BEFORE THE BRITISH COLUMBIA UTILITIES COMMISSION

British Columbia Hydro and Power Authority	)	
2005 Resource Expenditure and Acquisition Plan	)	**Project No. 3698388**

DIRECT TESTIMONY OF

PAUL CHERNICK

ON BEHALF OF

BRITISH COLUMBIA SUSTAINABLE ENERGY ASSOCIATION

AND

SIERRA CLUB OF CANADA BRITISH COLUMBIA CHAPTER

Resource Insight, Inc.

SEPTEMBER 9, 2005

TABLE OF CONTENTS

TABLE OF EXHIBITS

I. Identification and Qualifications

Q: Mr. Chernick, please state your name, occupation and business address.

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

Q: Summarize your professional education and experience.

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

I was a utility analyst for the Massachusetts Attorney General for more than three years, and was involved in numerous aspects of utility rate design, costing, load forecasting, and the evaluation of power supply options. Since 1981, I have been a consultant in utility regulation and planning, first as a research associate at Analysis and Inference, after 1986 as president of PLC, Inc., and in my current position at Resource Insight. In these capacities, I have advised a variety of clients on utility matters.

My work has considered, among other things, the cost-effectiveness of prospective new generation plants and transmission lines, retrospective review of generation-planning decisions, ratemaking for plant under construction, ratemaking for excess and/or uneconomical plant entering service, conservation program design, cost recovery for utility efficiency programs, the valuation of environmental externalities from energy production and use, allocation of costs of service between rate classes and jurisdictions, design of retail and wholesale rates, and performance-based ratemaking and cost recovery in restructured gas and electric industries. My professional qualifications are further summarized in Exhibit 1

Q: Have you testified previously in utility proceedings?

A: Yes. I have testified approximately one hundred and ninety times on utility issues before various regulatory, legislative, and judicial bodies, including the Ontario Energy Board, Arizona Commerce Commission, Connecticut Department of Public Utility Control, District of Columbia Public Service Commission, Florida Public Service Commission, Maryland Public Service Commission, Massachusetts Department of Public Utilities, Massachusetts Energy Facilities Siting Council, Michigan Public Service Commission, Minnesota Public Utilities Commission, Mississippi Public Service Commission, New Mexico Public Service Commission, New Orleans City Council, North Carolina Utilities Commission, Public Utilities Commission of Ohio, Pennsylvania Public Utilities Commission, Rhode Island Public Utilities Commission, South Carolina Public Service Commission, Texas Public Utilities Commission, Utah Public Service Commission, Vermont Public Service Board, Washington Utilities and Transportation Commission, West Virginia Public Service Commission, Federal Energy Regulatory Commission, and the Atomic Safety and Licensing Board of the U.S. Nuclear Regulatory Commission.

II. Introduction and Summary

Q: On whose behalf are you testifying?

A: My testimony is sponsored by the British Columbia Sustainable Energy Association and Sierra Club of Canada, British Columbia Chapter.

Q: What is the purpose of your direct testimony?

A: I have been asked by my clients to assess the adequacy of the treatment of demand-side management (DSM) and renewable energy in BC Hydro's 2005 Resource Expenditure and Acquisition Plan (REAP).

Q: What issues do you address?

A: Section III assesses the extent to which the Power Smart programs are likely to capture the full potential for cost-effective energy-efficiency savings. This section considers the role of Power Smart in Hydro's planning and selection of resources, Hydro's screening of Power Smart options, and problems with the design and scope of the existing Power Smart programs.

Section IV assesses the treatment of renewable resources in the F2006 Call, as proposed by Hydro. That analysis does not reflect the evidence of Matthew Bramley, appearing for the British Columbia Sustainable Energy Association and Sierra Club of Canada, British Columbia Chapter, regarding the likely cost of greenhouse-gas compliance.

Q: How should the Commission direct Hydro to improve DSM?

A: In the near term, Hydro should suspend its plans to suspend industrial DSM incentives as stepped rates are introduced and to penalize industrial customers for participation in DSM programs prior to the initiation of stepped rates.

Simultaneously, Hydro should improve its method for valuing DSM, especially by recognizing the economic benefits of DSM that I describe below in Section II.B.

Hydro should also be preparing to increase its expenditures for Power Smart, starting in F2007. Hydro should examine the most effective utility DSM programs across North America, in terms of the ratio of incremental energy savings to total utility energy delivery, and file with the Commission a report on the differences between those programs and Power Smart. Using the improved economic-screening values described above, Hydro should identify the changes in program design that would be cost effective for total resource costs and amend Power Smart programs to incorporate those changes. If necessary, Hydro should suspend the cap it has imposed on the utility costs it is willing to expend for each megawatt-hour of savings. In evaluating the equity of its Power Smart portfolio, Hydro should de-emphasize the rate-impact measure and pay more attention to the balance of benefits from the portfolio and the effects on rates over time, compared to the rates that would be charged with new supply resources.

Q: How should the Commission direct Hydro to improve its treatment of renewable energy in the F2006 Call and subsequent solicitations?

A: Hydro should increase the Green Attributes credit for renewable energy; recognize the reliability value of intermittent renewables, particularly wind; and treat energy delivered by wind plants as firm.

More generally, Hydro should correct its penalties for failure to deliver firm energy, to more realistically estimate the costs of balancing energy and to be symmetrical

- between hourly energy deliveries above and below average levels,
- between hours when market prices exceed the contract price and hours in which market prices are below the contract price.

III. Hydro's Procurement of DSM through Power Smart

Q: What materials did you review in preparation of this testimony?

A: I reviewed the following materials:

1. BC Hydro's Resource and Expenditure Acquisition Plan, especially
   - Chapter 4 Demand Side Management
   - Appendix A, Energy Efficiency Plan (EEP),
   - Appendix B, Energy Efficiency Program Summaries
   - Appendix D, Electric Load Forecast
2. BC Hydro 2004 Integrated Electricity Plan (2004 IEP), especially
   - Part 2, Demand-Supply Outlook
   - Part 3, Resource Options, particularly (1) Appendix B, Demand-Side Management; (2) Appendix E, Thermal; and (3) Appendix H, BC Hydro's Conservation Potential Review 2002 (May 2003)
   - Part 6, Portfolio Evaluation Results
3. BC Hydro Semi-Annual Report on DSM, June 2005
4. Information responses in this proceeding, particularly
   - BC Hydro Conservation Potential Review 2004: Residential and Commercial Capacity-Reduction Technical Potential Study (Attachment to Response to Information Request BCUC 2.80.0)
   - Response to Information Requests IPPBC 2.5.1 through 2.5.4 Attachment 2
   - Revised Response to Information Request BCSEA 1.40.4
5. Selected information responses and the order in BC Hydro's 2004 Revenue Requirements proceeding

Q: Based on this review, did you find that Hydro plans to procure all demand management resources achievable for less than the cost of avoided supply?

A: No. On the contrary, I found three aspects of Hydro's Power Smart portfolio planning and management that would tend to reduce the amount of economic DSM resources in Hydro's resource portfolio. By correcting these problems, Hydro could increase its procurement of energy-efficiency resources avoiding more-costly supply options and resulting in lower total costs to Hydro's ratepayers.

Q: What three areas in which Hydro should correct problems that impede its identification and acquisition of more cost-effective DSM resources?

A: First, Hydro's resource planning process fails to systematically address the full potential contribution of additional demand-management resources in place of supply expansion. This problem is compounded by Hydro's systematic under-valuation of electricity savings, the second problem I found in its approach to demand-management-resource procurement. Finally, Hydro could improve the Power Smart portfolio's performance by rectifying two limiting proposals in its Energy Efficiency Plan.

Q: Is Hydro doing a particularly bad job of DSM resource planning and procurement, by national and continental utility standards?

A: No. Hydro's DSM efforts are well above average. Nonetheless, Hydro could and should be doing better in acquiring all efficiency resources achievable for less than avoided supply costs.

A. Power Smart in Hydro's Resource-Planning Process

Q: Are the Power Smart programs described in the Resource Expenditure and Acquisition Plan likely to capture the efficiency savings identified in the conservation potential review in Hydro's 2004 Integrated Electricity Plan?

A: Apparently so, at least for the "most likely" scenario in the conservation potential review through 2012. According to the REAP, based on net cumulative savings, Hydro plans to realize more than 150% of the "most likely" economically achievable potential identified by the conservation potential review for this year, and 10% more than that identified in the 2004 IEP for 2012. After that, Hydro's REAP procures a little more than half the economically achievable potential Hydro found for 2016.

Q: How does the planned DSM in Hydro's REAP compare to the "upper bound" of economically achievable potential identified in the Conservation Potential Review?

A: Hydro plans to acquire about two thirds of the "upper bound" achievable potential by 2012 and slightly more than a third of that potential in 2016.

Q: Do these findings suggest that Hydro could procure more cost-effective electricity savings than it currently plans in the REAP?

