PROVINCE OF MANITOBA

BEFORE THE PUBLIC UTILITY BOARD

Manitoba Hydro	**)**	**Case No. 136-07**
2008/09 General Rate Application	**)**	

DIRECT TESTIMONY OF

PAUL CHERNICK

ON BEHALF OF

RESOURCE CONSERVATION MANITOBA

AND

TIME TO RESPECT EARTH'S ECOSYSTEMS

Resource Insight, Inc.

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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, integrated resource planning, 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 (PBR) and cost recovery in restructured gas and electric industries. My professional qualifications are further summarized in Exhibit____PLC-1.

Q: Have you testified previously in utility proceedings?

A: Yes. I have testified over two hundred times on utility issues, before regulators in thirty US jurisdictions, Ontario and Alberta. My previous testimony is listed in my resume.

II. Introduction

Q: On whose behalf are you testifying?

A: My testimony is sponsored by the Resource Conservation Manitoba ("RCM") and Time to Respect Earth's Ecosystems ("TREE").

Q: What is the purpose of your direct testimony?

A: My sponsors have asked me to evaluate the revenue allocation, rate design and demand-side management ("DSM") proposals of Manitoba Hydro ("MH" or "Hydro"), in light of the Public Utility Board's concern about below-cost pricing and environmental emissions:

> The Board seeks to assure itself that MH's rate design and rates are consistent with the pursuit of the environmental objectives of The Sustainable Development Act (SDA). Energy efficiency presents the potential for a virtuous circle, wherein lower domestic consumption results in reduced customer bills, higher MH aggregate net export revenue and net income, and lower carbon emissions by MH's American export customers. (PUB Order 117/06, p. 3)

Q: What specific issues does your testimony address?

A: I address the following issues:

- The reasonableness of the Cost of Service Study ("COSS") for use in rate design.
- Inclusion of market prices, T&D costs, losses, and environmental values in the estimate of marginal costs
- Changes to rate structure to promote more efficient energy use, such as the following:
    - Elimination of declining block rate schedule and introduction of inverted rates
    - Introduction of time-of-use rates, initially for large volume non-residential customers,
    - Demand-energy rebalancing to move cost recovery from demand to energy charges,
    - Reduction and eventual elimination of demand ratchets, and
    - Design of a marginal-cost-based rate for new high consumption firm customers or large expansions.
- Alternative uses of revenues from exports, new-customer marginal rates, and increased tail blocks.
- Evaluation of Manitoba Hydro's efforts to promote DSM.

III. Use of Cost-of-Service Study in Allocation and Rate Design

Q: What role should the study of embedded costs of service play in revenue allocation and rate design?

A: The study should serve only as a guide to allocation and rate design, not as a determinant. Consideration of marginal cost and incentive effects, not embedded cost, should be the primary basis of rate design.

Q: Do the Board and Manitoba Hydro agree that the COSS should be regarded as a guide, not a determinant, of allocation and rate design?

A: Yes. In the Board's view, the COSS is only one of the many guides to rate design and cost allocation:

> COSS neither determines nor changes rates but serves as an assist in rate setting. The COSS is a tool used to assist in evaluating whether customer classes pay their fair share of costs through rates, and serves as one test of the fairness of rates between customer classes. (PUB Order 117-06, p. 8)

Hydro agrees that the COSS is approximate and judgmental:

> Although the study has the appearance of exactness, it does not disclose the actual cost of serving a particular customer or group of customers within a customer class, it only provides an approximation of such costs. This is because there are many judgements involved in the process of classifying and allocating costs, particularly those costs related to capital investment. (Appendix 11.1, p. 1)[1]

Q: Have you identified specific problems with using Manitoba Hydro's COSS as a guide in rate design?

A: Yes. The COSS is based on a faulty model of cost causality. It ignores the effects of energy use on transmission and distribution ("T&D") costs. Reflecting these effects in energy charges will encourage energy efficiency improvements.

Q: How does the COSS classify and allocate T&D?

A: The COSS (pp. 6, 73–79) treats T&D costs as follows:

- Transmission is classified as 100% demand-related and allocated based on the average of winter (top 50 coincident hours) and summer (also top 50 coincident hours) demands (see also p. 12).

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[1]Hydro provides two documents labeled Appendix 11.1. In this report I only refer to the one titled "Prospective Cost of Service Study for Fiscal Year Ending March 31, 2008"

- Subtransmission is classified as 100% demand-related and allocated based on class Non-Coincident Peak demands.
- Distribution plant is classified as 60% demand-related and 40% customer related. The demand-related portion is allocated on the basis of Non-Coincident Peak Demand.

Q: What rationale has Manitoba Hydro provided for its classification of T&D?

A: Manitoba Hydro's primary justification appears to be that the classification has been accepted for use for a long time (Appendix 11.1, p. 6).

Q: Is a fundamental change in the approach to T&D cost causation in line with the Board's current concerns?

A: Yes. Taking into account the effect of energy on T&D costs will advance the Board's commitment to the promotion of energy efficiency.

Q: How is the transmission system designed to reduce energy costs?

A: In at least three respects: First, a large portion of Manitoba Hydro's transmission is required to move power from the remote hydro stations to the load centers in the south and for export. Were generation located nearer to the load centers the long expensive transmission lines out to the northern hydro plants would not be required (and transmission losses would be smaller). Hydro and the Board accept these transmission costs as part of the tradeoff against the greater operating and environmental costs of fossil-fired plants that could be located nearer to the load centers, in other words as a tradeoff against energy-related costs.

Second, Manitoba Hydro's transmission system is more expensive because it is designed to allow for large transfers of energy between neighboring utilities. Third, Manitoba Hydro'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 transformers would be needed, as discussed further below.

Q: How does energy use affect distribution costs?

A: The sizing of transformers and underground lines is driven by the energy use on the equipment in high-load periods, in addition to maximum hourly loads.

Q: How does energy use in high-load hours affect the cost and sizing of transformers?

A: At least three energy-use factors determine the cost 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.

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 over-heating 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.[2] 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.

Q: Will a higher load factor affect the cost of other components of the T&D system?

A: Yes. 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

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

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.[3] Since the number and sizing of underground lines is a function of load factor, a portion of the cost of the lines should be recovered through energy charges, even if demand charges could reasonably measure the contribution of customer loads to peak demands on distribution equipment.

IV. Estimate of Marginal Costs

Q: Why are marginal costs important for Hydro's planning and ratemaking?

A: Marginal costs indicate the value of load reductions and the cost of load increases. Those values are important in both the evaluation of DSM options and the design of rates.

Q: How does Manitoba Hydro develop marginal costs for rate-design purposes?

A: Hydro apparently estimates marginal generation costs from historical prices charged to Surplus Energy Program customers:

> ...marginal cost indicators were based on....indicators from Manitoba Hydro's own SEP.... The advantages are that it is based not only on prices pertaining to sales in the interconnected MAPP market, but also reflects Manitoba Hydro's ability to access those prices and the effect of Transmission constraints on the prices Manitoba Hydro can realize. (Appendix 11.1, p. 12)

In some contexts, Manitoba Hydro also references the costs of new hydraulic generation as supplementary information on marginal generation costs

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

(e.g., Manitoba Hydro response to MIPUG motion, January 7, 2008, p.2; PUB/MH I-98(e)).

Hydro includes marginal transmission and distribution costs, but does not cite a source for those costs. During the Hydro COS 05/06 COSS Review, the Board requested a copy of Hydro's current marginal T&D study, but Hydro refused to provide it on the grounds that "The source document for these estimates has not been reviewed by Manitoba Hydro's Executive" (PUB/MH 1-1 in the Hydro COS 05/06 COSS Review). The rate-design study in Appendix 11.4 provides estimates of marginal T&D different from those Hydro provides in this proceeding, and cites a document, "Marginal Transmission and Distribution Cost Estimates. SPD 04/05" Manitoba Hydro, September 23, 2004. I have not been able to locate either that document or the source of Hydro's current estimates of marginal T&D costs.

Hydro also adds losses on the transmission system and on the distribution system.

Q: What are Hydro's estimates of marginal costs for rate design purposes?

A: Hydro provides apparently inconsistent avoided-cost estimates for generation in various parts of its evidence. Two avoided-cost components that do seem to be consistent (although not documented) are as follows:

- Transmission: $67.75 per kW of coincident peak for General Service Large (greater than 100 kV) and $74.06 per kW of coincident peak for all other classes.
- Distribution: $42.71 per kW of noncoincident peak for all classes except General Service Large.

