Docket No. NSPI-P-891

NOVA SCOTIA UTILITY AND REVIEW BOARD

In the Matter of: An Application by Nova Scotia Power Inc. for Approval of Depreciation Rates

DIRECT TESTIMONY OF PAUL CHERNICK ON BEHALF OF THE CONSUMER ADVOCATE

Resource Insight, Inc.

FEBRUARY 7, 2011

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I. Identification & 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 St, Arlington, Massachusetts.

Q: Summarize your professional education and experience.

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

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

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

Q: Have you testified previously in utility proceedings?

A: Yes. I have testified more than 250 times on utility issues before various regulatory, legislative, and judicial bodies, including utility regulators in thirty states and five Canadian provinces, and two U.S. Federal agencies. This testimony has included the review of many utility-proposed power plants and purchased-power contracts.

Q: Have you previously testified before this Board?

A: Yes. I testified in the Board's review of the following cases:

- Nova Scotia Power's Demand Side Management Plan for 2010 and Demand Side Management Cost Recovery Rider in May 2009,
- the proposed purchased-power agreement between Nova Scotia Power Inc. ("NSPI") and a biomass project to be constructed at the NewPage Pt. Hawkesbury ("NPPH") pulp and paper mill (NSUARBP-172),
- Nova Scotia Power's proposal to build the biomass project at NPPH (NSUARBP-128.10),
- Heritage Gas's 2010 rate case (NSUARBNG-HG-R-10).

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II. Introduction

Q: On whose behalf are you testifying?

A: My testimony is sponsored by the Nova Scotia Consumer Advocate.

Q: What is the purpose of your testimony?

A: The Consumer Advocate has asked me to comment on the proposal of NSPI to increase its depreciation rates for power plants to include decommissioning costs and to catch up alleged past under-collections prior to the assumed retirement dates.

The NSPI 2010 Depreciation Study ("the Study") summarizes NSPI's analysis, but the depreciation rates are actually estimated in Appendix A to the Study, prepared by John F. Wiedmayer of Gannett Fleming, Inc. The decommissioning cost estimates are derived in Study Appendices C and D, prepared by engineering firms.

I have not reviewed the depreciation rates for transmission or distribution plant.

Q: Please summarize your observations on NSPI's proposal.

A: The Study makes the following five assumptions that are unjustified and in some cases implausible:

- Assuming that the steam plants will be retired at unsupported dates, rather than operating as back-up, or burning gas or biomass.
- Assuming that steam plants will be demolished when retired, rather than reused, sold or left in place for extended periods.
- Assuming that hydro plants will be retired, even though NSPI cannot provide any reason for them to be removed from service.
- Assuming that hydro powerhouses will be demolished when retired.
- Assuming that inflation will be 3.4%, even though NSPI projects 1.92% inflation.

The Company also makes a policy decision to front-load significantly the recovery of decommissioning costs by treating them as part of depreciation rather than as an internal fund, accumulating interest. The Company's approach would reduce rates in the late years of the plants lives, at the expense of much higher rates in early years. Neither the Study nor NSPI's discovery responses justify this approach.

Q: How do you recommend the Board respond to NSPI's filing in this case?

A: I recommend that the Board reject NSPI's requested rates and order NSPI to refile decommissioning cost rates with the following requirements:

- No plants are retired prior to 2032, consistent with the IRP, unless NSPI can demonstrate that earlier retirement is probable.
- The retirement dates of fossil-fueled units must be based on a reasonable analysis of useful life and NSPI's need for capacity, energy, load following, and reserves.
- The hydro plants do not retire, and are depreciated only based on the historical rate of interim retirements, based on the 95-S1.5 survivor curve estimated in Study Appendix A.

The Board should allow NSPI to file for recovery of fossil- and wind-plant decommissioning costs in an appropriate forum, such as its next rate application, with the following requirements:

- Regardless of when the individual units are retired, the Tufts Cove, Trenton, Burnside, and Tusket sites are never assumed to be dismantled.
- The dismantlement years for other fossil units must be justified by historical experience and opportunities for reuse of structures (including need for replacement capacity).
- Decommissioning funding will be designed to collect the same nominal value each year.

Q: Is the depreciation life for a plant investment the same as the operating life of the plant?

A: No. Parts of a plant (the boiler tubes, the turbine vanes, the generator, condenser tubes, the roof, and various pumps and piping) wear out, are retired and are replaced. The average dollar of investment in a plant lasts fewer years than the operating life of the plant.

III. Retirement Dates

A. Steam Plants

Q: What retirement dates are assumed in the Study and Appendix A for NSPI's steam plants?

A: The steam-plant retirement dates assumed by NSPI are listed in Table 1.

Table 1: NSPI Assumed Retirement Dates for its Steam Plants

Unit	In-service Year	Assumed Retirement Year	Assumed Life
Lingan 1	1980	2026	46
Lingan 2	1981	2026	45
Lingan 3	1984	2030	46
Lingan 4	1985	2030	45
Point Aconi 1	1994	2039	45
Point Tupper 2	1973	2028	55
Trenton 5	1970	2025	55
Trenton 6	1992	2037	45
Tufts Cove 1	1966	2020	54
Tufts Cove 2	1973	2020	47
Tufts Cove 3	1977	2020	43

Source: Study Appendix A, p. II-29

Q: What is the basis for these assumptions?

A: Mr. Wiedmayer admits that NSPI told him what dates to assume: "The estimated probable retirement dates for each power generating unit were provided to

Gannett Fleming by NSPI's management." (Study Appendix A, p. II-27) He also makes a range of claims regarding the basis for these assumptions:

> The life span estimates for power generating stations were the result of considering experienced life spans of similar generating units, the age of surviving units, general operating characteristics of the units, major refurbishing, and discussions with management personnel, concerning the outlook for the units….
>
> …Several factors are expected to impact the service lives of the coal-fired units in the future: 1) stricter environmental regulations related to air quality and greenhouse gas (GHG) emissions; 2) a significant increase in the amount of electricity generated by renewable energy sources such as wind and biomass; 3) the availability of natural gas in Nova Scotia from various sources including liquefied natural gas terminals (LNG) and the development of competitive generation technologies, e.g., a combined cycle gas turbine; 4) the potential development of the Lower Churchill hydroelectric project and other new generation technologies such as tidal units. (Study Appendix A, p. II-27)

Mr. Wiedmayer continues with a description of the environmental regulations facing NSPI's coal plants, and then observes that the

> Environmental Goals and Sustainable Prosperity Act requires NSPI to reduce their GHG emissions by 2.1 million metric tonnes by 2020.… Each coal-fired unit emits approximately 1 million metric tonnes of carbon dioxide per year. Therefore, the baseload operations of coal fired generation from the equivalent of about 2 coal-fired units are estimated to cease in 2020. The future operating mode is uncertain at this time as NSPI anticipates using coal units as emergency back-up. While a specific date for retirement is uncertain, the generation output for these coal-fired units will be significantly reduced beyond the year 2020. (Study Appendix A, p. II-28)

Q: Does the reduction in carbon dioxide emissions require the retirement of any coal units, or their relegation to "emergency back-up?"