A: Yes. This conclusion certainly holds during the period 2012–2016, when Hydro could expand the Power Smart portfolio to realize the other half of the economically achievable potential it found in that period in the 2004 IEP. Hydro's REAP leaves between a third of the 2012 "upper bound" potential and two thirds of the 2016 potential unexploited in its resource plans. This strongly suggests that Hydro could lower the total costs of its entire resource portfolio by expanding its Power Smart portfolio in the next ten years.

Q: Does your comparison of Hydro's REAP targets to its achievable potential estimates provide any other evidence that additional cost-effective efficiency savings are achievable?

A: Yes. It is significant that Hydro plans to acquire in 2005 more than 150% of the "most likely" achievable potential it found in 2002 for this year (and double the commercial-sector potential it found three years ago). If Hydro can actually acquire so much more of the achievable potential it found for 2005, it is hard not to believe that it has likewise underestimated what can be truly achieved five and ten years from now. This is further supported by Hydro's mid-year results, which put its accomplishments to date well ahead of its current-year goals.[1]

Q: Did you find any other evidence to reinforce your observation that Hydro is understating the potential for energy efficiency?

A: Yes. Hydro has found relatively small potential savings as a percentage of "base case" consumption, compared to other such studies . This is particularly true for the more recent technical-potential studies Hydro conducted. For example, the 2004 technical-potential study found that immediate installation of all technically feasible efficiency technologies throughout the commercial sector would reduce total electric energy usage by only 14 percent between 2005 and 2016 (2004 Technical Potential Study, Table 6-37, at 6-31). Such theoretically attainable savings are far below the percentage reductions I have seen in other studies. For example, a 2003 technical-potential study for New York State found efficiency technical potential in the commercial sector of 42.1 percent in 2012 and 40.4 percent in 2022.[2]

Q: How did Hydro model the Power Smart programs in the 2005 REAP?

A: Hydro appears to have treated Power Smart 2 as an exogenous adjustment to the demand-supply balance. The REAP does not discuss the alternative of

---

[1]British Columbia Hydro and Power Authority Semi-Annual Report on DSM, June 2005

[2]Energy Efficiency and Renewable Energy Resource Development Potential in New York State, Final Report, Volume Two: Technical Report Analysis Approach and Consolidated Results, August 2003. This study was conducted for the New York State Energy Research and Development Authority by Optimal Energy.

enhancing DSM programs as an alternative to some or all of the energy sought in the F2006 Call. Power Smart appears in the REAP as a fixed program. Other than continuing Power Smart 2, the only DSM initiatives in the REAP involve monitoring of Power Smart 2 performance, "exploring new energy efficiency opportunities to aid future decisions regarding energy efficiency (Power Smart 3, 4 & 5)," and estimating the peak-load benefits of DSM. Hydro reports that the changes in its projections for Power Smart since previous plans "reflect new information on the energy efficiency potential in these sectors," rather than changes in Hydro's program designs or marketing plans (2005 REAP at 4-12).

Q: How did Hydro model the Power Smart programs in the 2004 Integrated Electricity Plan?

A: Hydro evaluated various Power Smart portfolios by computing the revenue requirements and rate effects of resource plans including those portfolios (and several other plans, including a base case) compared to current revenue requirements and rates. This screening exercise would normally be part of the process of selecting resources to be included in the final plan.

Hydro screened the existing Power Smart–2 portfolio, continuing through 2012; Power Smart 3, which would extend savings from 2012 through 2017; and Power Smart 4, which would supplement Power Smart 2 from 2010 and continue savings through 2024.

Hydro also developed its Power Smart–5 portfolio, which would supplement Power Smart 2 starting in 2008 and further increase savings through 2024. Even though Hydro developed and described this more aggressive DSM portfolio in the 2004 IEP, Hydro does not appear to have gone on to run the screening tests for the Power Smart–5 portfolio in the 2004 IEP.

Q: Would Power Smart 3, 4 and 5 contribute significantly to closing the resource gap that Hydro has identified?

A: Yes. By F2009, when the projects from the F2006 call would be expected to be on line, the enhanced Power Smart programs would save 193 GWh/year, nearly 20% of Hydro's acquisition target. By F2011, when Hydro "forecasts a supply shortfall of 1,600 GWh" (Hemmingsen Direct at 6), the incremental savings from enhanced Power Smart programs would be 715 GWh. Table B.1, Appendix B, Part 3, 2004 IEP lists annual savings from each of the Power Smart portfolios.

Q: Would the enhanced Power Smart savings be economic?

A: Yes. As shown in IEP Part 6, Figure 7.2, revenue requirements would be reduced by Power Smart 3 and even more by the combination of Power Smart 3 and 4. In each case, the cost of the Power Smart program in Hydro's rates would be more than offset by reductions in Hydro's other costs of service. Those options would also reduce rates, especially if energy prices are close to Hydro's "High" case, which certainly appears likely from today's perspective.

As noted above, Hydro did not screen Power Smart 5, but the 2004 IEP estimated the cost of that resource as $60/MWh, the same as the power-supply avoided cost Hydro used in screening DSM.

The cost-effectiveness and rate-effect results for the enhanced Power Smart programs would be even better if the evaluation included the various benefits Hydro appears to have omitted from its screening of DSM, including avoided T&D costs, greenhouse-gas-compliance risk, load shape, and firmness. I discuss these benefits of DSM below in §B, in connection with Hydro's screening of DSM.

B. Hydro's Economic Assessment Of Power Smart Programs and Portfolios

Q: How did the Utility Commission direct Hydro to assess the economic performance of its portfolio of its DSM programs?

A: In its October 29, 2004 order in Hydro's 2004 Revenue Requirements case, the Commission directed, "For the purpose of regulatory review, the TRC, UC and RIM [screening tests] should be presented and calculated for the portfolio, by sector and by program" and that "BC Hydro to seek approval for and file tariffs for all new Power Smart programs with a RIM benefit/cost ratio of less than 0.8 and/or a TRC benefit/cost ratio of less than 1.0. For those Power Smart programs with a RIM benefit to cost ratio of less than 0.8, BC Hydro is directed to justify with each REAP filing the continuation of those programs" (Order at 121, 122).[3]

Q: Has Hydro complied with these directions?

A: Yes. Hydro proposed no new programs, so the approval requirement was not triggered.

Q: Has Hydro adequately justified continuation of the Power Smart programs with RIM benefit-to-cost ratios of less than 0.8?

A: Yes. The justification in §4.2.6 of the REAP demonstrates that these programs create no significant equity problems. These programs would collectively provide DSM services to a large percentage of Hydro customers and would have minimal effects on the bills of non-participants, even under Hydro's screening assumptions. Including the additional benefits that Hydro did not include in screening DSM, these programs may well decrease rates, and will substantially decrease customer bills.

[3]I refer to the combination of TRC and RIM tests for programs, and the estimation of revenue requirement and rate effects for portfolios, as "screening."

In addition, as Hydro notes, these programs will help transform equipment and design markets, producing additional savings that Hydro has not quantified.

Q: When a DSM program passes the TRC test, but not the RIM test, how should Hydro modify the program?

A: In most cases, Hydro should not modify the program. The RIM test does not test the equity of a program in any meaningful way. The equity effect of a DSM program depends on the following factors:

- whether the customer group served by the program is otherwise served more or less than other groups.
- whether the customer group served by the program is more in need of Hydro's assistance to overcome the barriers to efficiency.
- whether the program is available to a large group of customers.
- whether the magnitude of the program results in a significant rate effect.

As Hydro demonstrates in the Table 4-7 of the 2005 REAP (at 4-21), programs with RIM ratios of 0.6 or 0.7 can have miniscule effects on the bills of non-participants. If those non-participants chose to participate in any Smart Power program, they would almost certainly save more than the miniscule costs that might be shifted to them by low-RIM programs.

Avoiding adverse effects on groups of customers is certainly an important consideration for Hydro and the Commission. Those effects can be better assessed by analyses such as Table 4-7 of the REAP, or more detailed analyses of rates that would be charged to specific customer groups, rather than the uninformative RIM test.[4]

Q: Has Hydro reflected all the value of DSM in its screening?

[4]In addition, Hydro's RIM results are almost certainly understated, due to the problems in valuation I discuss below.

