STATE OF UTAH

BEFORE THE PUBLIC SERVICE COMMISSION

The Application of Rocky Mountain	**)**	
Power for Authority To Increase Retail	**)**	**Docket No. 07-035-93**
Electric Rates and for Approval of a	**)**	
New Large-Load Surcharge	**)**	

DIRECT TESTIMONY OF

PAUL CHERNICK

ON BEHALF OF

THE UTAH COMMITTEE OF CONSUMER SERVICES

Resource Insight, Inc.

JULY 21, 2008

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I. Identification and Qualifications

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

A: I am Paul L. Chernick. I am the president of Resource Insight, Inc., 5 Water Street, Arlington, 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 described in CSS Exhibit (PLC-8D.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 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, New York Public Service Commission, 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.

Q: Have you testified previously before the Commission?

A: Yes. I testified on behalf of the Utah Committee of Consumer Services ("the Committee") in the following dockets:

- Docket No. 98-2035-04, on the proposed acquisition of PacifiCorp by Scottish Power. My testimony addressed proposed performance standards and valuation of performance.

- Docket No. 99-2035-03, on the sale of the Centralia coal plant. My testimony addressed the costs of replacement power, the allocation of plant sale proceeds, and the potential rate impacts on Utah customers of PacifiCorp's decision to sell the plant. I testified that the sale of Centralia was not in the interest of ratepayers and that if the Commission approved the sale it should allocate more of the sale proceeds to Utah to mitigate potentially high replacement power costs. The Commission adopted this latter recommendation as part of approving the sale.

I also assisted the Committee in analyzing various issues in the multi-state process. These issues included resource planning, cost allocation of generation-and-transmission plant, regulatory policy and risk analysis.

II. Introduction

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

A: My testimony is sponsored by the Committee.

Q: What issues does your testimony address?

A: I evaluate the following proposals of Rocky Mountain Power ("RMP" or "the Company"):

- The classification and allocation factors in the Cost of Service Study ("COS Study");
- The irrigator-load-research study;
- The Company's reliance on its Cost of Service Study as the basis for its class rate spread proposal;
- Proposed rate design changes to Residential Schedule 1, in particular the introduction of the Customer Load Charge ("CLC") for usage over 1000 kWh in the summer months.

Q: Prior to hearings on the revenue-requirement phase of the case in early June 2008, RMP reduced its rate request from approximately $99 million (7.5%) to $74.5 million (5.6%) (excluding special contract customers). What COS Study and proposed rate schedules do you address?

A: I evaluated the COS Study and proposed rate schedules presented in Exhibits RMP__(CCP-3S) and RMP__(WRG-1S through 4S), which are both linked to the 7.5% rate increase request. The Company did not update its proposed rate schedules to comport with its lower 5.6% revenue requirement request.

III. Evaluation of RMP's Cost-of-Service Study

Q: What is the purpose of the cost-allocation process?

A: The purpose of the cost-allocation process is the fair assignment of the total Utah jurisdictional revenue requirement to the various tariffed rate classes.[1] A fundamental principle of the process is that allocation based on cost causation results in an equitable sharing of embedded costs. As Company Witness William Griffith explains in his Direct Testimony (at 3), the COS Study process "recognize[s] the way a utility provides electrical service and assigns cost responsibility to the groups of customers for whom those costs were incurred."

Q: What role should the embedded COS Study play in revenue allocation?

A: Any embedded-cost-based COS Study is approximate and based on judgment. Therefore, it should serve only as a guide to class rate spread.

Q: Should the COS Study be the basis of rate design as well as rate spread?

[1] There are also cost-allocation implications for certain special contract customers due to escalation clauses in their respective contracts.

A: No. Considerations of marginal cost and incentive effects, not embedded cost, should be the primary basis for design of rates for individual classes.

Q: Should the Commission expect allocation methods to change over time?

A: Yes. The COS Study methodology should not be fixed in stone. It should be updated or revised as needed to address changes in any of the following:

- the conceptual models of cost causation;
- data availability;
- the environment in which utilities operate, such as the structure of wholesale markets and cost patterns;
- energy and regulatory policy.

A. Reasonableness of Classification and Allocation Factors

Q: Does RMP's COS Study reasonably reflect cost causation?

A: No. I have identified a number of problems with the Company's classification and allocation decisions that are likely to overstate the net costs incurred to serve the residential, small commercial and irrigation classes. In particular, RMP's COS Study

- understates the energy-related costs of generation, especially coal and wind resources;
- understates the energy-related portion of firm power purchase costs;
- almost certainly understates the energy-related costs of transmission;
- misallocates monthly off-system firm sales revenues to rate classes, in that the Study ignores individual class contributions to supporting the resources from which off-system sales are made and the extent to which class loads allow PacifiCorp to make those sales;
- minimizes the effects of energy use on distribution costs;

- ignores the sharing of service drops by residential customers in multi-family dwellings.

1. The Classification of Generation Plant

Q: How is generation plant classified?

A: The COS Study classifies "seasonal" generation plant (including combustion turbines) as 100% demand-related and baseload and intermediate generation plant as 75% demand-related and 25% energy-related. This approach recognizes that power production facilities are built both to serve demand (i.e., to meet reliability requirements) and to produce energy economically.

Q: How did PacifiCorp come to use the 75-25 demand-energy classification split for generation?

A: As I understand the history of this classification split, 75-25 split was initially a compromise between the Pacific Power and Light's 50-50 classification and the Utah Power and Light's 100% demand classification, in place at the time of the PacifiCorp merger. I also understand that PacifiCorp analyzed the demand-energy classification in the early 1990s, as part of the work performed within the PacifiCorp Interjurisdictional Task Force on Allocations process. However, the Utah Commission never ruled on the classification issue until its rate case decision in Docket No. 97-035-01.

Q: What did the Commission decide in that rate case proceeding?

A: Acknowledging that energy needs are a significant driver of generation capital costs, the Commission adopted the Division's qualitative argument in support of a 75-25 demand-energy classification:

> Citing both past operating experience and future resource planning, the Division notes that resources with higher energy availability are chose over those with lower energy availability. Since energy plays a role in the selection of least-cost resources, the Division concludes that some weight needs to be given to energy in planning for new capacity, and the current weight of 25 percent is reasonable. We find the *qualitative argument* offered by the Division to be…convincing. (PSC Order, Docket No. 97-035-01 at 82, emphasis added)

Q: From a quantitative standpoint, how can the energy-related portion of generation plant costs be estimated?

A: One approach is the *peaker method,* which considers the demand-related portion of production plant to be the minimum cost of providing the current system reliability level, and the remainder to be the energy-related portion. The Company previously endorsed this concept in the 1989 UP&L Distribution Study at 11:

> The increased cost of a baseload unit over a peaking plant represents an investment made to save fuel costs. The additional investment can be classified as energy related.… The generation plants have two equally important ratings, energy and demand.

Q: Is the peaker approach consistent with the current electricity markets?

A: Yes. The Independent System Operators ("ISOs") for restructured markets apply a pricing model similar to the peaker method, which are even more weighted to energy. For example,

- The New York ISO and PJM determine the price of capacity from a formula that sets the capacity price near the cost of a peaking unit, net of energy revenues, when installed capacity is close to the required level.
- The New England ISO sets capacity prices through a forward auction. The initial starting price for the auction, as well as minimum and maximum prices, are determined by the cost of a new peaker, net of energy revenues.

- Other ISOs, including the California ISO, Midwest ISO, and ERCOT, have no installed capacity requirements at all, and charge load primarily on time-of-use energy consumption.

Q: Please explain how the peaker method would be used to classify generation plant in a COS Study.