A: No. The coal units may continue operating on lower-carbon fuels, including natural gas or biomass. Rather than retire any of the eight operating coal plants, or even limit them to emergency back-up, NSPI may run the units at lesser capacity factors. The 2009 IRP Update indicates that NSPI's 1,247 MW of coal generation was expected to produce about 9,150 GWh in 2010, which would be an average capacity factor of 84%.[1] Reducing carbon emissions 22% without changing the fuel mix for the coal plants (mostly coal and petroleum coke) would reduce the capacity factor to 66%. Since the IRP projects that the coal plants would burn increasing amounts of pet coke and biomass, the capacity factor could be much greater than 66%.

Q: Did Mr. Wiedmayer provide any information to support his claim that he considered "experienced life spans of similar generating units"?

A: Only in a limited sense. In CA IR-8, Mr. Wiedmayer provided lists of retired coal and oil/gas units, generally with their dates of initial operation and retirement. However, since he did not provide any information on the number of units of similar vintage that have not been retired, these data are of little value.

Q: Did you find any errors in Mr. Wiedmayer's list of retired plants?

A: Yes. While I did not go looking for errors, I noticed that Mr. Wiedmayer listed Mirant's Kendall Square 1–3 in Cambridge, Massachusetts, as having been retired in 2002 (CA IR-8, Attachment 4, p. 10). The 2010 resource list of the New England ISO shows all three of these units to be in service.

Q: Given that Mr. Wiedmayer relied on unit retirement dates provided by NSPI, has NSPI been able to justify those dates?

A: No. Asked for "all analyses and workpapers supporting NSPI management's estimate of probable retirement year for each steam generation unit" (CA IR-10), NSPI provided no such documentation. Indeed, NSPI admits, "The 2007 IRP and the 2009 IRP Update forecast continued operation of the steam generation units over the planning period at relatively high capacity factors under the Base

[1] Actual output was probably lower, due to low gas prices.

Case assumptions" (CA IR-10). The Company also points to the 2009 IRP update as representing the most recent "analyses conducted by NSPI of the cost-effectiveness of continued operation of any or all steam plants" (CA IR-11).

As NSPI acknowledges, "each steam plant is unique and each life span has to be assessed in relation to the circumstances in which the plant operates….Steam plant retirements are an economic decision regarding a choice among two or more alternatives. Management ultimately will make the decision when to retire steam plants and that date will occur when electricity can be produced for less at another location or can be purchased for less than the cost to produce it at a certain plant unless there is a prescriptive environmental regulation" (CA IR-8).[2] The Company has provided no economic analysis indicating that the assumed retirement dates are likely. And as NSPI admits, "There are no planned retirements of the generation assets in the 2009 IRP Update assumptions" (CA IR-12).

Q: Are the retirements assumed in this docket consistent with the 2009 IRP?

A: No. I estimated the generation from the coal plants assumed in the base-case IRP energy plan provided in CA IR-12, Attachment 1, p. 2, including coal, petroleum coke, and co-fired biomass. In Table 2, I compare that output to the capacity that would be available with the retirements assumed in Study Appendix A.

[2] I assume that NSPI refers here to situations in which an owner is required to shut down a plant, rather than meet environmental standards that make continued operation uneconomic. While such a situation is conceivable, I am not aware of any.

Table 2: Coal Retirements and IRP Energy Outputs

	Units Retired	MW	Remaining	GWh	Capacity Factor
2010			1,247	9,145	84%
2025	Trenton 5	150	1,097	7,375	77%
2026	Lingan 1 & 2	306	791	7,257	105%
2028	Point Tupper 2	152	639	7,021	125%
2030	Lingan 3 & 4	311	328	6,844	238%

Sources: Retirements from Table 1. Capacities and coal-plant energy from 2009 IRP update

Even with the retirement of one unit in 2025, the capacity factor for the remaining coal plants would be less than in 2010. But retirement of two more units in 2026 would require physically impossible output levels from the remaining plants. The situation becomes even worse thereafter. Lingan 1 could be retired in 2030, but the rest of the coal units would be needed through the end of the IRP period in 2032. At that point, NSPI could have retired two units, not the six units implied by NSPI's unsupported retirement dates.[3]

Q: Are there other reasons for NSPI to keep additional coal units on line, as output falls as predicted in the IRP or faster?

A: Yes. As NSPI has argued in the 2009 IRP and in the Port Hawkesbury biomass proceedings, increasing supply from wind farms will require load-following and reserve capacity. Indeed, NSPI cited its concern about the cost of integrating wind generation in cancelling the IRP's planned 2010 RFP for 100 MW of wind capacity. Similarly, if NSPI becomes dependent on 500 MW of imports from Labrador over an undersea HVDC cable, NSPI will need back-up capacity in the event of failure of that cable or the DC converter stations in Newfoundland or Nova Scotia.

[3]This result is roughly consistent with the analysis in Study Appendix A, p. II-28, which notes that carbon-emission limits would reduce coal usage by about two units' consumption.

In addition, the co-firing of biomass will tend to reduce capacity of the existing plants, requiring more units to remain on line to produce the required energy.

Q: If environmental constraints limit coal consumption in the existing coal plants, can the plants operate on other fuels?

A: Yes. Some of the units listed in CA IR-8 as burning coal were converted to burn oil or gas later in their lives (e.g., Mystic 1–3, Kearny 1–6, Essex 7, Burlington 1–4, Montville 1–3, Somerset 3, Barbadoes 3&4, Chester 1–4, Richmond, West End 1–6, Marysville 2–5, Gould Street 1&2, Hell Gate). Mr. Wiedmayer lists Schiller 5 as retired, but it is still operating, burning biomass.[4] The Company has proposed burning large amounts of biomass in its coal plants.

B. Hydro-Electric Plants

Q: What retirement dates are assumed in the Study and Appendix A for NSPI's hydro plants?

A: The thirteen hydro-electric projects distinguished in Study Appendix A are assumed to retire between 2013 and 2061, when their various units would be aged from 75 to 131 years. It is important to note that the assumed retirement dates relate to the powerhouses and other generation-related facilities, not to the dams, which are assumed to remain in place (Study Appendix D, p. 2).

Q: What is the basis for these assumptions?

A: As is the case for the steam plants, these retirement dates were supplied by NSPI management.

[4] He also lists Schiller 4 as retired, but it is still operating, burning coal.