A: No. It appears that Hydro used a screening value, or avoided cost, of 6¢/kWh (2002 Conservation Potential Review, Summary Report, at 4–5; 2004 IEP, Part 3, Appendix H, at 4–21). This appears to be based on the cost of a gas combined-cycle plant, at a levelized gas cost of $4.80/Gj and an 80% dispatch rate (2004 IEP Part 3 at Appendix E). While the gas price forecast may have been reasonable when the IEP was prepared, recent increases in prices suggest that cost will be greater in the future. More fundamentally, the screening value appears to omit (or understate) the following costs avoided by DSM:

- The benefits represented by the Green Attributes Adder, which Hydro sets at $3/MWh, and which I argue below in §IV should be much greater. DSM provides much the same benefits as green power supply (diversity, lack of fuel price risk, lack of environmental costs), and should receive at least the same credit.
- Financial-liability risk associated with climate-change regulations, which Hydro values at $2 to $3/MWh (Hemmingsen Direct at 28) for a gas-fired combined-cycle in the F2006 Call and which could be higher, as discussed in the testimony of Matthew Bramley.
- Financial-liability risk associated with greenhouse-gas emissions and climate-change harm above and beyond those captured by greenhouse-gas offset regulations (e.g. from lawsuits for greenhouse-gas emissions).
- The firmness of energy efficiency, which will generally persist as long as the installed equipment remains in place, and certainly will not fail abruptly to any significant extent. Hydro proposes to value hourly firmness at $3/MWh in the F2006 Call; energy efficiency should receive about a similar credit.
- Demand-side management has a favorable load shape, in terms of high-load hour energy and peak reduction, generally similar to that of overall

load. While Hydro does not provide details on its valuation of load shaping, DSM should certainly be valued at more than the cost of a combined-cycle plant. Hydro assumes that the combined-cycle plant will be dispatched at an average of 80% of capacity, so it must be dispatched at an even higher percentage (90% or 95%) when it is available. Clearly, the combined-cycle plant will provide energy in a representative mix of hours, and its energy will be less valuable than the load shape of typical DSM.

- Unlike central generation, DSM will contribute to reducing the need for future investment in transmission and distribution. Hydro recognizes the benefit of DSM in avoiding 500kV transmission reinforcements (2004 IEP Part 6, Section 8.2) in evaluating portfolios, but does not appear to reflect that value in screening. Nor does Hydro appear to recognize DSM's ability to avoid investments in lower-voltage transmission or in distribution. Typical estimates of avoided T&D costs used in screening DSM elsewhere in North America run about $100/kW-yr., or about $15–20/MWh for a measure with a load factor of 65%.[5]
- Hydro appears to have understated the transmission and distribution losses avoided by energy efficiency.

Q: Please describe how Hydro understated the transmission and distribution losses avoided by energy efficiency.

A: In its Power Smart–portfolio evaluation, Hydro credited DSM with avoiding line losses of 7% for residential and commercial programs and 3.6% for industrial programs (Hydro Response to BCUC IR 1.60.0 in the 2004 Revenue Requirements proceeding). These included only 4% distribution losses (for residential,

[5]While I generally state prices in Canadian dollars, I do not intend this range to be precise enough that the distinction between Canadian and U.S. dollars is important.

commercial and part of the industrial load) and 3% intra-regional transmission losses, and explicitly ignore 5.1% inter-regional losses. In the IEP, Hydro recognized that the total losses avoided by DSM should be evaluated at the system level (IEP Part 3, Appendix B, at B-2).

It is not clear what losses Hydro applied in screening DSM for the IEP, or in the valuations reported in the REAP. The IEP estimates that total losses are about 11% of total firm sales (October 2003 Forecast, IEP Part 2, Appendix A, Table A-2). That average is consistent with the wholesale sales and 85% of industrial load incurring 8.3% transmission losses, and the remaining load incurring about 12.4% losses. That result is essentially identical to the sum of the losses to distribution of 4% on the distribution system and 8.3% the transmission system. Hence, DSM at the distribution level should be credited with avoiding average losses of 12.4%.

Even for customers who are metered at the transmission level, virtually all end uses (and hence DSM) operate at secondary distribution voltage, and distribution losses are incurred in the customers' transformers and internal distribution. Hydro's estimate of distribution losses apparently represents a mix of sales metered at primary and secondary. Losses to secondary would exceed 12.4%.

More importantly, these computations are all for average losses, averaging over both the hours of the year and all the load in an hour. In reality, variable line losses increase as the square of load, so losses are greater in high-load hours and the losses on the marginal kW on a line are greater than those on the first kW. Since more electricity is used (and hence is available to be conserved) at high-load hours than low-load hours, and since all conserved energy avoids the marginal load on the lines, the losses avoided by conservation would be even higher than the average losses.

Q: Did you find other problems with Hydro's rules for deciding how much efficiency resources it would procure?

A: Hydro (REAP at 4-9) states that "the complete portfolio UC (levelized) should be less than $0.025/kWh." Striving to hold portfolio-wide costs to 2.5¢/kWh or less is equivalent to requiring the portfolio to return a minimum benefit-cost ratio of 2.4. The problem with this rule in practice is that it has the potential to unduly and artificially restrict Hydro's acquisition of cost-effective supply alternatives. In an effort to keep the levelized cost per kWh below 2.5¢/kWh, Hydro would tend to dismiss all efficiency portfolio options costing between 2.5¢/kWh and 6.0¢/kWh, its avoided supply costs. This would lead Hydro to favor more-expensive supply over less-expensive efficiency resources. It could also lead Hydro to select only the easiest and cheapest efficiency savings, leaving behind lost opportunities for more-costly but still-cost-effective efficiency savings.

Q: Summarize your conclusions regarding Hydro's screening of DSM.

A: Hydro's screening of its Power Smart options omits or understates a number of benefits of DSM. As a result, Hydro's estimates of the TRC and RIM benefit-cost ratios for the programs and portfolios are understated. Improved screening might well result in Hydro intensifying its efforts with Power Smart and reducing its acquisitions of fossil-fired generation and its transmission-and-distribution investment.

C. Potential for Improving Power Smart Portfolio Performance

Q: What evidence did you find that Hydro could improve the performance of its Power Smart portfolio?

A: Four aspects of Hydro's Energy Efficiency Plan indicate that it could raise the economic and electricity yield from the Power Smart portfolio.

Q: What is the first indication you found that Hydro could improve the performance of the Power Smart portfolio?

A: Substantial portions of Hydro's Energy Efficiency Plan (revised), REAP, Appendix A, report extraordinarily high costs of saved energy. Costs of several commercial and residential programs render them barely cost-effective under the TRC test, despite showing quite favorable results under the utility test. In other words, these programs offer what appear to be cost-effective supply resources when only Hydro's expenditures are counted, but in reality would be barely worthwhile investments for British Columbia's economy. Indeed, Hydro's plan meets its problematic portfolio objective (discussed above) of a levelized cost of saved energy of less than 2.5¢/kWh under the utility test (with a levelized cost of 1.6 cents/kWh and a utility benefit/cost ratio of 2.9) (EEP revised at 19). It is particularly troubling that some of Hydro's flagship efficiency programs fall into this category.

Q: Which programs in the EEP appear to be barely cost-effective under the TRC?

A: Including all Hydro's portfolio-wide costs, the following programs show benefit/cost ratios in the 1.0 to 1.1 range:

- Commercial & Government Power Smart Partners (1.0)
- Schools, Universities, Colleges and Hospitals (1.0)
- Lighting Redesign (1.1)
- Residential fuel substitution (1.0)

Indeed, lackluster yields from the first two programs result in a sector-wide benefit/cost ratio of only 1.1, with a levelized cost of 4.5¢/kWh. Such poor economic returns from commercial programs such as these do not accord with my knowledge of commercial energy-efficiency program outcomes, either past or planned. Much more typical are costs of saved energy in the neighborhood of 2.5¢/kWh, and benefit/cost ratios exceeding 2.0.

Q: To what do you attribute these disappointing outcomes?

A: While I have not had the time or opportunity to review underlying details of Hydro's DSM program experience or plans, there are a number of plausible, mutually reinforcing explanations to account for this. One possibility is high Hydro portfolio-administration costs. Another would be erroneously large cost estimates of efficiency technologies. In the case of fuel substitution, it is entirely possible that the technology is not cost-effective in the number of applications Hydro plans. However, the cause I consider most likely responsible for the poor showing of the commercial programs is that Hydro is needlessly restricting program activity.

Q: How would increased program activity improve economic performance of the portfolio?

A: As with any well-run energy-efficiency portfolio, Power Smart entails substantial fixed administrative costs. Hydro can achieve broader participation and deeper savings among participants in its programs by intensifying marketing, financial, technical, and delivery strategies. Increasing electricity savings by stimulating more investment in cost-effective technologies would spread Hydro's fixed program costs over more electricity savings, thus resulting in reduced costs of saved energy and greater benefits in proportion to costs.

Q: What else in the EEP suggests that Hydro could improve portfolio performance by intensifying these programs?

A: The EEP calls for steep and sustained declines in future expenditures and savings for these programs. Spending on Power Smart Partners for commercial and governmental customers would fall by half next year, and then drop precipitously starting in 2009. Likewise, expenditures on schools, universities, colleges and hospitals would fall by two-thirds after next year. I have little doubt that Hydro could restore these planned cuts, and indeed steadily increase spending on and savings from these programs starting in 2007.

I also discovered that Hydro's program design for commercial and governmental Power Smart Partners tends to unduly restrict savings from potential efficiency projects. In this program, projects that "prove to be the most cost-effective on a $/kWh basis receive incentives." (REAP Appendix B, Program Summaries, at 5). If Hydro actually follows this decision rule in practice, then it will tend to favor *cream skimming*—encouraging only the cheapest and easiest savings. Declining to provide incentives for more-comprehensive-yet-cost-effective efficiency projects would decrease the electricity and economic yield from the program. The proper approach is to encourage the competing project alternative that offers the maximum net benefits under the TRC (not the maximum benefit/cost ratio, which would have the same effect as the cents-per-kWh rule).

