMARY OF PROFESSIONAL EXPERIENCE

1986–Present **President, Resource Insight, Inc.** Consults and testifies in utility and insurance economics. Reviews utility supply-planning processes and outcomes: assesses prudence of prior power planning investment decisions, identifies excess generating capacity, analyzes effects of power-pool-pricing rules on equity and utility incentives. Reviews electric-utility rate design. Estimates magnitude and cost of future load growth. Designs and evaluates conservation programs for electric, natural-gas, and water utilities, including hook-up charges and conservation cost recovery mechanisms. Determines avoided costs due to cogenerators. Evaluates cogeneration rate risk. Negotiates cogeneration contracts. Reviews management and pricing of district heating systems. Determines fair profit margins for automobile and workers' compensation insurance lines, incorporating reward for risk, return on investments, and tax effects. Determines profitability of transportation services. Advises regulatory commissions in least-cost planning, rate design, and cost allocation.

1981–86 **Research Associate, Analysis and Inference, Inc.** (Consultant, 1980–81). Researched, advised, and testified in various aspects of utility and insurance regulation. Designed self-insurance pool for nuclear decommissioning; estimated probability and cost of insurable events, and rate levels; assessed alternative rate designs. Projected nuclear power plant construction, operation, and decommissioning costs. Assessed reasonableness of earlier estimates of nuclear power plant construction schedules and costs. Reviewed prudence of utility construction decisions. Consulted on utility rate-design issues, including small-power-producer rates; retail natural-gas rates; public-agency electric rates, and comprehensive electric-rate design for a regional power agency. Developed electricity cost allocations between customer classes. Reviewed district-heating-system efficiency. Proposed power-plant performance standards. Analyzed auto-insurance profit requirements. Designed utility-financed, decentralized conservation program. Analyzed cost-effectiveness of transmission lines.

1977–81 **Utility Rate Analyst, Massachusetts Attorney General.** Analyzed utility filings and prepared alternative proposals. Participated in rate negotiations, discovery, cross-examination, and briefing. Provided extensive expert testimony before various regulatory agencies. Topics included demand forecasting, rate design, marginal costs, time-of-use rates, reliability issues, power-pool operations, nuclear-power cost projections, power-plant cost-benefit analysis, energy conservation, and alternative-energy development.

EDUCATION

SM, Technology and Policy Program, Massachusetts Institute of Technology, February 1978.

SB, Civil Engineering Department, Massachusetts Institute of Technology, June 1974.

HONORS

Chi Epsilon (Civil Engineering)

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Institute Award, Institute of Public Utilities, 1981.

PUBLICATIONS

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"Power by Efficiency: An Assessment of Improving Electrical Efficiency to Meet Jamaica's Power Needs," (with Conservation Law Foundation, et al.), June 1990.

"Analysis of Fuel Substitution as an Electric Conservation Option," (with Ian Goodman and Eric Espenhorst), Boston Gas Company, December 22 1989.

"The Development of Consistent Estimates of Avoided Costs for Boston Gas Company, Boston Edison Company, and Massachusetts Electric Company" (with Eric Espenhorst), Boston Gas Company, December 22 1989.

"The Valuation of Externalities from Energy Production, Delivery, and Use: Fall 1989 Update" (with Emily Caverhill), Boston Gas Company, December 22 1989.

"Conservation Potential in the State of Minnesota," (with Ian Goodman) Minnesota Department of Public Service, June 16 1988.

"Review of NEPOOL Performance Incentive Program," Massachusetts Energy Facilities Siting Council, April 12 1988.

"Application of the DPU's Used-and-Useful Standard to Pilgrim 1" (With C. Wills and M. Meyer), Massachusetts Executive Office of Energy Resources, October 1987.

"Constructing a Supply Curve for Conservation: An Initial Examination of Issues and Methods," Massachusetts Energy Facilities Siting Council, June 1985.

"Final Report: Rate Design Analysis," Pacific Northwest Electric Power and Conservation Planning Council, December 18 1981.

PRESENTATIONS

"Distributed Utility Planning." With Steve Litkovitz. Presentation to the Vermont Distributed-Utility-Planning Collaborative, November 1999.

"The Economic and Environmental Benefits of Gas IRP: FERC 636 and Beyond." Presentation as part of the Ohio Office of Energy Efficiency's seminar, "Gas Utility Integrated Resource Planning," April 1994.

"Cost Recovery and Utility Incentives." Day-long presentation as part of the Demand-Side-Management Training Institute's workshop, "DSM for Public Interest Groups," October 1993.

"Cost Allocation for Utility Ratemaking." With Susan Geller. Day-long workshop for the staff of the Connecticut Department of Public Utility Control, October 1993.

"Comparing and Integrating DSM with Supply." Day-long presentation as part of the Demand-Side-Management Training Institute's workshop, "DSM for Public Interest Groups," October 1993.

"DSM Cost Recovery and Rate Impacts." Presentation as part of "Effective DSM Collaborative Processes," a week-long training session for Ohio DSM advocates sponsored by the Ohio Office of Energy Efficiency, August 1993.

"Cost-Effectiveness Analysis." Presentation as part of "Effective DSM Collaborative Processes," a week-long training session for Ohio DSM advocates sponsored by the Ohio Office of Energy Efficiency, August 1993.

"Environmental Externalities: Current Approaches and Potential Implications for District Heating and Cooling" (with R. Brailove), International District Heating and Cooling Association 84th Annual Conference; June 1993.

"Using the Costs of Required Controls to Incorporate the Costs of Environmental Externalities in Non-Environmental Decision-Making." Presentation at the American Planning Association 1992 National Planning Conference; presentation cosponsored by the Edison Electric Institute. May 1992.

"Cost Recovery and Decoupling" and "The Clean Air Act and Externalities in Utility Resource Planning" panels (session leader), DSM Advocacy Workshop; April 15 1992.

"Overview of Integrated Resources Planning Procedures in South Carolina and Critique of South Carolina Demand Side Management Programs," Energy Planning Workshops; Columbia, S.C.; October 21 1991;

"Least Cost Planning and Gas Utilities." Conservation Law Foundation Utility Energy Efficiency Advocacy Workshop; Boston, February 28 1991.

"Least-Cost Planning in a Multi-Fuel Context," NARUC Forum on Gas Integrated Resource Planning; Washington, D.C., February 24 1991.

"Accounting for Externalities: Why, Which and How?" Understanding Massachusetts' New Integrated Resource Management Rules; Needham, Massachusetts, November 9 1990.

"Increasing Market Share Through Energy Efficiency." New England Gas Association Gas Utility Managers' Conference; Woodstock, Vermont, September 10 1990.

"Quantifying and Valuing Environmental Externalities." Presentation at the Lawrence Berkeley Laboratory Training Program for Regulatory Staff, sponsored by the U.S. Department of Energy's Least-Cost Utility Planning Program; Berkeley, California, February 2 1990;

"Conservation in the Future of Natural Gas Local Distribution Companies," District of Columbia Natural Gas Seminar; Washington, D.C., May 23 1989.

"Conservation and Load Management for Natural Gas Utilities," Massachusetts Natural Gas Council; Newton, Massachusetts, April 3 1989.

New England Conference of Public Utilities Commissioners, Environmental Externalities Workshop; Portsmouth, N.H., January 22–23 1989.

"Assessment and Valuation of External Environmental Damages," New England Utility Rate Forum; Plymouth, Massachusetts, October 11 1985; "Lessons from Massachusetts on Long Term Rates for QFs".

"Reviewing Utility Supply Plans," Massachusetts Energy Facilities Siting Council; Boston, Massachusetts, May 30 1985.

"Power Plant Performance," National Association of State Utility Consumer Advocates; Williamstown, Massachusetts, August 13 1984.

"Utility Rate Shock," National Conference of State Legislatures; Boston, Massachusetts, August 6 1984.

"Review and Modification of Regulatory and Rate Making Policy," National Governors' Association Working Group on Nuclear Power Cost Overruns; Washington, D.C., June 20 1984.

"Review and Modification of Regulatory and Rate Making Policy," Annual Meeting of the American Association for the Advancement of Science, Session on Monitoring for Risk Management; Detroit, Michigan, May 27 1983.

ADVISORY ASSIGNMENTS TO REGULATORY COMMISSIONS

District of Columbia Public Service Commission, Docket No. 834, Phase II; Least-cost planning procedures and goals; August 1987 to March 1988.

Connecticut Department of Public Utility Control, Docket No. 87-07-01, Phase 2; Rate design and cost allocations; March 1988 to June 1989.

EXPERT TESTIMONY

1. **MEFSC** 78-12/MDPU 19494, Phase I; Boston Edison 1978 forecast; Massachusetts Attorney General; June 12 1978.

   Appliance penetration projections, price elasticity, econometric commercial forecast, peak demand forecast. Joint testimony with Susan C. Geller.