Q: Does Mr. Wiedmayer provide any support for the hydro-plant retirement dates?

A: No. To the contrary, his discussion of the Province's commitment to renewable energy and reduced emissions, intended to support NSPI's projected retirement dates for the coal units, suggests that the hydro units will be operated as long as feasible.

Q: Has NSPI provided any basis for its hydro retirement assumptions?

A: No. The Company is unable to "explain how each of the hydraulic plant retirement dates…was derived" or provide any supporting workpapers (CA IR-19) and simply says that its projections are "reasonable given the numerous uncertainties between now and the first probable retirement date" (CA IR-22). Since all the "numerous uncertainties" discussed in Study Appendix A and in discovery responses apply to steam plants, especially coal plants, NSPI has not demonstrated the reasonableness of its projections.

Q: Why are hydro-electric plants usually retired?

A: In my experience, most recent such retirements have been associated with removal of the dams to allow fish passage, especially in the Pacific Northwest and in Maine. A number of projects from the Pacific Northwest appear in CA IR-20 Attachment 1 (listed under Avista, Chelan PUD, Grant PUD, Idaho Power, PacifiCorp, Portland General, Puget Sound, U.S. Bureau of Reclamation); those are likely to be primarily fish-related. Specifically, I have identified as fish-related the retirement of Portland General's four Bull Run units and PacifiCorp's Powerdale and two Condit units listed in CA IR-20.

I am not aware of similar pressures in Nova Scotia to remove dams to restore fish runs. In any case, Mr. Yates explicitly excludes dam removal from his analysis.

There are other reasons for hydroelectric plants to cease operation. Some dams are retired when new impoundments would flood them. Others are redeveloped to increase capacity. The Company has not identified opportunities in either of these categories that would result in retirement of any of its existing hydro plants.

Removal of power generation from facilities when the dam is to remain in place appears to be rare now, although it was more common in periods of very inexpensive power supply.

C. Combustion Turbines

Q: Has NSPI provided any justification for the retirement date for its peaking units at Tusket, Victoria Junction, and Burnside, or for the Tufts Cove combined-cycle plant?

A: No.

IV. Fate of Retired Plants

Q: Why does the fate of retired plants matter for this proceeding?

A: The Company has proposed to charge customers today for the cost of dismantling power plants and restoring them to Greenfield condition immediately following retirement. If plants remain in place for extended periods, if structures are reused, if buildings are sold, and if sites are sold at a profit, current rates can be lower than if NSPI's assumptions are accepted.

A. Steam Plants

Q: What happened to previously retired steam plants in Nova Scotia?

A: The Company's responses to discovery on this point have been spotty. The Consumer Advocate asked NSPI for an accounting of the retirement and disposal of "all steam units previously operated by NSPI or its predecessors" (CA IR-5). NSPI made the following statements in reply:

- Some unidentified number of "smaller, lower steam pressure and temperature, oil and coal generating units.… went into operation in the 1920s to 1950s and some operated into the 1980s.… in Maccan, Glace Bay and Water Street."
- Point Tupper Unit 1 and Glace Bay Unit 7 were "high pressure units that cogenerated heat and power" with the heat sold to the heavy water plants.
- "When the heavy water plants were shut down, Point Tupper Unit 1 went out of operations and eventually retired."
- Glace Bay 7 was upgraded in the 1990s, but "after several years of a very low capacity factor, the unit was retired and demolished."

This response does not provide the number of units at Maccan or Water Street, or any information about the fate of Glace Bay 1–6. Nor does it even acknowledge the existence of Trenton 1–4. Even for the units discussed in the most detail, NSPI does not describe the fate of Point Tupper 1, or the interval between retirement and demolition of Glace Bay 7.

In CA IR-8 Attachment 3, Mr. Wiedmayer does list the in-service and retirement dates of Glace Bay 1–5 (retired 2000), Maccan 1 (retired 1993), and Water Street 1–5 (retired 1978). Glace Bay 6 and 7, Point Tupper 1, and Trenton 1-4 do not appear on these lists.

In NPB IR-22, NSPI states that "At Maccan and Glace Bay, NSPI has returned the sites to industrial green field sites and maintain it as such. Water Street is in the process of being transformed into the new NSPI corporate offices."

Q: Have you been able to determine the fate of any of the retired units?

A: To some extent. The Point Tupper plant has only one operating unit, but two stacks, suggesting that at least some of the Unit 1 infrastructure is still in place.

From NSPI's own web site, I found that the Water Street site "remained dormant" from plant retirement in 1978 until 1997, when it was converted to a movie studio. In 2011, the Water Street plant was converted to NSPI's headquarters. Thus, this plant has been reused and not dismantled, more than 30 years after it last generated power.

Q: What information was NSPI able to provide regarding the fate of other retired steam plants in the U.S. and Canada?

A: None. When asked for "any available information on the interval from cessation of operation and demolition for each retired steam unit in Canada and the United States," NSPI answered that "Gannett Fleming does not have such analysis" (CA IR-14). Obviously, NSPI has some information on its own retired plants, but did not provide that information in response to either CA IR-8 or CA IR-14.

Q: How have other retired steam plants been used?

A: Some units have been dismantled, but by no means all. For example, various retired steam plants have been

- converted to museums:
  - The Tate Modern in London.
  - The coal-fired Durango plant in Colorado.
  - Puget Power's Georgetown plant, retired in 1972 and converted in 1995 to Georgetown Powerplant Museum.
- returned to service:

    - Ontario's Hearn station was shut in 1983; units 7 and 8 were in the process of being returned to operation in 1990, when falling load eliminated need for the plant.
    - Various New England units returned to service during capacity shortages in the 1980s and 1990s, including the reactivation in 1997 of Mason 3–5 (deactivated in 1991) and West Springfield 1&2 (retired in the early 1990s).
    - Consolidated Edison returned the retired Hudson Avenue 10 to operation in 2001.
- reused as power-plant sites:
    - Consolidated Edison's East River,
    - part of Ontario's Hearn Station site
    - Alberta's Clover Bar,
    - Connecticut's Devon and Middletown plants,
    - United Illuminating's English Station, retired in 1992, transferred to a power-plant developer in 2000 (no reuse yet)
- used as synchronous condensers to provide reactive power:
    - One unit at Manitoba Hydro's Brandon
    - Some units at Ontario's Hearn
    - Mirant's Delta units in California from retirement in 1995 to 2008.
- used for utility storage:
    - Public Service of Colorado's Salida coal plant, from retirement in 1963 to sale in 1987
    - Northern States Power's Island Station, from 1975 retirement to 1985 sale.
- converted to commercial and public space:

