STATE OF NORTH CAROLINA

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of the Application of	)	
Biennial Determination of	)	Docket No. E-100, Sub 74
Avoided Cost Rates for Electric Utility	)	
Purchases from Qualifying Facilities	)	

DIRECT TESTIMONY OF
PAUL CHERNICK
ON BEHALF OF
HYDRO-ELECTRIC POWER PRODUCERS GROUP

Resource Insight, Inc.

February 4, 1995

TABLE OF CONTENTS

I. Identification and Qualifications

Q: Please state your name, occupation, and business address.

A: I am Paul L. Chernick. I am president of Resource Insight, Inc., 18 Tremont Street, Suite 1000, Boston, Massachusetts.

Q: Please summarize your qualifications.

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

I was a utility analyst for the Massachusetts Attorney General for more than three years, and was involved in numerous aspects of utility rate design, costing, load forecasting, and the evaluation of power supply options. Since 1981, I have been a consultant in utility regulation and planning, since August 1990 in my current position at Resource Insight. In those capacities, I have advised a variety of clients on utility matters, including, the need for, cost of, and cost-effectiveness of prospective new generation plants and transmission lines; retrospective review of generation planning decisions; ratemaking for plant under construction; ratemaking for excess and/or uneconomical plant entering service; conservation program design; cost recovery for utility efficiency programs; and the valuation of environmental externalities from energy production and use. My resume is attached as Exhibit ____ (PLC-1).

Q: Have you previously testified before the North Carolina Utilities Commission?

A: Yes. In 1992, I testified twice in North Carolina Utilities Commission Docket No. E-100, Sub 64 (Integrated Resource Planning Docket), once on IRP principles and practice, and once on cost recovery and incentives.

Q: Have you ever testified about rates for small power producers?

A: Yes. Before the Massachusetts Department of Public Utilities, I have testified on the DPU's regulations pursuant to §210 of PURPA in MDPU 535 (1981) and MDPU 84-276 (1985), concerning determination of avoided costs and other issues; on the risk-reduction value of non-utility generation in MDPU 88-19 (1987); and on the avoided costs of Western Massachusetts Electric Company in MDPU 88-123 (1988).

Q: What other professional work have you engaged in related to determining avoided costs?

A: I have been involved in litigation, negotiation and collaboration over avoided costs for energy-conservation programs in a number of jurisdictions, including Massachusetts, Maryland, Vermont, New Jersey, New York, South Carolina, Florida, and Illinois.

Q: What other professional work have you engaged in related to purchases from non-utility generation?

A: I filed testimony before the New Jersey Board of Regulatory Commissioners in Docket EM 92030359 (1994), on including environmental effects in comparing cogeneration projects; testified before the PUC of Texas on the environmental costs and benefits of a proposed cogenerator in Docket 11000 (1993); assisted in preparation of my firm's testimony on Delmarva Power and Light's bidding process for the Delaware PSC in 1991; testified before the Pennsylvania PUC on auxiliary service rates for cogenerators in Docket R-850290 (1986); and testified on the effects of rate design and service conditions on cogeneration and small power production in MDPU 558 (1981).

II. Introduction

Q: On whose behalf are you testifying?

A: I am testifying on behalf of the group of hydro-electric power producers that has intervened in this proceeding.

Q: What is the purpose of your testimony?

A: The purpose of my testimony is to describe some problems in the derivation of avoided costs offered to small hydro-electric power producers by Duke Power and Carolina Power and Light (CP&L), and to propose alternative avoided-cost methods and estimates to be used in setting rates for small hydro facilities.

Projections of avoided costs determine the rates to be paid under new and renewal contracts, and thus the viability of new and existing plants. Inadequate and unreliable rates may result in the cancellation of potential new cost-effective and beneficial hydro projects, the abandonment of existing units if renewed contract rates are inadequate to cover the costs of maintaining the plants and their licenses, and the loss of the trust and good-will of developers of desirable power supplies in the future.

Q: What are the fundamental problems in the Companies' approach to estimating avoided costs and setting rates for small hydro-electric power producers?

A: CP&L and Duke have used similar methods for calculating their avoided costs, with similar problems.

The first problem is that the Companies have estimated avoided costs by combining energy costs that are primarily coal with the capacity costs of a gas turbine peaker. The total avoided cost is therefore lower than the cost of power from a coal plant—which is expensive to build and operate, but burns inexpensive fuel—or from a gas turbine, which is relatively inexpensive to build but burns much more expensive oil and gas. In essence, the Companies estimate avoided costs as though hydro purchases replaced coal-burning peaker plants, at costs below those of real coal plants and real peakers.

The second problem is that the limitation of contracts, past and present, to a fifteen year term, combined with the Companies' avoided-cost estimation method, is very likely to understate the long-term value of hydro plants, with long lead times and long lives.

The third problem is that the Companies' estimates of avoided costs ignore many benefits power purchased from independent hydro plants, including

- increasing profitable off-system sales of capacity and energy;
- shifting risks of plant construction and operating cost, and reliability, from the Companies and their customers to the hydro developers and owners;
- reducing the Companies' exposure to numerous environmental regulations;

- diversifying the environmental risks to North Carolina's electric supply;
- eliminating fuel-price risks;
- reducing transmission and distribution costs;
- providing environmental benefits directly to the Companies' customers, in improved air quality, improved health, and reduced compliance costs.

Q: How have you proposed to correct these problems?

A: Estimating avoided costs always involves uncertainties and approximations. Given the relatively small amount of energy, capacity and costs affected by the rates for small hydro plants, the methodology used to set those rates should be fairly simple. I thus propose the reasonable and simple method for setting small hydro rates at the full long-run avoided cost of a coal plant.

The long-run value of small hydro is higher than the cost of a new coal plant, because hydro purchases reduce construction and operating risk, avoid the risks of fuel prices and environmental regulations, and provide environmental benefits to the Companies and their customers. On the other hand, the value of small hydro in the next few years may be lower than the cost of a new coal plant. Using the coal-plant cost is a reasonable and unbiased approximation of avoided costs over the next fifteen years.

III. Correcting the Companies' Mixing of Peaking Capacity with Baseload Energy

Q: How do CP&L and Duke calculate avoided generation costs?

A: Both CP&L and Duke use the component, or peaker, method of calculating avoided capacity and energy costs of generation. This method has been recognized as acceptable in North Carolina, as well as certain other jurisdictions. The Companies jointly sponsored the testimony by Mr. Bruce Ambrose, to respond to the Commission's requirement that they justify the use of the peaker method over the differential-revenue-requirements method and the proxy-plant method.

Q: Please summarize Mr. Ambrose's description of the peaker method.

A: The capacity credit for each year is the annualized or carrying cost of the least-cost source of capacity (usually a combustion turbine or CT), if capacity is not in surplus. Total annual capacity cost may then be spread over certain on-peak time intervals during the year as kW-month or kW-hour capacity credits. Energy credits are the marginal operating costs for each time period (hour) in the year. The marginal operating costs for all annual time periods are usually calculated by computer model simulations that dispatch supply resources contained in the resource plan for each year in a least-cost manner. The marginal operating costs are those associated with the last (most expensive) supply resource used in each time period.

A. The Problems with the Peaker Method

Q: Does Mr. Ambrose correctly describe the peaker method?

A: Mr. Ambrose's description of the peaker method is generally clear and correct, as far as it goes. However, he fails to mention one important weakness of the method: that it can produce avoided-cost estimates lower than the costs of utility plants that are actually avoided.

This fundamental problem is not obvious in the highly simplified example that Mr. Ambrose presents, in which fuel prices, load, and the annual load-duration curve remain constant from one year to the next and marginal supply does not change as a new unit is added. In this simplified world, Mr. Ambrose only needed to analyze the total costs of existing and new supply options for one year. He correctly found that, for his example,

- A baseload plant would be economic to add to the utility's system only if the extra costs of building and operating the baseload plant are less than the resulting fuel cost savings (both compared to the alternative of adding a peaker).
- The peaker method will produce avoided costs at least equal to the cost of the avoidable baseload plant, since the sum of the avoided energy costs and the peaker capacity must be greater than the cost of the coal plant (or otherwise the baseload plant would have failed the test in the previous point, and not been built).
- The same total annual cost results from using (1) the capital cost of a peaker plus the operating costs of the marginal supply resources as (2) the capital and operating costs of the baseload plant.

Q: If Mr. Ambrose's simple example is correct, why would the peaker method not work in the real world?

A: In the real world, utilities select particular types of power plants to minimize expected costs over the life of the plant, or some other long analysis period. Mr. Ambrose assumes that the baseload plant pays for its extra costs by its fuel savings in its first year of operation. In fact, the baseload plant may be selected over a peaker because it avoids expensive fuel in the future, when

- the fuel is more expensive in dollars per gallon,

- load growth would require the use of more of the expensive fuels than at present,[1] and
- off-peak load growth may increase the number of hours in which baseload capacity is insufficient and peaking capacity must operate.

In all these situations, the utility may be rationally building baseload plants that are more expensive than the avoided costs computed in the peaker method. As Mr. Ambrose makes clear, real-world systems are always attempting to move closer to an unobtainable equilibrium, which shifts as loads, supplies and prices change. Avoided-cost credits should reflect avoidable costs in the real world, not in some idealized static-equilibrium world.

Q: Does the building of capacity for the long term present the only situation in which avoidable baseload plants may have costs higher than the peaker method would imply?