If Hydro in fact applies this criterion to custom project incentive offers, it is a major problem. It would at least partially account for disappointing results for this major component of Hydro's Power Smart portfolio.

Q: What is the third aspect of Hydro's EEP that indicates it could improve the Power Smart portfolio's performance?

A: Hydro proposes to do away with financial incentives in its industrial Power Smart Partners program as it introduces stepped (i.e., increasing-block) rates to industrial customers that reflect Hydro's long-run marginal costs (i.e., avoided costs). Hydro expects stepped rates to induce the same level of savings that would otherwise have resulted from the Power Smart Partners program with financial incentives. Hydro's theory appears to be that higher electricity prices will be just as effective as financial incentives currently offered in overcoming market barriers preventing industrial customers from undertaking custom efficiency upgrades on their own (REAP at 4-41, 4-42).

Q: What is it about this approach that suggests Hydro could improve portfolio performance?

A: Withholding financial incentives from the array of program strategies Hydro uses to overcome industrial efficiency market barriers will likely severely deter participation as well as the depth of savings participants accomplish. Over the past generation, utilities with industrial rates far above 6¢/kWh (for example, in California, New York, New Jersey, Connecticut, and Massachusetts) have found financial incentives to be necessary to achieve the significant and highly cost-effective savings they realize from their industrial programs. Hydro's plan is likely to eliminate much of the Power Smart portfolio's most cost-effective efficiency savings (which Hydro expects to acquire at less than 2¢/kWh). Conversely, restoring financial incentives to the program in conjunction with stepped rates would probably increase savings compared to previous experience, as the stepped rates increase customers' interest in participation.

Q: Does Hydro's industrial DSM plan do anything else to retard industrial efficiency savings?

A: Yes. Hydro further plans to prevent current Power Smart partners from displacing more-expensive Tier-2 electricity consumption in the future. According to Hydro's REAP at 4-41,

> Until the implementation of stepped rates: Stepped rate customers receiving a DSM incentive will have their stepped rate baseline reduced by 100% of the amount of their committed savings. This provides the financial incentive needed to implement the project yet prevents the customer from benefiting twice, from the incentive and the Tier 2 savings, after the implementation of stepped rates.

This means that the more DSM an industrial customer undertakes, the less discounted Tier-1 energy it would be entitled to, cutting into (or perhaps eliminating) its savings. This is hardly a strategy for encouraging participation in Power Smart by Hydro's industrial customers.

Q: What is the fourth kind of evidence you found to suggest that Hydro could increase economic and electricity savings from its DSM portfolio?

A: I calculated two performances indices of Hydro's actual and planned efficiency portfolio investments, and compared this with comparable information for one of Hydro's DSM peers, Pacific Gas & Electric (PG&E), which serves northern California. The first indicator is yield: electricity savings per dollar of program investment in 2004. High yield can be caused by programs that capture only the least-expensive opportunities, ignoring more-comprehensive cost-effective savings. The second indicator is depth: electricity savings as a percentage of electricity sales, for which I compared the utilities both for actual 2004 results and for projections for 2005 through 2008. This information is presented in Exhibit 2 and Exhibit 3, respectively.

Q: What did you find from these comparisons between Hydro's and PG&E's DSM recent experience and future plans?

A: I found that

- Hydro's kWh yield per dollar invested in both the residential and commercial-industrial sectors significantly exceeded PG&E's in 2004 (7.9 kWh/$ for Hydro and 4.4 kWh/$ for PG&E). (See Exhibit 2.)

- Pacific Gas and Electric's savings depth in 2004 was considerably greater than Hydro's in both the residential and nonresidential sectors (2004 DSM accounted for 0.94% of Hydro's total 2003 sales, as compared to 1.18% for PG&E). (See Exhibit 3.)
- This year Hydro plans to significantly reduce savings depth in both sectors, while PG&E plans a slight decline in residential savings depth coupled with a major increase in savings depth among commercial-and-industrial customers (up from 1.10% in 2004 to 1.81% in 2005)
- From 2006 to 2007, Hydro plans on steadily restoring C&I savings depth to 1.10%, its 2004 level, with another decline between 2007 and 2008. During the same period, PG&E plans on continuing its strong and steady upward trend in savings depth. While sectoral figures were not available, PG&E plans on continuing to increase portfolio savings depth. By 2008, PG&E expects to increase portfolio savings depth to 2.40% from this year's 1.56%. By then, PG&E's portfolio savings depth will be four times that planned by Hydro.

Q: What do you conclude from these findings?

A: I draw the following related conclusions that reinforce others discussed earlier in this testimony.

- Savings yield and savings depth tend to vary inversely, i.e. move in opposite directions. The deeper the savings, the more costly they tend to be, which is consistent with the diminishing returns to be expected from efficiency investment.
- Neither indicator is very revealing by itself; both should be considered together.

- Compared to PG&E, Hydro's much higher savings yield, coupled with its smaller and diminishing savings depth, strengthens the case that Hydro could substantially improve portfolio performance by intensifying and expanding its Power Smart programs.
- Pacific Gas and Electric's plans for dramatically increasing the size of its DSM portfolio in the future reinforce the foregoing conclusion. PG&E's 2006 budget of $240 million represents an 80% increase over its 2004 portfolio budget, and it plans to increase its portfolio another 17% in 2007 and 22% in 2008. As discussed earlier, Hydro plans to decrease portfolio spending despite clear indications that additional efficiency savings are both achievable and cost-effective compared to supply.

IV. Treatment of Renewable Resources in Proposed Calls for Power Supply

Q: Do renewable resources differ from fossil-fueled resources in fundamental ways?

A: Yes. Renewables provide fuel diversity, environmental benefits, reduced cost of compliance with environmental regulations, avoidance of risks of fuel-price variability, and reduced pressure on natural gas prices. For some renewable resources, such as wind and solar, technology and infrastructure are being driven by market demand, so acquisition of resources in the near term will tend to reduce the costs of future acquisitions.

Q: How does Hydro propose to treat renewable resources in its calls for power supply, including the F2006 Call described by Hydro Witness Mary Hemmingsen?

A: Hydro proposes to offer bidders whose projects conform to Environment Canada's Environmental Choice Program a credit of $3/MWh in January 2006, inflating at the CPI, in exchange for the transfer to Hydro of the rights to any green attributes of the project. A qualifying renewable bidder could thus charge $3/MWh more than a non-renewable project while being equally likely to be selected by Hydro in the Call. Alternatively, the bidder could retain the green attributes and sell them in the market, potentially reducing the required bid price and increasing the project's probability of success.

Q: Is this approach adequate?

A: No. As Ms. Hemmingsen notes, "Green Attributes are currently trading in the range of $2 to $3 (U.S.) per MWh" or roughly $2.50 to $3.75/MWh CDN (Hemmingsen Direct at 4). The only other comparisons Hydro provides are as follows:

- Renewable projects bidding to Public Service Company of Colorado are eligible for a credit of $8.75 (U.S.)/MWh [or about $11/MWh CDN] for "green rights."
- Canada's federal government proposes a $10/MWh power-production-incentive payment for renewable and wind power projects for a 10-year term.

Ms. Hemmingsen is certainly correct that the Hydro proposal is "at the lower end of the range of values provided by relevant benchmarks." Aiming for the lower end of the reasonable range seems inappropriate.

In areas other than those discussed by Hydro, the market value of renewable-energy credits is higher. For example, in Massachusetts in 2005, power suppliers are paying a premium of $53.19/MWh (U.S.) for renewable energy attributes.[6]

[6]This price is the administrative alternative-compliance price that power suppliers must pay if they cannot obtain enough renewable energy to meet the renewable-portfolio standard; since

Q: Other than the level of the Green Attributes credit, may Hydro's proposal result in unnecessarily undervaluing, or creating other problems for, cost-effective renewables?

A: There are at least three such problems, involving the preference for hourly firm energy, the penalties for non-firm energy delivery, and insufficient assurance that the risks of complying with future greenhouse-gas regulations will in fact be transferred entirely to the bidders, who nominally accept that risk.

Q: Please describe the problems resulting from the firm-energy provisions in Hydro's proposal.

A: The firm-energy issues primarily disadvantage wind power, which is a highly reliable resource for energy delivery on an annual and multi-year basis, but is highly variable from hour to hour, and even month to month.

The first firm-energy issue is Hydro's \$3/MWh evaluation credit adjustment for hourly firm power (Hemmingsen Direct at 7). Since wind projects are not firm on an hourly basis, they cannot qualify for this credit.