2. **MEFSC** 78-17; Northeast Utilities 1978 forecast; Massachusetts Attorney General; September 29 1978.

   Specification of economic/demographic and industrial models, appliance efficiency, commercial model structure and estimation.

3. **MEFSC** 78-33; Eastern Utilities Associates 1978 forecast; Massachusetts Attorney General; November 27 1978.

   Household size, appliance efficiency, appliance penetration, price elasticity, commercial forecast, industrial trending, peak demand forecast.

4. **MDPU** 19494; Phase II; Boston Edison Company Construction Program; Massachusetts Attorney General; April 1 1979.

Review of numerous aspects of the 1978 demand forecasts of nine New England electric utilities, constituting 92% of projected regional demand growth, and of the NEPOOL demand forecast. Joint testimony with S.C. Geller.

5. **MDPU** 19494; Phase II; Boston Edison Company Construction Program; Massachusetts Attorney General; April 1 1979.

   Reliability, capacity planning, capability responsibility allocation, customer generation, co-generation rates, reserve margins, operating reserve allocation. Joint testimony with S. Finger.

6. **ASLB, NRC** 50-471; Pilgrim Unit 2, Boston Edison Company; Commonwealth of Massachusetts; June 29 1979.

   Review of the Oak Ridge National Laboratory and NEPOOL demand forecast models; cost-effectiveness of oil displacement; nuclear economics. Joint testimony with S.C. Geller.

7. **MDPU** 19845; Boston Edison Time-of-Use Rate Case; Massachusetts Attorney General; December 4 1979.

   Critique of utility marginal cost study and proposed rates; principles of marginal cost principles, cost derivation, and rate design; options for reconciling costs and revenues. Joint testimony with S.C. Geller. Testimony eventually withdrawn due to delay in case.

8. **MDPU** 20055; Petition of Eastern Utilities Associates, New Bedford G. & E., and Fitchburg G. & E. to purchase additional shares of Seabrook Nuclear Plant; Massachusetts Attorney General; January 23 1980.

   Review of demand forecasts of three utilities purchasing Seabrook shares; Seabrook power costs, including construction cost, completion date, capacity factor, O&M expenses, interim replacements, reserves and uncertainties; alternative energy sources, including conservation, cogeneration, rate reform, solar, wood and coal conversion.

9. **MDPU** 20248; Petition of MMWEC to Purchase Additional Share of Seabrook Nuclear Plant; Massachusetts Attorney General; June 2 1980.

   Nuclear power costs; update and extension of MDPU 20055 testimony.

10. **MDPU** 200; Massachusetts Electric Company Rate Case; Massachusetts Attorney General; June 16 1980.

    Rate design; declining blocks, promotional rates, alternative energy, demand charges, demand ratchets; conservation: master metering, storage heating, efficiency standards, restricting resistance heating.

11. **MEFSC** 79-33; Eastern Utilities Associates 1979 Forecast; Massachusetts Attorney General; July 16 1980.

Customer projections, consistency issues, appliance efficiency, new appliance types, commercial specifications, industrial data manipulation and trending, sales and resale.

12. **MDPU** 243; Eastern Edison Company Rate Case; Massachusetts Attorney General; August 19 1980.

    Rate design: declining blocks, promotional rates, alternative energy, master metering.

13. **Texas PUC** 3298; Gulf States Utilities Rate Case; East Texas Legal Services; August 25 1980.

    Inter-class revenue allocations, including production plant in-service, O&M, CWIP, nuclear fuel in progress, amortization of canceled plant residential rate design; interruptible rates; off-peak rates. Joint testimony with M. B. Meyer.

14. **MEFSC** 79-1; Massachusetts Municipal Wholesale Electric Company Forecast; Massachusetts Attorney General; November 5 1980.

    Cost comparison methodology; nuclear cost estimates; cost of conservation, cogeneration, and solar.

15. **MDPU** 472; Recovery of Residential Conservation Service Expenses; Massachusetts Attorney General; December 12 1980.

    Conservation as an energy source; advantages of per-kWh allocation over per-customer-month allocation.

16. **MDPU** 535; Regulations to Carry Out Section 210 of PURPA; Massachusetts Attorney General; January 26 1981 and February 13 1981.

    Filing requirements, certification, qualifying facility (QF) status, extent of coverage, review of contracts; energy rates; capacity rates; extra benefits of QFs in specific areas; wheeling; standardization of fees and charges.

17. **MEFSC** 80-17; Northeast Utilities 1980 Forecast; Massachusetts Attorney General; March 12 1981 (not presented).

    Specification process, employment, electric heating promotion and penetration, commercial sales model, industrial model specification, documentation of price forecasts and wholesale forecast.

18. **MDPU** 558; Western Massachusetts Electric Company Rate Case; Massachusetts Attorney General; May 1981.

    Rate design including declining blocks, marginal cost conservation impacts, and promotional rates. Conservation, including terms and conditions limiting renewable, cogeneration, small power production; scope of current conservation program; efficient insulation levels; additional conservation opportunities.

19. **MDPU** 1048; Boston Edison Plant Performance Standards; Massachusetts Attorney General; May 7 1982.

    Critique of company approach, data, and statistical analysis; description of comparative and absolute approaches to standard-setting; proposals for standards and reporting requirements.

20. **DCPSC** FC785; Potomac Electric Power Rate Case; DC People's Counsel; July 29 1982.

    Inter-class revenue allocations, including generation, transmission, and distribution plant classification; fuel and O&M classification; distribution and service allocators. Marginal cost estimation, including losses.

21. **NHPUC** DE1-312; Public Service of New Hampshire-Supply and Demand; Conservation Law Foundation, et al.; October 8 1982.

    Conservation program design, ratemaking, and effectiveness. Cost of power from Seabrook nuclear plant, including construction cost and duration, capacity factor, O&M, replacements, insurance, and decommissioning.

22. **Massachusetts Division of Insurance;** Hearing to Fix and Establish 1983 Automobile Insurance Rates; Massachusetts Attorney General; October 1982.

    Profit margin calculations, including methodology, interest rates, surplus flow, tax flows, tax rates, and risk premium.

23. **Illinois Commerce Commission** 82-0026; Commonwealth Edison Rate Case; Illinois Attorney General; October 15 1982.

    Review of Cost-Benefit Analysis for nuclear plant. Nuclear cost parameters (construction cost, O&M, capital additions, useful like, capacity factor), risks, discount rates, evaluation techniques.

24. **New Mexico PSC** 1794; Public Service of New Mexico Application for Certification; New Mexico Attorney General; May 10 1983.

    Review of Cost-Benefit Analysis for transmission line. Review of electricity price forecast, nuclear capacity factors, load forecast. Critique of company ratemaking proposals; development of alternative ratemaking proposal.

25. **Connecticut Public Utility Control Authority** 830301; United Illuminating Rate Case; Connecticut Consumers Counsel; June 17 1983.

    Cost of Seabrook nuclear power plants, including construction cost and duration, capacity factor, O&M, capital additions, insurance and decommissioning.

26. **MDPU** 1509; Boston Edison Plant Performance Standards; Massachusetts Attorney General; July 15 1983.

Critique of company approach and statistical analysis; regression model of nuclear capacity factor; proposals for standards and for standard-setting methodologies.

27. **Massachusetts Division of Insurance;** Hearing to Fix and Establish 1984 Automobile Insurance Rates; Massachusetts Attorney General; October 1983.

    Profit margin calculations, including methodology, interest rates.

28. **Connecticut Public Utility Control Authority** 83-07-15; Connecticut Light and Power Rate Case; Alloy Foundry; October 3 1983.

    Industrial rate design. Marginal and embedded costs; classification of generation, transmission, and distribution expenses; demand versus energy charges.

29. **MEFSC** 83-24; New England Electric System Forecast of Electric Resources and Requirements; Massachusetts Attorney General; November 14 1983, Rebuttal, February 2 1984.

    Need for transmission line. Status of supply plan, especially Seabrook 2. Review of interconnection requirements. Analysis of cost-effectiveness for power transfer, line losses, generation assumptions.

30. **Michigan PSC** U-7775; Detroit Edison Fuel Cost Recovery Plan; Public Interest Research Group in Michigan; February 21 1984.

    Review of proposed performance target for new nuclear power plant. Formulation of alternative proposals.

31. **MDPU** 84-25; Western Massachusetts Electric Company Rate Case; Massachusetts Attorney General; April 6 1984.

    Need for Millstone 3. Cost of completing and operating unit, cost-effectiveness compared to alternatives, and its effect on rates. Equity and incentive problems created by CWIP. Design of Millstone 3 phase-in proposals to protect ratepayers: limitation of base-rate treatment to fuel savings benefit of unit.