A: For each generation unit, a good initial estimate of the demand- or reliability-related portion of its cost is the cost per kW of a contemporaneous peaker (generally a simple-cycle combustion turbine) times the rated capacity of the unit. The cost of the unit in excess of the equivalent gas turbine capacity is energy-related.[2]

Q: Have you applied the peaker method to PacifiCorp's existing coal plants?

A: Yes. Figure 1, below, shows the gross capital cost per kilowatt at the end of 2006, for each existing PacifiCorp coal plant and for the combustion-turbine plants, sorted by in-service date.[3] The peakers averaged under $200/kW, compared to $500–$1,000/kW for the PacifiCorp coal plants, suggesting that 60% to 80% of the coal plant capital costs are energy-related.

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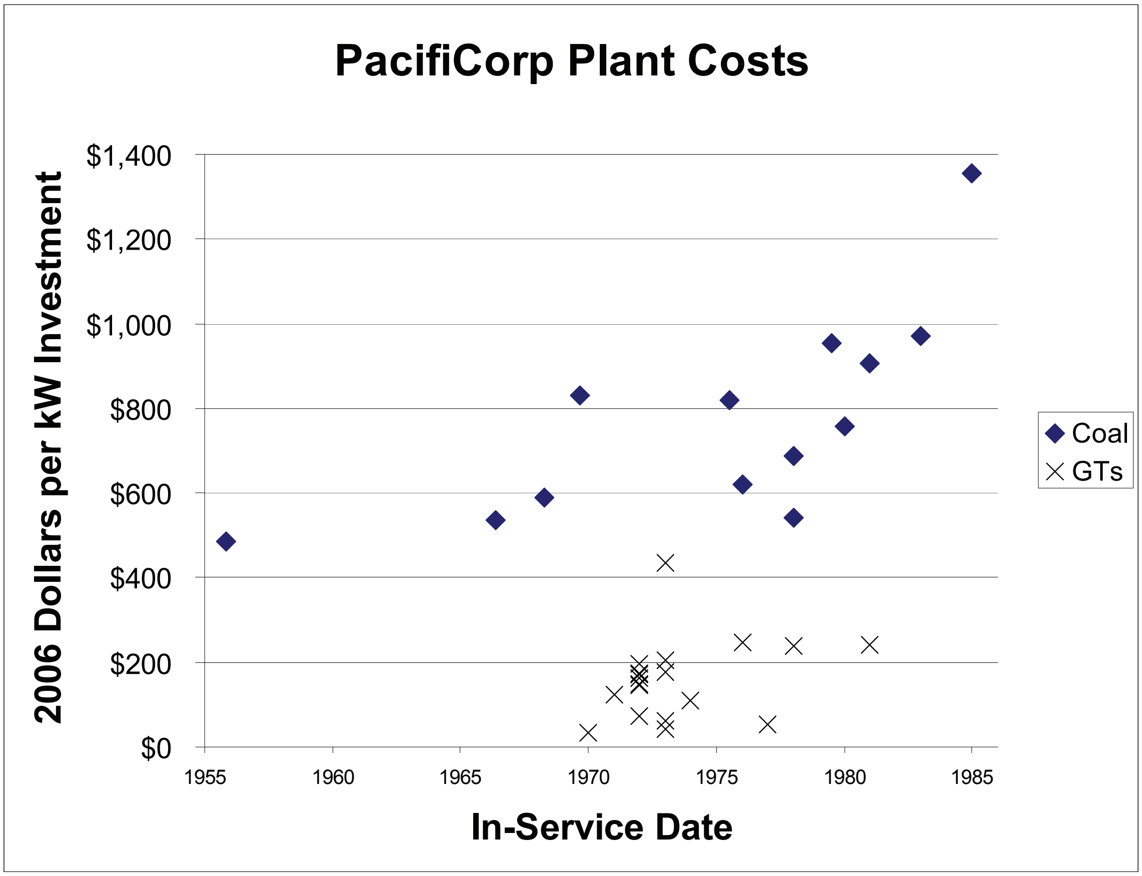
[2]This calculation overstates the reliability-related portion of plant cost: it assumes steam plant supports as much firm demand as would be supported by the same capacity of combustion turbines. Higher forced outage rates, large maintenance requirements, and the size of large units all tend to reduce the contribution of large units to system reliability.

[3]The peakers are those owned by investor-owned utilities in Arizona, Colorado, Montana, New Mexico, Nevada, Oregon, and Washington, and were all built during the period 1970–1981. PacifiCorp does not own any peakers built in the same period as its coal plants.

Figure 1: PacifiCorp Plant Costs



Q: Do PacifiCorp's projections of new generation plant costs support your findings from existing plant data?

A: Yes. According to the 2007 Integrated Resource Plan ("IRP"), the lowest-cost new coal plant would be a Wyoming supercritical plant, at fixed costs of \$217/kW-yr. Netting out the fixed costs of a frame simple-cycle combustion turbine, at \$48/kW-year, the energy-related fixed cost of the new coal plant would be \$169/kW-year, or 78% of the total fixed cost.

Similar computations indicate that the energy-related fixed costs of a new 2×1 F-class combined-cycle combustion turbine (including the duct firing) would be about 32% of its total fixed cost. Assuming that 0.2 MW of combustion turbine would provide the same reliability contribution as one megawatt of installed wind capacity, the fixed costs of wind are about 95% energy-related.[4]

Q: Would changing the demand-energy classification split for PacifiCorp's generation plant have a significant effect on the cost allocation?

A: Yes. Just changing RMP's Factor 10 (the demand-allocated portion of fixed plant costs) from 75% to 50% shifts about $8.5 million off of Schedules 1, 6, and 23, and about $3.8 million onto Schedules 8 and 9.[5]

Table 1

Schedule	Change in Allocation (Million $)
1	−2.4
6	−4.3
8	0.4
9	3.4
23	−1.8

The demand-related portion of PacifiCorp owned generation, weighted across PacifiCorp's generation mix, may be much lower than 50%, so the effects may be much larger.

2. Allocation of Firm Non-Seasonal Purchases

Q: How does RMP allocate firm non-seasonal purchases?

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[4]The costs of PacifiCorp's new wind plants, and of the Gadsby peakers, are very similar to the assumptions in the IRP.

[5]This example, and the other examples I present of allocation effects, are based on RMP's 8.19% target return. In addition to the impacts on the major tariffed classes, reducing Factor 10 to 50% would increase the allocation to special contract customers. Regarding subsequent changes in "Factors," the allocation impacts for special contract customers is in the same directions as that in Schedule 9.

A: The Company classifies firm non-seasonal purchases as 75% demand-related and 25% energy-related and allocates each month's cost separately based on class coincident peak and kWh usage in that month.

Q: Has the energy-related portion of firm non-seasonal purchase costs been understated?

A: Yes, in two important ways. First, the non-seasonal purchases are likely to reflect RMP's mix of non-seasonal generation plant, which are more energy-related than the COS Study assumes, as discussed above in Section III.A.1.