A: Another problem arises because the peaker method allows the utility to skim the cream of avoided energy cost, and leave lower-value baseload energy for small power producers to compete with. Typically, the utility will justify its baseload plant by comparison with the most expensive energy sources it would otherwise operate. The utility then assumes that it will build baseload generation, backing out those most-expensive sources, and estimates avoided costs for what's left behind, which may be much less expensive than the costs the baseload plant was compared to. The utility gets the first bite at the

[1]In the first year, oil and gas plants may only be needed to meet load 1% of the time. But if the utility added only peakers, oil and gas plants might be running 25% of the time in ten years.

apple of avoiding expensive fuel, and may not leave much for small producers, hydro or otherwise.

The hydro plant should be paid for avoiding the expensive fuel, or for avoiding the expensive coal plant; the peaker method gives them neither. By paying less than the utility's avoidable costs, the peaker method may result in the cancellation or abandonment of hydro projects that could have saved the ratepayers money.[2]

Mr. Ambrose's description (at 29) of his approach actually makes my point quite nicely:

> Obviously, every kilowatt-hour delivered by a QF saves the utility's marginal energy cost—the operating cost of the unit which can be turned down as a result of the QF's delivery. It is these same marginal energy costs over time which are compared to the operating costs of proposed new units in the generation planning process to determine if a new unit will provide sufficient fuel savings to offset its capital costs. Thus, for a long-term QF contract, avoided costs can be estimated as the annual equivalent of the utility's least-cost capacity option (as a capacity payment) and marginal energy costs in each year of the contract (as an energy payment). That is exactly what the component method does.

Notice that the first reference to marginal energy costs is as a benchmark for evaluating whether to include a new baseload unit in the supply plan. Suppose its fuel savings are sufficient to offset its additional capital costs. With the baseload plant included in the supply plan, marginal energy costs from that point onward will be lower than otherwise. If this revised set of marginal energy costs are then used to estimate avoided energy costs, but only the low capital cost of a CT has been included as the avoided capacity cost, something for nothing has been obtained.

[2] As I discuss below, the hydro plant has other benefits to the utility, its customers, and the state as a whole.

Q: Is this just a theoretical concern?

A: No. In Mr. Ambrose's Exhibit BJA-6, he shows how a baseload coal plant with a 25-year present-value cost of almost $2,600/kW would be selected over a peaker costing over $4,200/kW. Once the coal plant is planned, the avoided energy cost for the utility may be almost entirely coal, especially if the utility continues to add coal plants in later years. The peaker method, applied to a 25-year contract, would pay a small power producer about $1,000/kW for avoiding the peaking capacity and another $1,000/kW for avoiding coal fuel, for a total of $2,000/kW, even though the avoidable coal capacity costs $2,600/kW, or 30% more.

Q: Have CP&L and Duke left the costs of coal plants out of their estimates of avoided costs?

A: Yes. Both utilities include new baseload coal plants in their supply plans, but neither includes any costs of the coal plants in their avoided costs. They combine the lower marginal operating costs made available by baseload capacity additions in the year 2006 (Duke) and 2008 (CP&L and Duke) with the low capital costs of a peaker. Starting at least in 2006 for Duke, and 2008 for CP&L, their avoided energy costs are underestimated as a result of using the peaker method. The lower avoided energy costs for these years, resulting from the lower operating costs made available by investments in baseload coal plant capacity, do not include the extra capital cost of the baseload capacity.

Mr. Young states in his prefiled testimony (at 5, lines 8–10) that Duke's avoided cost estimates use the resource acquisition assumptions as filed in the 1994 Short Term Action Plan. Duke estimates avoided energy costs from the difference in PROMOD costs for a simulation with 100 MW of QFs at

100% capacity factor versus simulation without QFs (at 6, lines 8–12). Mr. Young also states that the carrying cost of a CT was used for estimating avoided capacity costs (at 6, lines 5–7). The same real annual capacity cost was used for each year, from 1995 to 2009 (at 10, Exhibit SKY-3).

Carolina Power & Light's avoided-cost estimates are similarly based on PROMOD model runs and a method essentially the same as Duke's.

Q: Does the peaker method ever give correct results?

A: The peaker method gives correct results for basic avoided energy costs whenever the utility plans to build only peaking units, with the minimum *capacity* cost. However, whenever the utility adds capacity other than peakers, the method often under-estimates avoided costs.[3]

B. Fixing the Hole in the Peaker Method

1. The Basic Fix

Q: How can this error be fixed?

A: The solution is simple; the difference between the fixed costs of the baseload and peaker plant is really part of energy costs.[4] This solution is consistent with the generally accepted view that the portion of a utility's costs attributable to meeting peak demand should never exceed the cost of peaking capacity. In fact, Mr. Ambrose suggests that both the differential-revenue-requirements method and the proxy-plant method should also include capital

---

[3]The peaker method is also accurate if the first-year cost of the base-load plant is lower than the cost of the peaker plus avoided system fuel.

[4]The same is true for intermediate plants, which are units between peakers and baseload plants in their cost structure.

costs in excess of peaker costs in the energy value, while leaving only the capital cost of a peaker in the demand value. While it is correct that the cost of meeting peak demand should not exceed the cost of the least-cost source of pure capacity, it is wrong to ignore the incremental capital and operating costs of other supplies.

For consistency, there are two alternative ways that avoided energy costs may be estimated with the peaker method. One is to restrict the resource plan to additions of the least-cost capacity option in each year. Then, as peak load grows over time, marginal operating costs will increase as intermediate- and peak-load resources are responsible for a greater share of marginal operating units. If the overall least-cost capacity addition would be an intermediate or baseload plant, this alternative will result in higher than necessary total avoided costs. It has the simplicity, however, of not requiring any capital cost "adder" to avoided energy costs. For small deviations from the optimal mix of supply resources, avoided energy costs will not differ by much, even if the least-cost expansion plan calls for other than investment in CTs.

The second alternative is to use a realistic resource plan for estimating avoided operating costs. For this alternative, consistency requires that the "excess" capacity costs of any resource additions other than peakers be included in avoided energy costs.[5] I recommend this second approach.

[5]These extra costs can be allocated to time period in several ways. Since the energy cost savings due to using a baseload plant instead of a CT occur throughout the year, utilities often allocate the excess capacity costs as a percentage adder to all avoided energy costs.

2. *Fixes Used in Other Jurisdictions*

Q: Have any other states adopted methods for consistently estimating capacity and energy avoided costs?

A: Yes. I have not done a formal study of the methods used around the country, but my experience indicates that utilities commonly capture the full cost of new capacity in one way or another. I will list a few examples.

New York requires use of avoided energy costs based on PROMOD or other simulation model results up to the need date for new baseload capacity. After the baseload need date, avoided energy costs are based on the proxy method, by including the incremental capital costs in avoided energy costs. Capacity payments are based on the cost of a CT.[6] New Hampshire uses a similar method.

Massachusetts computes avoided costs using a decremental method, in which the entire revenue requirements of the utility system are computed (1) for the base case and (2) with reduction in load (representing the non-utility generation) and without the avoidable plant. Avoided costs are thus the cost of the avoided plant (once it would have been built), minus its fuel savings, plus the cost of avoided fuel. The capacity cost of a peaker is allocated to demand (and typically spread over on-peak hours), and all other costs are

[6]Full capacity cost credits given whenever capacity is required anywhere in the entire state utility system. This rule was implemented in recognition of the ease of exchanging capacity between individual utilities with surplus and deficit capacity levels. Also, before the new capacity need date, avoided capacity costs are phased in from current market values over several years to reflect the value of increased reliability.

allocated to energy. The difference between the cost of the avoided plant and the cost of a peaker is termed "capitalized energy."[7]

The major Maryland utilities also reflect the costs of baseload additions, although they use different methods. Baltimore Gas and Electric uses a capitalized energy approach, similar to Massachusetts. Potomac Electric Power (PEPCo) computes a marginal energy cost for each year, and then calculates the net capacity cost of avoidable new generation as the total capacity cost, minus fuel savings at the marginal energy cost. Other than the assignment of capacity costs between peak demand and energy, the result of PEPCo's method is very similar to the Massachusetts method.

3. *Figuring Out When Baseload Additions Will Be Economical*

Q: Why does the date on which new baseload capacity will be needed matter for avoided costs?

A: As demonstrated above, the need date for base load capacity can have a major impact upon avoided costs. This sensitivity underlines the importance of a careful consideration of how need date should be established for use in the development of avoided costs.

In its 1992 IRP and subsequent STAPs, Duke plans on adding baseload coal capacity beginning in 2006. CP&L also assumed that a 2006 need date for baseload capacity in its 1992 IRP. In its 1994 STAP, CP&L has delayed addition of baseload capacity until 2008. However, there is substantial justification for assuming an earlier need date for these two utilities.

---

[7]Vermont utilities generally use a similar approach, although the excess capacity costs of baseload plants are sometimes called "capitalized fuel savings."

Q: Why would CP&L or Duke's baseload-need dates be earlier than they have planned?

A: First, for a variety of reasons, there is uncertainty as to when Duke and CP&L will require additional base load capacity. Factors such as high load growth, carbon taxes, emissions caps, and lower capacity factors for existing generation would advance the need for new base load supply.

Second, it is relevant to consider the regional supply-demand balance. Duke and CP&L are interconnected to each other, as well as to other utilities. As the utility industry becomes more competitive, the market for various types of electricity trade is becoming more active. Transactions can take place over long distances. For example, Duke has recently entered into a power sales agreement with a utility in Louisiana.

To the extent that other regional utilities require base load and intermediate capacity prior to 2006, Duke and CP&L may have opportunities for selling power off-system. By the same token, if other utilities will have substantial excess capacity, it may be possible for Duke and CP&L to purchase power at a cost below that of a new base load plant. In any event, such opportunities should be reflected in each utility's avoided costs.

Q: Have you been able to analyze the regional power market?