32. **MDPU** 84-49 and 84-50; Fitchburg Gas & Electric Financing Case; Massachusetts Attorney General; April 13 1984.

    Cost of completing and operating Seabrook nuclear units. Probability of completing Seabrook 2. Recommendations regarding FG&E and MDPU actions with respect to Seabrook.

33. **Michigan PSC** U-7785; Consumers Power Fuel Cost Recovery Plan; Public Interest Research Group in Michigan; April 16 1984.

    Review of proposed performance targets for two existing and two new nuclear power plants. Formulation of alternative policy.

34. **FERC** ER81-749-000 and ER82-325-000; Montaup Electric Rate Cases; Massachusetts Attorney General; April 27 1984.

Prudence of Montaup and Boston Edison in decisions regarding Pilgrim 2 construction: Montaup's decision to participate, the Utilities' failure to review their earlier analyses and assumptions, Montaup's failure to question Edison's decisions, and the utilities' delay in canceling the unit.

35. **Maine PUC** 84-113; Seabrook 1 Investigation; Maine Public Advocate; September 13 1984.

    Cost of completing and operating Seabrook Unit 1. Probability of completing Seabrook 1. Comparison of Seabrook to alternatives. Rate effects. Recommendations regarding utility and PUC actions with respect to Seabrook.

36. **MDPU** 84-145; Fitchburg Gas and Electric Rate Case; Massachusetts Attorney General; November 6 1984.

    Prudence of Fitchburg and Public Service of New Hampshire in decision regarding Seabrook 2 construction: FGE's decision to participate, the utilities' failure to review their earlier analyses and assumptions, FGE's failure to question PSNH's decisions, and utilities' delay in halting construction and canceling the unit. Review of literature, cost and schedule estimate histories, cost-benefit analyses, and financial feasibility.

37. **Pennsylvania PUC** R-842651; Pennsylvania Power and Light Rate Case; Pennsylvania Consumer Advocate; November 1984.

    Need for Susquehanna 2. Cost of operating unit, power output, cost-effectiveness compared to alternatives, and its effect on rates. Design of phase-in and excess capacity proposals to protect ratepayers: limitation of base-rate treatment to fuel savings benefit of unit.

38. **NHPUC** 84-200; Seabrook Unit 1 Investigation; New Hampshire Public Advocate; November 15 1984.

    Cost of completing and operating Seabrook Unit 1. Probability of completing Seabrook 1. Comparison of Seabrook to alternatives. Rate and financial effects.

39. **Massachusetts Division of Insurance;** Hearing to Fix and Establish 1985 Automobile Insurance Rates; Massachusetts Attorney General; November 1984.

    Profit margin calculations, including methodology and implementation.

40. **MDPU** 84-152; Seabrook Unit 1 Investigation; Massachusetts Attorney General; December 12 1984.

    Cost of completing and operating Seabrook. Probability of completing Seabrook 1. Seabrook capacity factors.

41. **Maine PUC** 84-120; Central Maine Power Rate Case; Maine PUC Staff; December 11 1984.

Prudence of Central Maine Power and Boston Edison in decisions regarding Pilgrim 2 construction: CMP's decision to participate, the utilities' failure to review their earlier analyses and assumptions, CMP's failure to question Edison's decisions, and the utilities' delay in canceling the unit. Prudence of CMP in the planning and investment in Sears Island nuclear and coal plants. Review of literature, cost and schedule estimate histories, cost-benefit analyses, and financial feasibility.

42. **Maine PUC** 84-113; Seabrook 2 Investigation; Maine PUC Staff; December 14 1984.

    Prudence of Maine utilities and Public Service of New Hampshire in decisions regarding Seabrook 2 construction: decisions to participate and to increase ownership share, the utilities' failure to review their earlier analyses and assumptions, failure to question PSNH's decisions, and the utilities' delay in halting construction and canceling the unit. Review of literature, cost and schedule estimate histories, cost-benefit analyses, and financial feasibility.

43. **MDPU** 1627; Massachusetts Municipal Wholesale Electric Company Financing Case; Massachusetts Executive Office of Energy Resources; January 14 1985.

    Cost of completing and operating Seabrook nuclear unit 1. Cost of conservation and other alternatives to completing Seabrook. Comparison of Seabrook to alternatives.

44. **Vermont PSB** 4936; Millstone 3; Costs and In-Service Date; Vermont Department of Public Service; January 21 1985.

    Construction schedule and cost of completing Millstone Unit 3.

45. **MDPU** 84-276; Rules Governing Rates for Utility Purchases of Power from Qualifying Facilities; Massachusetts Attorney General; March 25 1985, and October 18 1985.

    Institutional and technological advantages of Qualifying Facilities. Potential for QF development. Goals of QF rate design. Parity with other power sources. Security requirements. Projecting avoided costs. Capacity credits. Pricing options. Line loss corrections.

46. **MDPU** 85-121; Investigation of the Reading Municipal Light Department; Wilmington (MA) Chamber of Commerce; November 12 1985.

    Calculation on return on investment for municipal utility. Treatment of depreciation and debt for ratemaking. Geographical discrimination in street-lighting rates. Relative size of voluntary payments to Reading and other towns. Surplus and disinvestment. Revenue allocation.

47. **Massachusetts Division of Insurance;** Hearing to Fix and Establish 1986 Automobile Insurance Rates; Massachusetts Attorney General and State Rating Bureau; November 1985.

    Profit margin calculations, including methodology, implementation, modeling of investment balances, income, and return to shareholders.

48. **New Mexico PSC** 1833, Phase II; El Paso Electric Rate Case; New Mexico Attorney General; December 23 1985.

    Nuclear decommissioning fund design. Internal and external funds; risk and return; fund accumulation, recommendations. Interim performance standard for Palo Verde nuclear plant.

49. **Pennsylvania PUC** R-850152; Philadelphia Electric Rate Case; Utility Users Committee and University of Pennsylvania; January 14 1986.

    Limerick 1 rate effects. Capacity benefits, fuel savings, operating costs, capacity factors, and net benefits to ratepayers. Design of phase-in proposals.

50. **MDPU** 85-270; Western Massachusetts Electric Rate Case; Massachusetts Attorney General; March 19 1986.

    Prudence of Northeast Utilities in generation planning related to Millstone 3 construction: decisions to start and continue construction, failure to reduce ownership share, failure to pursue alternatives. Review of industry literature, cost and schedule histories, and retrospective cost-benefit analyses.

51. **Pennsylvania PUC** R-850290; Philadelphia Electric Auxiliary Service Rates; Albert Einstein Medical Center, University of Pennsylvania and AMTRAK; March 24 1986.

    Review of utility proposals for supplementary and backup rates for small power producers and cogenerators. Load diversity, cost of peaking capacity, value of generation, price signals, and incentives. Formulation of alternative supplementary rate.

52. **New Mexico PSC** 2004; Public Service of New Mexico, Palo Verde Issues; New Mexico Attorney General; May 7 1986.

    Recommendations for Power Plant Performance Standards for Palo Verde nuclear units 1, 2, and 3.

53. **Illinois Commerce Commission** 86-0325; Iowa-Illinois Gas and Electric Co. Rate Investigation; Illinois Office of Public Counsel; August 13 1986.

    Determination of excess capacity based on reliability and economic concerns. Identification of specific units associated with excess capacity. Required reserve margins.

54. **New Mexico PSC** 2009; El Paso Electric Rate Moderation Program; New Mexico Attorney General; August 18 1986. (Not presented).

    Prudence of EPE in generation planning related to Palo Verde nuclear construction, including failure to reduce ownership share and failure to pursue alternatives. Review of industry literature, cost and schedule histories, and retrospective cost-benefit analyses.

    Recommendation for rate-base treatment; proposal of power plant performance standards.

55. **City of Boston, Public Improvements Commission;** Transfer of Boston Edison District Heating Steam System to Boston Thermal Corporation; Boston Housing Authority; December 18 1986.

    History and economics of steam system; possible motives of Boston Edison in seeking sale; problems facing Boston Thermal; information and assurances required prior to Commission approval of transfer.

56. **Massachusetts Division of Insurance;** Hearing to Fix and Establish 1987 Automobile Insurance Rates; Massachusetts Attorney General and State Rating Bureau; December 1986 and January 1987.

    Profit margin calculations, including methodology, implementation, derivation of cash flows, installment income, income tax status, and return to shareholders.

57. **MDPU** 87-19; Petition for Adjudication of Development Facilitation Program; Hull (MA) Municipal Light Plant; January 21 1987.

    Estimation of potential load growth; cost of generation, transmission, and distribution additions. Determination of hook-up charges. Development of residential load estimation procedure reflecting appliance ownership, dwelling size.

58. **New Mexico PSC** 2004; Public Service of New Mexico Nuclear Decommissioning Fund; New Mexico Attorney General; February 19 1987.