    - Baltimore Gas and Electric Pratt Street plant, converted to restaurants, retail space, and other commercial spaces
    - Ontario’s Hearn Generation Station, built in 1951, retired in 1983, used as a film studio.
    - Public Service of Colorado’s Salida, retired in 1963, converted to a theatre in 1989.
    - Ameren’s Cahokia, converted to a bulk commodity transfer site,
    - The Homan Square power house in Chicago, retired in 1973, converted to high school in 2009.
    - The Ottawa Street plant in Lansing Michigan, retired in 1992, now being converted to insurance company headquarters.
    - The Hudson and Manhattan Railroad power plant in Jersey City, retired in 1929, now under conversion to mixed-use art, retail, and entertainment center.
    - Con Edison’s Glenwood-Yonkers plant was retired in 1963, sold as storage space in 1978.
    - South Street plant in Providence, retired in 1991, donated as a museum in 1999, now under development as hotel, offices, retail, and museum.
    - Austin’s Seaholm plant, retired by 1996, rented out for events, now under development as hotel, condos, entertainment, and retail
    - Battersea power plant in London, retired in 1983, sold in 2006, now in development as subway station, office space, and conference center.
    - Seattle’s Lake Union plant, converted to corporate headquarters.
- converted to residential space:

- San Diego G&E's Station B, built in 1911, retired in 1983, and converted to condominiums and an art gallery in 2008.
- Northern States Power's Island Station, retired in 1975, sold in 1985, condominiums still in development.
- Pennsylvania Railroad's Long Island Powerhouse is currently being converted to condominiums.
- Exelon's Chester Waterside plant, retired in 1981, sold in 2001, now converted to residential and office space.
- Lower Colorado River Authority's Comal power plant, retired in 1973, sold in 2004, converted to condominiums.

• sold for redevelopment at prices that paid for demolition, in some cases with substantial profits (e.g., Consolidated Edison's Waterside).

Q: Is it possible that some of NSPI's steam plant sites would be reused for new generation?

A: Yes. If the large amount of generation NSPI has assumed will be retired by 2030 is actually taken out of service, NSPI will almost certainly need to add capacity for load-following and operating reserves to firm up wind and potential imports from Labrador, and perhaps for planning reserves as well. Those new resources may be gas peakers, combined-cycle plants, or various storage technologies (batteries, regenerative fuel cells, flywheels).

The Company concedes that "It is likely peaking capacity will be required after the retirement dates of the existing units. The characteristics and location of these facilities has yet to be determined" (CA IR-18). While CA IR-8 also asked whether "there any reason to believe that NSPI will have better sites for future peakers than the existing sites of peaking plants and steam plants," NSPI did not respond to that part of the question. In general, the existing steam plant sites, with land and transmission connections, would be appealing sites for new peaking capacity. This is particularly true for Tufts Cove, located in the Halifax load center, as well as Trenton, Burnside, and Tusket.

Q: Have steam plant sites been used for new gas turbines without dismantlement of the steam plant equipment and buildings?

A: Yes. The Devon steam units in Connecticut have all been retired in place, with new gas turbines added on the sites. The same is true for Middletown 1–4 in Connecticut; in that case, the Middletown 5 and 6 steam units are still operating. At the Mystic station near Boston, units 1–3 were retired in the 1970s and removed in 2003, when the combined-cycle units 8 and 9 units were constructed; units 4–6 were shut down in 2003 and remain in place.

Q: Does NSPI offer any estimate of how decommissioning costs would be affected by reuse of the sites for generation?

A: No. When asked in CA IR-17 for Stantec's estimate of the cost of decommissioning for a plant site that would be reused as generation, NSPI fails to provide any cost information, and instead says that "Historically, NSPI has not re-used a decommissioned plant site for power generation…. [T]he IRP does not show additional generation requiring the use of these sites."

Q: Is it true that "NSPI has not re-used a decommissioned plant site for power generation"?

A: That is not clear, since NSPI has not provided any information about the retirement and fate of Trenton 1–4.

Q: Why doesn't the IRP "show additional generation requiring the use of these sites"?

A: In the IRP, no additional generation is needed because all the steam units and gas turbines continue to operate through 2032. In this proceeding, NSPI assumes that 1,462 MW of generation will be retired by 2030.

Q: Is it possible that the sale of NSPI's steam-plant sites would pay for all or a large portion of dismantlement costs, if dismantlement is required?

A: It is possible, but NSPI "has not estimated the market value of the land occupied by each of its thermal plants for purposes of this application…. Market value of land is not a determinant in setting depreciation rates" (CA IR-15).[5]

It is not clear how NSPI could justify including in depreciation rates the costs of dismantling the existing plant, but not the value of land following dismantlement. Until the latter can be reflected in depreciation rates, the Board should be wary of including the former.

Q: Aside from the plants that are eventually redeveloped, are steam plants routinely demolished immediately after retirement?

A: No. A number of examples are listed in the discussion of reuse above, in which retired plants remained in place for many years. In addition,

- Con Edison's Kent Avenue plant was retired in 1972 but not demolished until 2008.
- FirstEnergy' Mad River units were shut down in 1980 and 1985, but not demolished until 2010.

The annual capability reports of New England ISO lists generating units that are "deactivated" but not removed. This list does not include all retired New England units still in place. Table 3 lists the steam plants in that status from 2002 onward. I have not been able to confirm the dismantling of any of these

[5]This response suggests that NSPI may have the requested information, but does not choose to provide it in this case.

units.[6] English 7 & 8, Somerset 5 (and at least portions of Somerset 1–4, retired in the 1970s), Bridgeport 1, and Devon 7 & 8 are certainly still in place.

Table 3: New England Deactivated Units

	Operating Company	Fuel	Deactivated	Last Year on List	Years Listed as Deactivated
Cabot 9	Holyoke Gas & Electric	Oil	1981	2002	21
Mason 1 & 2	Central Maine Power	Oil	1983	2006	23
English 7 & 8	United Illuminating	Oil	1992	2006	14
Graham 4 & 5	Bangor Hydro-Electric	Oil	1992	2006	14
Somerset 5	NRG Power Marketing	Coal	1994	2006	12
Bridgeport Harbor 1	United Illuminating	Oil	1998	2006	8
Devon 7 & 8	NRG Power Marketing	Oil	2004	2007	3

Source: ISO New England Capacity, Energy, Load and Transmission reports, 2002–2008.

B. Hydro-Electric Plants

Q: What information has NSPI provided on the fate of retired hydro-electric powerhouses?

A: Mr. Wiedmayer has indicated that Gannett Fleming has no information on the "fate of retired hydraulic plants in Canada or the United States, specifically the interval between retirement and decommissioning" (CA IR-21).

Q: Have you found any such information?

[6] Graham may have been dismantled in conjunction with the construction of the Maine Independence combined-cycle power station on the same property.