The second firm-energy issue is the requirement that bidders provide firm energy (although they can also provide some non-firm energy, at a substantial discount) and that the generator must pay as liquidated damages the difference between "the adjusted bid price [and] the Mid-Columbia (Mid-C) price (capped at \$100/MWh escalating at CPI)" for "firm delivery shortfalls" on a monthly basis (Hemmingsen Direct at 22). This proposal creates the following problems for wind power:

- The adjustment applies only when deliveries are below the monthly contract level, not when deliveries exceed the contract level. A fossil-fired

---

there is not currently enough qualifying renewable energy available to meet the demand, prices have risen to the alternative compliance price.

generator that contracts to provide Hydro with monthly energy equal to its rated capacity reduced for scheduled maintenance by month and an allowance for forced outages would rarely generate much more than the contract quantity. Wind plants typically generate an average of 25%–30% of their peak capacity. If a wind developer contracts with Hydro for its average monthly energy output, it would frequently generate twice or even three times its contract amount on an hourly basis.[7] Even averaged over a month, generation will vary significantly with weather. PacifiCorp's data on the probability of various levels of generation from a wind plant suggest that the plant would produce more than twice its average output in about a quarter of the hours.

- The "adjusted bid price" is reduced by the Green Attributes credit, so even were the Mid-C price the same as the contract price, the renewables developer would be charged $3/MWh in each hour its generation fell below the contract amount. This feature would penalize biomass and other renewable sources, as well as wind.
- The liquidated-damages provision penalizes power suppliers if the price at Mid-C (plus transmission to Hydro) is higher than the adjusted bid price, but does not appear to credit suppliers if the price at Mid-C is less than the adjusted bid price. Thus, if Mid-C prices are 4¢/kWh half the time and 8¢/kWh the other half of the time, a wind project with a 6¢/kWh bid price would be charged liquidated damages of 2¢/kWh for half the hours in which energy deliveries are less than the firm contract level, even were

[7]Ms. Hemmingsen (Direct at 8) says, "BC Hydro will accept and pay for all energy delivered up to 120% of plant capacity," so it appears that wind plants would be able to sell all their output to Hydro, even well in excess of the contract level. (However, it is not clear whether Hydro would pay the firm energy contract price.)

Hydro paying the same average price for replacement energy as for the wind contract price.

- Hydro proposes to add transmission costs "from Mid-C to the border," even if the flow of generation in a particular month is primarily *from* the border to Mid-C. In those periods, the cost to Hydro of not receiving the contract power is the Mid-C price *minus* the cost of transmission from the border to Mid-C. This penalty and the previous one would apply to all generators, but the effect would be greater for wind, due to its intrinsic variability.

Q: Is there any purpose in applying these multiple penalties to wind generation?

A: No. Ms. Hemmingsen (Direct at 22) asserts that "successful bidders are in the best position to manage the risk of fluctuations in output for their projects." This is true for most generation technologies, but not for wind plants, for which the "fluctuations in output" are mostly due to the weather.

Q: Does a GWh of wind generation provide much less capacity value, in terms of the firm peak load it can support, than other energy resources?

A: No. Studies have generally found that wind generation provides firm capacity that is close to its average energy output.[8] In other words, a wind plant with a 25% capacity factor is likely to support load equal to about 25% of its rated capacity or provide reliability equivalent to 25% of its rated capacity in

[8]In the 2004 IEP, Part 3, Table 7.3, Hydro asserts that wind provides no "dependable capacity" but provides no basis for that opinion. That table reports dependable capacity for various thermal technologies of 94% to 100% of installed capacity, even though any thermal generator may be out of service during all of the high-load hours for days or weeks at a time. A wind project is likely to generate some energy every day and is almost certain to generate some energy over any longer period. These Hydro assumptions are thus internally inconsistent.

conventional fossil units. For example, a 400 MW wind plant might generate an average of 100 MWh each hour, and support as much firm load as 100 MW of thermal capacity.

In its 2004 Integrated Resource Plan (at Appendix J), PacifiCorp estimated the amount of extra peak load the company could serve in July (its peak month) at constant reliability if it added 100 MW of wind generation in Washington with a 19% July capacity factor. The result was that PacifiCorp could serve another 24 MW of load with the 100 MW of wind generation. Serving the same load would require about 28 MW of thermal capacity. In that case, wind provided the energy of about 24 MW of baseload thermal capacity and the capacity benefit of somewhat more thermal capacity.

More generally, a series of studies by the National Renewable Energy Laboratory have found that the effective-load-carrying capability of wind plants is generally similar to their capacity factor in the 10% to 30% of hours with the highest loads, and found effective-load-carrying capabilities of around 30% of installed capacity. A 2004 study for Xcel Energy and the Minnesota Department of Commerce reached similar conclusions. A 2004 California Energy Commission study found ELCCs of about 24% of installed capacity for wind in that state's mountain passes.[9]

[9]"Choosing Wind Power Plant Locations and Sizes Based on Electric Reliability Measures Using Multiple-Year Wind Speed Measurements," Milligan, M.R. and Artig, R., NREL/CP-500-26724, July 1999; "Modeling Utility-Scale Wind Power Plants Part 2: Capacity Credit," Milligan, M.R., NREL/TP-500-29701, March 2002. "Wind Integration Study—Final Report," EnerNex Corporation, September 28, 2004. California Renewables Portfolio Standard Renewable Generation Integration Cost Analysis Phase III: Recommendations for Implementation, July 2004, P500-04-054.

Hydro, with larger percentage of capacity provided by hydroelectric plants, should be in an even better position than PacifiCorp, Xcel, or the California utilities to incorporate variable output from wind power. Every MWh of above-average wind generation in windy hours that allows Hydro to keep more water behind its dams provides an extra MWh that can be used in the low-wind hours.[10]

Q: How should Hydro treat the firmness of wind generation?

A: Hydro should price and evaluate wind generation as firm energy, except for forced and maintenance outages. So long as the generators maintain their mechanical availability, they should be paid the contract price for all energy delivered and they should not be charged liquidated damages.

Q: How does Hydro's proposed treatment of the greenhouse-gas risk undervalue the benefits of renewables?

A: Hydro's treatment of the greenhouse-gas risk understates the benefits of renewables by leaving ratepayers at risk for some of the effects of future greenhouse-gas-compliance costs. The 2006 Call would not require that bidders offer financial assurances that they would continue to be available to Hydro at the bid prices, for the plausible range of greenhouse-gas compliance prices presented in Hydro's evidence. Hence, the bids may not include greenhouse-gas internalization sufficient to cover risk over life of project, as suggested by Hydro witness Hemmingsen at 27.

Hydro should require continued financial security through the life of the contract (or the bulk of the life, for very long-lived projects), sufficient to cover the costs of potential future greenhouse-gas compliance. If a project defaults on

[10] In addition, the higher water levels would increase head and hence the energy generated by all the other water running through the turbines.

its contract, due to the cost of greenhouse-gas compliance, it could leave Hydro scrambling to replace that energy in an environment of high energy prices.

Q: Does this conclude your testimony?

A: Yes.

Exhibit 1

PAUL L. CHERNICK

Resource Insight, Inc.
5 Water Street
Arlington, Massachusetts 02176

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

"Environmental Regulation in the Changing Electric-Utility Industry" (with Rachel Brailove), *International Association for Energy Economics Seventeenth Annual North American Conference* (96–105). Cleveland, Ohio: USAEE. 1996.

"The Price is Right: Restructuring Gain from Market Valuation of Utility Generating Assets" (with Jonathan Wallach), *International Association for Energy Economics Seventeenth Annual North American Conference* (345–352). Cleveland, Ohio: USAEE. 1996.

"The Future of Utility Resource Planning: Delivering Energy Efficiency through Distributed Utilities" (with Jonathan Wallach), *International Association for Energy Economics Seventeenth Annual North American Conference* (460–469). Cleveland, Ohio: USAEE. 1996.

"The Future of Utility Resource Planning: Delivering Energy Efficiency through Distribution Utilities" (with Jonathan Wallach), *1996 Summer Study on Energy Efficiency in Buildings,* Washington: American Council for an Energy-Efficient Economy 7(7.47–7.55). 1996.

"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 Sabrina Birner), *The Electricity Journal* 5:2, March 1992.

“Determining the Marginal Value of Greenhouse Gas Emissions” (with Jill 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 Emily Caverhill). *Public Utilities Fortnightly* 127(5), March 1 1991.

“Methods of Valuing Environmental Externalities” (with Emily Caverhill), *The Electricity Journal* 4(2), March 1991.

“The Valuation of Environmental Externalities in Energy Conservation Planning” (with Emily 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 Emily 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 Eric Espenhorst and Ian 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 Emily Caverhill), in *Proceedings from the NARUC National Conference on Environmental Externalities*, October 1990.

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

“Analysis of Residential Fuel Switching as an Electric Conservation Option” (with Eric Espenhorst and Ian 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 John Plunkett and Jonathan Wallach), in *Proceedings from the NARUC Biennial Regulatory Information Conference*, September 1990.

"Incorporating Environmental Externalities in Evaluation of District Heating Options" (with Emily 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 John Plunkett), *Proceedings from the Canadian Electrical Association Demand-Side Management Conference*, June 1990.