A: Within the constraints of this proceeding, I have not been able to complete an extensive review of regional power markets. Duke and CP&L did not provide any quantitative information in response to an interrogatory concerning its own market assessment (Intervenors' Question 6b). A brief analysis indicates that regional supply additions over the next ten years are dominated by combustion turbines. However, some utilities are planning to install new coal and combined cycle capacity beginning in the year 1999, and this capacity is not yet under construction. Thus, there would appear to be market opportunities for off-system sales of base and intermediate capacity prior to the 2006 need date of Duke, and certainly before the 2008 need date assumed by CP&L.

Q: How much additional sales do you expect that CP&L and Duke could make?

A: It is unclear to what extent Duke and CP&L could be successful in making sales to displace this planned capacity. Moreover, the pricing of these sales would be established in the marketplace, reflecting the avoided costs of buying and selling utilities, as well as wheeling costs.

Q: Have you estimated the missing baseload plant costs in CP&L and Duke's avoided costs?

A: Yes. The levelized values of the missing capital costs for a new baseload coal plant are shown in Exhibit PLC-C1 for CP&L and Exhibit PLC-D1 for Duke. These estimates also include a range of new baseload need dates from the year 2000 on to the dates presently forecasted by the utilities. For Duke, the missing capital cost for a new coal plant is equivalent to a nominal levelized cost of 0.2¢/kWh at its assumed 2006 need date. However, if the need date were to be as early as the year 2000, the missing capital cost would increase to about 0.4¢/kWh. For CP&L, the missing capital cost starts higher, at about 0.3¢/kWh in 2000, but falls to zero if the baseload capacity has no value until after 2003, by which time CP&L's running cost is higher than the cost of the coal plant.[8]

[8] In other words, after 2003, the coal plant is no longer avoidable, since it is more profitable to avoid the combination of peaker and marginal energy.

C. Avoided-Cost Method and Contract Duration

Q: Are there any avoided-cost concerns specific to hydropower QFs?

A: Yes, there are. Hydro projects are very front-loaded in their costs since they are very capital-intensive and have quite long useful lives. Under the peaker method, a hydro project may be penalized for helping to reduce the amount of baseload capacity the utility builds in the first 15 years of the project's life. This occurs because the avoided costs estimated when the contract comes up for renewal may show an excess of baseload capacity (as both utilities' avoided costs indicate in this case), resulting in low energy costs.[9] But for the hydro plants, the utility would presumably have built more baseload plant, and been stuck paying for even more surplus. Yet the hydro contract renewal ignores this continuing avoided cost.

D. Understatement of Costs Included in the Peaker Method

Q: Are there any other problems with either CP&L's or Duke's application of the peaker method?

A: Yes, there is a problem with CP&L's derivation of capacity credits in the years 1995 to 1997. While Duke includes the full capacity cost of a CT in each year, CP&L proposes to do so only from 1998 onward, according to Mr. King (at 3–4). CP&L justifies its method by asserting that 1998 is the first year that required capacity additions have not been fully committed. CP&L includes the cost of a CT, discounted at the utility's cost of capital, as the capacity value for the years 1995 to 1997 in recognition of the added reliability value of QF additions.

[9]Under the peaker method, capacity values are always low.

These capacity values for 1995 to 1997 may be too low for several reasons. First, Duke needs additional capacity from 1995 to 1997, so a nearby market exists for CP&L to sell any surplus capacity in those years. Second, hydro plants coming on line or renewing contracts in 1995 will have generally been known to CP&L for several years, prior to its need to commit to CT construction. Capacity payments should be set with respect to installation date, not commitment date. Third, other utilities have been able to reschedule peaker additions as little as a year in advance, and have reflected that ability in their avoided costs. For all three of these reasons, the Commission should require that CP&L use the full carrying cost of a CT as its capacity value for 1995 to 1997, as well as thereafter.

Q: Are there any costs that CP&L or Duke neglected to include in their avoided costs?

A: Yes. Both CP&L and Duke neglected to include the market value of avoided SO_2 allowances, required by the 1990 Clean Air Act Amendments (CAAA), in their original submissions. Young's revised Exhibit SKY-3 for Duke now includes SO_2 allowances, although at a low value. CP&L has asserted that it included compliance costs in its PROMOD runs, but has declined to provide any information on what, if any, market value it applied to allowances.

Sulfur-dioxide allowances have become a tradable commodity. Whether utilities must purchase additional allowances in order to comply with the SO_2 regulations, or are selling surplus, the allowances have a tradable value. By purchasing clean hydropower (or through DSM programs), a utility can either avoid paying for one more SO_2 allowance, or it can sell an additional surplus allowance to another utility. In either case, the marginal value or cost of the allowances to CP&L and Duke is the same. Currently, SO_2 allowances sell for over $150 per ton, even though most utilities do not need allowances until the year 2000; as we get closer to that date, the market value of allowances is generally expected to increase in real value.

Q: By how much would inclusion of SO_2 allowance costs increase the avoided costs of CP&L and Duke?

A: Conservatively low estimates of SO_2 allowance prices would start about $300 in 2000, and to about $500 in 2010. The year 2000 value is based on the Department of Energy's *1995 Annual Energy Outlook* (at 30), escalated to 2010 at Duke's assumed inflation rates. These values are significantly less than those projected in a NERA report cited by CP&L in its 1992 IRP (at F-19).

Based on these allowance values, I estimated the value of SO_2 allowances for marginal changes in the supply resources of CP&L and Duke for baseload-need dates from the year 2000 onward. The levelized SO_2 allowances per kWh is shown in Exhibit PLC-2. The full cost of allowances for existing generation would be 0.2–0.3¢/kWh for 2000–2009, with a levelized average (including zeroes in the early years) of 0.2¢/kWh. The allowance cost of a new coal plant would be much smaller, about 0.04¢/kWh. Since Duke includes some SO_2 value, the additional cost that would be appropriate for Duke is only about 0.14¢/kWh (levelized) for existing supply; Duke's allowance costs for existing units are actually higher than a realistic estimate of allowance costs for a clean new unit. The 15-year levelized SO_2 allowance value for a mix of existing and new supplies ranges from about 0.03¢/kWh if the first baseload addition is in 2000, to about 0.1¢/kWh for a need date of 2006 or 2007; the value net of Duke's modest allowance value is about 0.02¢/kWh lower.

IV. Other Benefits of Purchasing Hydro Power

A. Mitigation of Construction and Operation Risks

Q: Does utility purchase of hydropower offer any risk-mitigation benefits, compared to reliance on fossil or nuclear generation?

A: Yes. There are five major financial-risk-management benefits for the utility and its ratepayers associated with purchase of hydropower:

- There is no fuel-price risk to anyone.
- The developer, rather than the utility and its customers, bears all the risks of construction cost overruns.
- The developer, rather than the utility and its customers, bears all the risks of unforeseen operating costs and capital retrofits.
- If the plant fails to generate as reliably as expected, the utility loses access to the power, but also does not pay for the energy it does not receive.
- Hydro plants have no exposure to the pending and potential environmental regulations most important to the Companies' plants, reducing and diversifying the Companies risks of environmental regulations.

Q: Please explain why the absence of fuel-price risk is a benefit of hydro purchases.

A: The short-term volatility and long-term uncertainty of fossil fuel prices gives an economic advantage to hydro power, which has no fuel costs. Both CP&L and Duke calculate avoided energy costs for a best-guess forecast of fuel prices. This technique would only give correct forecasted avoided energy costs if fuel prices were known with complete certainty. To the extent that the prices in long-term contracts that can vary, and for any fuel purchased on the spot market, avoided energy costs are risky.

Q: Why is hydro's lack of exposure to potential new environmental regulations a financial benefit?

A: As discussed below, the trend toward stricter and more comprehensive environmental regulations means that hydropower does not face the potential compliance costs of fossil or nuclear generation. Air emissions of SO_2, NOx, fine particulates, mercury, heavy metals, greenhouse gases, and power plant cooling systems are all likely to be more heavily regulated in the future.[10] By purchasing hydropower, ratepayers avoid the financial risks associated with paying higher environmental compliance costs and emission allowances than those currently enacted.

Q: Why is the absence of investment risk and operating-reliability risk for hydro projects a benefit to the utility?

A: When a utility sets out to build a coal plant, the utility or its customers assume the risk that the construction cost will be higher than expected, that the plant will cost more to run, and that the plant may not operate reliably. When the utility purchases from a hydro plant, it pays only the contract price, and only for the amount of energy delivered, avoiding these problems.

Q: Are there any jurisdictions that evaluate avoided costs differently for hydro than for fossil-fueled units?

---

[10]Similarly, nuclear generation may be restricted by safety concerns with aging plant equipment and by the difficulty and cost of finding sites for disposal of low-level and high-level nuclear waste.

A: Yes. Ontario Hydro, one of the largest utilities in North America, adds 10% to avoided costs for renewable forms of energy, including hydropower, to reflect the absence of fuel-cost risks.

A number of states (including California and Minnesota) and utilities (including New England Electric) have set aside supply blocks for renewable projects, particularly non-utility renewable generation.

Small producers are often granted somewhat more favorable standard contract terms, due in part to their dispersed locations and their lower individual risk. Duke and CP&L are both offering to treat hydro producers more favorably than larger non-utility projects, for good reasons.

B. Environmental Risks and Benefits

Q: Please explain what environmental considerations should be recognized in CP&L and Duke's avoided costs.

A: Utility power plant effects on the environment can be split into four groups:

1. known compliance costs;
2. unknown costs of compliance with pending requirements;
3. costs of compliance that is not now required but may be in the near future;
4. costs of residual environmental damages to ratepayers and other parties in North Carolina and beyond.

