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BEFORE THE NOVA SCOTIA UTILITY AND REVIEW BOARD

In the Matter of the Maritime Link	**)**	
Act Maritime Link Cost Recovery	**)**	**Matter No. 05419**
Process Regulations	**)**	

DIRECT TESTIMONY OF

PAUL CHERNICK

ON BEHALF OF

THE CONSUMER ADVOCATE

Resource Insight, Inc.

APRIL 17, 2013

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I. Identification

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 PC-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 testified previously regarding cost allocation issues?

A: Yes. I have testified in at least two dozen proceedings on utility allocation of costs among rate classes, as listed in my resume.

Q: Have you testified previously regarding energy-efficiency programs?

A: Yes. I have testified in at least three score proceedings on utility-funded energy-efficiency efforts, as listed in my resume.

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 Port Hawkesbury pulp and paper mill (NSUARB P-172).
- Nova Scotia Power's proposal to build the biomass project at NewPage Port Hawkesbury (NSUARB P-128.10).
- Heritage Gas's 2010 rate case (NSUARB NG-HG-R-10).

- Nova Scotia Power's proposal to increase production depreciation rates (NSUARB NSPI-P-891).
- The Board's review of proposed feed-in tariffs for certain distribution-connected renewable projects (NSUARB BRD-E-R-10).
- The Nova Scotia Power general rate application (NSUARB NSPI P-892), with respect to cost allocation and rate design.
- The Board's review of proposed a proposed load-retention tariff and rate (NSUARB NSPI P-202).
- The application of Efficiency Nova Scotia Corporation Electricity Demand-Side Management Plan for 2013–2015, Matter No. 4819.
- The application of NSPI and Pacific West Commercial Corporation for a load-retention rate mechanism for the Port Hawkesbury paper mill, Matter No. 4862.
- The Board's review of NSPI's 2013 Annual Capital Expenditure Plan, Matter No. 5339.
- The application of NSPI for approval of the South Canoe Wind Project, Matter No. 5416.

II. Introduction and Summary

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: I review aspects of the analysis filed by Nova Scotia Power Maritime Link, Inc. (NSPML or "the Sponsor") in its application for approval of the construction of the Maritime Link and a series of supporting contracts. Specifically, I discuss the load forecasts that the Sponsor has used in its analysis, and the assumed cost of indigenous wind development. I also provide an assessment of the net benefits of the Maritime Link as proposed and options for improving the cost-effectiveness of the project for Nova Scotia ratepayers.

While the Sponsor is responsible for the application and most of the discovery responses I cite below, some of the relevant documents were produced by Nova Scotia Power, Inc. (NSPI); I will attempt to be clear in attributing each document to the affiliate that developed it.

Q: To which of the issues enumerated by the Board is your testimony relevant?

A: My testimony provided information relevant to the following five items in the Board's Final Issues List:

1. Does the ML Project represent the lowest long-term cost alternative for electricity for ratepayers in the Province?
7. Will NSPI ratepayers receive benefits from the ML Project commensurate with the risks and costs they will bear if the ML Project is approved?
9. If the Board approves the Maritime Link Project, should it order any terms and conditions in its approval?
15. How does the provision for delivery of energy other than the NS Block affect the distribution of benefits, costs, and risk among the parties... including whether Nova Scotia ratepayers are subsidizing transactions?
16. Will the ML Project result in a requirement for increased reserves to meet the reliability standards and criteria?

Q: What topics do you cover in this testimony?

A: I start by describing the problems with the load forecasts and wind-generation costs that the Sponsor uses in its Application in this case. I then briefly discuss the Sponsor's failure to demonstrate that the Maritime Link as currently proposed represents the lowest long-term cost alternative for Nova Scotia electric consumers. Finally, I propose some modifications to the Maritime Link deal to improve the economics for Nova Scotia consumers.

Q: Do you have any other introductory comments.

A: Yes. The analyses conducted by the Sponsor in support of its Application are seriously biased in favor of the Maritime Link. Examples of those biases include the following, among others:

- redefining NSPI's base forecast as a "Low" load case without justification,
- characterizing extreme load swings as "typical,"
- basing ramping requirements on the assumption that wind generation operates at 100% of capacity at minimum load level in the early morning and shuts down at peak load hours,
- pricing purchases from Hydro Quebec as if they would come through central New England, resulting in prices equal to the New England market price plus transmission charges, rather than the shorter and less expensive route through New Brunswick,
- ignoring the costs of increased reserves to support imports through the Maritime Link above 170 MW,
- overstating the costs of wind integration and ignoring the benefits of the storage resources included in the integration costs.