"Incorporating Environmental Externalities in Utility Planning" (with Emily 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 John 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

“Evaluation and Cost Effectiveness” (principal author), Ch. 14 of “California Evaluation Framework” Prepared for California utilities as required by the California Public Utilities Commission. 2004.

“Energy Plan for the City of New York” (with Jonathan Wallach, Susan Geller, Brian Tracey, Adam Auster, and Peter Lanzalotta). 2003. New York: New York City Economic Development Corporation.

“Review and Critique of the Western Division Load-Pocket Study of Orange and Rockland Utilities, Inc.” (with John Plunkett, Philip Mosenthal, Robert Wichert, and Robert Rose). 1999. White Plains, N.Y.: Pace University School of Law Center for Environmental Studies.

“Avoided Energy Supply Costs for Demand-Side Management in Massachusetts” (with Rachel Brailove, Susan Geller, Bruce Biewald, and David White). 1999. Northborough, Mass.: Avoided-Energy-Supply-Component Study Group, c/o New England Power Supply Company.

“Performance-based Regulation in a Restructured Utility Industry” (with Bruce Biewald, Tim Woolf, Peter Bradford, Susan Geller, and Jerrold Oppenheim). 1997. Washington: NARUC.

“Distributed Integrated-Resource-Planning Guidelines.” 1997. Appendix 4 of “The Power to Save: A Plan to Transform Vermont’s Energy-Efficiency Markets,” submitted to the Vermont PSB in Docket No. 5854. Montpelier: Vermont DPS.

“Restructuring the Electric Utilities of Maryland: Protecting and Advancing Consumer Interests” (with Jonathan Wallach, Susan Geller, John Plunkett, Roger Colton, Peter Bradford, Bruce Biewald, and David Wise). 1997. Baltimore, Maryland: Maryland Office of People’s Counsel.

“Comments of the New Hampshire Office of Consumer Advocate on Restructuring New Hampshire’s Electric-Utility Industry” (with Bruce Biewald and Jonathan Wallach). 1996. Concord, N.H.: NH OCA.

“Estimation of Market Value, Stranded Investment, and Restructuring Gains for Major Massachusetts Utilities” (with Susan Geller, Rachel Brailove, Jonathan Wallach, and Adam Auster). 1996. On behalf of the Massachusetts Attorney General (Boston).

From Here to Efficiency: Securing Demand-Management Resources (with Emily Caverhill, James Peters, John Plunkett, and Jonathan Wallach). 1993. 5 vols. Harrisburg, Penn: Pennsylvania Energy Office.

“Analysis Findings, Conclusions, and Recommendations,” vol. 1 of “Correcting the Imbalance of Power: Report on Integrated Resource Planning for Ontario Hydro” (with Plunkett, John, and Jonathan Wallach), December 1992.

“Estimation of the Costs Avoided by Potential Demand-Management Activities of Ontario Hydro,” December 1992.

“Review of the Elizabethtown Gas Company’s 1992 DSM Plan and the Demand-Side Management Rules” (with Jonathan Wallach, John Plunkett, James Peters, Susan Geller, Blair. Hamilton, and Andrew Shapiro). 1992. Report to the New Jersey Department of Public Advocate.

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 Jonathan Wallach et al.); Report to the New Jersey Department of Public Advocate, June 1992.

“The AGREA Project Critique of Externality Valuation: A Brief Rebuttal,” March 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 David Argue et al.), February 1992.

“Report on the Adequacy of Ontario Hydro’s Estimates of Externality Costs Associated with Electricity Exports” (with Emily Caverhill), January 1991.

“Comments on the 1991–1992 Annual and Long Range Demand-Side-Management Plans of the Major Electric Utilities,” (with John Plunkett et al.), September 1990. Filed in NY PSC Case No. 28223 in re New York utilities’ DSM plans.

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

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

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

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

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

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

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

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

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

PRESENTATIONS

"Adding Transmission into New York City: Needs, Benefits, and Obstacles." Presentation to FERC and the New York ISO on behalf of the City of New York. October 2004.

"Plugging Into a Municipal Light Plant," With Peter Enrich and Ken Barna. Panel presentation as part of the 2004 Annual Meeting of the Massachusetts Municipal Association. January 2004.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

ADVISORY ASSIGNMENTS TO REGULATORY COMMISSIONS

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

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

EXPERT TESTIMONY

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

    Cost comparison methodology; nuclear cost estimates; cost of conservation, co-generation, and solar.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

    Profit margin calculations, including methodology, interest rates.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

    Profit margin calculations, including methodology and implementation.

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

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

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

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

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

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

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

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

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

    Construction schedule and cost of completing Millstone Unit 3.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

72. **Vermont PSB** 5270, Module 6; Investigation into Least-Cost Investments, Energy Efficiency, Conservation, and the Management of Demand for Energy; Conservation Law Foundation, Vermont Natural Resources Council, and Vermont Public Interest Research Group; September 26 1988.

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

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

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

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

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

75. **Vermont PSB** 5270; Status Conference on Conservation and Load Management Policy Settlement; Central Vermont Public Service, Conservation Law Foundation, Vermont Natural Resources Council, Vermont Public Interest Research Group, and Vermont Department of Public Service; May 1 1989.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

84. **Maryland PSC** 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** 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** 90-286; Adequacy of Conservation Program of Bangor Hydro Electric; Penobscot River Coalition; February 19 1991.

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

89. **Virginia State Corporation Commission** PUE900070; Order Establishing Commission Investigation; Southern Environmental Law Center; March 6 1991.

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

90. **MDPU** 90-261-A; Economics and Role of Fuel-Switching in the DSM Program of the Massachusetts Electric Company; Boston Gas Company; April 17 1991.

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

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

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

92. **Vermont PSB** 5491; Cost-Effectiveness of Central Vermont's Commitment to Hydro Quebec Purchases; Conservation Law Foundation; July 19 1991.

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

93. **South Carolina PSC** 91-216-E; Cost Recovery of Duke Power's DSM Expenditures; South Carolina Department of Consumer Affairs; September 13 1991. Surrebuttal October 2 1991.

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

94. **Maryland PSC** 8241, Phase II; Review of Baltimore Gas & Electric's Avoided Costs; Maryland Office of People's Counsel; September 19 1991.

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

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

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

96. **MDPU** 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** 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** 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** 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** 91-606-E; Petition of South Carolina Electric and Gas for a Certificate of Public Convenience and Necessity for a Coal-Fired Plant; South Carolina Department of Consumer Affairs; January 20 1992.

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

101. **MDPU** 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** 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** E-100, Sub 64; Integrated Resource Planning Docket; Southern Environmental Law Center; September 29 1992.

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

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

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

105. **Texas PUC** 110000; Application of Houston Lighting and Power Company for a Certificate of Convenience and Necessity for the DuPont Project; Destec Energy, Inc.; September 28 1992.

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

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

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

107. **Maryland PSC** 8473; Review of the Power Sales Agreement of Baltimore Gas and Electric with AES Northside; Maryland Office of People's Counsel; November 16 1992.

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

108. **North Carolina Utilities Commission** E-100, Sub 64; Analysis and Investigation of Least Cost Integrated Resource Planning in North Carolina; Southern Environmental Law Center; November 18 1992.

Demand-side management cost recovery and incentive mechanisms.

109. **South Carolina PSC** 92-209-E; In Re Carolina Power & Light Company; South Carolina Department of Consumer Affairs; November 24 1992.

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

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

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

111. **Maryland PSC** 8487; Baltimore Gas and Electric Company, Electric Rate Case; January 13 1993. Rebuttal Testimony: February 4 1993.

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

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

Economic analysis of proposed coal-fired cogeneration facility.

112.A **Michigan PSC** U-10102; Detroit Edison Rate Case; Michigan United Conservation Clubs; February 17 1993.

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

113. **Ohio PUC** 91-635-EL-FOR, 92-312-EL-FOR, 92-1172-EL-ECP; Cincinnati Gas and Electric demand-management programs; City of Cincinnati. April 1993.

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

114. **Michigan PSC** U-10335; Consumers Power Rate Case; Michigan United Conservation Clubs; October 1993.

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

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

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

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

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

117. **Vermont PSB** 5270-CV-1,-3, and 5686; Central Vermont Public Service Fuel-Switching and DSM Program Design, on behalf of the Vermont Department of Public Service. Direct, April 1994; rebuttal, June 1994.

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

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

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

119. **Vermont PSB** 5724, Central Vermont Public Service Corporation rate request; Vermont Department of Public Service. Joint surrebuttal testimony with John Plunkett. August 1994.

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

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

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

121. **Michigan PSC** U-10554, Consumers Power Company DSM Program and Incentive; Michigan Conservation Clubs. November 1994.

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

122. **Michigan PSC** 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** EM92030359, Environmental costs of proposed cogeneration; Freehold Cogeneration Associates. November 1994.

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

124. **Michigan PSC** U-10671, Detroit Edison Company DSM Programs; Michigan United Conservation Clubs. January 1995.