    Decommissioning cost and likely operating life of nuclear plants. Review of utility funding proposal. Development of alternative proposal. Ratemaking treatment.

59. **MDPU** 86-280; Western Massachusetts Electric Rate Case; Massachusetts Energy Office; March 9 1987.

    Marginal cost rate design issues. Superiority of long-run marginal cost over short-run marginal cost as basis for rate design. Relationship of consumer reaction, utility planning process, and regulatory structure to rate design approach. Implementation of short-run and long-run rate designs. Demand versus energy charges, economic development rates, spot pricing.

60. **Massachusetts Division of Insurance** 87-9; 1987 Workers' Compensation Rate Filing; State Rating Bureau; May 1987.

Profit margin calculations, including methodology, implementation, surplus requirements, investment income, and effects of 1986 Tax Reform Act.

61. **Texas PUC** 6184; Economic Viability of South Texas Nuclear Plant #2; Committee for Consumer Rate Relief; August 17 1987.

    STNP operating parameter projections; capacity factor, O&M, capital additions, decommissioning, useful life. STNP 2 cost and schedule projections. Potential for conservation.

62. **Minnesota PUC** ER-015/GR-87-223; Minnesota Power Rate Case; Minnesota Department of Public Service; August 17 1987.

    Excess capacity on MP system; historical, current, and projected. Review of MP planning prudence prior to and during excess; efforts to sell capacity. Cost of excess capacity. Recommendations for ratemaking treatment.

63. **Massachusetts Division of Insurance** 87-27; 1988 Automobile Insurance Rates; Massachusetts Attorney General and State Rating Bureau; September 2 1987. Rebuttal October 8 1987.

    Underwriting profit margins. Effect of 1986 Tax Reform Act. Biases in calculation of average margins.

64. **MDPU** 88-19; Power Sales Contract from Riverside Steam and Electric to Western Massachusetts Electric; Riverside Steam and Electric; November 4 1987.

    Comparison of risk from QF contract and utility avoided cost sources. Risk of oil dependence. Discounting cash flows to reflect risk.

65. **Massachusetts Division of Insurance** 87-53; 1987 Workers' Compensation Rate Refiling; State Rating Bureau; December 14 1987.

    Profit margin calculations, including updating of data, compliance with Commissioner's order, treatment of surplus and risk, interest rate calculation, and investment tax rate calculation.

66. **Massachusetts Division of Insurance;** 1987 and 1988 Automobile Insurance Remand Rates; Massachusetts Attorney General and State Rating Bureau; February 5 1988.

    Underwriting profit margins. Provisions for income taxes on finance charges. Relationships between allowed and achieved margins, between statewide and nationwide data, and between profit allowances and cost projections.

67. **MDPU** 86-36; Investigation into the Pricing and Ratemaking Treatment to be Afforded New Electric Generating Facilities which are not Qualifying Facilities; Conservation Law Foundation; May 2 1988.

    Cost recovery for utility conservation programs. Compensating for lost revenues. Utility incentive structures.

68. **MDPU** 88-123; Petition of Riverside Steam & Electric Company; Riverside Steam and Electric Company; May 18 1988, and November 8 1988.

    Estimation of avoided costs of Western Massachusetts Electric Company. Nuclear capacity factor projections and effects on avoided costs. Avoided cost of energy interchange and power plant life extensions. Differences between median and expected oil prices. Salvage value of cogeneration facility. Off-system energy purchase projections. Reconciliation of avoided cost projection.

69. **MDPU** 88-67; Boston Gas Company; Boston Housing Authority; June 17 1988.

    Estimation of annual avoidable costs, 1988 to 2005, and levelized avoided costs. Determination of cost recovery and carrying costs for conservation investments. Standards for assessing conservation cost-effectiveness. Evaluation of cost-effectiveness of utility funding of proposed natural gas conservation measures.

70. **Rhode Island PUC** Docket 1900; Providence Water Supply Board Tariff Filing; Conservation Law Foundation, Audubon Society of Rhode Island, and League of Women Voters of Rhode Island; June 24 1988.

    Estimation of avoidable water supply costs. Determination of costs of water conservation. Conservation cost-benefit analysis.

71. **Massachusetts Division of Insurance** 88-22; 1989 Automobile Insurance Rates; Massachusetts Attorney General and State Rating Bureau; Profit Issues, August 12 1988, supplemented August 19 1988; Losses and Expenses, September 16 1988.

    Underwriting profit margins. Effects of 1986 Tax Reform Act. Taxation of common stocks. Lag in tax payments. Modeling risk and return over time. Treatment of finance charges. Comparison of projected and achieved investment returns.

72. **Vermont PSB** Docket No. 5270, Module 6; Investigation into Least-Cost Investments, Energy Efficiency, Conservation, and the Management of Demand for Energy; Conservation Law Foundation, Vermont Natural Resources Council, and Vermont Public Interest Research Group; September 26 1988.

    Cost recovery for utility conservation programs. Compensation of utilities for revenue losses and timing differences. Incentive for utility participation.

73. **Vermont House of Representatives, Natural Resources Committee;** House Act 130; "Economic Analysis of Vermont Yankee Retirement"; Vermont Public Interest Research Group; February 21 1989.

    Projection of capacity factors, operating and maintenance expense, capital additions, overhead, replacement power costs, and net costs of Vermont Yankee.

74. **MDPU** 88-67, Phase II; Boston Gas Company Conservation Program and Rate Design; Boston Gas Company; March 6 1989.

Estimation of avoided gas cost; treatment of non-price factors; estimation of externalities; identification of cost-effective conservation.

75. **Vermont PSB** Docket No. 5270; Status Conference on Conservation and Load Management Policy Settlement; Central Vermont Public Service, Conservation Law Foundation, Vermont Natural Resources Council, Vermont Public Interest Research Group, and Vermont Department of Public Service; May 1 1989.

    Cost-benefit test for utility conservation programs. Role of externalities. Cost recovery concepts and mechanisms. Resource allocations, cost allocations, and equity considerations. Guidelines for conservation preapproval mechanisms. Incentive mechanisms and recovery of lost revenues.

76. **Boston Housing Authority Court** 05099; Gallivan Boulevard Task Force vs. Boston Housing Authority, et al.; Boston Housing Authority; June 16 1989.

    Effect of master-metering on consumption of natural gas and electricity. Legislative and regulatory mandates regarding conservation.

77. **MDPU** 89-100; Boston Edison Rate Case; Massachusetts Energy Office; June 30 1989.

    Prudence of BECo's decision of spend $400 million from 1986–88 on returning the Pilgrim nuclear power plant to service. Projections of nuclear capacity factors, O&M, capital additions, and overhead. Review of decommissioning cost, tax effect of abandonment, replacement power cost, and plant useful life estimates. Requirements for prudence and used-and-useful analyses.

78. **MDPU** 88-123; Petition of Riverside Steam and Electric Company; Riverside Steam and Electric; July 24 1989. Rebuttal, October 3 1989.

    Reasonableness of Northeast Utilities' 1987 avoided cost estimates. Projections of nuclear capacity factors, economy purchases, and power plant operating life. Treatment of avoidable energy and capacity costs and of off-system sales. Expected versus reference fuel prices.

79. **MDPU** 89-72; Statewide Towing Association, Police-Ordered Towing Rates; Massachusetts Automobile Rating Bureau; September 13 1989.

    Review of study supporting proposed increase in towing rates. Critique of study sample and methodology. Comparison to competitive rates. Supply of towing services. Effects of joint products and joint sales on profitability of police-ordered towing. Joint testimony with I. Goodman.

80. **Vermont PSB** 5330; Application of Vermont Utilities for Approval of a Firm Power and Energy Contract with Hydro-Quebec; Conservation Law Foundation, Vermont Natural Resources Council, Vermont Public Interest Research Group; December 19 1989. Surrebuttal February 6 1990.

Analysis of a proposed 450-MW, 20 year purchase of Hydro-Quebec power by twenty-four Vermont utilities. Comparison to efficiency investment in Vermont, including potential for efficiency savings. Analysis of Vermont electric energy supply. Identification of possible improvements to proposed contract.

Critique of conservation potential analysis. Planning risk of large supply additions. Valuation of environmental externalities.

81. **MDPU** 89-239; Inclusion of Externalities in Energy Supply Planning, Acquisition and Dispatch for Massachusetts Utilities; December 1989; April 1990; May 1990.

    Critique of Division of Energy Resources report on externalities. Methodology for evaluating external costs. Proposed values for environmental and economic externalities of fuel supply and use.

82. **California PUC**; Incorporation of Environmental Externalities in Utility Planning and Pricing; Coalition of Energy Efficient and Renewable Technologies; February 21 1990.

    Approaches for valuing externalities for inclusion in setting power purchase rates. Effect of uncertainty on assessing externality values.