A: It is time-consuming to determine which hydro plants are retired with their dams intact, as opposed to those retired when their dams are demolished for environmental purposes.

I investigated the fate of the Hydro-Quebec units (Chute-Bell, Magpie, Sherbrooke, and Corbeau) listed in CA IR-20. Chute-Bell units 1–3 were built in 1918, closed down by 1984, and were redeveloped in 1999, preserving the historic powerhouse while installing new generators.[7] Hydro Quebec shut down the old Magpie hydroelectric generating station in 1989; in 2007, the dam was redeveloped into a new power plant, while the original generating powerhouse was demolished about 15 years after retirement.[8] The former Hydro-Quebec Sherbrooke units may be some of the units in Sherbrooke now owned by Hydro-Sherbrooke. I have not found any information on the current status of Corbeau.

It appears that hydro generation equipment and structures, even when not in active use, can remain in place for many years and in some cases can be reused in new generation development.

C. Combustion Turbines

Q: Did NSPI provide any information about the fate of retired combustion turbines?

A: No.

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[7]"Chute Bell x 2.5," Canadian Consulting Engineer, June 2001 (www.canadianconsultingengineer.com/issues/story.aspx?aid=1000165807)

[8]http://www.hydromega.com/en/projets/Magpie.html

V. Cost of Decommissioning

Q: How does Mr. Wiedmayer adjust the decommissioning cost estimates prepared by Stantec and JB Yates?

A: He increases the estimates by 3.4% inflation from 2009 to the NSPI-selected retirement date.

Q: Does he adjust the cost downward, to reflect the time value of money from the present time until the assumed decommissioning?

A: No.

Q: How did Mr. Wiedmayer select the 3.4% inflation rate?

A: Mr. Wiedmayer used the average escalation in the Handy-Whitman index of costs for building power plants in the northern U.S. from 1980–2009.[9]

Q: What is the basis for this assumption?

A: The Company says that "The advantages of the HW Cost Indices are that they are: 1) electric utility specific; and 2) specific to steam and hydro plants" (CA IR-1).

Q: What inflation rate does NSPI use for other purposes?

A: In the IRP, and in every other analysis I have seen over the last couple years, NSPI assumes a future inflation rate of 1.92%.

Q: What range of inflation forecasts is typical?

A: Recent U.S. and Canadian long-term inflation forecasts are generally in the 2% to 2.5% range.

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[9]While Mr. Wiedmayer is generally vague about the specific Handy-Whitman index he uses, the data in DUC IR-97 Attachment 1 are consistent with the "Total Plant-All Steam & Hydro Gen.," line 3 of the Handy-Whitman report for the North Atlantic region.

Q: Are historical inflation rates good predictors for future inflation rates?

A: No. There is no reason why historical inflation rates would be good predictors for future rates, unless economic and financial conditions (including rates of change) are expected to be similar in the future as in the past.

In Table 4, I backcast Mr. Wiedmayer's technique for similar choices in each decadal year from 1950 to 1990. I compute the Handy-Whitman inflation rate for thirty-year periods ending in that year and the rate experienced in the next twenty years. The past Handy-Whitman is not a particularly useful

Table 4: Handy-Whitman Escalation, Past and Future, Various Dates

	Handy-Whitman Index	Inflation Rate, Previous 30 Years	Inflation Rate, Next 20 Years
1950	40	2.2%	3.6%
1960	59	3.8%	6.1%
1970	81	4.4%	6.7%
1980	193	5.4%	3.5%
1990	294	5.5%	3.7%

Q: Does Mr. Wiedmayer explain why he did not use NSPI's inflation rate?

A: Yes, in a manner of speaking.

> The inflation rate used in the 2009 IRP Update is based on general inflation forecasts used for integrated resource planning, a different application than the industry-specific escalation rate Gannett Fleming has used in the Depreciation Study. The escalation rate in the Depreciation Study is intended to calculate the future cost of decommissioning generating plants that are estimated to retire many years into the future. As a result, the Handy-Whitman Indices, which are both electric utility and plant account specific, are more appropriate for this application. (CA IR-3)

It is not clear why Mr. Wiedmayer believes that the costs included in integrated resource planning are not "industry-specific." The Company uses the 1.92% inflation rate for a range of utility-specific capital and operating costs.[10]

[10]Fuel costs are escalated at different rates.

Q: How utility-specific are decommissioning costs?

A: Not very. The Handy-Whitman index that Mr. Wiedmayer used is dominated by the costs of purchasing boilers, turbines, generators and other electrical equipment and structural materials, as well as the skilled labor required for building boilers, fitting steam pipes, building dams and the like. Decommissioning of steam plants, gas turbines, and hydroelectric powerhouses does not involve the purchase of substantial amounts of equipment or materials, and even the labor required is different from than required in construction.

Q: Does Mr. Wiedmayer explain why he used historical escalation rates for the Handy-Whitman index to predict future escalation?

A: No. Both in Study Appendix A and on discovery, Mr. Wiedmayer repeatedly asserts that he has somehow selected the historical period that best predicts future escalation in decommissioning costs.

> The period analyzed in determining the escalation rate used for the Depreciation Study provides a better proxy for long-term cost increases associated with decommissioning expenditures than broader based inflation forecasts. (CA IR-3)

Mr. Wiedmayer also notes, "this period represents the time frame in which NSPI's larger coal-fired units were installed, beginning with Lingan Unit 1 in 1980" (Study Appendix A, p. II-31), as if that fact would determine future inflation. Using Mr. Wiedmayer's logic, a utility that installed its coal plants starting in the 1960s would expect higher future inflation than NSPI, while a generation company with plants primarily from the 1990s would expect lower inflation.

Q: Do other portions of the NSPI filing in this case support the use of the Handy-Whitman index?

A: No. The Stantec report opines that the Halifax Industrial Structure Construction Price index is "the most relevant data representative of demolition cost indices for the purposes of this study" (Study Appendix C, p. 98). From 2002 to 2009, Stantec's most-relevant index has increased 15%, or 2.05% annually, while Mr. Wiedmayer's preferred Handy-Whitman index has increased 45%, or 5.41% annually. Mr. Wiedmayer has not explained why he ignored Stantec's opinion regarding the relevant index.

Q: How much would NSPI's depreciation request be reduced by using a 1.92% inflation rate, rather than Mr. Wiedmayer's arbitrary 3.4% rate?

A: The Company refused to provide that information (CA IR-4). I have reproduced Mr. Wiedmayer's computation in Study Appendix A, pp. II-32 through II-34, using a 1.92% escalation rate. The results are shown in Table 5.

The use of Mr. Wiedmayer's inflation rate, rather than NSPI's standard estimate, increases the cost of decommissioning by 39% for the average steam plant, 112% for the hydro plants with 2061 retirement dates (Wreck Cove, Bear River, Black River and Fall River), and 66% for NSPI's total production plant.