In addition, the Sponsor has refused to provide many relevant documents that it has in its possession, including data related to wind integration that it provided to General Electric for its overdue analysis of wind-integration costs and the draft results of the General Electric study.[1] The same is true for the data

[1]See CA IR-22, IR-23, IR-24, and IR-80. In November 2012, NSPI promised that the final Renewable Energy Integration Study would be available in first quarter of 2013, which has now

provided by NSPI to John Dalton, the Renewable Energy Administrator and consultant to the Nova Scotia Department of Energy on the Maritime Link. (CA IR-15 to IR-19 and IR-80)

III. Load Forecast

Q: What load forecasts does the Sponsor use in its analyses supporting its application?

A: The Application presents two forecasts, which are described in Appendix 6.03. The Application refers to these forecasts as the "Base" and "Low" forecasts.

Q: Are the Base and Low load forecasts appropriately titled?

A: No. The Application's use of these terms is nearly Orwellian. The "Low" load case is actually NSPI's current load forecast (plus two years of load from the Port Hawkesbury mill), while the "Base" load forecast is an arbitrarily higher forecast. In any reasonable application of the English language, and following normal utility practice, the "Low" case would be called the base or reference forecast, and the "Base" forecast would be called the high case. In most cases, a utility that presents a high forecast (such as the Sponsor's "Base" case) would also present a low forecast (which in this proceeding would be lower than the "Low" case).[2]

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passed. On March 11, NSPI reported that the study release would be delayed until the second quarter of 2013, which we are now in (CA IR-22).

[2]I do not generally include quotes around terms after the initial citation. In this case, due to the Sponsor's misrepresentation of the forecasts, I will continue calling these the "Base" and "Low" case, by which I mean the high forecast and the reference forecast.

A. *The Sponsor's "Low" Case*

Q: Please describe the Sponsor's "Low" forecast.

A: As I noted above, the "low" forecast is actually NSPI's current base forecast, with the inclusion of two years of the Port Hawkesbury mill load. As the Sponsor explains in Application Appendix 6.03, the "Low" load forecast "was developed using the July-2012 GRA-Refresh load forecast" as the starting point." The GRA Refresh (Exhibit N-103 in the 2013 GRA) revised the April 2012 load-term forecast filed as Exhibit SR-02 for changes in economic forecasts, large-industrial surveys and the shutdown of the Bowater mill. To create the "Low" forecast, the Sponsor took the following steps:

- extended the econometric models for residential, commercial, and small and medium industrial sales to 2025,
- kept "large industrial load for 2013 and beyond…flat throughout the forecast,"
- eliminated the 690 GWh of energy load from the Bowater Mersey mill,
- projected the load of each class (residential, commercial and industrial) for 2026–2040 at the 2025 growth rate,
- subtracted the DSM load reductions projected by Efficiency Nova Scotia Corporation in that company's long-term outlook through 2032,
- set annual DSM load reductions equal to load growth in 2033 through 2040 (setting net load growth to zero in that period),
- added the Port Hawkesbury paper mill energy load until 2019.

While the load forecasts include estimates for 2013–2040, only the loads after the in-service date of the Maritime Link, which the Sponsor projects to occur in October 2017 (Application Figure 6-2), matter for the economic analyses.

Q: Does the "Low" load forecast represent a reasonable extrapolation of NSPI's current load forecast?

A: Yes, with two exceptions. First, the decision to keep Large Industrial load flat is inconsistent with the projections in the April 2012 forecast and the July 2012 GRA Refresh. The April 2012 forecast projected a decline in Large Industrial of 80 MW, or 1.5% annually, "based on based on trends and customer input. Customers are surveyed regularly in order to gather their forecast monthly electricity requirements over the next three year period, any planned production levels or equipment changes" (2013 GRA SR-02 Attachment 1 at 24).[3] The GRA Refresh (Appendix B) states that "Industrial load has not demonstrated the level of recovery anticipated in the previous forecast so future sales have been reduced." The GRA Refresh showed a 19 GWh reduction in industrial sales from 2013 to 2014; assuming that the Refresh included the 24 GWh of econometrically driven increases in the Small and Medium sales from the April 2012 forecast, the Large Industrial load must have dropped by 43 GWh.[4]

In short, the Sponsor's forecast for Large Industrial load appears high, compared to NSPI's previous analyses. Since the Sponsor offers no basis for changing NSPI's previous projections, which were based on trends and information from customers, the Sponsor's forecast should be adjusted downward.