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

125. **Michigan PSC** U-10710, Power-supply-cost-recovery plan of Consumers Power Company; Residential Ratepayers Consortium. January 1995.

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

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

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

127. **North Carolina Utilities Commission** E-100, Sub 74, Duke Power and Carolina Power & Light avoided costs; Hydro-Electric–Power Producer's Group. February 1995.

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

128. **New Orleans City Council** UD-92-2A and -2B, Least-cost IRP for New Orleans Public Service and Louisiana Power & Light; Alliance for Affordable Energy. Direct, February 1995; rebuttal, April 1995.

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

129. **DCPSC** Formal 917, II, Prudence of DSM expenditures of Potomac Electric Power Company; Potomac Electric Power Company. Rebuttal testimony, February 1995.

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

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

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

131. **New Orleans City Council** CD-85-1, New Orleans Public Service rate increase; Alliance for Affordable Energy. Rebuttal, May 1995.

Allocation of costs and benefits to rate classes.

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

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

133. **Maryland PSC** 8697, Baltimore Gas & Electric gas rate increase; Maryland Office of People's Counsel. July 1995

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

134. **North Carolina Utilities Commission** E-2, Sub 669. December 1995.

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

135. **Arizona Commerce Commission** U-1933-95-317, Tucson Electric Power rate increase; Residential Utility Consumer Office. January 1996.

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

136. **Ohio PUC** 95-203-EL-FOR; Campaign for an Energy-Efficient Ohio. February 1996

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

137 **Vermont PSB** 5835; Vermont Department of Public Service. February 1996.

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

138. **Maryland PSC** 8720, Washington Gas Light DSM; Maryland Office of People's Counsel. May 1996.

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

138A. **MDPU** DPU 96-100; Massachusetts Utilities' Stranded Costs; Massachusetts Attorney General. Oral testimony in support of "estimation of Market Value, Stranded Investment, and Restructuring Gains for Major Massachusetts Utilities," July 1996.

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

139. **MDPU** DPU 96-70; Massachusetts Attorney General. July 1996.

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

140. **MDPU** DPU 96-60; Massachusetts Attorney General. Direct testimony, July 1996; surrebuttal, August 1996.

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

141. **Maryland PSC** 8725; Maryland Office of People's Counsel. July 1996.

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

142. **New Hampshire PUC** DR 96-150, Public Service Company of New Hampshire stranded costs; New Hampshire Office of Consumer Advocate. December 1996.

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

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

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

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

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

145. **Vermont PSB** 5980, proposed statewide energy plan; Vermont Department of Public Service. Direct, August 1997; rebuttal, December 1997.

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

146. **MDPU** 96-23, Boston Edison restructuring settlement; Utility Workers Union of America. September 1997.

Performance incentives proposed for the Boston Edison company.

147. **Vermont PSB** 5983, Green Mountain Power rate increase; Vermont Department of Public Service. Direct, October 1997; rebuttal, December 1997.

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

148. **MDPU** 97-63, Boston Edison proposed reorganization; Utility Workers Union of America. October 1997.

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

149. **MDTE** 97-111, Commonwealth Energy proposed restructuring; Cape Cod Light Compact. Joint testimony with Jonathan Wallach, January 1998.

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

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

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

151. **Maryland PSC** 8774; APS-DQE merger; Maryland Office of People's Counsel. February 1998.

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

152. **Vermont PSB** 6018, Central Vermont Public Service Co. rate increase; Vermont Department of Public Service. February 1998.

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

153. **Maine PUC** 97-580, Central Maine Power restructuring and rates; Maine Office of Public Advocate. May 1998; Surrebuttal, August 1998.

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

154. **MDTE** 98-89, purchase of Boston Edison municipal streetlighting, Towns of Lexington and Acton. Affidavit, August 1998.

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

155. **Vermont PSB** 6107, Green Mountain Power rate increase, Vermont Department of Public Service. Direct, September 1998; Surrebuttal drafted but not filed, November 2000.

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

156. **MDTE** 97-120, Western Massachusetts Electric Company proposed restructuring; Massachusetts Attorney General. Joint testimony with Jonathan Wallach, October 1998. Joint surrebuttal with Jonathan Wallach, January 1999.

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

157. **Maryland PSC** 8794 and 8804; BG&E restructuring and rates; Maryland Office of People's Counsel. Direct, December 1998; rebuttal, March 1999.

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

158. **Maryland PSC** 8795; Delmarva Power & Light restructuring and rates; Maryland Office of People's Counsel. December 1998.

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

159. **Maryland PSC** 8797; Potomac Edison Company restructuring and rates; Maryland Office of People's Counsel. Direct, January 1999; rebuttal, March 1999.

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

160. **Connecticut DPUC** 99-02-05; Connecticut Light and Power Company stranded costs; Connecticut Office of Consumer Counsel. April 1999.

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

161. **Connecticut DPUC** 99-03-04; United Illuminating Company stranded costs; Connecticut Office of Consumer Counsel. April 1999.

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

162. **Washington UTC** UE-981627; PacifiCorp–Scottish Power Merger, Office of the Attorney General. June 1999.

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

163. **Utah PSC** 98-2035-04; PacifiCorp–Scottish Power Merger, Utah Committee of Consumer Services. June 1999.

Review of proposed performance standards and valuation of performance.

164. **Connecticut DPUC** 99-03-35; United Illuminating Company proposed standard offer; Connecticut Office of Consumer Counsel. July 1999.

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

165. **Connecticut DPUC** 99-03-36; Connecticut Light and Power Company proposed standard offer; Connecticut Office of Consumer Counsel. Direct, July 1999; Supplemental, July 1999.

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

166. **W. Virginia PSC** 98-0452-E-GI; electric-industry restructuring, West Virginia Consumer Advocate. July 1999.

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

167. **Ontario Energy Board** RP-1999-0034; Ontario Performance-Based Rates; Green Energy Coalition. September 1999.

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

168. **Connecticut DPUC** 99-08-01; standards for utility restructuring; Connecticut Office of Consumer Counsel. Direct, November 1999; Supplemental January 2000.

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

169. **Connecticut Superior Court** CV 99-049-7239; Connecticut Light and Power Company stranded costs; Connecticut Office of Consumer Counsel. Affidavit, December 1999.

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

170. **Connecticut Superior Court** CV 99-049-7597; United Illuminating Company stranded costs; Connecticut Office of Consumer Counsel. December 1999.

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

171. **Ontario Energy Board** RP-1999-0044; Ontario Hydro transmission-cost allocation and rate design; Green Energy Coalition. January 2000.

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

172. **Utah PSC** 99-2035-03; PacifiCorp Sale of Centralia plant, mine, and related facilities; Utah Committee of Consumer Services. January 2000.

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

173. **Connecticut DPUC** 99-09-12; Nuclear Divestiture by Connecticut Light & Power and United Illuminating; Connecticut Office of Consumer Counsel. January 2000.

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

174. **Ontario Energy Board** RP-1999-0017; Union Gas PBR proposal; Green Energy Coalition. March 2000.

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

175. **NY PSC** 99-S-1621; Consolidated Edison steam rates; City of New York. April 2000.

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

176. **Maine PUC** 99-666; Central Maine Power alternative rate plan; Maine Public Advocate. Direct, May 2000; Surrebuttal, August 2000.

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

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

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

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

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

179. **Connecticut DPUC** 99-09-12RE01; Proposed Millstone Sale; Connecticut Office of Consumer Counsel. November 2000.

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

180. **MDTE** 01-25; Purchase of Streetlights from Commonwealth Electric; Cape Light Compact. January 2001

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

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

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

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

Review of decision in early 1990s to commit to long-term uneconomic purchase from Hydro Québec. Calculation of present damages from imprudence.

183. **New Jersey BPU** EM00020106; Atlantic City Electric Company sale of fossil plants; New Jersey Ratepayer Advocate. Affidavit, May 2001.

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

184. New Jersey BPU GM00080564; Public Service Electric and Gas transfer of gas supply contracts; New Jersey Ratepayer Advocate. Direct, May 2001.

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

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

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

186. New Jersey BPU EX01050303; New Jersey electric companies' procurement of basic supply; New Jersey Ratepayer Advocate. August 2001.

Review of proposed statewide auction for purchase of power requirements. Market power. Risks to ratepayers of proposed auction.

188. NY PSC 00-E-1208; Consolidated Edison rates; City of New York. October 2001.

Geographic allocation of stranded costs. Locational and postage-stamp rates. Causation of stranded costs. Relationship between market prices for power and stranded costs.

187. MDTE 01-56, Berkshire Gas Company; Massachusetts Attorney General. October 2001.

Allocation of gas costs by load shape and season. Competition and cost allocation.

188. New Jersey BPU EM00020106; Atlantic City Electric proposed sale of fossil plants; New Jersey Ratepayer Advocate. December 2001.

Current market value of generating plants vs. proposed purchase price.