In some places (e.g., RCM/TREE/MH II-4), Manitoba Hydro assumes that losses are 4% on the distribution system (except for General Service Large) and

10% on the transmission system. In others (e.g., Appendix 11.1, p. 54), Manitoba Hydro assumes a more complex pattern of losses. On p. 63 of the PCOSS, Manitoba Hydro estimates average distribution losses of 5.40% of energy and 6.84% at peak. In Appendix 11.1, pp. 62 and 64 (Schedule D3 and D5), Manitoba Hydro reports transmission losses of 9.8% of energy deliveries to the common bus and 11.56% of peak demand for all customers, and the following distribution energy losses as a percentage of sales:

Class	Distribution Energy Losses
Residential	6.47%
GS Small—Single Phase	6.47%
GS Small—Three Phase	4.77%
GS Medium	4.77%
GS Large (less than 30 kV)	3.87%
GS Large 30–100 kV	1.17%
GS Large (greater than100 kV	—

The sales-weighted average of these energy losses is 5.40%, matching p. 63 of the PCOSS.

Hydro provides a number of estimates of marginal generation costs, including the following:

- Lost short-term firm export "revenues in the order of 5.5¢ per kW hour" (Manitoba Hydro response to MIPUG motion, January 7, 2008, p. 1).
- "In the longer term, [advancing] the construction of costly new generation [at] 6.07¢ per kW hour," apparently excluding losses. (ibid., p. 2)
- 4.834¢/kW.h for baseload energy and $71.49/kW-yr for generation capacity (RCM/TREE/MH I-13), totaling 5.65¢/kW.h for baseload, apparently excluding losses.
- In the PCOSS, Manitoba Hydro recognizes that marginal energy costs, estimated from the SEP rates, vary with the distribution of load across the SEP rating periods. In Appendix 11.2-Class Revenue to Marginal Cost

Ratios, Manitoba Hydro provides its estimate of total marginal energy costs, including losses; in the following table, I compute the average marginal cost by rate using the sales values from p. 19 of the PCOSS, as follows:

	2008 PCOSS Sales	Generation Marginal Cost $000	Generation Marginal Cost $/kW.h
Residential	6,577,526	431,132	0.0665
GS Small, Non-Demand	1,328,832	88,005	0.0662
GS Small, Demand-metered	2,038,415	131,804	0.0647
GS Medium	2,948,717	190,133	0.0645
GS Large (less than 30Kv)	1,611,803	102,319	0.0635
GS Large 30–100Kv	987,630	59,196	0.0599
GS Large (greater than 100kV)	5,202,246	307,116	0.0590

Q: Can you reconcile these multiple estimates and suggest a best set of marginal costs for rate design?

A: My ability to sort out Hydro's data is limited by Manitoba Hydro's failure to explain the differences in its assumptions and methods among the estimates. The best I can do is to start with the avoided energy costs above, and add in capacity costs, and suggest some additions.

Q: What is Hydro's source for the marginal generation energy costs in Appendix 11.2?[4]

A: That is not clear. Hydro's estimate of marginal energy costs (Appendix 11.2) is based on "20 year levelized marginal cost of generation of $55.38 per MW.h referenced to northern generation."[5] It is not clear whether Hydro derived this estimate of marginal generation cost from the cost of new northern generation,

[4]Manitoba Hydro provides two Appendices 11.2. In my testimony, I refer only to the one titled "Response to PUB Order 117/06, PUB Order 117/06—Directive 2."

[5]I understand the phrase "referenced to northern generation" to mean "without transmission or distribution losses." Hydro denies deriving marginal costs from the cost of new generation.

from the value of exports, or the related prices for SEP energy. Hydro's responses appear to rule out all sources except SEP prices.

- Hydro claims that "the expected value of electricity exports is commercially sensitive" and refuses to provide that value (RCM/TREE/MH I-4(d)), so the $55.38/MW.h does not appear to be the 20-year value of exports. In addition, Hydro estimates short-term firm export "revenues in the order of 5.5¢ per kW hour" (Manitoba Hydro response to MIPUG motion, January 7, 2008, p. 1); it is likely that long-term prices, including the costs of new capacity and carbon allowances, would be higher than the near-term prices.
- Hydro also claims that "The response to RCM/TREE/MH I-4(a) was incorrect in stating that the avoided cost of new generation was utilized currently in estimating the generation-related marginal benefit component." In addition, Hydro estimates that advancing "the construction of costly new generation [would cost] 6.07¢ per kW hour" (Manitoba Hydro response to MIPUG motion, January 7, 2008, p. 2) So the $55.38/MW.h does not appear to be the cost of new generation.

Hence, Hydro's estimate of marginal energy costs in Appendix 11.2 appears to be based on a projection of SEP prices.

Q: If the marginal generation costs you derived from Appendix 11.2 are based on projected SEP prices, are they reasonably complete estimates of Hydro's marginal generation costs?

A: No. SEP prices are for interruptible energy, set weekly, without capacity. Marginal generation costs would include the costs of the higher-priced periods in which Manitoba Hydro interrupts SEP supply, as well as firm capacity and other costs of firming supply. It is not clear whether the $71.49/kW-yr generation capacity cost that Hydro estimates in RCM/TREE/MH I-13 is an appropriate estimate for this value, but it seems reasonable compared to the costs of peaking capacity.

The SEP pricing also appears to be for relatively flat energy deliveries to industrial customers, rather than the weather-sensitive varying loads of residential and smaller general-service customers. A small upward adjustment for intra-period load shape is probably warranted.

Q: What is your best estimate of the loss factors for various classes?

A: Based on the discussion above, I believe the best estimate of losses as a percentage of deliveries is 9.8% for energy and 11.56% for peak demand on the transmission system and the following values on the distribution system, calculating class peak losses from p. 65 of the PCOSS:

Class	Distribution Energy Losses	Extrapolated Peak Losses
Residential	6.47%	8.84%
GS Small—Single Phase	6.47%	8.84%
GS Small—Three Phase	4.77%	6.68%
GS Medium	4.77%	6.68%
GS Large (less than 30 kV)	3.87%	5.56%
GS Large 30–100 kV	1.17%	1.57%
GS Large (greater than 100 kV)	—	—

Q: Did Manitoba Hydro use these losses in computing marginal costs?

A: No. The transmission-and-distribution marginal costs in dollars per kW-yr reported in Appendix 11.2 are the same values per kW of load at the meter for each class (other than GS over 100 kV), even though the classes have different losses. Line losses do appear to be included in the weighted energy-cost computation (Appendix 11.1, p. 61).

Q: What are your best estimates of marginal costs, including firm generation supply?

A: I computed direct short-term marginal generating capacity costs from Hydro's $71.49/kW-yr, times coincident peak at the meter, added peak losses to all the capacity components, and divided by sales. The results of these computations are as follows:

	Marginal Costs (Dollars per kW.h)				
	Generation				
	Energy	Capacity	*Transmission*	*Distribution*	*Total*
Residential	0.0655	0.0066	0.0068	0.0046	0.0836
GS Small, Non-Demand	0.0662	0.0054	0.0056	0.0040	0.0812
GS Small, Demand-metered	0.0647	0.0051	0.0052	0.0035	0.0784
GS Medium	0.0645	0.0049	0.0050	0.0032	0.0776
GS Large (less than 30Kv)	0.0635	0.0046	0.0048	0.0033	0.0761
GS Large 30-100Kv	0.0599	0.0045	0.0046	0.0033	0.0723
GS Large (more than 100kV)	0.0590	0.0042	0.0040	–	0.0672

Q: Do these direct costs include all the costs of domestic consumption of electricity?

A: No. Reducing domestic sales either increases exports, reduces purchases, or reduces Manitoba Hydro thermal generation. Any of these effects will reduce emissions of conventional pollutants—various combinations of particulates, SO_2, and NOx, depending on the thermal units turned down—and CO_2. The costs of some of the conventional pollutants are internalized for US utilities through cap-and-trade systems, but the costs of greenhouse gases are not currently internalized. The total social cost of domestic consumption of electricity is thus higher than the direct costs above.

Q: What is the significance of these results for rate design?

A: Whether one uses my estimates or Hydro's unadjusted ones, the marginal costs exceed embedded costs for all classes, with the possible exception of area and roadway lighting (Appendix 11.2—Class Revenue to Marginal Cost Ratios). Thus, inclining-block rates are needed to provide customers with appropriate marginal price signals.

Q: What marginal costs did Manitoba Hydro use in evaluating DSM?

A: Hydro says, "The marginal cost used for the analysis in the 2006 Power Smart Plan was 7.93 cents per kWh" (RCM/TREE/MH I-4(d)).

Q: How did Manitoba Hydro derive this values?