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[3]The forecast does not list Large Industrial load separately. I backed out NSPI's forecast of Large Industrial load from the total industrial on page 46, Small Industrial on page 44, Medium Industrial on page 45 (all from the GRA April forecast), and the Bowater load in Appendix B of Exhibit N-103 of the 2013 GRA.

[4]Some of the 2014 reduction was probably the result of annualizing the 78 GWh "adjustment…related to the Imperial Oil refinery, which is at risk of closure in 2013" (GRA Refresh Appendix B). Unfortunately NSPI did not provide much detail in the GRA Refresh, and the Sponsor provided only limited detailed on the Refresh and its extrapolation of the Refresh forecast (e.g., in response to CA IR-49), so I cannot be more specific about the forecasts.

Second, the load forecast should not include any energy to serve the Port Hawkesbury paper mill. The mill has long been an interruptible load for peak-demand purposes, and the Sponsor properly does not include any peak-load requirement for the mill. The forecast should also not include any energy load from the mill.

As part of the package of arrangements that took the mill out of bankruptcy in 2012, the current mill owner and NSPI developed a special contract (since approved by the Board in Matter No. 4862) that provides that the mill will be a non-firm energy customer. The mill will not pay for any current or future fixed power-supply costs (including the Maritime Link). Nor are the prices fixed. NSPI posts a set of incremental hourly prices a day ahead (for a range of mill load levels) and the mill specifies its planned energy take for each hour, subject to certain revisions during the delivery day. The mill also has the option of importing energy on its own account to meet its load. Other than $2/MWh styled as a contribution to fixed costs, the prices are designed to cover only NSPI's incremental fuel, variable O&M and purchased-power costs.[5]

Since the mill will not be contributing to existing or future fixed costs, the only way in which the contract could be economic for firm ratepayers (who pay the cost of service, including fixed costs) would be for no fixed costs to be incurred for the mill. Hence, NSPI was very clear throughout the special-rate proceeding that no other costs would be incurred to meet the mill load. For

[5] The mill has also committed to pay NSPI 18% of its pre-tax net earnings, capped at another $2/MWh. The $2–$4/MWh charge can also be viewed as providing some assurance to firm ratepayers that the contract price will cover the costs of incremental wear-and-tear capital, variable O&M, and ramping generation to meet the pattern of usage the mill selects. Those ramping costs may differ from the posted hourly prices, which cannot incorporate the ramping implications for all variations in mill power consumption.

example, Mark Sidebottom, NSPI's Vice-President for Power Generation and Delivery, testified that NPSI would start with

> a plan that has [the mill] not served, and then that we would provide them the incremental cost calculation that would then compare not serving them to serving them, and in that way we'll cover the incremental costs of them taking that decision to take that energy at the time. (Transcript at 400)

and that "the obligation [to the mill] is limited to covering the incremental cost, not planning for the future" (Transcript at 459–460). NSPI provided the following representations:

> To be clear, the agreement between NS Power and PWCC is that the mill will be served on a purely incremental basis only. As a result, NS Power will assume for all planning purposes, that the load required to be served is that excluding the mill's load. The Company will plan and optimize its fleet on this basis, independent of whether the mill operates. (NS Power Reply Evidence at 9–10)

> Mill electricity consumption [is] treated as fully incremental throughout the term of the agreement. This means that the Company will not build generation capacity to serve this load, will not include this load in its planning work and will not manage its fuel portfolio to minimize cost associated with this load. (NSPI closing submission at 14)

> NSPI will not include PWCC in its planning considerations, including future capacity additions or the restart of generation which has been seasonally shut down. (Order of September 12, 2012, Appendix B)

This proceeding is exactly the type of "planning work" from which the mill energy consumption must be excluded. Hence, the mill energy load should not be included in any forecast used in estimating the economics of the Maritime Link.