189. Vermont PSB 6545; Vermont Yankee proposed sale; Vermont Department of Public Service. Direct, January 2002.

Comparison of sales price to other nuclear sales. Evaluation of auction design and implementation. Review of auction manager's valuation of bids.

190. Connecticut Siting Council 217; Connecticut Light & Power proposed transmission line from Plumtree to Norwalk; Connecticut Office of Consumer Counsel. March 2002.

Nature of transmission problems. Potential for conservation and distributed resources to defer, reduce or avoid transmission investment. CL&P transmission planning process. Joint testimony with John Plunkett.

191. **Vermont PSB** 6596; Citizens Utilities Rates; Vermont Department of Public Service. Direct, March 2002; Rebuttal, May 2002.

Review of 1991 decision to commit to long-term uneconomic purchase from Hydro Québec. Alternatives; role of transmission constraints. Calculation of present damages from imprudence.

192. **Connecticut DPUC** 01-10-10; United Illuminating rate plan; Connecticut Office of Consumer Counsel. April 2002

Allocation of excess earnings between shareholders and ratepayers. Asymmetry in treatment of over- and under-earning. Accelerated amortization of stranded costs. Effects of power-supply developments on ratepayer risks. Effect of proposed rate plan on utility risks and required return.

194. **Connecticut DPUC** 01-12-13RE01; Seabrook proposed sale; Connecticut Office of Consumer Counsel. July 2002

Comparison of sales price to other nuclear sales. Evaluation of auction design and implementation. Assessment of valuation of purchased-power contracts.

195. **Ontario EB** RP-2002-0120; Review of transmission-system code; Green Energy Coalition. October 2002.

Cost allocation. Transmission charges. Societal cost-effectiveness. Environmental externalities.

196. **New Jersey BPU** ER02080507; Jersey Central Power & Light rates; N.J. Division of the Ratepayer Advocate. Phase I December 2002; Phase II (oral) July 2003.

Prudence of procurement of electrical supply. Documentation of procurement decisions. Comparison of costs for subsidiaries with fixed versus flow-through cost recovery.

197. **Connecticut DPUC** 03-07-02; CL&P rates; AARP. October 2003

Proposed distribution investments, including prudence of prior management of distribution system and utility's failure to make investments previously funded in rates. Cost controls. Application of rate cap. Legislative intent.

198. **Connecticut DPUC** 03-07-01; CL&P transitional standard offer; AARP. November 2003.

Application of rate cap. Legislative intent.

199. **Vermont PSB** 6596; Vermont Electric Power Company and Green Mountain Power Northwest Reliability transmission plan; Conservation Law Foundation. December 2003.

Inadequacies of proposed transmission plan. Failure of to perform least-cost planning. Distributed resources.

200. **Ohio PUC** Case 03-2144-EL-ATA; Ohio Edison , Cleveland Electric, and Toledo Edison Cos. rates and transition charges; Green Mountain Energy Co. Direct February 2004.

Pricing of standard-offer service in competitive markets. Critique of anticompetitive features of proposed standard-offer supply, including non-bypassable charges.

201. **NY PSC** Cases 03-G-1671 & 03-S-1672; Consolidated Edison Company Steam and Gas Rates; City of New York. Direct March 2004; Rebuttal April 2004; Settlement June 2004.

Prudence and cost allocation for the East River Repowering Project. Gas and steam energy conservation. Opportunities for cogeneration at existing steam plants.

202. **OEB** RP 2004-0188; cost recovery and DSM for Ontario electric-distribution utilities; Green Energy Coalition. Exhibit, September 2004.

Differences in ratemaking requirements for customer-side conservation and demand management versus utility-side efficiency improvements. Recovery of lost revenues or incentives. Reconciliation mechanism.

203. **NY PSC** 04-E-0572; Consolidated Edison rates and performance; City of New York. Direct, September 2004; rebuttal, October 2004.

Consolidated Edison's role in promoting adequate supply and demand resources. Integrated resource and T&D planning. Performance-based ratemaking and streetlighting.

204. **MDTE** 04-65; Cambridge Electric Light Co. streetlighting; City of Cambridge. Direct, October 2004; Supplemental January 2005.

Calculation of purchase price of street lights by the City of Cambridge..

205. **NY PSC** 04-W-1221; rates, rules, charges, and regulations of United Water New Rochelle; Town of Eastchester and City of New Rochelle. Direct, February 2005.

Size and financing of proposed interconnection. Rate design. Water-mains replacement and related cost recovery. Lost and unaccounted-for water.

206. **NY PSC** 05-M-0090; system-benefits charge; City of New York. Comments, March 2005.

Assessment and scope of, and potential for, New York system-benefits charges.

207 **Maryland PSC** 9036; Baltimore Gas & Electric rates; Maryland Office of People's Counsel. Direct, August 2005

Allocation of costs. Design of rates. Interruptible and firm rates.

Exhibit 2: Hydro vs. Pacific Gas and Electric
Actual 2004 Savings Yield

2004 Savings Yield (kWh Savings per Canadian Dollar)

	Res.	C&I	Total
BC Hydro	6.2	9.3	7.9
PG&E	3.9	5.0	4.4

Sources:

Appendix A Energy Efficiency Plan of BC Hydro's Resource and Expenditure Acquisition Plan (2005 REAP), Table 1. Net Incremental Electricity Savings at Customer Meter (GWh), page 6

Appendix A Energy Efficiency Plan of BC Hydro's Resource and Expenditure Acquisition Plan (2005 REAP), Table 5. Total BC Hydro Costs ($ 000), page 12

Pacific Gas and Electric Company's Energy Efficiency Programs Annual Report—May 2005, Table 1.1, Summary of Costs (Electric), page I-6

Pacific Gas and Electric Company's Energy Efficiency Programs Annual Report—May 2005, Table 1.2a Summary of EEP Effects (Annual Energy Reductions, Net MWH), page I-7

Pacific Gas and Electric Company's Energy Efficiency Programs Annual Report—May 2005, Table 4.1 Summary of Costs New Construction Program Area (Electric), page 4-8

Pacific Gas and Electric Company's Energy Efficiency Programs Annual Report—May 2005, Table 4.2 Summary of Energy Efficiency Program Effects New Construction Program Area PGC and Procurement, page 4-10

Pacific Gas and Electric Company's Energy Efficiency Programs Annual Report—May 2005, Table 6.1 Market Assessment & Evaluation Budget *MA&E) (Electric), page 6-8

$US = 1.18 $CDN; Bank of Canada, September 8, 2005

Exhibit 3: Hydro vs. Pacific Gas and Electric
Savings Depths

Savings Depth (Savings per 2003 Sales)

	2004 Results			2005 Plan			2006	2007	2008
	Res.	**C&I**	**Total**	**Res.**	**C&I**	**Total**	**Total**	**Total**	**Total**
BC Hydro	0.96%	0.93%	0.94%	0.65%	0.43%	0.50%	0.59%	0.87%	0.63%
PG&E	1.29%	1.10%	1.18%	1.20%	1.81%	1.56%	1.83%	2.08%	2.40%
Ratio	74%	85%	80%	54%	24%	32%	32%	42%	26%

Sources:

Appendix A Energy Efficiency Plan of BC Hydro's Resource and Expenditure Acquisition Plan (2005 REAP), Table 1. Net Incremental Electricity Savings at Customer Meter (GWh), page 6

Appendix D Electric Load Forecast of BC Hydro's Resource and Expenditure Acquisition Plan (2005 REAP), Table 5.2 Reference Forecast before Power Smart, December 2004 Forecast, page 16

Pacific Gas and Electric Company's Energy Efficiency Programs Annual Report—May 2005, Table 1.2a Summary of EEP Effects (Annual Energy Reductions, Net MWH), page I-7

Pacific Gas and Electric Company's Energy Efficiency Programs Annual Report—May 2005, Table 4.1 Summary of Costs New Construction Program Area (Electric), page 4-8

Pacific Gas and Electric Company's Energy Efficiency Programs Annual Report—May 2005, Table 4.2 Summary of Energy Efficiency Program Effects New Construction Program Area PGC and Procurement, page 4-10

Pacific Gas and Electric Company's Energy Efficiency Programs Annual Report—May 2005, Table 6.1 Market Assessment & Evaluation Budget *MA&E) (Electric), page 6-8

Pacific Gas and Electric Company EnergyEfficiency2006-2008-Programs_CPUC_Draft-Dec_20050817-01Atch01, Attachment 4: Program Budgets and Projected Savings, page 38

US Energy Information Agency, Table 14. Class of Ownership, Number of Bundled Ultimate Consumers, Revenue, Sales, and Average Retail Price for the Residential Sector by State Utility, 2003

US Energy Information Agency, Table 15. Class of Ownership, Number of Bundled Ultimate Consumers, Revenue, Sales, and Average Retail Price for the Commercial Sector by State Utility, 2003

US Energy Information Agency, Table 16. Class of Ownership, Number of Bundled Ultimate Consumers, Revenue, Sales, and Average Retail Price for the Industrial Sector by State Utility, 2003