A: Hydro refused to explain the derivation. "The marginal cost contains the expected value of electricity exports, is commercially sensitive and therefore, detailed information on the derivation of the avoided cost can not be provided" (RCM/TREE/MH I-4(d)).

Q: Can you review Hydro's economic evaluation of DSM without this information?

A: No.

Q: Do utilities generally release the derivation of their estimates of avoided costs for DSM evaluation?

A: Yes. I cannot recall a similar situation in which a utility has so broadly refused to document its estimates of avoided costs.[6]

In New England, the regional avoided costs (excluding losses and T&D, which are added by individual utilities) are derived in a collaborative process (for which I have been one of the consultants in three of the five biennial rounds) of the electric and gas utilities, consumer representatives, environmental interests and regulators.[7] This work shows detailed avoided-cost projections.

[6]In some cases, utilities will request protected status for certain inputs, such as detailed forecasts of market prices, releasing that information only to parties who are not engaged in power trading. In over 20 years of reviewing avoided-cost estimates, I cannot recall a situation in which the utility has refused to even break out generation energy and capacity costs, transmission costs, distribution costs, and losses.

[7]Most recently, Hornby, Rick, Carl Swanson, Michael Drunsic, David White, Paul Chernick, Bruce Biewald, and Jenifer Callay. 2007. "Avoided Energy Supply Costs in New England" 2007 Final Report.

Similar details on the derivation of avoided costs in California, developed through a public process of comments and workshops, are described at www.ethree.com/cpuc_avoidedcosts.html.

Forecasts of avoided costs, and their derivation, have been publicly available since the early 1980s, when they were used to value non-utility generation.

Q: Is it possible that 7.93 cents per kW.h is an appropriate avoided cost for all DSM?

A: No. Avoided costs vary among end uses and measures, for many of the same reasons that marginal costs vary among classes, particularly energy load shapes and load factors.[8]

Q: How did Manitoba Hydro treat environmental costs in its DSM valuation?

A: Hydro claims to have included some estimate of some sort of carbon-related charge for exports, but refuses to discuss that estimate.

> Manitoba Hydro includes environmental costs associated with GHG emissions by including a premium in the price for export energy into markets that are primarily dependent on fossil-fueled generation. As stated in the response to RCM/TREE/MH II-4(a), information on the premium in export price that is assumed for GHG emissions is confidential. It is derived by Manitoba Hydro using a number of consultants who specialize in electricity market prices in the MRO region. The price premium is based on the anticipated future legislation related to reduction of GHG emissions. (RCM/TREE/MH II-10)

Northborough, Mass.: Avoided-Energy-Supply-Component Study Group, c/o National Grid. This report, at resourceinsight.com/work/aesc_rev_2007.pdf, provides detailed avoided-cost projections.

[8]Unlike marginal costs for rate-design purposes, which end at the customer meter, avoided costs include costs all the way to the end use, which is almost always at secondary voltage. Hence, even for customers metered at primary or transmission voltage, losses and avoided T&D should be computed to secondary distribution.

Hydro does not report including any environmental costs for its own generation, or reflecting the value of emissions avoided by exports, above the portion actually included in the prices paid by its export customers. So if Manitoba Hydro estimates that the cost of greenhouse-gas abatement will be $40/ton, but that the US will only internalize $1/ton in 2012, Manitoba Hydro counts only the $1/ton that it expects the US government to internalize and ignores the rest of the real cost to the global economy and environment.

Q: What would be reasonable CO_2 values for Manitoba Hydro to include in valuing DSM?

A: There are several such studies.

A recent study by McKinsey and Company found that reducing emissions enough to restrain greenhouse gases to the equivalent of atmospheric concentration of 550 ppm CO_2 by 2030—a very modest reduction from business-as-usual—would result in a marginal emissions-reduction price of about 25€/ton, while a target of 450 ppm (which McKinsey describes as being "in the midrange of the targets put forward by advocates") would result in an emissions price around 40€/ton.[9]

A study by Synapse Energy Economics, reviewing analyses of the effects of proposed legislation, estimated mid-case US carbon emissions prices of $5/ton in 2010, $25/ton in 2020, and $35/ton in 2030, in 2005 U.S. dollars.[10] Based on a review of reports on the costs of reduce emissions to a sustainable

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[9]Enkvist, Per-Anders, Tomas Nauclér, and Jerker Rosander. 2007. "A Cost Curve for Greenhouse Gas Reduction" McKinsey Quarterly (Feb. 2007).

[10]Johnston, Lucy, Ezra Hausman, Anna Sommer, Bruce Biewald, Tim Woolf, David Schlissel, Amy Roschelle, and David White. 2007. "Climate Change and Power: Carbon Dioxide Emissions Costs and Electricity Resource Planning." Cambridge, Mass.: Synapse Energy Economics, Table 6.4.

level, Synapse also estimates that the marginal cost of control necessary to restrain global warming is \$60/ton.[11] Efficiency improvements that reduce carbon emissions would thus be worth \$60/ton globally, whether or not Manitoba Hydro could recover that benefit in its export revenues. Synapse's projections, or similar values, have been adopted by:

- ISO-NE in its Scenario Analysis planning.[12]
- Nova Scotia Power for its current IRP.[13]
- New Mexico Public Service Commission.[14]
- Southern California Edison, in its analyses of its Mohave coal plant.[15]

Q: Are there reasons to believe that some greenhouse gas costs will be internalized in the near future for Hydro's market area?

A: Yes. The Midwestern Greenhouse Gas Reduction Accord, signed by Manitoba and six states (including most importantly Minnesota) commits the states to

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[11]Hornby, Rick, Carl Swanson, Michael Drunsic, David White, Paul Chernick, Bruce Biewald, and Jenifer Callay. 2007. "Avoided Energy Supply Costs in New England" 2007 Final Report. Northborough, Mass.: Avoided-Energy-Supply-Component Study Group, c/o National Grid, pp. 7–16.

[12]ISO New England. 2007. "New England Electricity Scenario Analysis: Exploring the Economic, Reliability, and Environmental Impacts of Various Resource Outcomes for Meeting the Region's Future Electricity Needs." Holyoke, Mass.: ISO New England.

[13]Nova Scotia Power. 2006. "Integrated Resource Plan Basic Assumptions—Updated per Sept 22, 2006 Technical Conference," Nova Scotia Power.

[14]Order Approving Recommended Decision and Adopting Standardized Carbon Emissions Costs for Integrated Resource Plans." Case 06-00448-UT, June 19, 2007.

[15]Charles, Robert, Timmons Libson, Joseph Smith, David Stopek, Steven Warren, Robert Fagan, Alice Napoleon, Amy Roschelle, Anna Sommer, William Steinurst, and David White. 2006. "Study of Potential Mohave Alternative/Complementary Generation Resources Pursuant to CPUC Decision 04-12-016" SL-008587. Chicago: Sargent & Lundy.

reduce greenhouse-gas emissions through a cap-and-trade system, starting by mid-2010.[16]

Q: What emission rates should Manitoba Hydro use in turning the dollars-per-ton values of carbon emissions into dollars-per-MW.h?

A: A typical coal plant or gas-fired boiler plant (such as Selkirk) would have a heat rate of about 10 MMBtu/MW.h; a modern gas combined-cycle plant would have a heat rate of about 7.5 MMBtu/MW.h. Coal combustion releases about 0.095 tons of CO_2/MMBtu, natural gas about 0.053 tons of CO_2/MMBtu.[17] Thus, the emissions from avoided thermal generation would be about 0.95 tons CO_2/MW.h for coal, 0.53 tons CO_2/MW.h for boiler gas plants, and 0.40 tons CO_2/MW.h for gas-fired combined-cycle.

At \$30/ton CO_2, the greenhouse-gas-emissions cost for coal generation would be about \$30/MW.h, about \$15/MW.h for gas-steam generation, and about \$12/MW.h for gas-fired combined-cycle. The total global costs of the emissions would be about twice those values.

V. Changes to Rate Structure

Q: What rate-design changes do you address in this section of your testimony?

A: The Board has called for the promotion of efficient energy use through sweeping changes in rate design, including introduction of inclining block rates, rebalancing of demand and energy charges, elimination of demand ratchets,

[16]The participants also include Illinois, Iowa, Kansas, Michigan, and Wisconsin; Indiana, Ohio and South Dakota are observers, who may join the trading system.

[17]I computed these values from "Emissions of Greenhouse Gases in the United States 2000," November 2001, DOE/EIA-0573(2000), Appendix B.

implementation of time-of-use (TOU) rates, and introduction of a marginal-cost-based rate for new large energy-intensive customers. I address each of the Board's rate design initiatives.