Second, RMP allocates purchases and generation inconsistently. In the case of its own generation plant, RMP treats fuel costs and plant costs separately, and classifies fuel as 100% energy-related, and plant as 75% demand/25% energy-related. But in the case of firm non-seasonal purchases, RMP does not attempt to separate the variable and fixed components and instead treats all purchases costs as fixed plant costs. As a result, RMP allocates only 25% of all purchase costs, including fuel costs, on energy. This difference is illustrated in the table below:

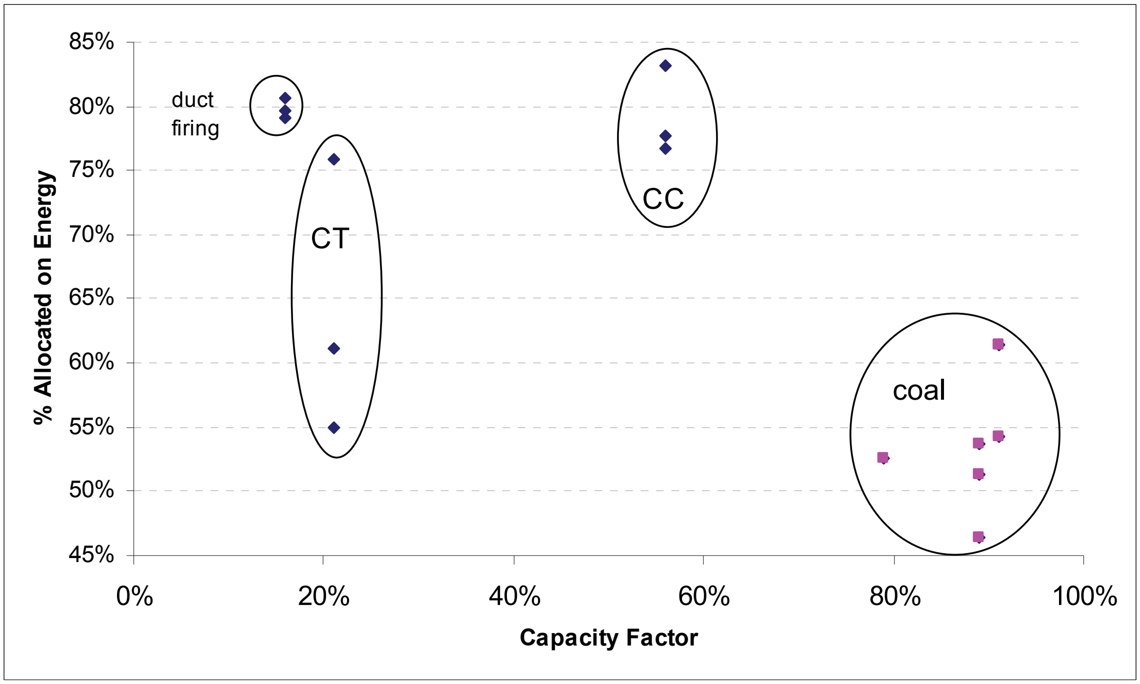
Table 2

	Percent Allocated on Energy		
	Fixed Costs	*Fuel And Variable Costs*	*Total if Half of Cost Is Fuel*
Plant	25%	100%	62.5%
Non-Seasonal Purchases	25%	25%	25%

Q: How significant is the disparity between RMP's classification of purchases and generation?

A: The disparity is quite large. From the 2007 PacifiCorp IRP, I computed the portion of total costs that RMP would allocate on energy for each potential new resource. The energy-related portion of the costs is the sum of variable costs plus 25% of fixed costs for non-seasonal resource, and just variable costs for peakers. The portion of generator costs allocated on energy under RMP's current classification and allocation method ranges from 46% for Wyoming IGCC to 61% for Utah pulverized coal, 55% to 76% for various types of combustion turbines, and 76%–83% for various combined-cycle configurations.

Figure 2: Energy-Related Share of New Resource Costs in RMP's COS Study



Q: Would changing the demand-energy classification split for firm non-seasonal purchases have a significant effect on the cost allocation?

A: Yes. Changing RMP's Factor 87 (the demand-allocated portion of firm non-seasonal purchases) from 75% to 25% shifts about $13 million off of Schedules 1, 6, and 23, and about $5.5 million onto Schedules 8 and 9.

Table 3

Schedule	Change in Allocation (Million $)
1	−2.4
6	−8.0
8	0.3
9	5.2
23	−2.5

3. *The Allocation of Firm Sales Revenue*

Q: How does RMP allocate firm sales revenue?

A: As with firm non-seasonal purchases, RMP classifies firm sales as 75% demand-related and 25% energy-related. The monthly allocation factors for sales and purchases are the same.[6]

Q: Why is this allocation approach inappropriate?

A: Under this allocator, the greater the rate class's demand and usage during a month, the greater its share of the months' firm sales revenue. The correct allocator would reward a class for having lower demand and usage in the month, thereby leaving generation (and transmission) capacity available to support the off-system sales.[7]

Q: Can you provide an example of the misallocation of firm sales revenues?

A: Yes. The irrigation class is assigned 0.761% of (non-seasonal) production plant, 0.627% of firm non-seasonal purchases and 1.519% of firm seasonal purchases, but receives only 0.58% of the firm sales revenues.

Q: Why are the allocations of costs and revenues so skewed in the case of the irrigation class?

A: In the test year, 96% of irrigation kWh usage occurs in the higher-cost summer months (May–September), but only 35% of the firm sales revenues are made in those months (Excel file COS UT Dec 2008 (MSP).xls, Tabs "Energy Factor" and "NPC Factors"). In the non-summer months, when irrigation kWh use is

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[6] The annual allocation factors differ in part because sales and purchases do not follow the same monthly pattern.

[7] The allocator must also recognize that purchases in the current month may also contribute to serving the off-system sales that month.

negligible, firm sales revenue is high; in particular, average sales in January through March exceed the summer average by 64%.

The irrigation class should receive a credit for making its share of capacity available for off-system sales in the winter months.

Q: Have you been able to determine the effect on the class allocation of an improved allocator for firm off-system firm sales?

A: No. The COS Study is not designed to allow a user to change the allocation of sales revenues among months. Furthermore, several factors should be reflected in the allocation of sales revenues, and those should vary with the type of sale (e.g., off-peak, around-the-clock, peak hours).

Q: Can you give the Commission a sense of the potential effect of a more appropriate allocation of off-system firm sales revenue?

A. Yes. I computed three additional sales allocators. The first allocates monthly sales revenues, in excess of July and August sales, in proportion to the difference between the class's contribution to annual coincident peak and the class's contribution to monthly coincident peak. The second allocator allocates each month's sales revenue in proportion to the class's unused energy in that month: its contribution to potential energy (annual coincident peak times the hours in the month) minus the class's energy use in the month. The third allocator is the same as the second, except that the potential energy is increased by a 15% reserve margin. The class results are as follows:

Table 4

		RMP Allocation	Unused Energy Compared to Peak		Unused CP Sales > Summer
			peak + 15%	*peak*	
Residential	Sch 1	30.54%	57.98%	64.84%	91.59%
GS Dist—Large	Sch 6	29.23%	24.34%	23.83%	4.00%
GS Dist—> 1MW	Sch 8	9.18%	6.02%	5.28%	3.43%
GS Trans	Sch 9	17.60%	4.57%	0.97%	-6.17%
Irrigation	Sch 10	0.58%	2.53%	2.91%	6.89%
GS Dist—Small	Sch 23	6.62%	9.19%	10.11%	8.88%

A fully developed allocator for off-system firm sales revenue would probably fall somewhere between RMP's allocator and those I developed. Such an allocator would increase allocation of off-system sales revenue to Schedules 1, 23, and, especially, 10, and decrease sale revenue allocations to Schedules 6, 8, and 9.

Q: Could these changes be significant?

A: Yes. RMP estimates $590 million in off-system sales revenues, so every 1% shift is worth $5.9 million.[8] A $5.9 million change in cost allocation would change the revenue allocated to Schedules 1, 6, and 9 by about 1%–3%; Schedules 8 and 23 by about 5%; and Schedule 10 by about 45%. In addition to the concerns with the irrigator load data discussed later in my testimony, the Commission should note that a small change in the off-system-sales revenue allocation could eliminate the revenue shortfall RMP reports for irrigation. The effects on other classes could also be material.