Q: What would the effect be of including the mill load in the NSPI load to be met by the Maritime Link and the alternatives?

A: The effect would be to select long-term resources to be financed by firm energy consumers to minimize costs to the mill, a non-firm customer, which will not pay for those resources.

Q: Did the Sponsor offer any coherent rationale for violating NSPI's promises, NSPI's representations, and the Board's orders in Matter No. 4862?

A: Not really. The Consumer Advocate asked detailed questions about the inconsistency of the Sponsor's modeling with NSPI's promises, in CA IR-51. In response, NSPML only referred to its response to NSUARB IR-78, in which the Sponsor did not respond directly to most of the Board's questions, but did offer the following claims:

- "NS Power does not plan generating capacity developments to serve the interruptible load of PH [the mill]." (NSUARB IR-78a)
- "In serving the energy requirements of PH, compliance with federal GHG requirements and provincial RES requirements (40 percent of energy sales) will require actions to be taken. All three alternatives considered address the needs to serve PH energy within the context of the hard cap on mercury and the RES." (NSUARB IR-78a)

Q: Is it true that NSPI does not plan generation capacity to serve the mill load?

A: Since the ink is barely dry on the special tariff for the mill, it is difficult to say what NSPI does outside the context of this proceeding. Certainly, NSPI has promised not to plan generation capacity to serve the mill load. Yet in the current application the Sponsor quite clearly offers plans for acquiring the rights to generating capacity at Muskrat Falls to serve the interruptible energy load of the mill. This for more than two years in the "Low" forecast case and more than twenty years in the "Base" forecast. The comparison of the costs of alternative supply portfolios include the costs of serving the mill load. Thus, while the Sponsor has properly stated what NSPI *should* do, it has misstated what NSPML is attempting to do in this case.

Q: What actions would be required to comply with the mill's contribution to "federal GHG requirements" and "the hard cap on mercury" under the mill's special tariff?

A: No planning actions, in terms of capital requirements or even fuel procurement, should be taken to comply with these requirements. Every day, NSPI is supposed to be offering the mill energy at the incremental cost of serving its load under a number of constraints, including the available generation, the GHG limits, and the mercury-emission cap. That incremental cost should reflect NSPI's best estimate of the costs resulting from meeting the mill load, including potential redispatch of resources (e.g., burning more gas and less coal, importing more energy) during the year to meet its regulatory requirements. Unless the gas plants and imports are already scheduled at their maximum feasible level for the rest of the compliance period (e.g., a year or a multi-year period for the GHG caps), NSPI should always be able to offset the emissions due to the mill's load. The mill's relationship with NSPI is essentially that of a purchaser of economy energy, much like NSPI's relationship to New Brunswick; NSPI will compute the cost of providing energy to the mill (while meeting its other obligations), and the mill can buy energy if it wishes.

Complying with the environmental regulations does not require NSPI to violate the terms of its tariff with the mill, or its promises to the Board, or the Board's orders.

Q: Is there any merit to the argument by the Sponsor regarding planning for meeting the mill's share of the renewable energy standard?

A: No. First, the Sponsor does not limit the inclusion of the mill load to a computation of renewable energy requirements. The mill load is also included in the computation of total revenue requirements. It is clear that NSPI has no obligation for planning for the mill's energy requirements, and is precluded from acquiring resources (even fuel supplies) to serve the mill. If the Sponsor really believed that NSPI has a narrower responsibility to plan for renewables to meet 25% of the mill load in 2015–2019, that consideration would have been reflected in a side computation demonstrating the availability of sufficient renewables.

Second, NSPI expects to have more than enough renewable energy to meet the RES through 2019, the year in which the mill is forecast to shut down in the "Low" forecast.[6] The Province settled any question of incremental cost of renewables for the mill by means of a letter to the Board dated July 20, 2012, which said in part:

> The Government commits to ensuring that if the mill load does trigger an additional RES obligation during the term of the proposed mechanism, and if this results in incremental costs, then the Province guarantees that neither PWCC nor other ratepayers will be required to pay these incremental costs.[7]

Hence, no RES costs related to the mill's contract would be included legitimately in the revenue-requirements analysis.