A. Inverted or Inclining-Block Rate Design

Q: Please provide a brief description of the Board's inverted-rate initiative.

A: In Directive 4(d) in PUB Order 117/06 (as well as previous Orders), the Board directed the Company to introduce inverted rates for large customers, with the tail block energy charges set at marginal cost.

Q: Has Hydro complied with the Board's requirement?

A: No. Hydro claims to support inverted rates, but asserts that, for the General Service classes, the wide range of customer sizes excessively complicates design and implementation (Appendix 12.2, pp. 2-3). Hydro recognizes that "the determination of baselines in the proposed General Service rates could be integrated with an inverted rate proposal for all General Service Large customers"—but it has not "fully contemplated the mechanics" or considered any alternative structures (RCM/TREE/MH I-13(l)). Hydro asserts,

> If Manitoba Hydro were to embark on a process of designing and implementing inverted rates for its major customers, it is expected that a [extensive] process of review and consultation would be required and that a proposal would be available for regulatory review within 12-18 months of embarking on that process. (Appendix 12.2, p. 4).

Rather than complying with the Board's directive, Manitoba Hydro has proposed an inclining-block rate only for the residential class, where Hydro believes such a rate can be "designed and administered the least problematically" (Appendix 12.2, p. 2).

Q: What is Manitoba Hydro's proposal for the residential class?

A: Manitoba Hydro proposes a two-block structure, with an initial block size of 900 kW.h per month and an initial block energy charge of 5.98¢. The tail block energy charge is 6.01¢, only 0.5% higher than the first block charge.[18] Manitoba Hydro acknowledges that "[t]he price distinction in the current Application is nominal," but assures the Board that the "intention is that the price in the second block will move toward marginal cost" (PUB/MH I-12(a)).

Q: What is Manitoba Hydro's rationale for the initial block size of 900 kW.h?

A: Manitoba Hydro assumes that 900 kW.h per month covers the use of basic appliances and lighting. In Manitoba Hydro's view, apparently, other electric uses are more price responsive and therefore more appropriately charged at marginal cost:

> This structure prices energy above standard residential usage (lighting, basic appliances) with a higher rate than the initial block.... the intention is that the price in the second block will move toward marginal cost, thereby sending a more appropriate price signal for uses which are discretionary (e.g. air conditioning, pool heating) or for which competing fuels are available (space and water heating). (PUB/MH I-12(a))

Q: Is 900 kW.h an appropriate cut-off for the first block?

A: No, for several reasons: First, with such a high cut-off, the proposed rate will not provide sufficient incentives for such prudent usage and purchase of basic appliances and lighting as the following:

- selecting efficient lighting and turning it off when it is unneeded;
- selecting the efficiency of computers;
- deciding the energy-saving settings on computers;

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[18] Hydro also has eliminated the residential declining block rate structure, but this change in the residential rate is also minimal. In the current rate, the lower tail block charge of 5.79¢ applies to all kW.h but the first 175 kW.h in the month (which has an energy charge of 5.94¢). Only 9.1% of all residential customers' bills are below 200 kW.h (COALITION/MH I-49(a)).

- deciding when to manually turn off computers and peripherals, audio and video equipment;
- bothering to unplug (or use a power strip to switch off) parasitic loads, such as battery chargers, computer peripherals, audio and video equipment;
- avoiding energy-hogging features (such as through-the-door icemakers);
- selecting the size of refrigerators;
- deciding whether to continuing operating an older refrigerator;
- choosing the length and temperature of showers;
- determining when the dishwasher is full enough to run, and whether to use the electric drying feature;
- selecting clothes-drying cycles;
- deciding whether to air-dry or power-dry clothes.

Second, Manitoba Hydro's determination of the 900 kW.h cut-off is based on the average monthly usage of non-heating customers, not on an actual study of the average energy use of basic appliances and lighting (COALITION/MH I-50). The usage of 900 kW.h by non-heating customers is also likely to include price-responsive "discretionary" uses (such as air conditioning and pool heating), "uses for which competing fuels are available" (such as water heating) and even some space-heating use (such as room space heaters and circulation fans).

Third, too few non-heating customers would face the higher tail block charge. Only 35% of bills of this subclass exceed the 900 kW.h cut-off point and customers would have to consume significantly more than the 900 kW.h break-point in order for the tail block charge to be an effective conservation incentive (COALITION/MH I-49(b)).

Q: Is Hydro's "nominal" price distinction consistent with its stated intention that "the price in the second block will move toward marginal cost?"

A: No. Hydro estimates an average avoided cost of 7.93¢/kW.h for DSM (and presumably more for residential load), or 32% over the proposed tail block charge. I estimate a marginal-cost of 11.3¢/kW.h, or 88% over the proposed tail block charge. At the pace Hydro proposes, the tail block charge will not reach any estimate of marginal cost for a long time, if ever.

Q: Have you developed an alternative approach for residential rate design?

A: Yes. I recommend that the rate structure for the residential class be derived as follows:

- Set the tail-block energy charge as the current energy charge, plus the percentage allowed revenue increase for the class, plus five percentage points. At Hydro's proposed 2008 energy rate of 5.98¢/kW.h (RCM/TREE/MH 1-8), a five-percent increase in the tail-block rate would bring the rate to 6.28¢/kW.h.
- Reduce the non-heating initial block size to a level likely to be infra-marginal for the vast majority of bills. The initial block size should be no greater than 600 kW.h per month, so that 84% of non-heating sales would be on bills above the initial block.[19]
- For existing heating customers, add kW.hs to the initial block in the heating season to increase the percentage of heating energy served on the initial block to roughly the 54% that the non-heating customers receive. That additional allowance would total about 6,400 kW.h over the year. Depending on the number of months included in the heating season, and the extent to which Manitoba Hydro shapes the heating

[19]About 54% of sales would be at the initial-block rate, since all larger customers would receive 600 kW.h/month at the initial-block rate. For example, a customer using 1,000 kW.h would pay the initial-block rate for 600 kW.h and the tail-block rate for the remaining 400 kW.h. Every additional kW.h used or saved would be at the higher tail-block rate, but the customer's bill would reflect the 600 kW.h allowance at the initial-block rate.

allowance by month, the monthly heating allowances might be about 1,100 over six month, or 700 kW.h for bills rendered in April and November, 1,100 in December and March, and 1,400 kW.h/month in January and February.[20]

- Reduce the customer charge to offset the increased revenue from the five-percent increment in the tail block. At Hydro's proposed 2008 rates, a five-percent increase in the tail-block rate (with about 54% of energy charged in the first block) would increase revenues about $7.5 million, allowing the customer charge to be reduced about $1.50 per month.[21]
- Set the initial-block charge as the current energy charge, plus the allowed revenue increase. In future rate cases, if the revenues from the tail-block price increase exceed the revenue reduction from eliminating the customer charge, reduce the initial block charge to absorb the excess.
- In future rate cases, if the previous step would cause the initial-block price to be less than 80% of the current energy charge (or 4.6¢/kW.h), set the initial-block price at that level and add an intermediate block of 400 kW.h to absorb the remainder of the excess revenues.[22] This intermediate block would not be needed in this rate case, but would be needed in the future, as the tail-block price continues to rise toward marginal cost.

In summary, the basic residential rate (with Hydro's proposed rate increase and residential allocation) would comprise the following charges:

- A customer charge of about $4.70/month.

[20]The Board should also require Hydro to determine the feasibility of differentiating the heating allowance by customer type (single- versus multi-family), size (such as square footage) and climate zone.

[21]Were the initial block limited to 600 kW.h/month for all residential load, the reduction in the customer charge would be about $2/month.

[22]The upper end of the intermediate block could be adjusted as necessary to maintain rate continuity.

- An initial block of 6¢/kW.h for 600 kW.h/month for non-heating customers and for all customers in non-winter months, plus a winter heating allowance totaling about 6,400 kW.h annually, distributed over the heating season.
- A tail block of 6.28¢/kW.h for all other usage.

Q: Can you perform similar analyses for the other rates?

A: Yes, in some cases. I do not have bill-frequency data for the other rates, so I am limited in how specific I can be.

From MIPUG/MH I-22(a), the average flat-rate-water-heating usage is about 423 kW.h/month. I propose that Hydro's proposed rate of 4.87¢/kW.h be increased 5%, to 5.11¢/kW.h above 300 kW.h/month. Without bill-frequency data, I cannot compute the initial-block rate for the flat-rate-water-heating tariff.