4. *The Classification of Transmission Plant*

Q: How does the COS Study classify transmission plant?

[8]There may be indirect allocation effects as well.

A: It classifies 75% of transmission costs as demand-related and 25% as energy-related. This classification recognizes that, while peak loads are a major driver of transmission costs, a significant portion of transmission costs are incurred to reduce energy costs. However, RMP has not performed a study of its transmission assets to determine what percentage is energy-serving (RMP Response to CCS DR 40.7).

Q: How is PacifiCorp's transmission system designed to reduce energy costs?

A: PacifiCorp's transmission system design lowers energy costs in at least three ways. First, a large portion of the Company's transmission is required to move power from the remote generators to the load centers and for export. Were generation located nearer to the load centers, the long, expensive transmission lines would not be required (and transmission losses would be smaller). These transmission costs were incurred as part of the tradeoff against the higher operating costs of plants that could be located nearer to the load centers; in other words as a tradeoff against energy-related costs.

Second, PacifiCorp's transmission system is more expensive because it is designed to allow for large transfers of energy between neighboring utilities. Third, PacifiCorp's transmission system is designed to minimize energy losses and to function over extended hours of high loadings. Were the system designed only to meet peak demands, a less costly system would suffice; in some cases lines or circuits would not be required, voltage levels could be lower, and fewer or smaller substations would be needed.

Energy efficiency is clearly a primary purpose of the Company's transmission investment plan, as RMP witness Douglas Bennion explains:

> Rocky Mountain Power must invest in transmission assets to move Company owned generation to substations and load centers. The Company must also build transmission facilities to move power generated by others (i.e. independent power producers) to substations and load centers. In addition, the Company must build facilities that interconnect with other transmission and generation providers as it enters into contracts with customers, generators and shippers that require transmission access. This transmission infrastructure is essential to enhance efficiencies as daily and seasonal loads fluctuate. (Bennion Direct Testimony at 5)

Q: Have you performed a comprehensive analysis of the factors driving RMP's transmission investment?

A: No. Such an analysis is quite data-intensive, involving consideration of the uses of each line, and the effect of energy and long hours of high usage on system design. That analysis would best be undertaken by RMP with input and review by interested parties. I recommend the Commission require such an analysis.

To give the Commission a sense of the possible impact of correcting the transmission classification, I reviewed the transmission-line cost data in PacifiCorp's 2006 FERC Form 1 at 422–423. From PacifiCorp's transmission maps, it appears that the highest-voltage lines (500 kV, 345 kV, and 230 kV) primarily connect PacifiCorp's load with remote baseload generation and would not be needed except to access low-cost energy. Those lines account for 55% of PacifiCorp's gross transmission investment and, since they tend to be newer, probably a higher percentage of PacifiCorp's net transmission investment. Hence, over half of PacifiCorp transmission revenue requirement is likely to be attributable to energy.

5. Distribution Classification and Allocation factors

Q: What is the basis for RMP's distribution cost classification and allocation?

A: The Company relies on UP&L's October 1989 Distribution Cost Allocation Study (provided as an attachment to DR CCS 38.3). The Study (at 11) attempts to reflect the distribution design guidelines in the selection of classification and allocation factors:

> We need to discover the chief characteristics of each of the physical sub-systems in order to effect an appropriate cost classification. To do this we will examine the design process for the distribution system. The rationale behind this approach is that costs are not driven directly by service characteristics but by the design engineer's response to those service characteristics.

Q: How does RMP's COS Study classify distribution?

A: The Company classifies substations, primary lines, line transformers and secondary lines as demand-related. The remaining distribution plant, services and meters, are classified as customer-related. In RMP's view, "there are no significant energy related costs associated with the distribution system." (Exhibit RMP___(CCP-3S), Tab 1, at 8.)

Q: How does RMP's COS Study allocate demand-related distribution plant?

A: The COS Study treats distribution costs as follows:

- Substations and primary lines are allocated based on weighted monthly coincident distribution peaks:

  > The coincident distribution peak is the simultaneous combined demand of all distribution voltage customers at the hour of the distribution system peak. These monthly values are weighted by the percent of substations that achieve their annual peak in each month of the year. (Exh. RMP (CCP-35), Tab 1, at 9)

- Line transformers and secondary lines are allocated based on weighted non-coincident peaks. In the case of line transformers,

> The allocation factor, F21, is based on the maximum monthly class NCP. This may be a different month for each class. For classes of customers where transformers are shared by more than one customer, the NCP is weighted by the appropriate coincidence factor from the Company's Job Designer's Manual to recognize the diversity of load at the transformer. (Exh. RMP (CCP-35), Tab 1, at 9)

Secondary lines are allocated to the residential and small General Service classes only, using a similar "weighted non-coincident peak" allocator.

Q: How does RMP allocate services and meters?

A: Services and meters are allocated based on weighted customer number, weighted by the current installed cost of the equipment.

Q: Does RMP's allocation of distribution costs reasonably reflect cost causation?

A: No. The Company's approach has the following problems:

- It overlooks many of the ways in which energy usage drives distribution investment.
- The weighting factors used in deriving the F20 allocator (for substations and primary feeders) are not cost based and overweight the July peak.
- It ignores the sharing by smaller customers of service drops.

a) Energy-Related Distribution Costs

Q: In what ways does energy use affect distribution costs?

A: Energy use, especially in high-load hours and in off-peak hours on high-load days, affects distribution investment and outage costs in the following ways:

- The number of high-load hours determines risk of load loss following equipment failure, and hence drives investment in redundant equipment to improve distribution system reliability.
- The number and extent of overloads determines the life of the insulation on lines and in transformers (both in substations and in line transformers), and

hence the life of the equipment. A transformer that is very heavily loaded for a couple of hours a year, and lightly loaded in other hours, may well last 40 years or more, until the enclosure rusts away. A similar transformer subjected to the same annual peaks, but to many smaller overloads in each year, may burn out in 20 years.

- All energy in high-load hours, and even all hours on high-load days, adds to heat buildup and results in (1) sagging of overhead lines, which often defines the thermal limit on lines; (2) aging of insulation in underground lines and transformers; and (3) a reduction the ability of lines and transformers to survive brief load spikes on the same day.
- Line losses depend on load in every hour (marginal line losses due to another kWh of load generally exceed the average loss percentage in that hour).

CSS Exhibit (PLC-8D.2) provides a more detailed explanation of the effect of energy on the cost and sizing of transformers.

Q: Does the 1989 UP&L study consider the effect of energy use on distribution costs?

A: Yes, but it concludes that the energy-related portion of distribution is negligible.

Q: Is the UP&L study comprehensive?

A: No. The study

- limits the category of "energy-related" investments to those that are specifically made to reduce energy load losses, namely, certain increases in the sizing of conductors and transformers. [9]
- credits energy loss reductions with fuel-savings only, assuming that only demand-loss reductions can avoid generation, transmission and distribution capacity costs.[10]
- relies on an out-of-date 1983 estimate of fuel-savings, which is likely to be much less than current marginal fuel costs and market prices. The lower the value of fuel-savings from increased capacity of lines and transformers, the smaller the portion of plant that will be considered energy-related.

In addition, UP&L performed few actual calculations to quantify the energy-related portion of distribution. Apparently, its conclusion was based on a cost comparison for only two transformer ratings and a single manufacturer, which UP&L acknowledged (in its 1989 Distribution Study at 21) "cannot be extrapolated to all transformers.…" There were no calculations of the energy-related portion of conductor costs.

Q: Do the Company's distribution guidelines and COS Study support the UP&L Distribution Study methodology and conclusions?