[6] The major question regarding renewables in Matter No. 4862 was whether the mill would pay for the opportunity costs of lost renewable-energy sales to New England.

[7] It is not clear who the Province expects would pay for any incremental renewable resources required to meet the mill's share of the RES.

Q: What would be a reasonable extrapolation of NSPI's current reference load forecast?

A: A reasonable reference forecast, consistent with NSPI's 2012 load forecast, would be essentially the same as the Sponsor's "Low" load forecast, minus 43 GWh in all years to reflect continuation of the reduction of Large Industrial load from 2013 to 2014 in the GRA update, and minus the 1,138 GWh that the Sponsor inappropriately included for the Port Hawkesbury mill. Table 1 shows the result of making these two corrections to the "Low" forecast provided in NSUARB IR-61, Attachment 1, at 1.

Table 1: Corrected Reference Forecast

	Reference Firm Load (GWh)		**Reference Firm Load** (GWh)
2017	9,670	*2029*	8,992
2018	9,620	*2030*	8,934
2019	9,602	*2031*	8,878
2020	9,561	*2032*	8,817
2021	9,518	*2033*	8,815
2022	9,456	*2034*	8,816
2023	9,404	*2035*	8,815
2024	9,338	*2036*	8,816
2025	9,263	*2037*	8,815
2026	9,195	*2038*	8,816
2027	9,127	*2039*	8,817
2028	9,053	*2040*	8,816

B. The Sponsor's "Base" Case

Q: If the Sponsor's "Low" case is slightly higher than a reasonable reference forecast, how should its "Base" forecast be described?

A: The Sponsor's "Base" load forecast is a high sensitivity that makes the following changes from the "Low" forecast (CA IR-49):

- The forecast assumes the use of 1,138 GWh annually (about 12% of NSPI's current firm load) for firm energy for the Port Hawkesbury mill or some other extra-large industrial customer throughout the forecast. None of the energy from the existing tariff for the Port Hawkesbury mill is firm, as I explained above, so the high sensitivity would have to assume that the mill renegotiates its tariff to move to firm service in 2017.

- The forecast increases the forecast growth in the economic drivers of residential and commercial loads (e.g., various components of Nova Scotia gross domestic product) by 50% above the current forecasts from the Conference Board of Canada's Economic Outlook.
- The forecast increases the saturation of residential space heating.
- The forecast increases the penetration of electric vehicles.

Interestingly, even though the "Base" forecast assumes more buildings, more electrically-heated homes, more appliances and equipment, and heavier use of electricity-consuming equipment, all of which would increase DSM potential, the forecast reflects no increase in DSM. Nor does it reflect any effect on load of the higher rates in the early years of Maritime Link operation, even though NSPI assumes that higher electric prices reduce residential consumption (2013 GRA SRA-2, Attachment 1, at 15).[8]

Q: Does the Sponsor recognize that the "Base" case is actually a high-load sensitivity?

A: Yes. On discovery, the Sponsor described the Base case as follows:

[8] The sensitivity analyses that NSPI provided in the 2103 GRA show a 10% increase in residential price, or about 1.2¢/kWh, in a single year reducing load by 57 GWh immediately and 144 GWh (about 3%) four years later (SR-02 Attachment 1 Page 60). No price elasticity is reflected in NSPI's commercial or industrial models.

> The NSPML base case began with the GRA-Refresh forecast then added certain load growth contingencies in consideration of compliance with the RES requirements. (CA IR-49 at 3)[9]

> It is a common practice in forecasting to perform sensitivity analysis in this manner. (CA IR-49 at 4)

In short, the Sponsor admits that its "Base" case is not really a base case, but a high-end sensitivity.

Q: Is the Sponsor's "Base" case a reasonable high-end-sensitivity load forecast?

A: Yes, except for the treatment of the Port Hawkesbury mill through 2019. Including the mill's economy-energy load in planning violates NSPI's promises and the Board's orders. Assuming that the mill load converts to firm energy service in 2020, and that its energy load would then be in NSPI's forecast, would be a plausible sensitivity. Since the Sponsor offers no information regarding the likelihood that the paper markets would make that change feasible, it is not possible to judge how extreme a sensitivity that would be.

C. The Missing Low Case

Q: Does the Sponsor present a true low-load-sensitivity case, to balance the high-load sensitivity of its "Base" forecast?