Only a part of the first of these four categories has been included in CP&L and Duke's avoided costs. A complete accounting of environmental costs would include costs under all four categories in avoided costs.

Q: Are there any potential environmental regulations that could impose significant costs on North Carolina utilities and their ratepayers?

A: Yes. Several more strict or new regulations may be imposed to control a variety of environmental damage effects:

- *Tighter NOx controls* may be required to bring regions into compliance with ambient ozone standards, and due to concern about accumulation of nitrogen in forest soils.[11]
- *Tighter ambient standards for SO_2 or sulfate particulates* could require reduced sulfur levels by coal plants or increased gas use. EPA has proposed a new short-term (five-minute average) ground-level SO_2 standard to protect asthmatics, which could require reduced sulfur levels or increased stack heights.
- *Regulation of heavy-metal air toxics from utility plants* could require scrubbers, improved particulate removal, and/or other modifications to operation of coal-fired plants. Extensive and expensive air-toxics controls are required for non-utility sources by the CAAA; regulation of utility sources is likely to follow completion of a Congressionally mandated EPA study in 1995.
- *Regulation of mercury emissions* from coal plants, which would probably require improved particulate removal and injection of activated carbon. The CAAA also mandates a study of coal-plant mercury emissions. Coal plants are a major source of mercury, which bioaccumulates and has been identified as a current danger to human health and fish-eating wildlife.

[11]The declining health of existing forests exacerbates the difficulty of achieving net greenhouse-gas stabilization, and has other economic and environmental effects.

- T*ighter controls on fine particulates,* which have been linked to increased death rates and also carry a disproportionate share of the heavy metals emitted by coal and oil units. Recent studies have indicated that particles smaller than 10 microns in effective diameter are responsible for more illness and deaths than previously thought; some studies suggest that particles smaller than 2.5 μ are particularly important. These very small particles are the most difficult and expensive to capture.
- *Restrictions on cooling systems,* in terms of thermal discharges to water bodies and/or entrainment and impingement effects on aquatic life, may require new intake and outlet structures (and, potentially, closed cooling systems). Such modifications would reduce capacity and increase heat rates. In an out-of court settlement, EPA has agreed to develop rules defining "best available technology" for cooling-water intakes, required by law since 1971.
- *Requirements for reduction of greenhouse gases,* particularly CO_2 from the burning of fossil fuels. These reductions may be achieved through the imposition of carbon taxes, emissions caps and trading, reductions in fuel use (requiring increased efficiency and/or non-fossil generation), or other means. While long-term average warming is not likely to be statistically demonstrated for decades, increased frequency and severity of damaging storms, flooding, drought, heat waves and other effects of changed warming patterns continue to cause concern and pressure for real limits on CO_2 emissions. Insurance organizations have been moving to limit coverage or increase rates for climate-related damages, making

climate change a near-term economic problem for many businesses and individuals.

Q: Could NOx-control costs have substantial effects on the cost-effectiveness of coal-plant-life extension?

A: Yes. The costs of additional controls, such as selective catalytic reduction (SCR) or selective non-catalytic reduction (SNCR), vary with the age, size, and design of the plant; the costs for small, old units may be greater than the range usually estimated. SNCR, which may achieve reductions in the range of 40–70%, has a capital cost estimated to be in the range of \$5–\$16/kW, and an operating cost of 0.5–4 mills/kWh.[12] SCR, which may reduce emissions by 70–90%, is estimated to cost \$70–\$150/kW.[13] SCR will, in addition, have operating costs, including costs for ammonia or urea injection and for catalyst replacement.

Q: How would more realistic consideration of life-extension and environmental-compliance costs affect avoided costs used in the valuation of other resource options, including small hydro?

A: More realistic consideration of life extension on a unit-specific basis would result in greater avoided costs. First, if life extension of certain units is not found to be economically feasible, retiring those units will raise energy costs in the short term and require spending on replacement baseload or cycling

---

[12]Torrens, Ian M., and Jeremy B. Platt. 1994. "Electric Utility Response to the Clean Air Act Amendments," *Power Engineering*, January 1994, at 46; and Bemis, et al. 1989. "Technology Characterizations," Staff Issue Paper #7, Docket No. 88-ER-8, California Energy Commission, September 6, 1989.

[13]Torrens and Platt at 46.

capacity in the long term. Replacement may be required before CP&L's current new baseload plant need date of 2008 or Duke's need date of 2006.

A number of sources have recently acknowledged the likelihood of retirement for older coal plants, as new regulations add to the problems of aging. The New England Electric System's 1994 IRP found that its three oldest coal units, built 1951–58 and with capacities of 72–143 MW, would be uneconomic to operate past 1999.[14] The NY State 1994 Energy Plan found that retirement by 1999 would be economical for 45% of the coal units of less than 150 MW, all of which also entered service prior to 1960.[15] Both of these studies concluded that the retirements would be driven by environmental compliance costs, combined with routine aging. A recent Bechtel study anticipated the retirement of virtually all pre-1958 coal plants by the year 2005, due to SO_2 and other regulations.[16] The Companies have many hundreds of megawatts of older coal plants that may be vulnerable to retirement in the next several years.[17]

---

[14]Looking further ahead, NEES projects the retirement in 2007 of a 430-MW oil plant that entered service in 1974 and two 235-MW coal units constructed in 1963–1964. NEES also included in its probabilistic analysis a 20% chance by 2001 of early retirement of 890 MW of "at risk" capacity; this appears to represent accelerated retirement of its Brayton 1 and 2 and Salem 4 units.

[15]A large amount of oil and gas capacity was also identified as economic to retire, and additional retirements were projected for early in the next decade.

[16]Lennox, Frank. 1994. "Emission Allowances—Long-Term Price Trend," *Cogeneration and Competitive Power Journal* 9(3):69–79.

[17]Duke has spent large sums modernizing some older units, which may be thus be more economical to continue operating, depending on the resulting physical condition of the plant, as well as its O&M costs, heat rate, and future environmental compliance costs. Adding a tall stack (to avoid short-term SO_2 peaks) and changing the cooling system (to minimize effects on fish

Second, some environmental controls expected to be required soon (e.g., SNCR, SCR, closed cooling systems, new water intakes, electrostatic precipitators, baghouses, carbon injection to remove mercury from flue gases) may significantly increase fuel costs, heat rates, and variable O&M, and hence, avoided energy costs.

More realistic treatment of life extensions would also reduce costs to ratepayers, since less-expensive resources can be procured to avoid spending millions of dollars on potentially futile attempts to extend the lives of old, small, expensive, and inefficient plants.

Q: Why should residual environmental effects of be included in avoided costs?

A: Even the emission allowed by environmental regulation permits costs on ratepayers and other parts of the North Carolina economy. Utility NOx emissions make ozone attainment more difficult in the urban areas, which may limit industrial growth, constrain consumers' choices in using their cars, and require yet another round of expensive backfits on utility and industrial boilers. Air pollution affects visibility and harms the health of forests; this reduces the revenues of the tourist industry, especially in the western part of the state. Declining forests also cost profits and jobs in the forest-product sector. Many pollutants, such as particulates, have direct health effects, with direct dollar costs in lost productivity and medical expenses. Beyond these direct financial effects, clean air and good health are valuable to the Companies' ratepayers, simply by improving the quality of life.

---

and wildlife) may be prohibitively expensive for a small, old, inefficient unit, even one that is in good physical condition.

Utility regulators in 14 states—California, Hawaii, Iowa, Massachusetts, Minnesota, Montana, Nevada, New Jersey, New York, Ohio, Oregon, Utah, Vermont, and Wisconsin—have adopted some form of quantitative environmental adder. Five states—California, Massachusetts, Nevada, Oregon, and Wisconsin—have developed specific monetized adders for various air emissions.[18] The other eight states have adopted percentage or cents-per-kWh adders.

Q: Have you estimated what environmental adder might be credited to hydropower in North Carolina?

A: Yes. For this purpose, I have estimated a set of air emission environmental values, to reflect a mix of uncertain future avoided utility costs, cash costs to other parts of the North Carolina economy, and non-cash benefits. I included only four pollutants, and used quite modest values for those. While I use $2,000/T for particulates, for example, the EPA uses a value of $17,700/T.[19] These emission values are shown in Exhibit PLC-3.

The environmental value per kWh is determined by multiplying the values per ton times the emission rates in tons per kWh, for typical existing coal plants prior to the avoidance of new baseload capacity, and for a new scrubbed coal plant afterwards.

---

[18]The Massachusetts environmental values were recently remanded to the Department of Public Utilities when a state court found that the DPU lacked the legislative authority for including external costs. The court was supportive of both the DPU's intent and its analytical approach.

[19]This value does not even include the results of recent studies indicating higher mortality levels from particulates.

As shown in Exhibit PLC-C3 for CP&L and Exhibit PLC-D3 for Duke, the total monetized value per kWh of these air emissions is quite significant: about 1¢/kWh for new units and 2.4¢/kWh for existing units. The total 15-year levelized air emission externality value ranges from about 1.6¢/kWh for a year 2000 base load plant need date to about 2.2¢/kWh for a need date in 2006.

V. Conclusion

Q: Please summarize your avoided cost findings for Duke and CP&L.

A: Exhibits PLC-C4 and PLC-D4 combine the missing baseload capital costs, the SO_2-allowance values, and the air-emissions environmental values. The total corrections come to about 2¢/kWh, with little variation due to different assumptions about the date at which baseload generation is first avoidable. These corrections do not include any reflection of the value of off-system sales, or the reduced risks of purchased hydro, compared to construction and operation of utility plants, or the value of avoiding environmental costs of a new baseload plant.

Q: Are you proposing that the Commission increase rates for small hydro producers by the values you list in Exhibit PLC-C4 and D4?