A: No, for the following reasons:

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[9]In the case of conductors, the UP&L study (at 14) specifies that Company selects the conductor size at the point at which

> …the incremental savings in capitalized energy losses from switching to the next larger conductor are equal to the incremental cost of installing the larger conductor. Thus the conductor selected is the most economical one to use for the initial loading of the circuit.

[10]This also appears to have been a problem with the 1983 version of "Distribution Specification No. L-100: Distribution Transformer Loss Evaluation," on which UP&L's distribution-cost allocation relied. Presumably, the Company has revised its transformer purchase practices to take into account the current power market and value of reducing energy usage.

- Utah Power & Light's assumption that reduction in energy losses saves only fuel costs is inconsistent with the Company's own cost allocation approach. The COS Study assumes that 25% of generation plant, transmission plant and firm purchase costs are driven by energy use.
- The Study misinterprets the distribution design guidelines.
- The Study overlooks the effect of energy use on the need for replacement and the failure rate of distribution equipment, also recognized in the distribution guidelines.
- The Study does not reflect the current condition of the RMP distribution system.

Q: Can you provide some examples from the distribution design guidelines that demonstrate that energy use is a driving factor in distribution capacity costs?

A: Yes. The Study identifies a number of ways in which expected energy use, especially in hours close to peak in load or time, affects both design standards and investment. For example, the sizing of new conductors and transformers is determined by the expected hours of high use as well as by the single peak. Figure 4 of the Guidelines sets out the maximum design loading without damage assuming four hours of usage and maximum emergency usage limited to 8 hours with some risk of equipment damage. So the greater the number of hours of maximum loading, the larger the conductor installed. Similarly, the Study (at 12) recognizes that heat buildup may limit the capacity of a substation transformer.

b) Coincident Distribution Peak Weighting Factors

Q: Why are the distribution weighting factors invalid?

A: RMP's approach produces illogical results. The only two months with weights greater than 10% are July (41%) and June (18.4%). The Utah distribution peak actually occurs in August, but receives a weight of only 8.5% (Excel file COS UT Dec 2008 (MSP).xls, Tab "Dist. Factors").

Weighting by the number of substations peaking in a month does not reflect cost causality. Under this weighting scheme, for example,

- The month with the most large substations seriously overloaded could be the highest cost month yet not receive the highest weight.
- A month would receive a weight of 100% whether each substation's maximum load were (1) only 1 kVA more than its maximum in every other month, or (2) four times its maximum in every other month.
- A small substation has as much effect on a month's weighting factor as a large substation does.

Q: Are there more reasonable distribution weighting factors the Commission should consider adopting?

A: Yes. I looked at two methods that recognize the size of individual substations and the effect of multiple peaks on substation sizing.[11] For the first method, I computed the ratio of the monthly peak on the substation to the annual peak on the substation, from Attachment CCS 10.28, squared the result so as to rapidly reduce the contribution as load falls, and summed the squares over the substations to derive the monthly weights. The second approach is similar, but starts with the ratio of the monthly peak on the substation (in MW) to the substation's capacity (in MVA). The resulting monthly weights are as follows:

[11] In both cases, I omitted substations for which PacifiCorp provided less than twelve months of data.

Table 5

	Method for Assigning Substation Costs to Months	
	Squared % of Annual Peak	*Squared % of Capacity*
January	7.1%	7.1%
February	6.4%	6.4%
March	6.0%	5.9%
April	6.8%	6.7%
May	8.1%	8.2%
June	11.6%	11.9%
July	12.8%	12.8%
August	11.6%	11.9%
September	9.4%	9.5%
October	5.9%	5.9%
November	7.1%	6.7%
December	7.4%	7.0%

Unfortunately, I do not have the data necessary to incorporate the number of high-load hours in each month into the allocation.

Q: How much would these monthly weights change the allocation of RMP costs?

A: Substituting either of these weights would shift about $16.4 million off of Schedules 1 and 10, and about $16.2 million onto Schedules 6, 8, and 23.

Table 6

	Schedule	**Change in Allocation** (Million $)
Residential	1	−15.4
GS Dist—Large	6	12.4
GS Dist— > 1MW	8	2.0
GS Trans	9	0.0
Irrigation	10	−1.0
GS Dist—Small	23	1.8

In addition, the allocation of distribution costs should reflect the extent to which energy use affects distribution costs.

c) Sharing of Service Drops

Q: How does RMP allocate service drops?

A: They are allocated based on customer number, weighting by the cost of a new service for each type of customer (Exhibit RMP__(CCP-3S), Tab 1, at 9).

Q: Has RMP considered the sharing of service drops in developing the service allocator?

A: No. It assumes that each residential customer requires its own service drop (RMP Response to CCS DR 10.14) and ignores the sharing of services by customers in multi-family buildings. The Company has not estimated the number of shared services or portion of its residential customers that are in multi-family buildings or the number of service drops installed (RMP Response to CCS DRs 10.11, 10.13).

Q: Have you estimated what the impact of shared services would be on the residential services allocator?

A: No. RMP does not have data on the mix of housing types and the number of customers per service in its Utah jurisdiction. However, census information indicates about 23% of housing in Utah is multi-family. According to the 2000 Census of Housing in Utah, 12.9% of the customers are in multi-family housing with two to nine units, and 10.3% in multi-family housing with more than nine units, as follows:

Table 7

Units in Structure		
1-unit, detached	520,101	71.5%
1-unit, attached	37,902	5.2%
2 units	29,243	4.0%
3 or 4 units	36,998	5.1%
5 to 9 units	27,677	3.8%
10 to 19 units	30,357	4.2%
20 or more units	44,848	6.2%
Total housing units	727,126	100.0%
Units in multi-family housing	169,123	23.3%

Depending on the number of units in each category sharing services, the total number of services to residential customers may well be 20% less than RMP assumes for allocation purposes.

Q: Would similar adjustments apply to other classes?

A: No. Other than multi-family residential customers on the residential rate, relatively few customers are likely to share services.[12]

B. Irrigation Class Load Study

Q: What does the new load study indicate for Irrigation customers?

A: The Company's current COS Study, which relies on this new load data, indicates that bringing the class to the Company average ROR would require at least a 30% increase to Schedule 10. The Company is proposing an increase of twice the jurisdictional average request for Schedule 10.

Q: Does the irrigation class present special load research challenges?

[12]In some cases, small commercial customers in a strip mall or office building will share a service.

A: Yes. The irrigation loads are diverse, highly variable from year to year, and hard to characterize. Recognizing this variability, RMP used an unusually large sample size.

Q: Please explain the derivation of the irrigation load estimates from the sample data.

A: The Company metered the hourly loads of 120 (out of 2,000) irrigation customers for the period July 1 through September 15, 2006 and May 25 through June 30 2007. It extrapolated from the sample to the entire class in the following five steps (as documented in CCS 23.4 and Attachment DR CCS 10.2):

1. In each strata, computed the average sample load in each hour;
2. Calculated a weighted sum of the hourly kWh over the strata to give an estimate of total class load in that hour, weighting the loads in a given strata by the percentage of the total population that fall in that strata;
3. Summed the class estimated hourly loads over all hours to produce an estimated total class load in each month;
4. Computed the ratio of the actual to the estimated total class load by month;
5. Adjusted each estimated hourly load by the ratio computed in the previous step to provide the load assumptions used in the COS Study.

In the off-peak months, RMP calculated the CP (and all other hourly loads) as the total kWh usage for the month divided by the number of hours in the month, assuming that in their low usage months, they have 100% load factors.

Q: Does the irrigation customer load data provide a valid basis for cost allocation?