Dividing the escalated decommissioning costs over the remaining years of plant life assumed by NSPI, I estimate that using NSPI's normal inflation forecast, rather than Mr. Wiedmayer's arbitrary 3.4% rate, would reduce annual revenue requirements by about $5.7 million.

Table 5: Corrected Decommissioning Computation, 1.92% Escalation

	NSPI Claimed Retirement Date	Total Decommissioning Costs 2009 Dollars	Annual Escalation Rate	Cost Escalation Factor	Total Decommissioning Costs Future Dollars	Depreciable Original Cost at 12/31/2009	Net Salvage Percent
Steam Production							
Lingan	2030	25,257,738	1.92%	1.49	37,656,692	523,742,227	7.2
Point Tupper	2028	19,751,122	1.92%	1.44	28,347,885	159,356,147	17.8
Point Aconi	2039	12,311,996	1.92%	1.77	21,782,660	504,952,024	4.3
Trenton	2037	22,253,610	1.92%	1.70	37,902,172	387,380,730	9.8
Tufts Cove	2020	17,807,886	1.92%	1.23	21,951,587	191,210,970	11.5
Marine Terminal	2037	6,493,110	1.92%	1.70	11,059,013	33,233,001	33.3
Hydro Production							
Avon	2041	3,292,153	1.92%	1.84	6,050,361	13,582,083	44.5
Annapolis Tidal	2047	2,651,517	1.92%	2.06	5,462,006	36,272,247	15.1
Bear River	2061	11,436,298	1.92%	2.69	30,745,039	36,282,999	84.7
Black River	2061	7,488,697	1.92%	2.69	20,132,413	28,359,899	71.0
Dickie Brook	2042	1,686,263	1.92%	1.87	3,158,537	8,158,836	38.7
Fall River	2061	1,116,635	1.92%	2.69	3,001,932	1,427,135	210.3
Harmony	2031	1,481,041	1.92%	1.52	2,250,475	3,471,334	64.8
Lequille System	2047	7,534,720	1.92%	2.06	15,521,185	18,522,726	83.8
Roseway	2051	1,224,318	1.92%	2.22	2,721,383	2,252,351	120.8
St. Margaret's	2036	7,479,310	1.92%	1.67	12,498,726	13,372,197	93.5
Sheet Harbour	2036	4,439,993	1.92%	1.67	7,419,702	22,864,098	32.5
Tusket	2041	2,443,166	1.92%	1.84	4,490,082	5,531,611	81.2
Wreck Cove System	2061	5,721,266	1.92%	2.69	15,380,899	161,917,415	9.5
Wind Production							
Wind Production Plant	*2023*	*939,000*	1.92%	1.31	1,225,455	*2,975,368*	41.2
Other Production							
Burnside	2023	1,963,895	1.92%	1.31	2,563,009	19,741,676	13.0
Tusket	2017	1,224,215	1.92%	1.16	1,425,388	5,044,977	28.3
Victoria Junction	2016	1,412,153	1.92%	1.14	1,613,235	7,437,789	21.7
Tufts Cove LM Units	2045	2,352,500	1.92%	1.98	4,665,182	73,817,296	6.3

Q: Have you found other errors in Mr. Wiedmayer's escalation computations?

A: Yes. In reproducing Study Appendix A, pp. II-32 through II-34, I found that Mr. Wiedmayer had assumed that the decommissioning cost estimates developed by Stantec in Study Appendix C and by James B. Yates in Study Appendix D were in 2009 dollars. Stantec is very clear that its estimates are in July 2010 dollars (Study Appendix C pp. 3 and 4), including 2% escalation from 2009 (Study Appendix C page 98). The Yates report does not specify the reference date for the estimates, but the analysis was performed in 2010.

VI. Decommissioning Ratemaking

Q: What observations does NSPI make regarding the recovery of decommissioning costs over time?

A: The Company asserts that recovery of depreciation, including decommissioning, should be moved forward, to avoid over-burdening future customers.

> Utility depreciation studies are intended to facilitate the recovery of the cost of delivering electric service from those customers who consume the electricity produced. To vary from this approach risks violating the principle of intergenerational equity.
>
> For NSPI's steam generating assets, equity assumes the maintenance of a consistently high capacity factor over the depreciable lives of the assets…. [I]t is likely that for at least some of these units the…capacity factors…will begin to deteriorate before the end of the currently estimated useful lives. The reduction in capacity factor will have the effect of transferring cost responsibility from current to future customers.
>
> The foregoing weighs in favour of maintaining the status quo with respect to steam generation unit service lives for the purpose of setting depreciation rates. (CA IR-10)

> Though there remains a benefit to customers of the future time from the fossil assets, it is an ever decreasing value. To limit intergenerational transfer of costs, it is appropriate to recover the capital cost from customers who enjoy the substantial portion of the benefit. (CA IR-12)

Q: Are these valid arguments to moving costs onto current ratepayers?

A: No. The Company's position is factually incorrect and inequitable.

Q: How does traditional utility rate-base cost recovery distribute costs over time?

A: Rate-based cost recovery heavily front-loads recovery of capital costs. Depreciation of the initial is constant over time, but return and associated income taxes on net plant in service falls over time. The falling net plant is the result of the rise of accumulated depreciation. Net plant in the first year equals the gross capital cost; in each subsequent year, the previous year's depreciation is subtracted from the previous net plant, resulting in a steady decline in net plant.[11]

Figure 1: Capital-Cost Recovery Example

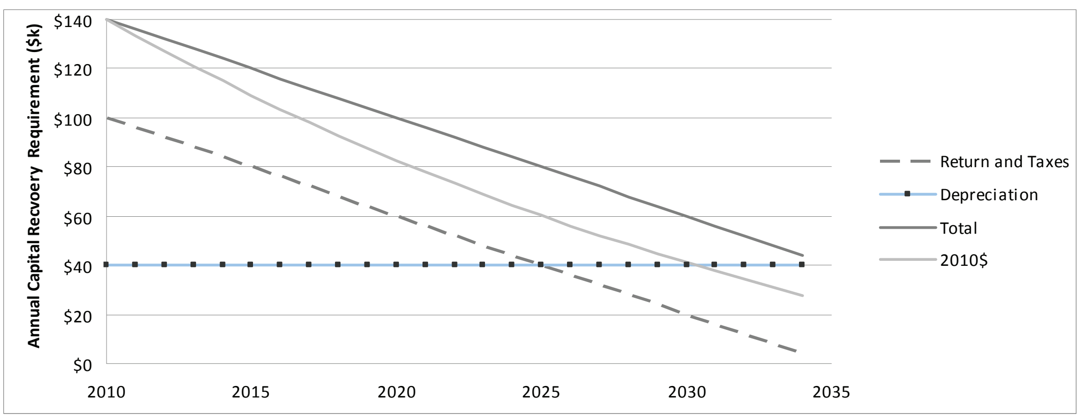


Figure 1 provides an example of annual revenue requirements resulting from an investment of $1 million, depreciated over 25 years, with a 10% annual charge on net plant for return and taxes. Total nominal cost recovery starts at

[11]This example ignores some complications, such as half-year accounting, accelerated tax depreciation, and the timing of rate cases.