A: No. Correcting the problems with the Companies' estimates in detail would require a series of uncertain and controversial inputs, including the timing of the next baseload addition, the value of risk reduction, the expected value of pending and future environmental regulations, and the regional power market. And even this detailed analysis would not really solve the fundamental problem of uncertainty in the value of contract renewals.

Instead, I recommend that the Commission order the Companies to offer small hydro producers a stable avoided cost, based on the full costs of building and operating a new baseload plant, including environmental controls and a realistic estimate of the costs of SO_2 allowances. Based on the analysis above, and using the utilities' input assumptions, the 15-year levelized contract rates starting in 1995 would thus be:

- for CP&L, 4.4¢/kWh for energy, and 0.4¢/kWh for peak-related capacity;
- for Duke, 3.4¢/kWh for energy, and 0.8¢/kWh for peak-related capacity.

In the utilities' compliance filings in this proceeding, these avoided-cost estimates should be updated to reflect any adjustments to the Companies' input cost assumptions, and allocated to time periods in accordance with the allocations in the utilities initial filings.

The Commission should also require the Companies to post rates for 15-year contracts starting in 1996 and 1997, to allow avoided costs to be consistent with the starting or renewal dates of contracts. The values for 1997 should only remain available for contracts to which producers commit themselves prior to the issuance of the Commission's order on the next set of avoided-cost filings.

This approach will at least partially compensate hydro producers for bearing all of the risk of avoided cost rates beyond the 15-year contract term, and for reducing risks to the Companies and their customers. The capacity cost of a peaker should be allocated to peak hours, while all other costs of the baseload plant should be allocated to energy.

Q: Are you recommending that this long-run-marginal-cost method be made available to all non-utility generation, regardless of type?

A: No. The short lead times, low capital costs, large size, large total potential, and shorter useful lives of many non-hydro power producers make other rate-setting approaches, particularly bidding, more feasible and necessary. Large gas and coal-fired cogenerators and independent power projects can entirely satisfy a utility's new capacity requirements, and displace virtually all the existing expensive energy sources, for years into the future. In these situations, each such large project essentially establishes a new avoided cost for other projects. The best way to select the lowest-cost large project (utility-owned or otherwise) is to establish a bidding process. Extending bidding to small hydro projects would not be feasible, due to their small size (which would make the administrative costs of bidding prohibitively expensive), lead time, fixed costs, and long lives. Many jurisdictions therefore offer simple and stable purchased power rates for small renewable power producers, but require bidding for large blocks of power. I recommend that the Commission do the same.

Q: Does this conclude your testimony?

A: Yes.

Qualifications of

PAUL L. CHERNICK

Resource Insight, Inc.
18 Tremont Street, Suite 1000
Boston, Massachusetts 02108

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)

Tau Beta Pi (Engineering)

Sigma Xi (Research)

Institute Award, Institute of Public Utilities, 1981.

Publications

"The Allocation of DSM Costs to Rate Classes," *Proceedings of the Fifth National Conference on Integrated Resource Planning.* Washington: National Association of Regulatory Utility Commissioners. May 1994.

"Environmental Externalities: Highways and Byways" (with Bruce Biewald and William Steinhurst), *Proceedings of the Fifth National Conference on Integrated Resource Planning.* Washington: National Association of Regulatory Utility Commissioners. May 1994.

"The Transfer Loss is All Transfer, No Loss" (with Jonathan Wallach), The *Electricity Journal* 6:6 (July, 1993).

"Benefit-Cost Ratios Ignore Interclass Equity" (with others), *DSM Quarterly*, Spring 1992.

"ESCOs or Utility Programs: Which Are More Likely to Succeed?" (with S. Birner), *The Electricity Journal* 5:2, March 1992.

"Determining the Marginal Value of Greenhouse Gas Emissions" (with J. Schoenberg), *Energy Developments in the 1990s: Challenges Facing Global/Pacific Markets, Vol. II*, July 1991.

"Monetizing Environmental Externalities for Inclusion in Demand-Side Management Programs" (with E. Caverhill), *Proceedings from the Demand-Side Management and the Global Environment Conference*, April 1991.

"Accounting for Externalities" (with E. Caverhill). *Public Utilities Fortnightly* 127(5), March 1, 1991.

"Methods of Valuing Environmental Externalities" (with E. Caverhill), *The Electricity Journal* 4(2), March 1991.

"The Valuation of Environmental Externalities in Energy Conservation Planning" (with E. Caverhill), *Energy Efficiency and the Environment: Forging the Link.*. American Council for an Energy-Efficient Economy; Washington: 1991.

"The Valuation of Environmental Externalities in Utility Regulation" (with E. Caverhill), *External Environmental Costs of Electric Power: Analysis and Internalization.* Springer-Verlag; Berlin: 1991.

"Analysis of Residential Fuel Switching as an Electric Conservation Option" (with E. Espenhorst and I. Goodman), *Gas Energy Review*, December 1990.

"Externalities and Your Electric Bill," *The Electricity Journal*, October 1990, p. 64.

"Monetizing Externalities in Utility Regulations: The Role of Control Costs" (with E. Caverhill), in *Proceedings from the NARUC National Conference on Environmental Externalities*, October 1990.

"Monetizing Environmental Externalities in Utility Planning" (with E. Caverhill), in *Proceedings from the NARUC Biennial Regulatory Information Conference*, September 1990.

"Analysis of Residential Fuel Switching as an Electric Conservation Option" (with E. Espenhorst and I. Goodman), in *Proceedings from the NARUC Biennial Regulatory Information Conference*, September 1990.

"A Utility Planner's Checklist for Least-Cost Efficiency Investment" (with John Plunkett) in *Proceedings from the NARUC Biennial Regulatory Information Conference*, September 1990.

Environmental Costs of Electricity (with Richard Ottinger et al.). Oceana; Dobbs Ferry, New York: September 1990.

"Demand-Side Bidding: A Viable Least-Cost Resource Strategy" (with J. Plunkett and J. Wallach), in *Proceedings from the NARUC Biennial Regulatory Information Conference*, September 1990.

"Incorporating Environmental Externalities in Evaluation of District Heating Options" (with E. Caverhill), *Proceedings from the International District Heating and Cooling Association 81st Annual Conference*, June 1990.

"A Utility Planner's Checklist for Least-Cost Efficiency Investment," (with J. Plunkett), *Proceedings from the Canadian Electrical Association Demand-Side Management Conference*, June 1990.

"Incorporating Environmental Externalities in Utility Planning" (with E. Caverhill), *Canadian Electrical Association Demand Side Management Conference*, May 1990.

"Is Least-Cost Planning for Gas Utilities the Same as Least-Cost Planning for Electric Utilities?" in *Proceedings of the NARUC Second Annual Conference on Least-Cost Planning*, September 10-13, 1989.

"Conservation and Cost-Benefit Issues Involved in Least-Cost Planning for Gas Utilities," in *Least Cost Planning and Gas Utilities: Balancing Theories with Realities*, Seminar proceedings from the District of Columbia Natural Gas Seminar, May 23, 1989.

"The Role of Revenue Losses in Evaluating Demand-Side Resources: An Economic Re-Appraisal" (with J. Plunkett), *Summer Study on Energy Efficiency in Buildings, 1988*, American Council for an Energy Efficient Economy, 1988.

"Quantifying the Economic Benefits of Risk Reduction: Solar Energy Supply Versus Fossil Fuels," in *Proceedings of the 1988 Annual Meeting of the American Solar Energy Society*, American Solar Energy Society, Inc., 1988, pp. 553-557.

"Capital Minimization: Salvation or Suicide?," in I.C. Bupp, ed., *The New Electric Power Business*, Cambridge Energy Research Associates, 1987, pp. 63-72.

"The Relevance of Regulatory Review of Utility Planning Prudence in Major Power Supply Decisions," in *Current Issues Challenging the Regulatory Process*, Center for Public Utilities, Albuquerque, New Mexico, April, 1987, pp. 36-42.

"Power Plant Phase-In Methodologies: Alternatives to Rate Shock," in *Proceedings of the Fifth NARUC Biennial Regulatory Information Conference*, National Regulatory Research Institute, Columbus, Ohio, September, 1986, pp. 547-562.

"Assessing Conservation Program Cost-Effectiveness: Participants, Non-participants, and the Utility System" (with A. Bachman), *Proceedings of the Fifth NARUC Biennial Regulatory Information Conference*, National Regulatory Research Institute, Columbus, Ohio, September, 1986, pp. 2093-2110.

"Forensic Economics and Statistics: An Introduction to the Current State of the Art" (with Eden, P., Fairley, W., Aller, C., Vencill, C., and Meyer, M.), *The Practical Lawyer*, June 1, 1985, pp. 25–36.

"Power Plant Performance Standards: Some Introductory Principles," *Public Utilities Fortnightly*, April 18, 1985, pp. 29-33.

"Opening the Utility Market to Conservation: A Competitive Approach," *Energy Industries in Transition, 1985-2000*, Proceedings of the Sixth Annual North American Meeting of the International Association of Energy Economists, San Francisco, California, November, 1984, pp. 1133–1145.

"Insurance Market Assessment of Technological Risks" (with Meyer, M., and Fairley, W) *Risk Analysis in the Private Sector*, pp. 401–416, Plenum Press, New York, 1985.

"Revenue Stability Target Ratemaking," *Public Utilities Fortnightly*, February 17, 1983, pp. 35–39.

"Capacity/Energy Classifications and Allocations for Generation and Transmission Plant" (with M. Meyer), *Award Papers in Public Utility Economics and Regulation*, Institute for Public Utilities, Michigan State University, 1982.