A: No. As can be seen from the ratios provided in Attachment DR CCS 10.2 (Tab PricingAdj7), there are sizeable discrepancies between estimated and actual monthly usage. The excess of estimated over actual usage in the summer months range from 7% in July to 75% in September:

Table 8

	May	June	July	August	September
Load Research (kWh)	44,565	48,669	39,758	44,099	33,430
Pricing (kWh)	35,418	38,735	37,081	33,885	19,062
Adj. Factor	0.79	0.80	0.93	0.77	0.57
Overestimate	26%	26%	7%	30%	75%

The load research data over-predicts actual annual usage of irrigation customers by 24%.

Q: Can RMP's pro rata adjustment to load in all hours provide an adequate correction to the estimated irrigation loads?

A: No. In its derivation of the class hourly load estimates from the sample load data (as explained above), RMP's adjustment holds load shape constant. In other words, RMP assumes that the class demand factors are in constant proportion to energy use and the load profile is unaffected, no matter what the cause of the discrepancy. This is an unrealistic assumption, especially in the case of discrepancies as large as 25–75%. The factors that significantly alter kWh usage (such as crop rotations, changes in weather, temperature and rainfall, and customer diversity) are likely also to affect load shape.

Q: Does the COS Study support RMP's proposed disproportionate increase in Irrigation rates?

A: No. RMP's irrigation load study represents a serious research effort, but since there is such a large disparity between sample and actual usage, the data should not be relied upon to support a major cost allocation action. As discussed earlier in my testimony, the problem is compounded by the significant under-allocation of off-system firm sales revenue to this class.

IV. Rate Design Proposal for Residential Schedule 1

Q: Were you asked by the Committee to address certain issues relating to RMP's residential rate design proposals?

A. Yes. My testimony addresses (1) concerns with the Company's Customer Load Charge proposal, (2) whether RMP's proposed increase in the customer charge may over-recover costs from small residential customers in multi-family buildings with shared services, and (3) the level of the summer tail-block charge.

Q: What are your general concerns with regard to RMP's residential rate design proposals?

A: Variable energy charges are better at signaling energy-related costs than a fixed charge that customers cannot avoid. The Company's proposal to collect approximately 83% of the residential class increase in fixed charges (customer charge and CLC) will reduce customer control over bills, reduce savings from DSM investments, and therefore reduce incentives for customers to conserve. Raising fixed charges is the wrong direction to go especially during a time of rising energy costs and ongoing concerns about Utah load growth.

1. Customer Load Charge

Q: Please explain RMP's Customer-Load-Charge ("CLC") Proposal.

A: Under RMP's CLC Proposal, a $72 charge would be triggered when monthly usage in the May through September billing months exceeds 1,000 kWh in more than one month. The CLC would appear in bills as a $6/month fee for continuous months upon issuance of the Commission's final order in this case.

Q: What is RMP's rationale for the charge?

A: Company Witness William Griffith claims (at 9–11) that the Company's proposal will improve residential rate design by providing the following benefits:

- a signal "to large customers about the costs of their above-average usage,"
- a more effective price signal,
- a "strong and persistent" price signal that will appear in every bill rather than solely in the month in which the kWh usage occurred,
- an easily understandable charge,
- smaller rate increases to the smaller residential customers.

Q: Has RMP provided any studies or reports to support these claims?

A: No. RMP has provided no evidence to support its claim that the CLC will provide an effective pricing signal. RMP acknowledges (in response to CCS 10.39) that it has not prepared or obtained any of the following analyses or data:

- any study of the relative effectiveness of CLCs versus tail block energy charges,
- any estimate of the effect of the CLCs on the residential class contribution to summer peak usage,
- any survey of customers' understanding or acceptance of CLCs,
- any survey of other utilities' experience with CLCs,
- any estimate of effect of CLCs on customers' peak usage.

Q: Did RMP properly assess the bill impacts of the CLC?

A: No. The Company's bill-impact analysis ignores several of the CLC's effects, particularly by computing the bills only for a customer whose usage is the same from month to month. As a result, the bill-impact analysis adds the CLC to all bills over 1,000 kWh, and to others. In reality, the CLC would be added to some small bills (e.g., 400 kWh) and not to some large bills (e.g., 2,000 kWh).

Do you believe that the CLC could provide an effective pricing signal?

A: No, for the following reasons:

- The charge is not cost-based. Usage during high-load periods is a primary driver of costs. Yet, customers incur the same $72 annual cost whether (a) they consume 2,000 kWh in all four summer months or (b) reach 1,100 kWh in only June and July and use 750 kWh in the other two months. In the extreme, a customer could end up paying $72 for a single kWh. On the other hand, a customer with very high usage in only one month (e.g., 4,000 kWh in the peak summer month) will not incur the $72 penalty. The CLC is inequitable, assigning the highest penalty per kWh to the customers with the lowest increment above 1000 kWh.
- Once incurred, the CLC will provide no incentive to conserve, even at peak times.
- Shifting revenues onto fixed charges will reduce energy charges and encourage increased summer electric use.
- If the CLC does provoke a response, it is more likely to come from the customers nearer the 1,000-kWh breakpoint. A small percentage reduction in load would be enough to avoid the charge, providing a significant reward for a relatively small effort. But for a 2,000 kWh residential customer with a very high air conditioning usage, a savings of $72 would probably not be worth the effort required to reduce usage by 50%.
- The CLC cannot be easily explained to customers, especially since it violates fundamental cost and fairness principles. Customers will have difficulty accepting fixed charges in winter bills that are in payment for high summer consumption.
- The CLC will be difficult to avoid. Determining whether to reduce usage is inherently difficult, since the customer must know (1) the start and stop date of the billing month and (2) its summer monthly usage. In addition,

the customer must on a daily basis (1) monitor usage so far in the billing month and (2) forecast usage in the remaining days of the billing month, under normal and various alternative operating conditions. In fact, in its survey RMP found that at least 67% of its residential customers do not know their billing cycle or their monthly usage—information that would be crucial to customer success at avoiding the CLC trigger.

- The CLC would be difficult, if not impossible, to implement. The kWh billing determinants in a given month are not entirely under customers' control. Customers are placed into one of 21 different billing cycles (RMP's Response to AARP DR 4.1). Some of the electric bills are calculated based on estimated rather than actual billing data because of missed meter readings, meter reading errors, and meter failures. On the other hand, a summer meter reading (and bill) can reflect anywhere from 26 to 34 days' electric use with no adjustment for the length of the billing period (RMP's Responses to AARP DR 4.2, 4.3). These factors are not generally a problem under the current residential rate, because the bills are self-correcting. When the actual kWh reading is billed, any prior misestimates are netted out in the following bill. On the other hand, the CLC is a spike in price that is fixed once incurred. When a small error in billing can result in a permanent $72 overcharge, there will be considerable customer frustration and billing disputes.

Q: Please explain why billing cycles can cause problems.

A: Suppose there are two customers A and B that have the same daily load profile but are billed on two different billing cycles X and Y. Billing cycle X includes ten hot days in each of two months, and Y includes 15 hot days in the first month and five days in the second month. Customer A has an 1,200 kWh bill in the first month but only 900 kWh in the second, while Customer B has two 1050 kWh in both months. As a result, only Customer B must pay the CLC.

2. Customer Charge Increase

Q: What is the Company's basis for doubling the customer charge to $4 per month?

A: The Company proposes to set the customer charge to recover the embedded costs of meters, service drops, meter reading, and billing for residential customers (Griffith Direct at 6–7). Exhibit RMP___(WRG-3S) derives an average cost per residential customer from the COS Study.

Q: Is it appropriate to set the customer charge at the average cost of the components you listed in the previous response?

A: Only if those costs are independent of the size of the customer (Commission Order, Docket No. 06-035-21, p. 30). Costs that vary with usage should be in the energy charge. Only the costs of serving the smallest customers should be in the customer charge. Otherwise, small customers would subsidize large customers.