For General Service Small, Hydro proposes to slightly flatten the declining-block energy rate, while increasing the basic charge by twice the overall rate increase and leaving the demand charge alone. Instead, I propose that Hydro increase its first-block energy rate by 5% above the overall increase, to 6.68¢/kW.h, and bring the second and third energy blocks to the same charge. The additional revenues would allow the customer charge for non-demand-metered customers to be reduced to about $9, and the demand charge for demand-metered customers to be reduced to about $6.40/kV.A.

For General Service Medium, Hydro proposes to switch from a flat energy rate to a declining-block rate, while keeping the basic charge and demand charge constant. This proposal flies in the face of the Board's directives. Instead, Hydro should increase the flat energy charge and decrease the customer and/or demand charge. For example, increasing the energy charge by 5% above the proposed overall 2.9% increase would bring the energy charge to 2.76¢/kW.h and raise revenues by $4 million above the overall increase: that additional revenue would allow for the reduction of the demand charge by about 50¢/kV.A.

I propose corrections to Hydro's proposed rate for General Service Large customers below in Section V.E, including suggesting that the basic rate be extended to existing customers by defining the baseline more reasonably.

B. Demand-Energy Rebalancing

Q: What is the purpose of the Board's Demand-Energy Rebalancing Directive?

A: The Board's Order 117/06 explains the purpose of demand-energy rebalancing as follows:

> [Manitoba Hydro is to provide] a report considering the appropriateness of the current split between energy and demand charges, towards enhancing energy efficiency gains for industry and enhanced export potential for MH. (PUB Order 117/06, p. 74)

Q: What is your understanding of the Board's approach to demand-energy rebalancing?

A: The Directive is flexible regarding implementation details and is explicit only in stating the PUB's rate-design goals: increased conservation and opportunity for exports. The Directive appears to seek a new look at system cost causation and at the incentive effects of demand versus energy charges.

Q: What energy-demand rebalancing does Manitoba Hydro propose?

A: Manitoba Hydro proposes gradual and very small increases in energy charges over the next several years, while maintaining the demand charges at current levels (PUB/MH I-12(a)).

Q: What is the basis of Manitoba Hydro's rebalancing proposals?

A: Manitoba Hydro relies on its embedded COSS to develop its rebalancing proposals. Therefore, under the Hydro's proposals, all T&D costs allocated to demand-metered customers on the basis of coincident or non-coincident demand would be recovered through demand charges (Appendix 12.1, PUB/MH I-12(a)).

Q: If Manitoba Hydro adjusts the balance to be consistent with its COSS, will the "appropriate" balance be achieved?

A: No, for the following reasons:

- Manitoba Hydro's approach to cost causation (in its COSS) is not a valid basis for rate design, particularly since it ignores the effect of energy on T&D costs, as discussed in detail above.
- Rate design should be based on marginal cost, not embedded cost, considerations.
- Demand charges do not provide appropriate incentives to conserve, even during high load hours.

Q: Please explain why demand charges do not provide the appropriate incentives.

A: Demand charges are a particularly ineffective means for giving price signals, for the following reasons:

- The demand-charge portion of the electric bill is determined by the customer's individual maximum demand. Capacity costs are driven by coincident loads at the times of the peak loads, not by the non-coincident maximum demands of individual customers. The customer's individual peak hour is not likely to coincide with the peak hours of the other customers sharing a piece of equipment, especially since the peaks on the secondary system, line transformer, primary tap, feeder, substations, subtransmission lines, and transmission lines occur at varying times.[23] In fact, Hydro acknowledges that T&D capacity is driven by diversified demand, not by billing demand (RCM/TREE/MH I-12(k)).

- Demand charges provide little or no incentive to control or shift load from those times which are off the customers' peak hours but which are very much on the generation and T&D peak hours. Customers can avoid demand charges merely by redistributing load within the peak period. Some of those customers will be shifting loads from their own peak to the peak hour on the local distribution system, on the transmission peak, or on the peak load hour of Manitoba Hydro , thereby causing customers to increase their contribution to maximum or critical loads on the local distribution system, the transmission system, or the regional generation system.
- Demand charges are difficult to avoid; even a single failure to control load results in the same demand charge as if the same demand had been reached in every day or every hour.
- Rather than promoting conservation at high-cost times, or shifting of load from system peak periods, demand charges encourage customers to waste resources on the arbitrary tasks of flattening their personal maximum loads, even if those occur at low-cost times. For instance, in order to respond to demand charges effectively, customers will need to install equipment to monitor loads, interrupt discretionary load, and schedule deferrable loads.

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[23]This diversity is demonstrated for substations in RCM/TREE/MH I-12(f)); substations peak at different times, on different days, in different months, and in different seasons. A customer that peaked at 9 AM on February 16, 2005 would have contributed to the substation peak if it was served by the Rallis substation, but not if it were served by the St. Boniface Dawson substation, which peaked at 1 PM on June 2.

Q: What pricing signals do demand charges give to customers?

A: Not only are demand charges ineffective in shifting loads off high-cost hours, they may cause some customers to shift loads in ways that increase costs.

Q: Should demand charges be eliminated entirely from rates?

A: Yes. When time-of-use energy charges are introduced, demand charges should be eliminated, and the revenues currently collected through demand charges instead collected through peak-period energy charges. In other words, all system and regional transmission, substation and feeder costs would be recovered through on-peak energy charges. This time-of-use rate design will encourage reduction of usage in high-load periods, when transmission and distribution equipment is heavily loaded.

C. Demand Ratchets

Q: What are demand ratchets?

A: Ratchets are rate provisions that charge demand-metered customers based on their maximum demand in current and previous months, not just on the maximum demand established in the month of the bill.

Q: How does Hydro use demand ratchets in its rates?

A: There is a winter ratchet, which has the effect of charging a significantly higher charge for winter billing demands (Appendix 10.2-Proposed Rate Schedules April 1-2008, p. 1). Under this ratchet, the customer's monthly billing demand is the greatest of:

- The customer's maximum demand in that month;

- 70% of the customer's highest demand in the Billing Year (December through November) for the months of December, January, February; or
- 25 % of contract demand;
- 25% of the highest measured demand in the previous 12 months.

Q: What changes in demand ratchets is the Board considering?

A: The PUB directed Manitoba Hydro to consider elimination of demand ratchets in developing Time-of-Use ("TOU") rate proposals:

> The Board will direct MH to file proposals for the appropriate implementations of Time of Use Rates for non- residential customers, including the possible elimination of the "winter ratchet." (PUB Order 117-06, p. 25)

The Board also directed Manitoba Hydro to consider the elimination of winter ratchets in its design of inverted rates for large volume consumption customers (PUB Order 117/06–Directive 4(d), p. 77).

Q: Does the Application provide any proposals that would eliminate ratchets?

A: No. All that Hydro provides in response to the Board's Directive is a weak excuse for delaying changes to the Small and Medium General Service rates. Manitoba Hydro ignores the rates for existing and new large customers entirely:

> Manitoba Hydro is not proposing any changes to the application of the winter ratchet. Although this application proposes a move towards class consolidation of the Small and Medium rate classes, they are still two separate rate classes and therefore the 70% winter ratchet will still apply to the Medium class customers. Elimination of the winter ratchet is however something to be considered for future rate changes once the Small and Medium classes are fully consolidated. (PUB/MH I-6)

Q: Should demand ratchets be eliminated?

A: Yes. I recommend that ratchets be eliminated from both TOU and existing non-TOU rates, for the following reasons:

- Ratchets worsen the adverse effects of demand charges. In the months when the customer's demand is below 70% of the annual maximum, demand charges are fixed and therefore, will provide no incentive to conserve at any time during the month.

- They excessively penalize the customer for a kW.h increase in its individual winter billing demand. For example, consider a Medium General Service customer that experiences a much higher billing demand in December than in any other month. For an additional kV.A in that month, this customer will pay December's demand charge of $8.34 plus 70% of that demand charge for all of the remaining months, or a total increase in annual payments of $73. This charge is more than 2,500 times the tail block charge of 2.65¢/kW.h charged in all other December hour.
- Winter ratchets do not reflect the importance of the summer peaks on the T&D system.
- Ratchets provide confusing and misleading signals to customers,
- Ratchets reduces customers' control over their bills, and
- Ratchets result in disruptive bill impacts, especially for a customer who unintentionally establishes a new maximum demand.

Ratchets may serve a utility's desire for revenue stability, but they are antithetical to the goal of conservation, cost-based rate design, reduction of system and environmental costs, and non-disruptive impacts on customer bills.

Q: How much of Hydro's distribution system is dominated by summer peaks?