Design, Costs and Acceptability of an Electric Utility Self-Insurance Pool for Assuring the Adequacy of Funds for Nuclear Power Plant Decommissioning Expense, (with Fairley, W., Meyer, M., and Scharff, L.) (NUREG/CR-2370), U.S. Nuclear Regulatory Commission, December, 1981.

Optimal Pricing for Peak Loads and Joint Production: Theory and Applications to Diverse Conditions (Report 77-1), Technology and Policy Program, Massachusetts Institute of Technology, September, 1977.

Reports

"Review of the Elizabethtown Gas Company's 1992 DSM Plan and the Demand-Side Management Rules" (with J. Wallach, J. Plunkett, J. Peters, S. Geller, B. Hamilton, and A. Shapiro); Report to the New Jersey Department of Public Advocate, November 1992.

"The AGREA Project Critique of Externality Valuation: A Brief Rebuttal," March 1992.

Environmental Externalities Valuation and Ontario Hydro's Resource Planning (with E. Caverhill and R. Brailove), 3 vols.; prepared for the Coalition of Environmental Groups for a Sustainable Energy Future, October 1992.

"Review of Jersey Central Power & Light's 1992 DSM Plan and the Demand-Side Management Rules" (with J. Wallach, et al.); Report to the New Jersey Department of Public Advocate, June 1992.

"The Potential Economic Benefits of Regulatory NO_X Valuation for Clean Air Act Ozone Compliance in Massachusetts," March 1992.

"Initial Review of Ontario Hydro's Demand-Supply Plan Update" (with Argue, David, et al.), February, 1992.

"Report on the Adequacy of Ontario Hydro's Estimates of Externality Costs Associated with Electricity Exports" (with E. Caverhill), January 1991.

"Comments on the 1991-1992 Annual and Long Range Demand Side Management Plans of the Major Electric Utilities," (with Plunkett, J., et al.), September 1990.

"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 I. Goodman and E. 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 E. Espenhorst), Boston Gas Company, December 22, 1989.

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

"Conservation Potential in the State of Minnesota," (with I. 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

"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.

DSM Advocacy Workshop; April 15, 1992; Session Leader for "Cost Recovery and Decoupling" and "The Clean Air Act and Externalities in Utility Resource Planning" panels.

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

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

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

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

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

"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;

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

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

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".

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

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

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

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; "Insurance Market Assessment of Technological Risks".

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 S. 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. Atomic Safety and Licensing Board, Nuclear Regulatory Commission 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 Public Service Commission 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 Public Service Commission 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 Public Service Commission 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 Public Service Commission 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 Public Service Commission 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. Massachusetts Department of Public Utilities 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. Massachusetts Department of Public Utilities 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. Massachusetts Department of Public Utilities 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 Public Utility Commission 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 Public Service Board 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 Public Service Board 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 Public Service Board Docket 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 Public Utilities Commission; 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 Public Service Commission 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. Commonwealth of 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. Massachusetts DPU 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. Commonwealth of Massachusetts; 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 Public Service Commission 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 Public Service Commission 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. Massachusetts DPU 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. Massachusetts DPU 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.

105. Public Utility Commission of Texas 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.

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

107. Maryland Public Service Commission Case No. 8473; In the Matter of the Application of the Baltimore Gas and Electric Company for the Review and Approval of the Power Sales Agreement Between the Baltimore Gas and Electric Company and AES Northside, Inc.; Maryland Office of People's Counsel; November 16, 1992.

108. North Carolina Utilities Commission Docket No. E-100, Sub 64; In the Matter of Analysis and Investigation of Least Cost Integrated Resource Planning in North Carolina—1992; Southern Environmental Law Center, on Demand-Side Management Cost Recovery and Incentive Mechanisms; November 18, 1992.

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

109 A Florida PDepartment of Environmental Regulation hearings on the Power Plant Siting Act; Legal Environmental Assistance Foundation, December, 1992.

110. Maryland Public Service Commission Case No. 8487; Application of the Baltimore Gas and Electric Company for an Increase in Electric Rates; January 13, 1993. Rebuttal Testimony: February 4, 1993.

111. Maryland Public Service Commission Case No. 8179; Petition of Potomac Edison for Approval of Amendment No. 2 to the Electric Energy Purchase Agreement with AES Warrior Run, Inc.; Maryland Office of People's Counsel; January 29, 1993.

112. Michigan Public Service Commission Case No. U-10102; In the Matter of the Application of the Detroit Edison Company for Authority to Amend its Rate Schedules Governing the Supply of Electric Energy; Michigan United Conservation Clubs; February 17, 1993.

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

114. Michigan Public Service Commission Case No. U-10335; In the Matter of the Application of Consumers Power Company for Authority to Increase Its Rates; Michigan United Conservation Clubs; October 1993.

115. Illinois Commerce Commission 92-0268, Electric-Energy Plan for Commonwealth Edison ; City of Chicago. Direct, 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. Federal Energy Regulatory Commission 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 Public Service Board Dockets No. 5270-CV-1,-3, and 5686; Central Vermont Public Service Fuel-Switching, DSM, and 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 Public Service Commission, Dockets 930548-EG–930551–EG, on behalf of the Legal Environmental Assistance Foundation, Inc. April 1994.

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

119. Vermont Public Service Board Docket No. 5724, on behalf of the Vermont Department of Public Service. Joint surrebuttal testimony with John Plunkett. August 1994.

120. Massachusetts Department of Public Utilities in DPU 94-49 on behalf of the Massachusetts Office of Attorney General. August 1994.

Analysis of Boston Edison's treatment of the effects of planning decision on customer bills, especially the company's its modeling and treatment of risk.

121. Michigan Public Service Commission in MPSC Case No. U-10554, Consumers Power Company DSM Program and Incentive; on behalf of the Michigan Conservation Clubs. November 1994.

Proposal to scale back DSM spending. Critique of proposed DSM changes; discussion of appropriate measurements of cost-effectiveness, role of DSM in competitive power markets.

122. Michigan Public Service Commission in MPSC 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 in Docket No. EM92030359; on behalf of 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 Public Service Commission in Case No. U-10671, Detroit Edison Company DSM Programs; on behalf of the 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 Public Service Commission in Case No. U-10710; on behalf of the 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.

Exhibit PLC-2
Sulfur Allowance Values

Year	DOE ($/Ton) [1]	Duke ($/Ton) [2]	DOE (¢/kWH) Existing [3]	DOE (¢/kWH) New [4]	Duke Estimate (¢/kWh) [5]	Additional values for Duke(¢/kWh) Existing [3]-[5]	Additional values for Duke(¢/kWh) New [4]-[5]
1995							
1996							
1997							
1998							
1999							
2000	303	81.00	0.195	0.043	0.052	0.143	-0.009
2001	321	85.94	0.207	0.045	0.055	0.151	-0.010
2002	341	91.18	0.219	0.048	0.059	0.161	-0.011
2003	362	96.74	0.233	0.051	0.062	0.170	-0.011
2004	384	102.64	0.247	0.054	0.066	0.181	-0.012
2005	407	108.90	0.262	0.057	0.070	0.192	-0.013
2006	424	113.36	0.273	0.060	0.073	0.200	-0.013
2007	441	118.01	0.284	0.062	0.076	0.208	-0.014
2008	459	122.84	0.296	0.065	0.079	0.216	-0.014
2009	478	127.88	0.308	0.067	0.082	0.225	-0.015
Levelized 1995-2009			0.19	0.04	0.05	0.14	-0.009

Real SO2 Allowance Escalation Rates	
2000-2005	2.51%
2006-2009	0.58%
General Inflation Rate	3.50%
SO2 Emission Rates (Lb/MMBtu)	
Existing Coal Plants	1.43
New Coal Plants	0.30
Heat Rates (MMBtu/kWh)	
Existing Coal Plants	9,000
New Coal Plants	9,404
SO2 Emission Rates (Lb/kWh)	
Existing Coal Plants	0.0129
New Coal Plants	0.0028

Sources:

Chernick Year 2000 Allowance Value per Ton	EIA, Annual Energy Outlook 1995 (Jan. 1995), p. 30, escalated from 1993 dollars by the utility's general inflation rate.
Utility Year 2000 Allowance Value per Ton	Duke Exhibit SKY-3 Revised.
Allowance Value Real Escalation Rates	Duke Exhibit SKY-3 Revised.