A: No.

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[9]It is not clear why the Sponsor refers here to "in consideration of compliance with the RES requirements," since it uses its "Base" case for estimating the cost of meeting energy requirements, not just for verifying compliance with the RES.

Q: What is the significance of high- and low-load-sensitivity cases in the evaluation of the economics of a power-supply project such as the Maritime Link?

A: The primary consideration in project evaluation is the reference case, representing the conditions that are most likely to occur or conditions in the middle of the likely range. Where alternatives have similar costs in the reference case, it is also useful to consider the effect of a range of future conditions, such as load. For example, if costs are very close for Alternative A and Alternative B with reference-case inputs, but Alternative A is far superior to Alternative B in the high sensitivity and only slightly worse than Alternative B in the low sensitivity, the decision-maker (such as the Board) may decide that Alternative A has more promise overall. But if the alternatives are close in the reference case, Alternative A is slightly superior in the high sensitivity and Alternative B is much better in the low sensitivity, Alternative B may be the preferred choice.

Q: What problem arises from the Sponsor's failure to model a low-load-sensitivity case?

A: The Maritime Link is a large fixed investment, providing a large amount of firm energy and potentially access to a very large amount of non-firm economy energy. If load is high, as in the Sponsor' "Base" case, the Maritime Link will be more advantageous than it would under a reference forecast, such as the Sponsor's "Low" case. Under a truly low forecast sensitivity, the Maritime Link would represent the same high level of fixed costs, but would provide much lower benefits. Nova Scotia electric customers would be committed to large payments for small benefits.

If the Maritime Link appears to be economic in the high case, that would indicate that the project *might* be cost-effective under the most favorable circumstances. Without a corresponding low case, the Board cannot assess the potential magnitude of the loss from the Maritime Link under unfavorable conditions.

The issue of uncertainty in load levels is particularly important in this proceeding, since the alternatives to the Maritime Link—indigenous wind and imports from Hydro Quebec—are more flexible in terms of the timing and magnitude of commitments. In the wind case, for example, NSPI would have until about 2018 to determine the amount of supply needed to meet the 2020 RES.

Q: What would be a suitable low-load sensitivity case?

A: To balance the high-load "Base" forecast, the true low forecast would use economic growth drivers substantially lower than the Sponsor's "Low" (actually reference) case, with lower electric-heating saturation, loss of additional large-industrial loads, and one or more electricity-saving contingencies, such as increased saturation of wood pellets for space heating.

IV. Wind-Power Costs

A. Wind Generation Costs

Q: What does the Sponsor assume regarding the cost of new wind plants as a part of an alternative to the Maritime Link?

A: In Appendix 6.03, the Sponsor reports that it estimated capital and O&M costs with a total "levelized cost of $80/MWh ($2012)."[10] Those costs were applied to 425 MW of wind to be added in January 2019, and an additional 50 MW in each

[10] Based on Synapse IR 1 Attachment 1, I interpret this to mean $80/MWh levelized in nominal terms, starting in January 2012.

of 2028, 2034 and 2037 (Appendix 6.03 at 14) to meet the RES requirement in the Sponsor's "Base" load case.[11]

Q: Is that a reasonable assumption for the costs of new wind?

A: No. The cost of NSPI's most recent acquisitions was less than $80/MWh, and the cost trend has been strongly downward. In August 2012, the Renewable Electricity Administrator (REA) selected 116 MW of new wind projects (South Canoe Oxford, South Canoe Minas, and Sable Wind), expected to produce 355 GWh annually by 2015, and announced that "The average purchase price from these three projects is in the mid $70/MWh range."[12] In fact, NSPI is a 49% owner of these projects and reports even lower costs—about $[redacted]/MWh, or $[redacted]/MWh net of the loss reductions due the plant's locations—for its share of the two South Canoe projects.[13] That price would be for installation in late 2014, so the price in early-2012 dollars would be about $[redacted]/MWh, or $[redacted]/MWh including the loss benefits.[14]

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[11] Traditionally, NSPI has added most of its wind resources in the December before the year that they were needed to meet the RES, so the January in-service date overstates the present value of the 2019 wind additions. Also, the Sponsor assumes that the later increments of wind are frequently curtailed and thus reduces projected capacity factor by about three percentage points, effectively raising the cost to about $90/MWh.