A: Hydro's data in RCM/TREE/MH I-12 indicate that 14% of its substations peak in the summer. Since summer capacity at the substations is lower than winter capacity, some of the nominally winter-peaking substations are likely to be constrained by their summer loads. Assuming that summer capacity is rated about 10% less than winter capacity, 28% of Hydro's substations are summer-constrained, representing 43% of the substation winter load.

D. Introduction of Time-of-Use Rates

Q: Has the Board required Manitoba Hydro to submit proposals for Time-of-Use rates in this proceeding?

A: Yes. Board Order 117/06 (p. 24) directs Manitoba Hydro to

> file proposals for the appropriate implementations of Time of Use Rates for non-residential customers, including the possible elimination of the "winter ratchet."

Q: Has Hydro provided any TOU rate proposals in response to the Board's requirement?

A: No. In a report filed on August 22, 2005, the Company acknowledged that TOU rates were at least "conceptually capable of providing efficient pricing," but claimed that it needed to perform additional studies because of large variability in price differentials, design complexity, and the potential for customer confusion (Appendix 12.3, p. 1). On the same page of Appendix 12.3, Hydro states that none of these additional studies have yet been performed, two years later. Curiously, Manitoba Hydro does not explain why it has failed to pursue any analysis of TOU rates over the last two years.

In the PCOSS, Manitoba Hydro provides relative marginal energy costs for three time periods in each of four seasons. It is not clear why Manitoba Hydro has neither used those data to design TOU rate, or improved on the estimates, if it believes such improvement to be warranted.

Q: Should ratchets be eliminated from TOU rates?

A: Yes. As noted above, demand charges as well as ratchets do not serve any purpose in TOU rates. The replacement of demand charges with on-peak energy charges provides a more-effective price signal

Q: Is it feasible to design a TOU rate that signals the highest cost hours?

A: Yes. A three-period (peak, shoulder, and off-peak), seasonally differentiated rate, with a narrow "critical peak" period, for example, would provide a useful price signal.

Q: Do all TOU pricing systems use fixed pricing approaches?

A: Not all TOU pricing systems use fixed periods or fixed on-peak prices. Some pricing systems for large customers flow through prices in real time, with the price of power in each hour determined in that hour. Another approach, which California is currently exploring, charges a premium price during certain critical hours, which may be defined based on energy prices, load levels, or reliability of the supply and delivery systems. The timing of those critical hours is determined based on short-term (hour-ahead or day-ahead) conditions, but the premium price is fixed in advance.

E. Marginal-Cost-Based Rates for Large New Loads

Q: What is Hydro's proposal for marginal-cost-based rates for new or expanded General Service Large loads?

A: At first blush, Hydro's proposal appears to charge marginal costs for all new loads over 39 GW.h annually, and for all increases in load for existing customers.

> New companies locating to Manitoba with load less than 78 GW.h of annual energy would be entitled to 39 GW.h of annual energy consumption at prevailing General Service Large rates, and would pay the higher rates for any consumption above that level or apply to Manitoba Hydro for an exemption to raise their baseline. New customers locating in Manitoba with load in excess of 78 GW.h of annual energy would pay higher rates for all consumption or would apply to Manitoba Hydro for an exemption to establish a baseline. (Tab 10, p. 10)

> Existing customers aggregated with their Manitoba based affiliated companies would be entitled to Baseline Energy consumption at proposed General Service Large Baseline Energy rates, and would pay higher rates for any consumption above that level or apply to Manitoba Hydro for an exemption to raise their baseline.

Unfortunately, there is much less to Hydro's proposal than Hydro implies. Hydro proposes to set the Baseline Energy for each customer at its maximum consumption for a floating three-year period, and allow an increase of 39 GW.h per customer, so almost all customers will face only embedded costs. Hydro's proposed exemptions for new loads in excess of 78 GW.h are listed in its document "General Service Large—New or Expansion Rate, Proposed Exemption Criteria," filed 17 December 2007:

> a) The sum of Incremental Direct Payroll plus contract labour is 3.0 times the incremental cost of new or expanded load to all ratepayers; or
>
> b) The sum of Incremental Direct Payroll, plus contract labour, plus incremental taxes paid to Manitoba or a Manitoba municipality is 4.0 times the incremental cost of new or expanded load to all ratepayers; or
>
> c) The sum of current total direct payroll, plus contract labour, plus taxes paid to Manitoba or a Manitoba municipality is 20.0 times the incremental cost of new or expanded load to all ratepayers. This option would normally apply only if a load increase does not expand production at a customer's plant, but is required to support and maintain existing operations.

Q: What are the problems with Hydro's proposal for marginal-cost-based rates for large customers?

A: The proposal is flawed in the following ways:

- The Baseline Consumption would be too high.
- The Baseline would increase to cover large amounts of increased load.
- If the customer exceeded its Baseline, the Baseline in future years would be increased, so marginal costs would apply in only the first year.

- The exemptions or discounts for economic development (payroll and taxes) would use the wrong mechanism, implemented by the wrong entity, and would not be properly targeted.
- The discounts would destroy the conservation incentives of marginal-cost pricing.
- The computation of the cost of additional load would fail to count the environmental costs of reducing exports and the lost benefits of the export revenues.
- New loads would be eligible for exemptions, regardless of the efficiency of the equipment and process installed.

1. Hydro's Basic Proposal

Q: Is Hydro's proposed marginal rate structure appropriate?

A: No. Hydro proposes to charge the embedded energy rate for a base level of consumption for each customer, which would be the sum of the following four components, from Tab 10, page 10:

- *"Maximum 12-month aggregated energy consumption for the previous 3 calendar years."* This provision would fail to provide any efficiency incentive to customers who expect annual energy consumption to be less than the three-year maximum. The provision also appears to apply to rolling three-year period, so increased usage in 2008 would increase the customer's entitlement to embedded-cost power in 2009, 2010, and 2011. Paying marginal cost for one more MW.h in 2008 would entitle the customer to a total of 3 MW.h at embedded cost in 2009–2011, potentially reducing the customer's bill over the four-year period and encouraging additional usage throughout that period.

- *"Total growth allowance of up to 39 GW.h (to qualifying companies)."* The only "qualification" for the growth allowance appears to be that the customer's load is less than 78 GW.h. This provision appears to eliminate any efficiency incentive for any customer adding less than 39 GW.h.
- *"Verified Power Smart Energy savings from 1992 to present."*
- *"50% of additional energy consumed by an energy efficient solution required for compliance with the Canadian Environmental Protection Act."*

The combined effect of the first two provisions appears to completely defeat the purpose of a marginal-cost based rate, since essentially all existing load, other than very large expansions, would be exempt from marginal costs.

Q: What approach would be more appropriate in designing a marginal-cost rate for existing General Service Large customers?

A: The base usage, for which each customer is charged embedded rates, should be less than a fixed historical base usage, such as maximum annual usage in 2005–2007. The base usage might be set as 95% of the historical value in 2008, falling 2% or so each year thereafter.[24] No growth allowance should be added to this declining base. As noted above, Manitoba can more effectively and efficiently encourage economic development through targeted incentives, which can be funded by Hydro's incremental revenues.

2. Hydro's Proposed Exemptions for Very Large New and Retained Loads

Q: Is the proposed exemption approach an appropriate accommodation of economic development and efficient price signals?

[24] The Board should review that decay rate periodically.

A: No. Manitoba Hydro's proposal is a very blunt instrument, in several respects. New payroll dollars are not all alike, because new jobs are not all alike. A particular number of jobs (150 to 200 jobs would be needed to earn an exception for a 78 GW.h load under Manitoba Hydro's first option) of a particular type may be very beneficial in some communities, absorbing unemployment, replacing failing businesses, stabilizing the local population, and allowing young people to stay near their families. In another community, the same project may have major disadvantages, driving up costs in tight labour and housing markets, requiring immigration of workers, disrupting the local community, encouraging sprawl and generally changing the nature of the community in ways not desired by the local population.

Similarly, a new industry that generates $8 million annually in tax revenues (about what would be needed to earn an exception for a 78 GW.h load under Manitoba Hydro's second option) may impose almost no costs on local and provincial government for infrastructure, security and social services, or it may impose costs exceeding the tax revenues.

The environmental effects of various industrial plants, from extraction, the plant's smokestacks, transportation, run-off, water usage, discharges to water, noise and other effects, also vary widely.

Some plants have few options and require little or no incentive to locate in Manitoba, due to locations of raw materials, labour and markets, while other plants can locate almost anywhere power is available.

Manitoba Hydro considered none of these differences in its proposal.

Q: How should incentives for economic development be incorporated in Hydro's rate structure?