Exhibit PLC-2
Sulfur Allowance Values

Additional values for Duke(¢/kWh)

	New Baseload Plant Startup Year								
Year	2000	2001	2002	2003	2004	2005	2006	2007	2008
1995	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1996	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1997	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1998	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1999	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2000	-0.01	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14
2001	-0.01	-0.01	0.15	0.15	0.15	0.15	0.15	0.15	0.15
2002	-0.01	-0.01	-0.01	0.16	0.16	0.16	0.16	0.16	0.16
2003	-0.01	-0.01	-0.01	-0.01	0.17	0.17	0.17	0.17	0.17
2004	-0.01	-0.01	-0.01	-0.01	-0.01	0.18	0.18	0.18	0.18
2005	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01	0.19	0.19	0.19
2006	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01	0.20	0.20
2007	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01	0.21
2008	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01
2009	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01
Levelized 1995-2009	-0.01	0.01	0.02	0.03	0.04	0.05	0.06	0.07	0.08

Discount Rate 8.98%

Exhibit PLC-2
Sulfur Allowance Values

SO2 Allowance Values

	New Baseload Plant Startup Year								
Year	2000	2001	2002	2003	2004	2005	2006	2007	2008
1995	-	-	-	-	-	-	-	-	-
1996	-	-	-	-	-	-	-	-	-
1997	-	-	-	-	-	-	-	-	-
1998	-	-	-	-	-	-	-	-	-
1999	-	-	-	-	-	-	-	-	-
2000	0.04	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19
2001	0.05	0.05	0.21	0.21	0.21	0.21	0.21	0.21	0.21
2002	0.05	0.05	0.05	0.22	0.22	0.22	0.22	0.22	0.22
2003	0.05	0.05	0.05	0.05	0.23	0.23	0.23	0.23	0.23
2004	0.05	0.05	0.05	0.05	0.05	0.25	0.25	0.25	0.25
2005	0.06	0.06	0.06	0.06	0.06	0.06	0.26	0.26	0.26
2006	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.27	0.27
2007	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.28
2008	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06
2009	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07
Levelized 1995-2009	0.03	0.04	0.05	0.06	0.07	0.08	0.09	0.10	0.11

Exhibit PLC-3
Estimates of Environmental Costs

		SO2	NOx	CO2	PM	VOC [3]	Mercury [3]	Heat Rate [4]
				(Lb/MMBtu)			(Lb/TBtu)	(Btu/kWh)
Existing Coal Plant, 1.2% S	[1]	1.43	0.607	209	0.150	0.030	8.30	9,000
New Coal Plant with FGD	[2]	0.30	0.100	220	0.015	0.003	8.30	9,404

Sources:
1. Pace University Center for Environmental Legal Studies, Environmental Costs of Electricity (1990) p. 351, except for SO2. SO2 from Duke Exhibit SKY-3 Revised, average for years 2000-2005.
2. New York State Energy Office, New York State Energy Plan, Vol. 3: Supply Assessments (Oct. 1994) p. 620, Table 62.
3. Adapted from [2] for coal plant with FGD.
4. Heat rates from Duke spreadsheet DPCO-AC.XLS for existing and Public Staff-1-10b for new plants.

Monetized Externality Values Per Ton
(Real 1994 $)

		SO2	NOx	CO2	PM	VOC	Toxics
Pace Report	[1]	4,775	1,929	16.0	2,799	N/A	N/A
UCS Report	[2]	901	6,577	28.2	2,365	3,108	N/A
New York, 1994 SEP	[3]	970	4,752	6.5	2,787	3,359	79,542
Massachusetts	[4]	1,791	7,586	25	4,636	6,217	N/A
Chernick for North Carolina		900	2,000	6.5	2,000	-	-

Sources:
1. Pace University Center for Environmental Legal Studies, Environmental Costs of Electricity (1990) p. 351.
2. Union of Concerned Scientists *et al.*, America's Energy Choices (1991) pp. 36-37.
3. New York State Energy Office, New York State Energy Plan, Vol. 2: Issue Reports (Oct. 1994) p. 184, Table 4.
4. Order in MDPU 91-131.

Note: Values inflated to 1994 by the GDP implicit price deflator index.

Air Emission Environmental Values of Generation Technologies
(Real 1994 Cents/kWh)

	SO2	NOx	CO2	PM	VOC	Toxics	Total
Existing Coal Plant, 1.2% S	0.579	0.546	0.611	0.135	-	-	1.872
Pulverized Coal w/FGD	0.127	0.094	0.672	0.014	-	-	0.907

Source: Calculated from above emission rates and Chernick environmental values per ton.

Exhibit PLC-C1
CP&L Additional Annual Energy Costs for New Coal Plants

(Cents/kWh)

	New Baseload Plant Costs					Utility Avoided Costs			Additional
	Fuel	Var. O&M	Energy	Capacity	Total	Energy	Capacity	Total	Energy Cost
Year	[1]	[2]	[3]=[1]+[2]	[4]	[5]=[3]+[4]	[6]	[7]	[8]=[6]+[7]	[9]=[5]-[8]
1995	1.38	0.15	1.53	2.39	3.92	1.63	0.32	1.95	1.97
1996	1.43	0.15	1.58	2.48	4.05	1.75	0.34	2.10	1.96
1997	1.48	0.16	1.63	2.56	4.20	1.75	0.37	2.13	2.07
1998	1.53	0.16	1.69	2.65	4.34	1.91	0.40	2.32	2.03
1999	1.58	0.17	1.75	2.74	4.50	2.48	0.42	2.90	1.59
2000	1.64	0.18	1.81	2.84	4.65	2.80	0.43	3.23	1.42
2001	1.69	0.18	1.88	2.94	4.82	3.21	0.45	3.66	1.16
2002	1.75	0.19	1.94	3.04	4.98	3.93	0.46	4.39	0.59
2003	1.82	0.19	2.01	3.15	5.16	3.79	0.48	4.27	0.89
2004	1.88	0.20	2.08	3.26	5.34	4.38	0.50	4.88	0.46
2005	1.94	0.21	2.15	3.37	5.53	5.36	0.52	5.87	0.00
2006	2.01	0.22	2.23	3.49	5.72	5.42	0.53	5.95	0.00
2007	2.08	0.22	2.31	3.61	5.92	6.18	0.55	6.74	0.00
2008	2.16	0.23	2.39	3.74	6.13	6.59	0.57	7.16	0.00
2009	2.23	0.24	2.47	3.87	6.34	6.07	0.59	6.66	0.00
Levelized 1995-09					4.77		0.43		

Inflation Rate	3.50%	King Revised Exhibit 2, p. 1
Discount Rate	8.98%	King Revised Exhibit 2, p. 1
New Baseload Pulverized Coal Plant Data		
Technology	Subcritical 500 MW Limestone	CP&L IR Public Staff-1-15
Net Heat Rate, Full Load (Btu/kWh)	9639	CP&L IR Public Staff-1-10b
Fuel Price, 1995 (¢/MMBtu)	143.0	CP&L IR Intervenors-1-2, p.2
Real Fuel Price Escalation	0.00%	Adapted from EIA, Annual Energy Outlook 1995 (Jan. 1995), p. 76, for 0.5% real.
Capital Cost Year	1994	CP&L IR Public Staff-1-10b
Installed Cost ($/kW)	1,168	CP&L IR Public Staff-1-10b
O&M Cost Year	1994	CP&L IR Public Staff-1-15, p. 3
Fixed O&M ($/kW-yr)	41.80	CP&L IR Public Staff-1-15, p. 3
Variable O&M (mills/kWh)	1.40	CP&L IR Public Staff-1-15, p. 3
Real Fixed Charge Rate	9.75%	CP&L IR Public Staff-2-8, p. 1
Life (Years)	40	CP&L IR Public Staff-2-8, p. 1
General Plant Factor	1.0075	King Revised Exhibit 4
Fuel O&M Working Capital Factor	1.05%	King Exhibit 1
Non-Fuel O&M Working Capital Factor	1.83%	King Exhibit 1
Plant Capacity Factor	80%	
Utility Capacity Costs		King Revised Exhibit 2
Utility On and Off-Peak Energy Costs		King Exhibit 3
Utility On-Peak Hours	3025	Implicit from King Revised Exhibit 7.

Exhibit PLC-C1
CP&L Additional Annual Energy Costs for New Coal Plants

	New Baseload Plant Startup Year								
Year	2000	2001	2002	2003	2004	2005	2006	2007	2008
1995	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1996	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1997	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1998	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1999	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2000	1.42	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2001	1.16	1.16	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2002	0.59	0.59	0.59	0.00	0.00	0.00	0.00	0.00	0.00
2003	0.89	0.89	0.89	0.89	0.00	0.00	0.00	0.00	0.00
2004	0.46	0.46	0.46	0.46	0.00	0.00	0.00	0.00	0.00
2005	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2006	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2007	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2008	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2009	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Levelized 1995-2009	0.29	0.19	0.11	0.07	0.00	0.00	0.00	0.00	0.00

Discount Rate 8.98%

Exhibit PLC-C3
Environmental Values for CP & L

	Environmental Value	
	Existing Units	New Units
	(c/kWh)	(c/kWh)
Year	[1]	[2]
1995	1.94	0.94
1996	2.01	0.97
1997	2.08	1.01
1998	2.15	1.04
1999	2.22	1.08
2000	2.30	1.11
2001	2.38	1.15
2002	2.47	1.19
2003	2.55	1.24
2004	2.64	1.28
2005	2.73	1.32
2006	2.83	1.37
2007	2.93	1.42
2008	3.03	1.47
2009	3.14	1.52
Levelized 1995-2009	2.36	1.14

Environmental Values:

Existing Coal Plant, 1994 (¢/kWh)	1.872	Exhibit PLC-3
New Coal Plant, 1994 (¢/kWh)	0.907	Exhibit PLC-3
Inflation Rate	3.50%	

Exhibit PLC-C3
Environmental Values for CP & L

	New Baseload Plant Startup Year								
	2000	2001	2002	2003	2004	2005	2006	2007	2008
1995	1.94	1.94	1.94	1.94	1.94	1.94	1.94	1.94	1.94
1996	2.01	2.01	2.01	2.01	2.01	2.01	2.01	2.01	2.01
1997	2.08	2.08	2.08	2.08	2.08	2.08	2.08	2.08	2.08
1998	2.15	2.15	2.15	2.15	2.15	2.15	2.15	2.15	2.15
1999	2.22	2.22	2.22	2.22	2.22	2.22	2.22	2.22	2.22
2000	1.06	2.25	2.25	2.25	2.25	2.25	2.25	2.25	2.25
2001	1.10	1.10	2.33	2.33	2.33	2.33	2.33	2.33	2.33
2002	1.14	1.14	1.14	2.41	2.41	2.41	2.41	2.41	2.41
2003	1.17	1.17	1.17	1.17	2.49	2.49	2.49	2.49	2.49
2004	1.21	1.21	1.21	1.21	1.21	2.57	2.57	2.57	2.57
2005	1.25	1.25	1.25	1.25	1.25	1.25	2.66	2.66	2.66
2006	1.30	1.30	1.30	1.30	1.30	1.30	1.30	2.76	2.76
2007	1.34	1.34	1.34	1.34	1.34	1.34	1.34	1.34	2.85
2008	1.39	1.39	1.39	1.39	1.39	1.39	1.39	1.39	1.39
2009	1.44	1.44	1.44	1.44	1.44	1.44	1.44	1.44	1.44
Levelized 1995-200	1.62	1.71	1.79	1.87	1.95	2.02	2.09	2.15	2.21