[12] "Three Contracts Awarded to Nova Scotia Renewable Energy Projects" News Updates August 2nd, available online from NS Department of Energy at https://nsrenewables.ca/news-updates. 2012, accessed 4/15/2013. Halifax: Nova Scotia Department of Energy.

[13] As NSPI explained, compared to its partners in the projects (Minas Basin Pulp and Paper and Minas Frozen Foods) NSPI's "ability to claim the accelerated capital cost allowance immediately and its cost of capital allows for…lowering the price overall" (South Canoe Wind Project Capital Work Order Application at 24).

[14] I believe that NSPI has slightly understated the ratemaking cost of all of its capital project, by treating administrative overhead (AO) as being a transfer from current costs, without any

In addition, NSPI's actual capital costs for wind farms have tended to be lower than its cost forecasts, as shown in Table 2. Another 4% reduction in costs of the South Canoe would bring the cost down to the $[redacted]–$[redacted]/MWh range.

Table 2: Past NSPI Wind Cost Variances

	Total Costs ($M)			
	Application Forecast	Actual	Variance	**% Variance**
Digby	79.8	76.8	−3.0	−3.8%
Nuttby	120.0	114.4	−5.6	−4.7%

Source: NSPI South Canoe Wind Project Reply Evidence at 16

The REA procurement severely constrained and penalized many potential project bids, based on the REA's judgmental perception of the costs and risks of projects that would be located in certain locations (including all of Cape Breton), take energy-resource integration service (ERIS), and/or be in early stages of development.[15] A less-constrained procurement might have received still lower bids, especially if NSPI were procuring turnkey projects, to utilize its tax and financing advantages.

Q: Have the costs of NSPI wind projects been stable over the last several years?

A: No. The costs have fallen dramatically. Prior to plant completion, NSPI estimated levelized costs of its previous wind farms as follows:

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incremental cost. This issue is under discussion in the Capital Expenditure Justification Criteria working group. Any AO adjustment to levelized cost would be very small, on the order of 0.1%.

[15]The REA scored each proposal on whether it had an experienced project team, financing commitments, completed wind-speed and environmental assessments, and demonstrated community acceptance. This screening may have screened out projects that would have produced power at lower prices, but did not meet the REA's criteria for having a high probability of project completion. Any of those projects that were developed or co-developed by NSPI would meet the project-team and financing criteria; completion of wind-speed and environmental assessments are primarily issues of timing.

- $84.54/MWh for Nuttby, completed December 2010 (Nuttby Application, September 2009,at 16);
- $91.65/MWh for Point Tupper, completed August 2010 (Point Tupper Application, February 23, 2010, at 16);[16]
- $86.71/MWh for Digby, completed December 2010 (Digby Application, July 23, 2010, at 25)

As noted above, Nuttby and Digby came in under budget, which might reduce the levelized cost by a few mills per kWh.[17] The costs of all of these projects were reduced by the federal EcoEnergy credit of $10/MWh for the first ten years of operation. Adding back the $7/MWh levelized value of the Eco-Energy credit would bring these prices to about $90/MWh. The decline to the cost of South Canoe (by more than [redacted]% in just four years) is partially due to falling debt costs, but the larger factor is the decline in capital costs. Since wind-turbine technology continues to improve, future wind farms are likely to be even less expensive than South Canoe.

B. Wind Integration Costs

Q: Did the Sponsor reasonably model the problems and costs of integrating additional wind generation into the NSPI system?

A: No. This issue is discussed in detail in the evidence of Levitan and Associates in this proceeding. I will comment on only a few issues that I identified in my review of the wind integration study (Application Appendix 6.02), specifically the "typical daily min/max range" of load, the daily range of wind generation,

[16] This total includes NSPI's 49% share, at about $[redacted]/MWh and the sponsor's 51% share.

[17] I do not have similar final cost data for Point Tupper readily available.

the coincidence of rising load and falling wind generation, and "minimum capacity of committed units" in Appendix 6.02, Table 3.3.

Q: What was the basis for NSPML's estimate of the typical daily load swing?