Q: Do any of the components of RMP's calculation of the customer charge overstate the cost of serving small customers?

A: Yes. The smallest residential customers are likely to live in multi-family housing. Those smaller customers would likely share a service drop with other customers in an apartment building. The cost of the service drop varies with the load of the building, not with the number of customers, and therefore does not belong in the customer charge.

Meter reading costs that are also included in the customer charge vary with the size and type of customer. In an apartment building, a single meter in a bank of meters is likely to require much less meter reading time than a single family home.

Q: Have you estimated a customer charge reflecting only the costs of minimum-size residential customers in multi-family housing?

A: Yes. To estimate the customer costs for customers living in multi-family dwellings, I made just one change in RMP's calculation: I removed the costs of service drops. This change alone (without any adjustment to the meter reading cost estimates) results in a customer charge of $2.40 per month.

3. Summer Tail Block Charge

Q: How do you recommend that the revenue increase be recovered from residential customers, if not through a CLC and increase in the customer charge?

A: This cost should be recovered in the energy charges, with the longer-term goal of moving the tail block to marginal cost.

Q: What is the cost of serving the summer tail-block load?

A: Additional summer load incurs the following costs, among others:

- summer energy costs, much of it in high-load, high-cost hours, especially for customers in the tail block;
- a large portion of the cost of peaking generation capacity, including reserves;
- a large portion of the incremental costs of transmission and distribution;
- line losses.

Q: Can you quantify those costs at this time?

A: In part. As of early June, the forward prices for third-quarter energy at Palo Verde and Mid-Columbia in 2009 and 2010 were running about 11¢/kWh on-peak and 7¢/kWh off-peak. Even for a nearly flat load shape, with 60% of the energy in the peak period, the average summer market value of the power is about 9¢/kWh. [13] For a real residential load shape, the energy costs would be greater. Peaking capacity, at $48/kW-year for a frame combustion turbine (in 2006 dollars, from the 2007 IRP), to meet peak plus a 12% reserve margin, spread over 1,400 summer kWh per kW of peak, would add another 1¢–2¢/kWh.[14] Including even 10% marginal losses, the total generation cost would be between 11¢ and 12¢/kWh. Marginal load-related T&D costs would add another couple cents per kWh.[15]

Q: Please summarize your recommendations.

A: On the cost-of-service study, I recommend in Section III.A improvements in classifications and allocations, specifically:

- classifying a greater percentage of fixed non-seasonal generation costs as energy-related,
- classifying a greater percentage of non-seasonal purchases as energy-related,
- classifying a greater percentage of transmission costs as energy-related,
- allocating firm sales revenues in a more realistic manner,
- classifying a portion of distribution costs as energy-related,

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[13] About 57% of hours are in the peak period.

[14] I assume that a flat energy forward would provide capacity value at the average load level; peaking would be required to make up the difference.

[15] On the other hand, some of the generation capacity is attributable to months outside the summer.

- recognizing the sharing of service drops by small residential customers,
- revising the monthly weights for the primary distribution allocator.

My recommended changes to the classifications and allocations should be addressed in an appropriate forum and implemented in the Company's next COS Study.

In setting the rate spread, the Commission should recognize that the deficiencies in the COS allocations and in the irrigation load study bias the COS results and in particular tend to overstate the costs of Schedule 1, 10, and 23. Since the COS Study is flawed in a number of areas, it should not be relied on for determining rate spread until these problems are corrected. In his testimony, Mr. Gimble discusses the Committee's rate spread proposals in greater detail.

In residential rate design, the Commission should reject RMP's proposed CLC and customer charge increase, and use the revenues to raise energy charges, especially in the summer tail block.

Q: Does this conclude your testimony?

A: Yes.

CCS Exhibit (PLC-8D.1)

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SUMMARY OF PROFESSIONAL EXPERIENCE

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

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

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

EDUCATION

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

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HONORS

Chi Epsilon (Civil Engineering)

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Institute Award, Institute of Public Utilities, 1981.

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"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

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"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.

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"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.

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"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, cogeneration, and solar.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

    Profit margin calculations, including methodology, interest rates.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

    Profit margin calculations, including methodology and implementation.

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

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

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

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

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

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

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

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

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

    Construction schedule and cost of completing Millstone Unit 3.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

72. **Vermont PSB** 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.

113. 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.

114. **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.

115. 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.

116. 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.

117. 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.

118. 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.

119. 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.

120. 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.

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

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

122. 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.

123. 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.

124. 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."

125. 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.

126. 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.

127. 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.

128. 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.

129. 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.

130. **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.

131. **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.

132. **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.

133. **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.

134. **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.

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

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

136. **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.

137. **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.

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

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

139. **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.

140. A. **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.

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

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

142. **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.

143. **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.

144. **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.

145. **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.

146. **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.

147. **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.

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

Performance incentives proposed for the Boston Edison company.

149. **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.

150. **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.

151. **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.

152. **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.

153. **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.

154. **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.

155. **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.

156. **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.

157. **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.

158. **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.

159. **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.

160. **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.

161. **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.

162. **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.

163. **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.

164. **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.

165. **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.

166. **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

167. **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.

168. **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.

169. **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.

170. **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.

171. **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.

172. **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.

173. **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.

174. **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.

175. **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.

176. **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.

177. **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.

178. **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.

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

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

180. **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.

181. **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.

182. **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.

183. **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.

184. **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.

185. **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.

186. **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.

187. **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.

188. **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.

189. **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.

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

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

191. **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.

192. **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.

193. **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.

194. **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.

195. **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.

196. **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.

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

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

198. **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.

199. **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.

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

Application of rate cap. Legislative intent.

201. **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.

202. **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.

203. **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.

204. **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.

205. **Ontario EB** RP 2004-0188; cost recovery and DSM for Ontario electric-distribution utilities; Green Energy Coalition. Exhibit, December 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.

206. **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.

207. **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.

208. **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.

209. **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.

210. **British Columbia Utilities Commission** Project No. 3698388, British Columbia Hydro resource-acquisition plan; British Columbia Sustainable Energy Association and Sierra Club of Canada BC Chapter. Direct, September 2005.

Renewable energy and DSM. Economic tests of cost-effectiveness. Costs avoided by DSM.

211. **Connecticut DPUC** 05-07-18; financial effect of long-term power contracts; Connecticut Office of Consumer Counsel. Direct September 2005.

Assessment of effect of DSM, distributed generation, and capacity purchases on financial condition of utilities.

212. **Connecticut DPUC** 03-07-01RE03 & 03-07-15RE02; incentives for power procurement; Connecticut Office of Consumer Counsel. Direct, September 2005. Additional Testimony, April 2006.

Utility obligations for generation procurement. Application of standards for utility incentives. Identification and quantification of effects of timing, load characteristics, and product definition.

213. **Connecticut DPUC** Docket 05-10-03; Connecticut L&P; time-of-use, interruptible and seasonal rates; Connecticut Office of Consumer Counsel. Direct and Supplemental Testimony February 2006.

Seasonal and time-of-use differentiation of generation, congestion, transmission and distribution costs; fixed and variable peak-period timing; identification of pricing seasons and seasonal peak periods; cost-effectiveness of time-of-use rates.

214. **Ontario Energy Board** Case EB-2005-0520; Union Gas rates; School Energy Coalition. Evidence, April 2006.

Rate design related to splitting commercial rate class into two classes: new break point, cost allocation, customer charges, commodity rate blocks.

215. **Ontario Energy Board** Case EB-2006-0021; natural gas demand-side-management generic issues proceeding; School Energy Coalition. Evidence, June 2006.