A: The actual allocation of incentives should be the responsibility of the economic development agency of the Manitoba government (such as Manitoba Competitiveness, Training and Trade), not Manitoba Hydro. If the PUB wants to use some Manitoba Hydro revenues to support economic development, it should designate an amount to be collected and instruct Manitoba Hydro disburse those funds as directed by the designated economic development agency, which should then decide which development projects are desirable and economically efficient. The revenues for economic development can be collected from the higher blocks of the inclining-block rate structures.

The mechanisms I propose for the collection and disbursement of economic-development incentives would retain the marginal-cost pricing the PUB builds into industrial rates, for both new and expanded loads, while avoiding burdening Manitoba Hydro with an economic-development role for which it has no special expertise or mandate.

Q: Is the exemption properly structured, were Manitoba Hydro to administer the economic-development program?

A: No. In its first discount option, Hydro proposes to offer no discount to new loads that offer new payroll of less than three times the incremental cost of marginal over embedded costs, and to offer the full discount (from marginal to embedded costs) to new loads with payroll equalling or exceeding three times the incremental cost. This is entirely the wrong approach. [25]

If the purpose of the exemption is to encourage incremental employment and contribution to the tax base, each additional job (or dollar of payroll) should entitle the customer to a discrete amount of energy at the embedded, rather than

[25]Hydro uses a similar approach in its other two options.

marginal, cost, or equivalently, a lump-sum credit in the form of a negative customer charge. To the extent possible, the discount should be infra-marginal, so that the customer always faces the marginal-cost signals for its marginal usage.

For the example in Manitoba Hydro's response to the "MIPUG Motion to Sever New or Expanded Industrial Load Rate," (January 7, 2008), a 100 MW load served at 3.2¢/kW.h with a short-term marginal cost of 5.5¢/kW.h, Manitoba Hydro estimates that the annual excess cost would be $18 million. A new load of this size would pay the full marginal cost if it had a payroll of $1 million, $30 million or $53 million, but would receive the full $18 million discount if it had a payroll of $55 million. This binary incentive structure does nothing to encourage employment at payrolls much below $54 million, and nothing to encourage additional employment once the payroll exceeds $54 million.[26] It would be a windfall for inherently high-payroll facilities, and provide employment incentives for only a small range of payroll-to-load ratios.

Q: Are the proposed discounts for new loads greater than 78 GW.h consistent with Hydro's proposed discounts for new loads of less than 78 GW.h?

A: No. Hydro (Tab 10, p. 10) proposes:

> New [General Service Large] companies locating to Manitoba with load less than 78 GW.h of annual energy would be entitled to 39 GW.h of annual energy consumption at prevailing General Service Large rates, and would pay the higher rates for any consumption above that level....

So a new customer with a load of 77 GW.h of annual energy would pay embedded costs for 39 GW.h and marginal costs for 38 GW.h, while a customer

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[26] If the new load would normally have a payroll of $40 or $50 million, under Hydro's proposal the customer could save money by hiring people to sit around, reach the $54 million breakpoint, and get an $18 million subsidy from MH.

with a load of 79 GW.h of annual energy would pay marginal costs for all 79 GW.h. The last MW.h that pushes the customer over the 78 GW.h threshold would cost the customer about $2 million. This approach makes no sense.

Q: Do you have any observations regarding the formula that Manitoba Hydro proposes to use in determining whether a new customer is exempt from marginal-cost pricing?

A: Yes. Aside from my previous point that the exemption should be incremental, rather than binary, the credit proposed for job creation or retention appears to be excessive.

For example, the 2006–2007 Annual Progress Report of the Canada-Manitoba Economic Partnership Agreement reports that a public investment of $600,000 in tourism (by means of the CDEM Tourism & Entreprises Riel Initiatives) has produced 111 new jobs, retained 72 jobs, created 69 spin-off jobs, and resulted in "redevelopment and housing starts investments valued at $45.2 M." (pp. 11 and 19). Depending on whether one includes the spin-off jobs in the computation, the cost of economic development was between $2,400 and $3,300 per job, excluding the additional investments.[27] Amortized over 20 years at Manitoba Hydro's 6.1%–6.5% discount rates, this cost is only about 1% of an annual wage of $30,000.[28]

[27]Additional jobs may have been and may be created from the original investment (announced November 2004) after the March 31, 2007 cut-off date for the latest report.

[28]According to Statistics Canada, the average hourly rate for full-time employees in Manitoba for December 2007 was $19.83/hour, or nearly $40,000 annually. I discounted this value to produce a conservatively high estimate of cost of economic development as a percentage of payroll. Hydro reports a 6.1% discount rate in its Power Resource Plans (Appendices 34 and 35) and a 6.5% discount rate in PUB/MH II-66 and in its Annual Report (Appendix 15).

In contrast, the Manitoba Hydro proposal offers new load incentives of 33% (under option 1) or 25% (under option 2) of the incremental payroll, and offers an incentive of 5% to retain existing load.

Q: Does Manitoba Hydro properly compute the benefits of exports in determining the cost of new large loads for the purpose of determining eligibility for exemptions?

A: No. Hydro includes only the revenues from the exports, and ignores the emissions. In addition, Hydro counts the secondary benefits of new loads (employment and taxes), but does not include the potential secondary benefits of its export revenues, which could include increased funding of economic development (as discussed above), DSM, increased assistance to low-income customers, reduction of Hydro's debt load, and potentially many other beneficial uses.

VI. Use of Revenues from Exports and Marginal-Cost-Based Rates

Q: How would marginal-cost-based rate designs increase revenues?

A: Since Hydro's rates are well below marginal costs, raising the tail-block energy rates towards marginal costs would increase revenues. Similarly, charging marginal costs for the energy used by new large General Service loads would increase revenues.

In addition, higher tail-block rates should encourage customers to use energy more efficiently and more carefully, increasing the energy available for export and the resulting revenues.

Q: How should Manitoba Hydro use the export revenues and the additional revenues from higher tail blocks and marginal-cost pricing of new large loads?

A: Appropriate uses for the additional revenues include the following:

- reducing or eliminating customer charges;
- reducing or eliminating demand charges, especially as Manitoba Hydro phases in time-of-use energy rates;
- reducing inner blocks;
- funding assistance to low-income customers and aboriginal communities;
- funding economic-development activities (including potentially infra-marginal discounts on power charges);
- funding expanded energy-efficiency and fuel-switching programs, especially for low-income and electric-heating customers;
- improving Hydro's financial structure;
- reducing tax burdens on Manitoba businesses and households.

In any case, the redistribution of revenue should not promote additional usage.

VII. Evaluation of Hydro's Efforts in Promoting Demand-Side Management

Q: How have you reviewed the aggressiveness of Hydro's efforts in promoting DSM?

A: I looked at two ratios:

- The savings rate, computed as the ratio of annual incremental DSM energy savings from energy efficiency, divided by total retail sales.
- The spending rate, computed as the ratio of annual utility energy-efficiency expenditures, divided by total retail sales.

Q: What is Hydro's current savings rate?

A: From the 2006 PowerSmart Plan (Appendix 9.1), Appendix A.3, Manitoba Hydro was expecting to save about 85 GW.h in 2006/07, rising to about 109 GW.h in 2008/09, and falling to 75 GW.h in 2011/12, and further thereafter.

Hydro's 2007 load forecast (Appendix 35, Table 1) projects sales of 20,498 GW.h in 2006/07 and 21,443 GW.h in 2008/09. Hydro's planned savings rate is thus 0.4% in 2006/07, 0.5% in 2008/09, and much less in later years.

Q: What is Hydro's current spending rate?

A: From the 2006 PowerSmart Plan (Appendix 9.1), Appendix A.5, Manitoba Hydro was expecting to spend $30.8 million on conservation in 2006/07, rising slighting in 2007/08, falling to $23.7 million in 2008/09, and then declining rapidly to $18.8 million in 210/11 and $11.1 million in 2017/18.

Hydro's planned spending rate is thus $1.5/MW.h of sales in 2006/07, $1.1/MW.h in 2008/09, and much less thereafter.

Q: How do these ratios compare to those of leading energy-efficiency programs in North America?

A: Hydro's ratios are smaller than the recent values for leading energy-efficiency providers and much lower than planned levels, as the following examples show:

- The Massachusetts investor-owned utilities and a public aggregator, under the guidance of collaboratives including government and public-interest groups, saved about 0.7% of sales and spent about $2.5/MW.h sold in 2005, the last year for which aggregate data are available.
- The Connecticut investor-owned utilities, Connecticut Power and Light and United Illuminating, under the guidance of the state Energy Conservation Management Board, have been saving about 1% of sales annually and spending about $2/MW.h of sales. They plan to increase spending to near $3/MW.h in 2008.