83. **Illinois Commerce Commission** Docket 90-0038; Proceeding to Adopt a Least Cost Electric Energy Plan for Commonwealth Edison Company; City of Chicago; May 25 1990. Joint rebuttal testimony with David Birr, August 14 1990.

    Problems in Commonwealth Edison's approach to demand-side management. Potential for cost-effective conservation. Valuing externalities in least-cost planning.

84. **Maryland PSC** Case No. 8278; Adequacy of Baltimore Gas & Electric's Integrated Resource Plan; Maryland Office of People's Counsel; September 18 1990.

    Rationale for demand-side management, and BG&E's problems in approach to DSM planning. Potential for cost-effective conservation. Valuation of environmental externalities. Recommendations for short-term DSM program priorities.

85. **Indiana Utility Regulatory Commission;** Integrated Resource Planning Docket; Indiana Office of Utility Consumer Counselor; November 1 1990.

    Integrated resource planning process and methodology, including externalities and screening tools. Incentives, screening, and evaluation of demand-side management. Potential of resource bidding in Indiana.

86. **MDPU** Dockets 89-141, 90-73, 90-141, 90-194, and 90-270; Preliminary Review of Utility Treatment of Environmental Externalities in October QF Filings; Boston Gas Company; November 5 1990.

Generic and specific problems in Massachusetts utilities' RFPs with regard to externality valuation requirements. Recommendations for corrections.

87. **MEFSC** 90-12/90-12A; Adequacy of Boston Edison Proposal to Build Combined-Cycle Plant; Conservation Law Foundation; December 14 1990.

    Problems in Boston Edison's treatment of demand-side management, supply option analysis, and resource planning. Recommendations of mitigation options.

88. **Maine PUC** Docket No. 90-286; Adequacy of Conservation Program of Bangor Hydro Electric; Penobscot River Coalition; February 19 1991.

    Role of utility-sponsored DSM in least-cost planning. Bangor Hydro's potential for cost-effective conservation. Problems with Bangor Hydro's assumptions about customer investment in energy efficiency measures.

89. **Virginia State Corporation Commission** Case No. PUE900070; Order Establishing Commission Investigation; Southern Environmental Law Center; March 6 1991.

    Role of utilities in promoting energy efficiency. Least-cost planning objectives of and resource acquisition guidelines for DSM. Ratemaking considerations for DSM investments.

90. **MDPU** Docket No. 90-261-A; Economics and Role of Fuel-Switching in the DSM Program of the Massachusetts Electric Company; Boston Gas Company; April 17 1991.

    Role of fuel-switching in utility DSM programs and specifically in Massachusetts Electric's. Establishing comparable avoided costs and comparison of electric and gas system costs. Updated externality values.

91. **Private arbitration;** Massachusetts Refusetech Contractual Request for Adjustment to Service Fee; Massachusetts Refusetech; May 13 1991.

    NEPCo rates for power purchases from the NESWC plant. Fuel price and avoided cost projections vs. realities.

92. **Vermont PSB** Docket No. 5491; Cost-Effectiveness of Central Vermont's Commitment to Hydro Quebec Purchases; Conservation Law Foundation; July 19 1991.

    Changes in load forecasts and resale markets since approval of HQ purchases. Effect of HQ purchase on DSM.

93. **South Carolina PSC** Docket No. 91-216-E; Cost Recovery of Duke Power's DSM Expenditures; South Carolina Department of Consumer Affairs; September 13 1991. Surrebuttal October 2 1991.

    Problems with conservation plans of Duke Power, including load building, cream skimming, and inappropriate rate designs.

94. **Maryland PSC** Case No. 8241, Phase II; Review of Baltimore Gas & Electric's Avoided Costs; Maryland Office of People's Counsel; September 19 1991.

    Development of direct avoided costs for DSM. Problems with BG&E's avoided costs and DSM screening. Incorporation of environmental externalities.

95. **Bucksport Planning Board;** AES/Harriman Cove Shoreland Zoning Application; Conservation Law Foundation and Natural Resources Council of Maine; October 1 1991.

    New England's power surplus. Costs of bringing AES/Harriman Cove on line to back out existing generation. Alternatives to AES.

96. **MDPU** Docket No. 91-131; Update of Externalities Values Adopted in Docket 89-239; Boston Gas Company; October 4 1991. Rebuttal, December 13 1991.

    Updates on pollutant externality values. Addition of values for chlorofluorocarbons, air toxics, thermal pollution, and oil import premium. Review of state regulatory actions regarding externalities.

97. **Florida PSC** Docket No. 910759; Petition of Florida Power Corporation for Determination of Need for Proposed Electrical Power Plant and Related Facilities; Floridians for Responsible Utility Growth; October 21 1991.

    Florida Power's obligation to pursue integrated resource planning and failure to establish need for proposed facility. Methods to increase scope and scale of demand-side investment.

98. **Florida PSC** Docket No. 910833-EI; Petition of Tampa Electric Company for a Determination of Need for Proposed Electrical Power Plant and Related Facilities; Floridians for Responsible Utility Growth; October 31 1991.

    Tampa Electric's obligation to pursue integrated resource planning and failure to establish need for proposed facility. Methods to increase scope and scale of demand-side investment.

99. **Pennsylvania PUC** Dockets I-900005, R-901880; Investigation into Demand Side Management by Electric Utilities; Pennsylvania Energy Office; January 10 1992.

    Appropriate cost recovery mechanism for Pennsylvania utilities. Purpose and scope of direct cost recovery, lost revenue recovery, and incentives.

100. **South Carolina PSC** Docket No. 91-606-E; Petition of South Carolina Electric and Gas for a Certificate of Public Convenience and Necessity for a Coal-Fired Plant; South Carolina Department of Consumer Affairs; January 20 1992.

     Justification of plant certification under integrated resource planning. Failures in SCE&G's DSM planning and company potential for demand-side savings.

101. **MDPU** Docket No. 92-92; Adequacy of Boston Edison's Street-Lighting Options; Town of Lexington; June 22 1992.

Efficiency and quality of street-lighting options. Boston Edison's treatment of high-quality street lighting. Corrected rate proposal for the Daylux lamp. Ownership of public street lighting.

102. **South Carolina PSC** Docket No. 92-208-E; Integrated Resource Plan of Duke Power Company; South Carolina Department of Consumer Affairs; August 4 1992.

Problems with Duke Power's DSM screening process, estimation of avoided cost, DSM program design, and integration of demand-side and supply-side planning.

103. **North Carolina Utilities Commission** Docket No. E-100, Sub 64; Integrated Resource Planning Docket; Southern Environmental Law Center; September 29 1992.

General principles of integrated resource planning, DSM screening, and program design. Review of the IRPs of Duke Power Company, Carolina Power & Light Company, and North Carolina Power.

104. **Ontario Environmental Assessment Board** Ontario Hydro Demand/Supply Plan Hearings; *Environmental Externalities Valuation and Ontario Hydro's Resource Planning* (3 vols.); October 1992.

Valuation of environmental externalities from fossil fuel combustion and the nuclear fuel cycle. Application to Ontario Hydro's supply and demand planning.

105. **Texas PUC** Docket No. 110000; Application of Houston Lighting and Power Company for a Certificate of Convenience and Necessity for the DuPont Project; Destec Energy, Inc.; September 28 1992.

Valuation of environmental externalities from fossil fuel combustion and the application to the evaluation of proposed cogeneration facility.

106. **Maine Board of Environmental Protection;** In the Matter of the Basin Mills Hydroelectric Project Application; Conservation Intervenors; November 16 1992.

Economic and environmental effects of generation by proposed hydro-electric project.

107. **Maryland PSC** Case No. 8473; Review of the Power Sales Agreement of Baltimore Gas and Electric with AES Northside; Maryland Office of People's Counsel; November 16 1992.

Non-price scoring and unquantified benefits; DSM potential as alternative; environmental costs; cost and benefit estimates.

108. **North Carolina Utilities Commission** Docket No. E-100, Sub 64; Analysis and Investigation of Least Cost Integrated Resource Planning in North Carolina; Southern Environmental Law Center; November 18 1992.

Demand-side management cost recovery and incentive mechanisms.

109. **South Carolina PSC** Docket No. 92-209-E; In Re Carolina Power & Light Company; South Carolina Department of Consumer Affairs; November 24 1992.

DSM planning: objectives, process, cost-effectiveness test, comprehensiveness, lost opportunities. Deficiencies in CP&L's portfolio. Need for economic evaluation of load building.

110 **Florida Department of Environmental Regulation** hearings on the Power Plant Siting Act; Legal Environmental Assistance Foundation, December 1992.

Externality valuation and application in power-plant siting. DSM potential, cost-benefit test, and program designs.

111. **Maryland PSC** Case No. 8487; Baltimore Gas and Electric Company, Electric Rate Case; January 13 1993. Rebuttal Testimony: February 4 1993.