$140,000 and falls steadily to $44,000 over the 25 years. In constant 2010 dollars, the cost recovery falls to $28,000 in the last year of operation.

Other plant costs moderate the strong frontloading in cost recovery. Operating and maintenance costs will typically be fairly steady in real terms, rising roughly with inflation in nominal terms. Recovery of capital additions is frontloaded, much like the initial investment, but they start later, depending on the timing of the additions.

Q: How does this apply to NSPI's approach to decommissioning cost recovery?

A: In the case of decommissioning, there is no initial plant investment. The decommissioning-related adder to depreciation that NSPI proposes increases accumulated depreciation, which reduces revenue requirements over time.

Figure 2: Example of NSPI's Decommissioning-Cost-Recovery Method

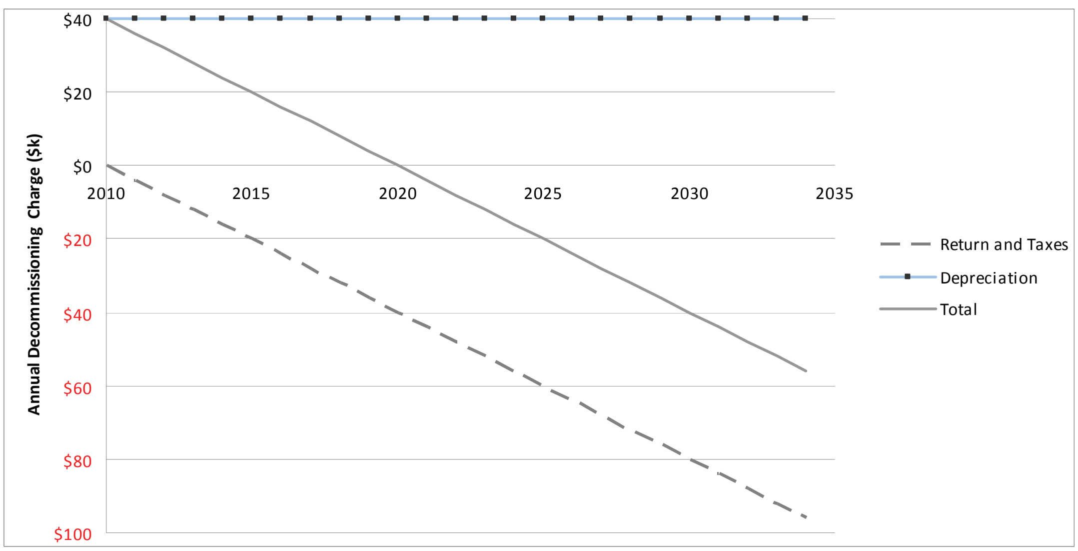


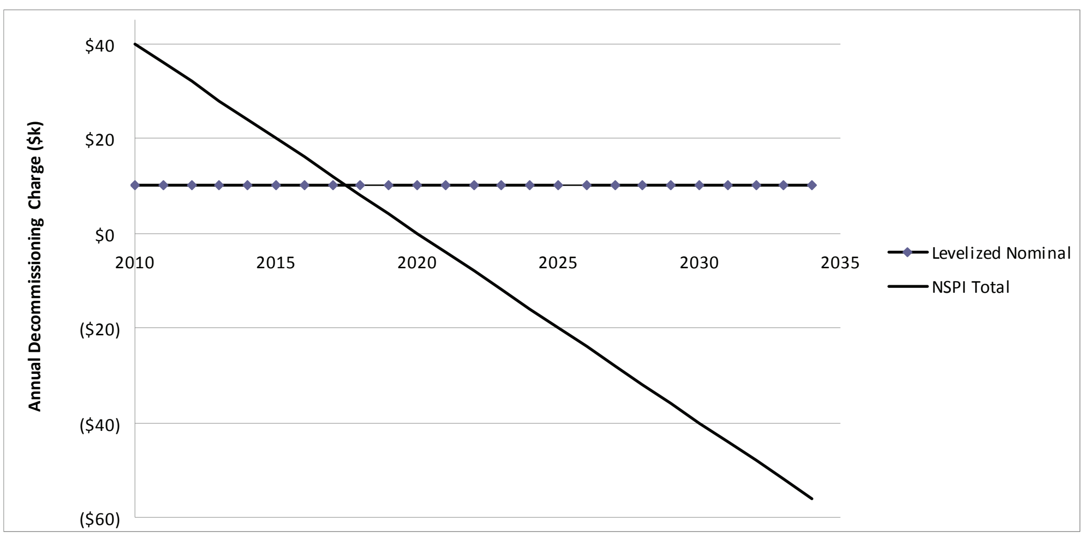
Figure 2 illustrates NSPI's approach, for an expected $1-million decommissioning cost 25 years in the future. Again, the annual depreciation charge is constant over time, but the effect of return and taxes is to reduce rate base and hence revenue requirements. The total decommissioning charge starts at $40,000 in the first year, falls to zero after ten years, and goes negative thereafter, reaching a credit of nearly $60,000 in the last year.

With this approach, customers in the early years pay much more than necessary, to create credits for ratepayers decades later.

Q: What is the alternative to this front-loaded treatment of decommissioning as a depreciation expense?

A: I expect that there would be several accounting approaches that would flatten the decommissioning costs in nominal or real terms. I constructed an example in which the decommissioning charge to ratepayers is constant in nominal terms; rather than reducing ratebase for future customers, the decommissioning fund would provide capital for NSPI and be credited with avoided return and taxes over time, building the fund and reducing the contributions required by all customers. This approach is illustrated in Figure 3, for the same $1 million future cost and the same 10% carrying cost.

Figure 3: Comparison of NSPI-proposed vs. Levelized Decommissioning Charge



Q: Does this conclude your testimony?

A: Yes.

Exhibit PLC-1

PAUL L. CHERNICK

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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.

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

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

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

PRESENTATIONS

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

ADVISORY ASSIGNMENTS TO REGULATORY COMMISSIONS

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

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

EXPERT TESTIMONY

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

    Profit margin calculations, including methodology, interest rates.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Profit margin calculations, including methodology and implementation.

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

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

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

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

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

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

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

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

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

    Construction schedule and cost of completing Millstone Unit 3.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Demand-side management cost recovery and incentive mechanisms.