- Efficiency Vermont, the state-wide energy-efficiency provider for that state, has been saving about 1% of sales and spending about $2.6/MW.h of sales. Efficiency Vermont's most recent plan was to save 1.6% of energy and spend $4.1/MW.h in 2007 and save 2.4% of energy and spend $5.2/MW.h in 2008. The increased efforts in 2007 and 2008 are focused on fast-growing areas in which major transmission and distribution investments can be avoided.
- In New York, the New York State Energy Research and Development Authority implements programs for all the customers of the investor-owned utilities. As of June 2007, the last date for which I have consistent data, NYSERDA was spending $0.7/MW.h and saving about 0.4% of sales annually. The state is in the process of developing mechanisms to reduce energy use 15% by 2015; in that proceeding, the Staff of the Public Service Commission has proposed NYSERDA- and utility-administered program that would increase spending to about $2.8/MW.h and reduce loads by 1.3% of sales annually by 2009.

The expenditures are reported in nominal US dollars for various recent and projected years (spanning 2004 through 2008), and the cost of most goods and services, including DSM, tends to be higher in the US Northeast than in Manitoba.[29]

Q: What do you conclude from this comparison?

A: I believe that Hydro should be able to double or triple its energy-efficiency spending and savings from current levels and maintain those higher levels for several years.

[29] I have attempted to exclude spending (and savings, where applicable) for demand-response, load-management, and gas-conservation programs.

Q: How does Hydro believe its DSM programs compare to those of industry leaders?

A: Sadly, Manitoba Hydro does not seem to be familiar with other utilities' DSM efforts. In response to question RCM/TREE/MH I-4:

> Please compare MH's current and planned spending on DSM in $/GW.h of load to the spending of continental leaders in energy efficiency, including California, Connecticut, Massachusetts, and Vermont.

Hydro replied

> As Manitoba Hydro does not have the detailed information on the referenced regions, a response to this request can not be provided. A request seeking this information has been forwarded to the appropriate regional entities; however a reply has not been received to date. No recent reports providing the requested information were found.

Hydro's decision to seek that information at this time is laudable; it should make a continuing commitment to learn whatever it can from the most aggressive DSM portfolios.

Q: Is there any particular urgency for Hydro to design and implement enhanced DSM programs?

A: Yes. Energy savings over the next few years would help to offset the following energy shortages that Manitoba Hydro anticipates for the next few years (Appendix 45, Table 3, p. 12):

- 169 GWh in 2009
- 276 GWh in 2010
- 287 GWh in 2011

While Hydro asserts that "the only option available for 2009 is imported power" (Appendix 45, p. 13), accelerated DSM is clearly an available option for 2009.

In addition, increased energy savings over the next decade would increase Hydro's flexibility, allowing it, for example, to avoid the anticipated 2020/21 energy deficit without extending the operation of Selkirk GS (Appendix 45, p. 11) and to commit to larger, longer-term firm sales. The next several years are likely to include increased opportunity for exports, driven by the needs for new supply for Minnesota and adjacent regions, carbon constraints in the US, and Ontario's decision to retire all of its coal plants by 2015.

VIII. Recommendations

Q: What are your recommendations to the Board on these issues?

A: I have two sets of recommendations: general instructions the Board should give Hydro in redesign rates in a continuing process over the next several years, and sample recommendations for the rates to be set in this proceeding.

Q: What general directions should the Board lay out for Hydro?

A: Hydro should be transforming rates in the following ways:

- Increasing tail-block energy rates and rates for new GS Large customers to marginal costs, including environmental costs.
- Using the increased revenues from tail-block sales to reduce customer, demand, and inner-block energy charges; fund enhanced energy-efficiency programs, low-income customer discounts, and economic development; and improve Hydro's financial structure.
- Eliminating demand ratchets.
- Implementing time-of-use energy charges, starting with the largest customers, and moving revenue-collection from demand charges to time-of-use energy charges.

Hydro should be required to comply with the Board's rate-design directives. Phasing in the first two initiatives can start in this proceeding. The third initiative can be entirely implemented in this proceeding. Time-of-use rates will require appropriate metering, and should be implemented as soon as feasible.

To support this process, the Board should require Hydro to participate in a public review of marginal costs, including environmental costs. The secrecy and confusion surrounding Hydro's estimates of marginal costs in this proceeding is incompatible with rational planning and regulation.

Q: What are your sample recommendations for the rates to be set in this proceeding?

A: My recommendations (assuming Hydro's proposed class revenue increases, and subject to correction for updated load data) are as follows:

1. Hydro should eliminate all demand ratchets. The revenues lost from that action in each class should be recovered by increasing the energy rate for that class.
2. Assuming a 2.9% residential rate increase, the basic residential rate should be modified as follows:
   - The basic monthly charge should be reduced to about $4.70/month.
   - The rate for the initial energy block should be set at 6¢/kW.h for 600 kW.h/month for non-heating customers and for all customers in non-winter months, plus a winter heating allowance totaling about 6,400 kW.h annually, distributed over the heating season.
   - The rate for additional energy should be set at about 6.28¢/kW.h.

3. The tail block of the flat-rate-water-heating rate should be set at about 5.11¢/kW.h above 300 kW.h/month, with the inner block reduced to meet the allocated revenue requirement.
4. The General Service Small energy rate should be increased to about 6.68¢/kW.h for all energy (plus any increase needed to offset the elimination of the demand ratchet), the customer charge for non-demand-metered customers should be reduced to about $9, and the demand charge for demand-metered customers should be reduced to about $6.40/kV.A.
5. The General Service Medium energy charge should be increased to 2.76¢/kW.h (plus any increase needed to offset the elimination of the demand ratchet), and the customer and/or demand charge decreased. If the reduction is taken entirely in the demand charge, it would be reduced by about 50¢/kV.A.
6. Each General Service Large customer should be charged the embedded energy rate for usage up to a baseline (such as 95% of its maximum annual usage in the last three years) and marginal cost above that level. New General Service Large customers should be charged entirely the marginal energy rate. The additional revenues should be used to fund economic development grants and increased DSM, and to decrease the demand charge.

If the Board increases funding for DSM, low-income programs, economic development, or strengthening Hydro's balance sheet, the additional costs should be recovered through energy rates, and through tail-block energy charges where possible.

Q: Does this conclude your testimony?

A: Yes.

Exhibit ____ PLC-1

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SUMMARY OF PROFESSIONAL EXPERIENCE

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

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

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

EDUCATION

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

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

HONORS

Chi Epsilon (Civil Engineering)

Tau Beta Pi (Engineering)

Sigma Xi (Research)

Institute Award, Institute of Public Utilities, 1981.

PUBLICATIONS

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ADVISORY ASSIGNMENTS TO REGULATORY COMMISSIONS

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

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

EXPERT TESTIMONY

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

    Profit margin calculations, including methodology, interest rates.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

    Profit margin calculations, including methodology and implementation.

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

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

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

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

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

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

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

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

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

    Construction schedule and cost of completing Millstone Unit 3.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

84. **Maryland PSC** 8278; Adequacy of Baltimore Gas & Electric's Integrated Resource Plan; Maryland Office of People's Counsel; September 18 1990.

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

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

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

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

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

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

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

88. **Maine PUC** 90-286; Adequacy of Conservation Program of Bangor Hydro Electric; Penobscot River Coalition; February 19 1991.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

96. **MDPU** 91-131; Update of Externalities Values Adopted in Docket 89-239; Boston Gas Company; October 4 1991. Rebuttal, December 13 1991.

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

97. **Florida PSC** 910759; Petition of Florida Power Corporation for Determination of Need for Proposed Electrical Power Plant and Related Facilities; Floridians for Responsible Utility Growth; October 21 1991.

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

98. **Florida PSC** 910833-EI; Petition of Tampa Electric Company for a Determination of Need for Proposed Electrical Power Plant and Related Facilities; Floridians for Responsible Utility Growth; October 31 1991.

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

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

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

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

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

101. **MDPU** 92-92; Adequacy of Boston Edison's Street-Lighting Options; Town of Lexington; June 22 1992.

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

102. **South Carolina PSC** 92-208-E; Integrated Resource Plan of Duke Power Company; South Carolina Department of Consumer Affairs; August 4 1992.

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

103. **North Carolina Utilities Commission** E-100, Sub 64; Integrated Resource Planning Docket; Southern Environmental Law Center; September 29 1992.

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

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

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

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

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

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

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

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

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

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

Demand-side management cost recovery and incentive mechanisms.

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

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

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

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

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

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

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

Economic analysis of proposed coal-fired cogeneration facility.

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.

    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 Rate Case; 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.