Class allocation of production plant and O&M; transmission, distribution, and general plant; administrative and general expenses. Marginal cost and rate design.

112. **Maryland PSC** Case No. 8179; for Approval of Amendment No. 2 to Potomac Edison Purchase Agreement with AES Warrior Run; Maryland Office of People's Counsel; January 29 1993.

Economic analysis of proposed coal-fired cogeneration facility.

112. A **Michigan PSC** Case No. U-10102; Detroit Edison Rate Case; Michigan United Conservation Clubs; February 17 1993.

Least-cost planning; energy efficiency planning, potential, screening, avoided costs, cost recovery, and shareholder incentives.

113. **Ohio PUC** Dockets No. 91-635-EL-FOR, 92-312-EL-FOR, 92-1172-EL-ECP; Cincinnati, City of Cincinnati, April 1993.

DSM planning, program designs, potential savings, and avoided costs.

114. **Michigan PSC** Case No. U-10335; Consumers Power Rate Case; Michigan United Conservation Clubs; October 1993.

Least-cost planning; energy efficiency planning, potential, screening, avoided costs, cost recovery, and shareholder incentives.

115. **Illinois Commerce Commission** 92-0268, Electric-Energy Plan for Commonwealth Edison; City of Chicago. Direct testimony, February 1 1994; rebuttal, September 1994.

Cost-effectiveness screening of demand-side management programs and measures; estimates by Commonwealth Edison of costs avoided by DSM and of future cost, capacity, and performance of supply resources.

116. FERC Projects Nos. 2422 et al., Application of James River–New Hampshire Electric, Public Service of New Hampshire, for Licensing of Hydro Power; Conservation Law Foundation; 1993.

Cost-effective energy conservation available to the Public Service of New Hampshire; power-supply options; affidavit.

117. Vermont PSB Dockets No. 5270-CV-1,-3, and 5686; Central Vermont Public Service Fuel-Switching and DSM Program Design, on behalf of the Vermont Department of Public Service. Direct, April 1994; rebuttal, June 1994.

Avoided costs and screening of controlled water-heating measures; risk, rate impacts, participant costs, externalities, space- and water-heating load, benefit-cost tests.

118. Florida PSC Dockets 930548-EG–930551–EG, Conservation goals for Florida electric utilities; Legal Environmental Assistance Foundation, Inc. April 1994.

Integrated resource planning, avoided costs, rate impacts, analysis of conservation goals of Florida electric utilities.

119. Vermont PSB Docket No. 5724, Central Vermont Public Service Corporation rate request; Vermont Department of Public Service. Joint surrebuttal testimony with John Plunkett. August 1994.

Costs avoided by DSM programs; Costs and benefits of deferring DSM programs.

120. MDPU 94-49, Boston Edison integrated resource-management plan; Massachusetts Attorney General. August 1994.

Least-cost planning, modeling, and treatment of risk.

121. Michigan PSC Case No. U-10554, Consumers Power Company DSM Program and Incentive; Michigan Conservation Clubs. November 1994.

Critique of proposed reductions in DSM programs; discussion of appropriate measurements of cost-effectiveness, role of DSM in competitive power markets.

122. Michigan PSC Case No. U-10702, Detroit Edison Company Cost Recovery, on behalf of the Residential Ratepayers Consortium. December 1994.

Impact of proposed changes to DSM plan on energy costs and power-supply-cost-recovery charges. Critique of proposed DSM changes; discussion of appropriate measurements of cost-effectiveness, role of DSM in competitive power markets.

123. New Jersey Board of Regulatory Commissioners Docket No. EM92030359, Environmental costs of proposed cogeneration; Freehold Cogeneration Associates. November 1994.

Comparison of potential externalities from the Freehold cogeneration project with that from three coal technologies; support for the study "The Externalities of Four Power Plants."

124. **Michigan PSC** Case No. U-10671, Detroit Edison Company DSM Programs; Michigan United Conservation Clubs. January 1995.

Critique of proposal to scale back DSM efforts in light of potential for competition. Loss of savings, increase of customer costs, and decrease of competitiveness. Discussion of appropriate measurements of cost-effectiveness, role of DSM in competitive power markets.

125. **Michigan PSC** Case No. U-10710, Power-supply-cost-recovery plan of Consumers Power Company; Residential Ratepayers Consortium. January 1995.

Impact of proposed changes to DSM plan on energy costs and power-supply-cost-recovery charges. Critique of proposed DSM changes; discussion of appropriate measurements of cost-effectiveness, role of DSM in competitive power markets.

126. **FERC** Projects Nos. 2458 and 2572, Bowater–Great Northern Paper hydropower licensing; Conservation Law Foundation. February 1995.

Comments on draft environmental impact statement relating to new licenses for two hydropower projects in Maine. Applicant has not adequately considered how energy conservation can replace energy lost due to habitat-protection or -enhancement measures.

127. **North Carolina Utilities Commission** Docket No. E-100, Sub 74, Duke Power and Carolina Power & Light avoided costs; Hydro-Electric–Power Producer's Group. February 1995.

Critique and proposed revision of avoided costs offered to small hydro-power producers by Duke Power and Carolina Power and Light.

128. **New Orleans City Council** Docket No. UD-92-2A and -2B, Least-cost IRP for New Orleans Public Service and Louisiana Power & Light; Alliance for Affordable Energy. Direct, February 1995; rebuttal, April 1995.

Critique of proposal to scale back DSM efforts in light of potential competition.

129. **DCPSC** Formal Case No. 917, II, Prudence of DSM expenditures of Potomac Electric Power Company; Potomac Electric Power Company. Rebuttal testimony, February 1995.

Prudence of utility DSM investment; prudence standards for DSM programs of the Potomac Electric Power Company.

130. **Ontario Energy Board** EBRO 490, DSM cost recovery and lost-revenue–adjustment mechanism for Consumers Gas Company; Green Energy Coalition. April 1995.

DSM cost recovery. Lost-revenue–adjustment mechanism for Consumers Gas Company.

131. **New Orleans City Council** Docket No. CD-85-1, New Orleans Public Service rate increase; Alliance for Affordable Energy. Rebuttal, May 1995.

Allocation of costs and benefits to rate classes.

132. **MDPU** Docket DPU-95-40, Mass. Electric cost-allocation; Massachusetts Attorney General. June 1995.

Allocation of costs to rate classes. Critique of cost-of-service study. Implications for industry restructuring.

133. **Maryland PSC** Case No. 8697, Baltimore Gas & Electric gas rate increase; Maryland Office of People's Counsel. July 1995

Rate design, cost-of-service study, and revenue allocation.

134. **North Carolina Utilities Commission** Docket No. E-2, Sub 669. December 1995.

Need for new capacity. Energy-conservation potential and model programs.

135. **Arizona Commerce Commission** Docket No. U-1933-95-317, Tucson Electric Power rate increase; Residential Utility Consumer Office. January 1996.

Review of proposed rate settlement. Used-and-usefulness of plant. Rate design. DSM potential.

136. **Ohio PSC** Case No. 95-203-EL-FOR; Campaign for an Energy-Efficient Ohio. February 1996

Long-term forecast of Cincinnati Gas and Electric Company, especially its DSM portfolio. Opportunities for further cost-effective DSM savings. Tests of cost effectiveness. Role of DSM in light of industry restructuring; alternatives to traditional utility DSM.

137 **Vermont PSB** Docket No. 5835; Vermont Department of Public Service. February 1996.

Design of load-management rates of Central Vermont Public Service Company.

138. **Maryland PSC** Case No. 8720, Washington Gas Light DSM; Maryland Office of People's Counsel. May 1996.

Avoided costs of Washington Gas Light Company; integrated least-cost planning.

138 A. **MDPU** in Docket No. DPU 96-100; Massachusetts Utilities' Stranded Costs; Massachusetts Attorney General. Oral testimony in support of "estimation of Market Value, Stranded Investment, and Restructuring Gains for Major Massachusetts Utilities," July 1996.

Stranded costs. Calculation of loss or gain. Valuation of utility assets.

139. **MDPU** in Docket No. DPU 96-70; Massachusetts Attorney General. July 1996.

Market-based allocation of gas-supply costs of Essex County Gas Company.

140. **MDPU** Docket No. DPU 96-60; Massachusetts Attorney General. Direct testimony, July 1996; surrebuttal, August 1996.

Market-based allocation of gas-supply costs of Fall River Gas Company.

141. **Maryland PSC** Case No. 8725; Maryland Office of People's Counsel. July 1996.

Proposed merger of Baltimore Gas & Electric Company, Potomac Electric Power Company, and Constellation Energy. Cost allocation of merger benefits and rate reductions.

142. **New Hampshire PUC** Case No. DR 96-150, Public Service Company of New Hampshire stranded costs; New Hampshire Office of Consumer Advocate. December 1996.