Discount Rate 8.98%

Exhibit PLC-C4
Summary of CP & L Avoided - Costs Corrections
(cents per kwh, levelized 1994-2009)

(Cents/kWh)

		New Baseload Plant Startup Year								
Adders		2000	2001	2002	2003	2004	2005	2006	2007	2008
Energy Cost	[1]	0.29	0.19	0.11	0.07	0.00	0.00	0.00	0.00	0.00
Environmental										
SO2 Allowance	[2]	-0.01	0.01	0.02	0.03	0.04	0.05	0.06	0.07	0.08
All Air Emissions	[3]	1.62	1.71	1.79	1.87	1.95	2.02	2.09	2.15	2.21
Total Correction										
SO2 Allowance	[1]+[2]	0.29	0.20	0.13	0.10	0.04	0.05	0.06	0.07	0.08
All Air Emissions	[1]+[3]	1.92	1.90	1.91	1.95	1.95	2.02	2.09	2.15	2.21

Exhibit PLC-D1
Duke Additional Annual Energy Costs for New Baseload Coal Plant

(Cents/kWh)

	New Baseload Plant Costs					Utility Avoided Costs			Additional
	Fuel	Var. O&M	Energy	Capacity	Total	Energy	Capacity	Total	Energy Cost
Year	[1]	[2]	[3]=[1]+[2]	[4]	[5]=[3]+[4]	[6]	[7]	[8]=[6]+[7]	[9]=[5]-[8]
1995	1.34	0.25	1.59	1.64	3.23	1.90	0.62	2.53	0.70
1996	1.39	0.26	1.65	1.69	3.35	1.94	0.65	2.59	0.76
1997	1.44	0.27	1.71	1.76	3.47	2.02	0.67	2.69	0.78
1998	1.50	0.28	1.77	1.82	3.59	2.09	0.69	2.79	0.80
1999	1.55	0.29	1.84	1.88	3.72	2.20	0.72	2.92	0.80
2000	1.60	0.30	1.90	1.95	3.85	2.22	0.74	2.96	0.89
2001	1.66	0.31	1.97	2.02	3.99	2.64	0.77	3.41	0.58
2002	1.72	0.32	2.04	2.10	4.14	2.57	0.80	3.37	0.76
2003	1.78	0.33	2.11	2.17	4.28	2.69	0.83	3.51	0.77
2004	1.85	0.34	2.19	2.25	4.44	3.26	0.86	4.12	0.32
2005	1.92	0.35	2.27	2.33	4.60	3.14	0.89	4.03	0.57
2006	1.98	0.37	2.35	2.41	4.76	3.21	0.92	4.13	0.64
2007	2.06	0.38	2.44	2.50	4.94	3.80	0.95	4.75	0.19
2008	2.13	0.39	2.52	2.59	5.11	3.18	0.99	4.17	0.95
2009	2.21	0.41	2.61	2.68	5.30	3.41	1.02	4.43	0.87

real-levelized 1995-09 4.18 0.81

Inflation Rate	3.60%	Duke Exhibit SKY-3, p. 10
Discount Rate	8.63%	Duke Exhibit SKY-3, p. 10
New Baseload Pulverized Coal Plant Data		
Technology	Super-Critical with FGD & SCR	Duke IR Public Staff-1-10b attachment
Net Heat Rate, Full Load (Btu/kWh)	9404	Duke IR Public Staff-1-10b attachment
Fuel Price, 1995 (¢/MMBtu)	143.0	CP&L IR Intervenors-1-2, p.2
Real Fuel Price Escalation	0.00%	Adapted from EIA, Annual Energy Outlook 1995 (Jan. 1995), p. 76, for 0.5% real.
Capital Cost Year	2004	Duke IR Public Staff-1-10b
Installed Cost ($/kW)	1,550	Duke IR Public Staff-1-14b attachment
O&M Cost Year	1994	Duke IR Public Staff-1-14d
Fixed O&M ($/kW-yr)	12.46	Duke IR Public Staff-1-14d, attach. p. 2, and 1-26 attach. p. 21
Variable O&M (mills/kWh)	2.32	Duke IR Public Staff-14d
Nominal Fixed Charge Rate	13.57%	Duke IR Public Staff-2-5c
Life (Years)	36	Duke IR Public Staff-2-5c
General Plant Factor	1.0000	Duke does not add overhead to avoided costs.
Fuel O&M Working Capital Factor	1.05%	Duke Exhibit SKY-3, p. 12
Non-Fuel O&M Working Capital Factor	3.31%	Duke Exhibit SKY-3, p. 12
Plant Capacity Factor	80%	
Utility Capacity Costs		Duke Exhibit SKY-3, p. 10, distribution level
Utility On and Off-Peak Energy Costs		Duke DPCO-AC.XLS, Sheet G (Revised SKY-3)

Exhibit PLC-D1
Duke Additional Annual Energy Costs for New Baseload Coal Plant

(Cents/kWh)

Year	2002	2003	2004	2005	2006
1995	0.00	0.00	0.00	0.00	0.00
1996	0.00	0.00	0.00	0.00	0.00
1997	0.00	0.00	0.00	0.00	0.00
1998	0.00	0.00	0.00	0.00	0.00
1999	0.00	0.00	0.00	0.00	0.00
2000	0.00	0.00	0.00	0.00	0.00
2001	0.00	0.00	0.00	0.00	0.00
2002	0.76	0.00	0.00	0.00	0.00
2003	0.77	0.77	0.00	0.00	0.00
2004	0.32	0.32	0.00	0.00	0.00
2005	0.57	0.57	0.57	0.57	0.00
2006	0.64	0.64	0.64	0.64	0.64
2007	0.19	0.19	0.19	0.19	0.19
2008	0.95	0.95	0.95	0.95	0.95
2009	0.87	0.87	0.87	0.87	0.87
Levelized 1995-200	0.34	0.29	0.21	0.21	0.18

Discount Rate

Exhibit PLC-D3
Duke Environmental Values

(Cents/kWh)

Year	Environmental Value Existing [1]	Environmental Value New [2]	Utility SO2 Allowance [3]	Additional Env. Value Existing [1]-[3]	Additional Env. Value New [2]-[3]
1995	1.939	0.940	0.000	1.939	0.940
1996	2.009	0.973	0.000	2.009	0.973
1997	2.082	1.009	0.000	2.082	1.009
1998	2.156	1.045	0.000	2.156	1.045
1999	2.234	1.082	0.000	2.234	1.082
2000	2.315	1.121	0.052	2.262	1.069
2001	2.398	1.162	0.055	2.343	1.106
2002	2.484	1.204	0.059	2.425	1.145
2003	2.574	1.247	0.062	2.511	1.185
2004	2.666	1.292	0.066	2.600	1.226
2005	2.762	1.338	0.070	2.692	1.268
2006	2.862	1.387	0.073	2.788	1.313
2007	2.965	1.436	0.076	2.888	1.360
2008	3.071	1.488	0.080	2.992	1.408
2009	3.182	1.542	0.083	3.099	1.459

Environmental Values:

Existing Coal Plant, 1994 (¢/kWh)	1.872
New Coal Plant, 1994 (¢/kWh)	0.907
Inflation Rate	3.60%

Sources:
1. Chernick Exhibit PLC-D5
2. Chernick Exhibit PLC-D5
3. Duke Exhibit SKY-3 Revised

Exhibit PLC-D3
Duke Environmental Values

(Cents/kWh)

	New Baseload Plant Startup Year				
	2000	2003	2004	2005	2006
1995	1.94	1.94	1.94	1.94	1.94
1996	2.01	2.01	2.01	2.01	2.01
1997	2.08	2.08	2.08	2.08	2.08
1998	2.16	2.16	2.16	2.16	2.16
1999	2.23	2.23	2.23	2.23	2.23
2000	1.07	2.26	2.26	2.26	2.26
2001	1.11	2.34	2.34	2.34	2.34
2002	1.14	2.43	2.43	2.43	2.43
2003	1.18	1.18	2.51	2.51	2.51
2004	1.23	1.23	1.23	2.60	2.60
2005	1.27	1.27	1.27	1.27	2.69
2006	1.31	1.31	1.31	1.31	1.31
2007	1.36	1.36	1.36	1.36	1.36
2008	1.41	1.41	1.41	1.41	1.41
2009	1.46	1.46	1.46	1.46	1.46
Levelized 1995-2009	1.63	1.88	1.96	2.03	2.10

Discount Rate

Exhibit PLC-D4
Duke Levelized 15-Year Avoided Cost Corrections Summary

(Cents/kWh)

		New Baseload Plant Startup Year						
Adders		2000	2001	2002	2003	2004	2005	2006
Energy Cost	[1]	0.44	0.38	0.34	0.29	0.21	0.21	0.18
Environmental								
SO2 Allowance	[2]	-0.01	0.01	0.02	0.03	0.04	0.05	0.06
All Air Emissions	[3]	1.63	1.72	1.80	1.88	1.96	2.03	2.10
Total Correction								
SO2 Allowance	[1]+[2]	0.43	0.38	0.35	0.31	0.25	0.26	0.23
All Air Emissions	[1]+[3]	2.06	2.09	2.14	2.17	2.17	2.24	2.28