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

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

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

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

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

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

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

Economic analysis of proposed coal-fired cogeneration facility.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

123. **Michigan PSC** U-10702, Detroit Edison Company Cost Recovery, on behalf of the Residential Ratepayers Consortium. December 1994.

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

124. **New Jersey Board of Regulatory Commissioners** EM92030359, Environmental costs of proposed cogeneration; Freehold Cogeneration Associates. November 1994.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Allocation of costs and benefits to rate classes.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Performance incentives proposed for the Boston Edison company.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Review of proposed performance standards and valuation of performance.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Application of rate cap. Legislative intent.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Rate decoupling and energy-efficiency goals.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

224. **NY PSC** Case 06-G-1332, Consolidated 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, Consolidated Edison electric rates; City of New York. Direct, September 2007.

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

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

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

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

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

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

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

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

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

232. **Utah PSC 07-035-93,** Rocky Mountain Power Rates; Utah Committee of Consumer Services. Direct, July 2008

Cost allocation and rate design. Cost of service. Correct classification of generation, transmission, and purchases.

233. **Ontario EB-2007-0707,** Ontario Power Authority integrated system plan; Green Energy Coalition, Penimba Institute, and Ontario Sustainable Energy Association. Evidence (with Jonathan Wallach and Richard Mazzini), August 2008.

Critique of integrated system plan. Resource cost and characteristics; finance cost. Development of least-cost green-energy portfolio.

234. **NY PSC** Case 08-E-0596, Consolidated Edison electric rates; City of New York. Direct, September 2008.

Estimated bills, automated meter reading, and advanced metering. Aggregation of building data. Targeted DSM program design. Using distributed generation to defer T&D investments.

235. CDPUC 08-07-01, integrated resource plan; Connecticut Office of Consumer Counsel. Direct, September 2008.

Integrated resource planning scope and purpose. Review of modeling and assumptions. Review of energy efficiency, peakers, demand response, nuclear, and renewables. Structuring of procurement contracts.

236. Manitoba PUB 2008 MH EIIR, Manitoba Hydro intensive industrial rates; Resource Conservation Manitoba and Time to Respect Earth's Ecosystem. Direct, November 2008.

Marginal costs. Rate design. Time-of-use rates.

237. Maryland PSC 9036; Columbia Gas rates; Maryland Office of People's Counsel. Direct, January 2009.

Cost allocation and rate design. Critique of cost-of-service studies.

238. Vermont PSB 7440; extension of authority to operate Vermont Yankee; Conservation Law Foundation and Vermont Public Interest Research Group. Direct, February 2009; Surrebuttal, May 2009.

Adequacy of decommissioning funding. Potential benefits to Vermont of revenue-sharing provision. Risks to Vermont of underfunding decommissioning fund.

239. Nova Scotia Review Board P-884(2), Nova Scotia Power DSM and cost recovery, Nova Scotia Consumer Advocate. May 2009.

Recovery of demand-side-management costs and lost revenue.

240. Nova Scotia Review Board P-172, proposed biomass project, Nova Scotia Consumer Advocate. June 2009.

Procedural, planning, and risk issues with proposed power-purchase contract. Biomass price index. Nova Scotia Power's management of other renewable contracts.

241. Connecticut Siting Council 370A, Connecticut Light & Power transmission projects; Connecticut Office of Consumer Counsel. Direct, July 2009.

Need for transmission projects. Modeling of transmission system. Realistic modeling of operator responses to contingencies

242. Mass. DPU 09-39, NGrid rates, Mass. Department of Energy Resources. August 2009.

Revenue-decoupling mechanism. Automatic rate adjustments.

243. **Utah PSC** Docket No. 09-035-23, Rocky Mountain Power rates; Utah Office of Consumer Services. Direct, October 2009. Rebuttal, November 2009.

Cost-of-service study. Cost allocators for generation, transmission, and substation.

244. **Utah PSC** Docket No. 09-035-15, Rocky Mountain Power energy-cost-adjustment mechanism; Utah Office of Consumer Services. Direct, November 2009; Surrebuttal, January 2010.

Automatic cost-adjustment mechanisms. Net power costs and related risks. Effects of energy-cost-adjustment mechanisms on utility performance.

245. **Penn. PUC** Docket No. R-2009-2139884, Philadelphia Gas Works energy efficiency and cost recovery; Philadelphia Gas Works. Direct, December 2009.

Avoided gas costs. Recovery of efficiency-program costs and lost revenues. Rate impacts of DSM.

246. **Ark. PSC** Docket No. 09-084-U, Entergy Arkansas rates; National Audubon Society and Audubon Arkansas. Direct, February 2010; Surrebuttal, April 2010.

Recovery of revenues lost to efficiency programs. Determination of lost revenues. Incentive and recovery mechanisms.

247. **Ark. PSC** Docket No. 10-010-U, Energy efficiency; National Audubon Society and Audubon Arkansas. Direct, March 2010; Reply, April 2010.

Regulatory framework for utility energy-efficiency programs. Fuel-switching programs. Program administration, oversight, and coordination. Rationale for commercial and industrial efficiency programs. Benefit of energy efficiency.

248. **Ark. PSC** Docket No. 08-137-U, Generic rate-making; National Audubon Society and Audubon Arkansas. Direct, March 2010.

Calculation of avoided costs. Recovery of utility energy-efficiency-program costs and lost revenues. Shareholder incentives for efficiency-program performance.

249. **Plymouth, Mass., Superior Court** Civil Action No. PLCV2006-00651-B (Hingham Municipal Lighting Plant v. Gas Recovery Systems LLC et al.) breach of agreement; defendants. Affidavit, May 2010.

Contract interpretation. Meaning of capacity measures. Standard practices in capacity agreements. Power-pool rules and practices. Power planning and procurement.

250. **Mass. DPU** 10-54, NGrid purchase of long-term power from Cape Wind; Natural Resources Defense Council et al. Direct, July 2010.

Effects of renewable-energy projects on gas and electric market prices. Impacts on system reliability and peak loads. Importance of PPAs to renewable development. Effectiveness of proposed contracts as price edges.

251. Maryland PSC 9230, Baltimore Gas & Electric rates; Maryland Office of People's Counsel. Direct, Direct, July 2010; Rebuttal, Surrebuttal, August 2010.

Allocation of gas- and electric-distribution costs. Critique of minimum-system analyses and direct assignment of shared plant. Allocation of environmental compliance costs. Allocation of revenue increases among rate classes.

252. Ontario EB-2010-0008, Ontario Power Generation facilities charges; Green Energy Coalition. Evidence August 2010.

Critique of including a return on CWIP in current rates. Setting cost of capital by business segment.

PLC 9/27/2010