Market price of capacity and energy; value of generation plant; restructuring gain and stranded investment; legal status of PSNH acquisition premium; interim stranded-cost charges.

143. **Ontario Energy Board** EBRO 495, LRAM and shared-savings incentive for DSM performance of Consumers Gas; Green Energy Coalition. March 1997.

LRAM and shared-savings incentive mechanisms in rates for the Consumers Gas Company Ltd.

144. **New York PSC** Case 96-E-0897, Consolidated Edison restructuring plan; City of New York. April 1997.

Electric-utility competition and restructuring; critique of proposed settlement of Consolidated Edison Company; stranded costs; market power; rates; market access.

145. **Vermont PSB** Docket No. 5980, proposed statewide energy plan; Vermont Department of Public Service. Direct, August 1997; rebuttal, December 1997.

Justification for and estimation of statewide avoided costs; guidelines for distributed IRP.

146. **MDPU** Docket No. 96-23, Boston Edison restructuring settlement; Utility Workers Union of America. September 1997.

Performance incentives proposed for the Boston Edison company.

147. **Vermont PSB** Docket No. 5983, Green Mountain Power rate increase; Vermont Department of Public Service. Direct, October 1997; rebuttal, December 1997.

In three separate pieces of prefiled testimony, addressed the Green Mountain Power Corporation's (1) distributed-utility-planning efforts, (2) avoided costs, and (3) prudence of decisions relating to a power purchase from Hydro-Quebec.

148. **MDPU** Docket No. 97-63, Boston Edison proposed reorganization; Utility Workers Union of America. October 1997.

Increased costs and risks to ratepayers and shareholders from proposed reorganization; risks of diversification; diversion of capital from regulated to unregulated affiliates; reduction in Commission authority.

149. **MDTE** Docket No. 97-111, Commonwealth Energy proposed restructuring; Cape Cod Light Compact. Joint testimony with Jonathan Wallach, January 1998.

Critique of proposed restructuring plan filed to satisfy requirements of the electric-utility restructuring act of 1997. Failure of the plan to foster competition and promote the public interest.

150. **NH PUC** Docket DR 97-241, Connecticut Valley Electric fuel and purchased-power adjustments; City of Claremont, N.H. February 1998.

Prudence of continued power purchase from affiliate; market cost of power; prudence disallowances and cost-of-service ratemaking.

151. **Maryland PSC** Case No. 8774; APS-DQE merger; Maryland Office of People's Counsel. February 1998.

Power-supply arrangements between APS's operating subsidiaries; power-supply savings; market power.

152. **Vermont PSB** Docket No. 6018, Central Vermont Public Service Co. rate increase; Vermont Department of Public Service. February 1998.

Prudence of decisions relating to a power purchase from Hydro-Quebec. Reasonableness of avoided-cost estimates. Quality of DU planning.

153. **Maine PUC** Docket No. 97-580, Central Maine Power restructuring and rates; Maine Office of Public Advocate. May 1998; Surrebuttal, August 1998.

Determination of stranded costs; gains from sales of fossil, hydro, and biomass plant; treatment of deferred taxes; incentives for stranded-cost mitigation; rate design.

154. **MDTE** Docket No. 98-89, purchase of Boston Edison municipal streetlighting, Towns of Lexington and Acton. Affidavit, August 1998.

Valuation of municipal streetlighting; depreciation; applicability of unbundled rate.

155. **Vermont PSB** Docket No. 6107, Green Mountain Power rate increase, Vermont Department of Public Service. September 1998.

Prudence of decisions relating to a power purchase from Hydro-Quebec. Least-cost planning and prudence. Quality of DU planning.

156. **MDTE** Docket No. 97-120, Western Massachusetts Electric Company proposed restructuring; Massachusetts Attorney General. Joint testimony with Jonathan Wallach, October 1998. Joint surrebuttal with Jonathan Wallach, January 1999.

    Market value of the three Millstone nuclear units under varying assumptions of plant performance and market prices. Independent forecast of wholesale market prices. Value of Pilgrim and TMI-1 asset sales.

157. **Maryland PSC** Case No. 8794 and 8804; BG&E restructuring and rates; Maryland Office of People's Counsel. Direct, December 1998; rebuttal, March 1999.

    Implementation of restructuring. Valuation of generation assets from comparable-sales and cash-flow analyses. Determination of stranded cost or gain.

158. **Maryland PSC** Case No. 8795; Delmarva Power & Light restructuring and rates; Maryland Office of People's Counsel. December 1998.

    Implementation of restructuring. Valuation of generation assets and purchases from comparable-sales and cash-flow analyses. Determination of stranded cost or gain.

159. **Maryland PSC** Case No. 8797; Potomac Edison Company restructuring and rates; Maryland Office of People's Counsel. Direct, January 1999; rebuttal, March 1999.

    Implementation of restructuring. Valuation of generation assets and purchases from comparable-sales and cash-flow analyses. Determination of stranded cost or gain.

160. **Connecticut DPUC** Docket No. 99-02-05; Connecticut Light and Power Company stranded costs; Connecticut Office of Consumer Counsel. April 1999.

    Projections of market price. Valuation of purchase agreements and nuclear and non-nuclear assets from comparable-sales and cash-flow analyses.

161. **Connecticut DPUC** Docket No. 99-03-04; United Illuminating Company stranded costs; Connecticut Office of Consumer Counsel. April 1999.

    Projections of market price. Valuation of purchase agreements and nuclear assets from comparable-sales and cash-flow analyses.

162. **Washington UTC** Docket No. UE-981627; PacifiCorp–Scottish Power Merger, Office of the Attorney General. June 1999.

    Review of proposed performance standards and valuation of performance. Review of proposed low-income assistance.

163. **Utah PSC** Docket No. 98-2035-04; PacifiCorp–Scottish Power Merger, Utah Committee of Consumer Services. June 1999.

Review of proposed performance standards and valuation of performance.

164. **Connecticut DPUC** Docket No. 99-03-35; United Illuminating Company proposed standard offer; Connecticut Office of Consumer Counsel. July 1999.

Design of standard offer by rate class. Design of price adjustments to preserve rate decrease. Market valuations of nuclear plants. Short-term stranded cost

165. **Connecticut DPUC** Docket No. 99-03-36; Connecticut Light and Power Company proposed standard offer; Connecticut Office of Consumer Counsel. Direct, July 1999; Supplemental, July 1999.

Design of standard offer by rate class. Design of price adjustments to preserve rate decrease. Market valuations of nuclear plants. Short-term stranded cost.

166. **W. Virginia PSC** Case No. 98-0452-E-GI; electric-industry restructuring, West Virginia Consumer Advocate. July 1999.

Market value of generating assets of, and restructuring gain for, Potomac Edison, Monongahela Power, and Appalachian Power. Comparable-sales and cash-flow analyses.

167. **Ontario Energy Board** File No. RP-1999-0034; Ontario Performance-Based Rates; Green Energy Coalition. September 1999.

Rate design. Recovery of demand-side-management costs under PBR. Incremental costs.

168. **Connecticut DPUC** Docket No. 99-08-01; standards for utility restructuring; Connecticut Office of Consumer Counsel. Direct, November 1999; Supplemental January 2000.

Appropriate role of regulation. T&D reliability and service quality. Performance standards and customer guarantees. Assessing generation adequacy in a competitive market.

169. **Connecticut Superior Court** Docket No. CV 99-049-7239; Connecticut Light and Power Company stranded costs; Connecticut Office of Consumer Counsel. Affidavit, December 1999.

Errors of the CDPUC in deriving discounted-cash-flow valuations for Millstone and Seabrook, and in setting minimum bid price.

170. **Connecticut Superior Court** Docket No. CV 99-049-7597; United Illuminating Company stranded costs; Connecticut Office of Consumer Counsel. December 1999.

Errors of the CDPUC, in its discounted-cash-flow computations, in selecting performance assumptions for Seabrook, and in setting minimum bid price.

171. **Ontario Energy Board** File No. RP-1999-0044; Ontario Hydro transmission-cost allocation and rate design; Green Energy Coalition. January 2000.

Cost allocation and rate design. Net vs. gross load billing. Export and wheeling-through transactions. Environmental implications of utility proposals.

172. **Utah PSC** Docket No. 99-2035-03; PacifiCorp Sale of Centralia plant, mine, and related facilities; Utah Committee of Consumer Services. January 2000.

Prudence of sale and management of auction. Benefits to ratepayers. Allocation and rate treatment of gain.

173. **Connecticut DPUC** Docket No. 99-09-12; Nuclear Divestiture by Connecticut Light & Power and United Illuminating; Connecticut Office of Consumer Counsel. January 2000.

Market for nuclear assets. Optimal structure of auctions. Value of minority rights. Timing of divestiture.