Multi-year planning and budgeting; lost-revenue adjustment mechanism; determining savings for incentives; oversight; program screening.

216. **Indiana Utility Regulatory Commission** Cause Nos. 42943 and 43046; Vectren Energy DSM proceedings; Citizens Action Coalition. Direct, June 2006.

Rate decoupling and energy-efficiency goals.

217. **Pennsylvania PUC** Docket No. 00061346; Duquesne Lighting; Real-time pricing; PennFuture. Direct, July 2006; surrebuttal August 2006.

Real-time and time-dependent pricing; benefits of time-dependent pricing; appropriate metering technology; real-time rate design and customer information

218. **Pennsylvania PUC** Docket No. R-00061366, et al.; rate-transition-plan proceedings of Metropolitan Edison and Pennsylvania Electric; Real-time pricing; PennFuture. Direct, July 2006; surrebuttal August 2006.

Real-time and time-dependent pricing; appropriate metering technology; real-time rate design and customer information.

219. **Connecticut DPUC** 06-01-08; Connecticut L&P procurement of power for standard service and last-resort service; Connecticut Office of Consumer Counsel. Reports and technical hearings September and October 2006.

Conduct of auction; review of bids; comparison to market prices; selection of winning bidders.

220. **Connecticut DPUC** 06-01-08; United Illuminating procurement of power for standard service and last-resort service; Connecticut Office of Consumer Counsel. Reports and technical hearings August and November 2006; March, September, October, and November 2007; February, April, and May 2008.

Conduct of auction; review of bids; comparison to market prices; selection of winning bidders.

221. **NY PSC** Case No. 06-M-1017; policies, practices, and procedures for utility commodity supply service; City of New York. Comments, November and December 2006.

Multi-year contracts, long-term planning, new resources, procurement by utilities and other entities, cost recovery.

222. **Connecticut DPUC** 06-01-08; procurement of power for standard service and last-resort service, lessons learned; Connecticut Office Of Consumer Counsel. Comments and Technical Conferences December 2006 and January 2007.

Sharing of data and sources; benchmark prices; need for predictability, transparency and adequate review; utility-owned resources; long-term firm contracts.

223. **PUCO** Case No. 05-1444-GA-UNC; recovery of conservation costs, decoupling, and rate-adjustment mechanisms for Vectren Energy Delivery of Ohio; Ohio Consumers' Counsel. Direct, February 2007.

Assessing cost-effectiveness of natural-gas energy-efficiency programs. Calculation of avoided costs. Impact on rates. System benefits of DSM.

224. **NY PSC** Case 06-G-1332, Consolidate Edison Rates and Regulations; City of New York. Direct, March 2007.

Gas energy efficiency: benefits to customers, scope of cost-effective programs, revenue decoupling, shareholder incentives.

225. **Alberta EUB** 1500878; ATCO Electric rates; Association of Municipal Districts & Counties and Alberta Federation of Rural Electrical Associations. Direct, May 2007

Direct assignment of distribution costs to streetlighting. Cost causation and cost allocation. Minimum-system and zero-intercept classification.

226. **Connecticut DPUC** Docket 07-04-24, Review of capacity contracts under Energy Independence Act; Connecticut Office of Consumer Counsel, Joint Direct Testimony June 2007.

Assessment of proposed capacity contracts for new combined-cycle, peakers and DSM. Evaluation of contracts for differences, modeling of energy, capacity and forward-reserve markets. Corrections of errors in computation of costs, valuation of energy-price effects of peakers, market-driven expansion plans and retirements, market response to contracted resource additions, DSM proposal evaluation.

227. **NY PSC** Case 07-E-0524, Consolidate Edison electric rates; City of New York. Direct, September 2007.

Energy-efficiency planning. Recovery of DSM costs. Decoupling of rates from sales. Company incentives for DSM. Advanced metering. Resource planning.

228. **Manitoba PUB** 136-07, Manitoba Hydro Rates; Resource Conservation Manitoba and Time to Respect Earth's Ecosystem. Direct, February 2008.

Revenue allocation, rate design, and demand-side management. Estimation of marginal costs.

229. **Mass. EFSB** 07-7, DPU 07-58 & -59, proposed Brockton Power Company plant; Alliance Against Power Plant Location. Direct, March 2008

Regional supply and demand conditions. Effects of plant construction and operation on regional power supply and emissions.

230. **CDPUC 08-01-01**, peaking generation projects; Connecticut Office of Consumer Counsel. Direct (with Jonathan Wallach), April 2008.

Assessment of proposed peaking projects. Valuation of peaking capacity. Modeling of energy margin, forward reserves, other project benefits.

231. **Ontario EB-2007-0905,** Ontario Power Generation payments; Green Energy Coalition. Direct, April 2008.

Cost of capital for Hydro and nuclear investments. Financial risks of nuclear power.

CCS Exhibit (PLC-8D.2)

The Effect of Energy Use in High-Load Periods on the Cost and Sizing of Transformers

by Paul Chernick

At least three energy-use factors determine the cost and sizing of transformers. The first two—the number of hours in the day in which the transformer operates near its peak period and the load factor on the transformer—affect the maximum load the transformer can tolerate without catastrophic overheating. The third factor is the effect of periodic overloads on useful transformer life.

Instantaneous peaks do not determine distribution capacity needs. Short peaks and low off-peak currents allow the transformer to cool between peaks, so that it can tolerate a higher peak current. The limit for very short-duration loads (e.g., 30 minutes) is generally stated as 200% of rated capacity, while utility practice for high load factors (e.g., 80%) and long peak periods (e.g., 8 hours) often limits loadings to 100%–120% of rated capacity, especially for underground service.

Thus, only about half the installed transformer capacity would be necessary to meet the brief peak loads measured by demand charges, were it not for the neighboring hours of high utilization and the relatively high off-peak loads on peak days. Even considering only system reliability criteria, only 50%–60% of transformer capacity can be attributed to the single-hour peak load.

Energy usage also affects the service life of transformers, due to overheating of the insulation. For example, a transformer that is overloaded by 20% for eight hours (due to high load, or failure of another transformer in a network) will lose about 0.25% of its useful life. With ten overloads annually at this level, the transformer would last 40 years, by which time accidents, corrosion, and other problems would likely lead to its retirement. Long overloads and higher load levels increase the rate of aging per overload, and frequent overloads lead to rapid failure of the transformer.

In a low-load-factor system, these high loads will occur less frequently, and the heavy loading will not last as long. If the only high-demand hours were the ones on which the peak loads are based, the chances of a first contingency coinciding with the peak would be small, and most transformers would be retired for other reasons before they experienced many overloads. In this situation, larger losses of service life per overload would be acceptable, and the short peak would allow greater overloads for the same loss of service life.

With high load factors, there are many hours of the year when the transformers are at or near full loads.[1] Thus, the size of the transformer must be increased to limit overloads to the small amount that is compatible with acceptable loss of service life per overload for this frequency of overloads, or the transformer will burn out far too rapidly.

Load factor has similar effects on the sizing of underground transmission, primary, and secondary lines. Since heat builds up around the lines, the length of peak loads and the amount of load relief in the off-peak period affects the sizing of underground lines. An underground line may be able to carry twice as much load for a needle peak as for an eight-hour peak with a high daily load factor. To reduce losses and the build-up of heat, utilities must install larger cables, or more cables, than they would to meet shorter loads.[2] Since the number and sizing of underground lines is a function of load factor, a portion of the cost of the lines should also be allocated on the basis of energy.

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[1]In networks, failure of other transformers or lines will frequently cause overloading at such times.

[2]Both lines and transformers are sized, in part, to reduce the costs of energy losses.