174. **Ontario Energy Board** File No. RP-1999-0017; Union Gas PBR proposal; Green Energy Coalition. March 2000.

Lost-revenue-adjustment and shared-savings incentive mechanisms for Union Gas DSM programs. Standards for review of targets and achievements, computation of lost revenues. Need for DSM expenditure true-up mechanism.

175. **NY PSC** Case No. 99-S-1621; Consolidated Edison steam rates; City of New York. April 2000.

Allocation of costs of former cogeneration plants, and of net proceeds of asset sale. Economic justification for steam-supply plans. Depreciation rates. Weather normalization and other rate adjustments.

176. **Maine PUC** Docket No. 99-666; Central Maine Power alternative rate plan; Maine Public Advocate. Direct, May 2000; Surrebuttal, August 2000.

Likely merger savings. Savings and rate reductions from recent mergers. Implications for rates.

177. **MEFSB** 97-4; MMWEC gas-pipeline proposal; Town of Wilbraham, Mass. June 2000.

Economic justification for natural-gas pipeline. Role and jurisdiction of EFSB.

178. **Connecticut DPUC** 99-09-03; Connecticut Natural Gas Corporation Merger and Rate Plan; Connecticut office of Consumer Counsel. September 2000.

Performance-based ratemaking in light of mergers. Allocation of savings from merger. Earnings-sharing mechanism.

179. **Connecticut DPUC** Docket No. 99-09-12RE01; Proposed Millstone Sale; Connecticut Office of Consumer Counsel. November 2000.

Requirements for review of auction of generation assets. Allocation of proceeds between units.

180. **MDTE** Docket No. 01-25; Purchase of Streetlights from Commonwealth Electric; Cape Light Compact. January 2001

Municipal purchase of streetlights; Calculation of purchase price under state law; Determination of accumulated depreciation by asset.

181. **Connecticut DPUC** Dockets Nos. 00-12-01 and 99-09-12RE03; Connecticut Light & Power rate design and standard offer; Connecticut Office of Consumer Counsel. March 2001.

Rate design and standard offer under restructuring law; Future rate impacts; Transition to restructured regime; Comparison of Connecticut and California restructuring challenges.

182. **Vermont PSB** Dockets Nos. 6460 & 6120; Central Vermont Public Service rates; Vermont Department of Public Service. Direct, March 2001; Surrebuttal, April 2001.

Review of power-planning decisions from early 1990s; Calculation of present damages from imprudence.

183. **New Jersey BPU** Docket No. EM00020106; Atlantic City Electric Company sale of fossil plants; New Jersey Ratepayer Advocate. Affidavit, May 2001.

Comparison of power-supply contracts. Comparison of plant costs to replacement power cost. Allocation of sales proceeds between subsidiaries.

184. **New Jersey BPU** Docket No. GM00080564; Public Service Electric and Gas transfer of gas supply contracts; New Jersey Ratepayer Advocate. Direct, May 2001.

Transfer of gas transportation contracts to unregulated affiliate. Potential for market power in wholesale gas supply and electric generation. Importance of reliable gas supply. Valuation of contracts. Effect of proposed requirements contract on rates. Regulation and design of standard-offer service.

185. **Connecticut DPUC** Dockets Nos. 99-04-18 Phase 3, 99-09-03 Phase 2; Southern Connecticut Natural Gas and Connecticut Natural Gas rates and charges; Connecticut Office of Consumer Counsel. Direct, June 2001; Supplemental, July 2001.

Identifying, quantifying, and allocating merger-related gas-supply savings between ratepayers and shareholders. Establishing baselines. Allocations between affiliates. Unaccounted-for gas.

Exhibit PLC____2:

Reduction in Stranded Costs Due to Higher NYC Energy Prices

	In-City Energy (MWH)			ConEd Projection of Market Energy Prices ($/MWh)			In-City NUG Revenues ($M)		
	NUGs 886 MW	*Retained 548 MW*	*Total In-City 1434 MW*	*In-City*	*Upstate*	*Difference*	*At In-City Prices*	*At Upstate Prices*	*Difference*
May-01	452,300	53,700	506,000	$62.00	$56.00	$6.00	$31.37	$28.34	$3.04
Jun-01	468,300	104,900	573,200	$72.00	$65.00	$7.00	$41.27	$37.26	$4.01
Jul-01	490,300	104,300	594,600	$93.00	$84.00	$9.00	$55.30	$49.95	$5.35
Aug-01	495,200	92,900	588,100	$93.00	$84.00	$9.00	$54.69	$49.40	$5.29
Sep-01	470,900	58,600	529,500	$62.00	$55.00	$7.00	$32.83	$29.12	$3.71
Oct-01	449,500	15,900	465,400	$58.00	$53.00	$5.00	$26.99	$24.67	$2.33
Summer Total	2,826,500	430,300	3,256,800				$242.46	$218.73	$23.73
Nov-00 to Apr-01			3,256,800			$5.00			$16.28
Annual Total	3,276,000	446,200	3,722,200						$40.01

Exhibit PLC____3:

Reduction in Stranded Costs Due to Higher NYC Capacity Prices

	ConEd Projection of Market Energy Prices ($/kW-mn)			In-City NUG Revenues ($M)		
	In-City	*Upstate*	*Difference*	*At In-City Prices*	*At Upstate Prices*	*Difference*
Nov-00 to Apr-01	$8.75	$1.10	$7.65	$75.29	$9.46	$65.82
May-00 to Oct-00	$8.75	$2.00	$6.75	$75.29	$17.21	$58.08
Total				$150.57	$26.67	$123.90

Exhibit PLC____4:

Sensitivity of New York City–Westchester Energy Price Differences to Location of Capacity

		Net Supply Growth from 2000 (MW)				Average Energy Price ($/MWH)		
Case[a]	**Year**	*Upstate*	*NYC*	*LIPA*	*Difference* [B]	*Zone H&I*	*Zone J*	*Difference* [C]
1	*As Is*							
	2003	-399	-335	-293	228	$29.76	$30.02	$0.26
	2005	-586	-509	-451	374	$29.95	$30.32	$0.37
	2008	-1016	-700	-702	386	$29.77	$30.39	$0.62
2	*All In*							
	2003	12753	6370	5639	744	$21.65	$21.91	$0.26
	2005	13074	6455	5709	909	$21.60	$21.86	$0.26
	2008	12142	6008	5232	902	$21.74	$21.97	$0.23
3a	*35% Balanced*							
	2003	6887	1840	1121	3,926	$24.13	$25.68	$1.55
	2005	6803	1697	983	4,123	$23.41	$25.30	$1.90
	2008	6546	1557	765	4,224	$23.32	$25.28	$1.96
3b	*35% Downstate*							
	2003	5038	2927	1882	228	$24.25	$24.90	$0.65
	2005	4928	2800	1755	374	$23.74	$24.53	$0.79
	2008	4627	2686	1555	386	$23.86	$24.63	$0.77
3c	*35% Upstate*							
	2003	7757	1296	795	5,666	$23.81	$25.96	$2.15
	2005	7685	1145	652	5,888	$23.08	$25.66	$2.58
	2008	7449	993	427	6,030	$22.88	$25.62	$2.74
5	*22%*							
	2003	3361	2006	701	654	$25.81	$25.81	$0.00
	2005	3174	1832	543	799	$25.86	$25.92	$0.06
	2008	2744	1641	291	812	$26.16	$26.27	$0.11

SOURCE

Sanford, Mark, Venkat Banunarayan, and Kim Wirgau. 2000. “Implications of Capacity Additions in New York on Transmission System Adequacy, A MAPS study Performed for New York Independent System Operator.” Report performed by General Electric for the NY ISO, December 27, 2000.

NOTES

[A] Case numbers for cases in Sanford, Banunarayan, and Wirgau.

[B] Difference between Upstate versus combined New York City and Long Island.

[C] Difference between Westchester County (zones H&I) and New York City (zone J).

Exhibit PLC____4:
Sensitivity of New York City–Westchester Energy Price Differences to Location of Capacity

Regression Results
Difference in energy prices, Zone J versus H&I =
a + b * MW added Upstate + c * MW added in Zone J + d* MW added on Long Island

Regression Statistics	
Multiple R	0.95
R Square	0.91
Adjusted R Square	0.89
Standard Error	0.31
Observations	18

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	3	13.12	4.37	44.63	2.04929E-07
Residual	14	1.37	0.10		
Total	17	14.49			

	Coefficients	*Standard Error*	*t Stat*	*P-value*
Intercept	0.34299	0.17663	1.94	0.07
Upstate	0.00038	0.00004	10.90	0.00
NYC	-0.00053	0.00018	(2.95)	0.01
LIPA	-0.00027	0.00020	(1.36)	0.19

$0.91/MWh per 1000 MW moved Up-NYC