A: That was one of the questions that the Sponsor declined to answer. When asked for "the data and analysis from which NSPI determined that the 'System Typical Daily Min/Max Range' is 580 MW," the Sponsor provided neither data nor analysis, and responded as follows:

> The daily Min/Max range of 580 MW was selected to demonstrate the challenges that could be faced by system operators under a high wind penetration scenario. Min to max swings of over 700 MW occurs on the NS Power system today. (CA IR-46b)

Q: Is the 580 MW daily minimum to maximum load swing posited by the Sponsor typical of the NSPI system?

A: No. I downloaded Nova Scotia load data from the NSPI Open Access Same-time Information System for 2011, the first eleven months of 2012 (NSPI has not yet posted the December 2012 data), and the first two months of 2013, and computed the load swing from the minimum to the maximum for each day. Table 3 summarizes some of those data. A swing is far from typical, since the average swings were a bit over 400 MW, and only 27 days of the 700 days in this period (less than 4%) had swings over 580 MW. Even looking at a somewhat broader range, down to 550 MW, only 38 days have higher swing (about 5% of the 700 days). Only January and December have more than three days with swings over 550 MW, and five months have no swings that large in either year.

Table 3: Daily Load Swings

	2011	2012 to Nov	Jan–Feb 2013
Average Swing (MW)	423	402	381
Days with Swing >			
580 MW	16	11	2
550 MW	25	13	3
Days with Swing >550 MW			
Jan	5	7	2
Feb	3	1	1
Mar	3	0	
Apr	0	0	
May	0	0	
Jun	0	0	
Jul	0	0	
Aug	1	0	
Sep	0	0	
Oct	1	2	
Nov	1	3	
Dec	11	–	

Far from being typical, the 580-MW swing is exceptionally large.

Q: Is it true that "Min to max swings of over 700 MW occurs on the NS Power system today," as the Sponsor claimed in CA IR-46b?

A: That characterization is a stretch. There are no load swings of more than 700 MW, over even 680 MW, in the months of 2012 and 2013 for which data are posted. There was one day with a swing over 700 MW in December 2010 and one in December 2011. In order for the Sponsor's characterization to be correct for load swings (in the plural), the term "today" must include a period of more than two years.

Q: What swing of wind output does the Sponsor combine with this load swing?

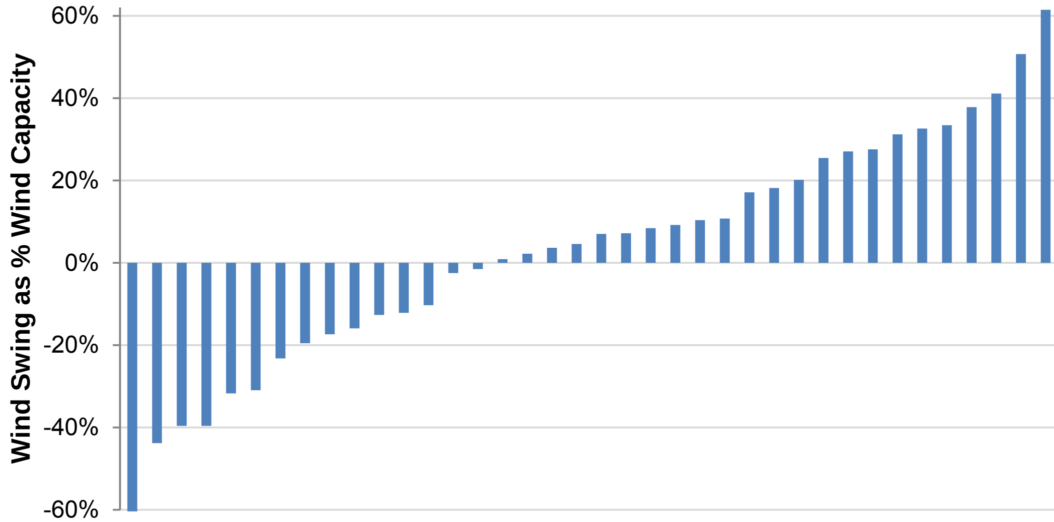
A: Appendix 6.02, Table 3.3, assumes that the very high load swing from minimum to maximum load perfectly coincides with the decline of wind generation from maximum at the time of minimum load to zero at the time of maximum load.

Q: Does the Sponsor present evidence that wind generation tends to fall as load rises?

A: No. My review of the wind data provided in Synapse IR-5 Attachment 1 does not find any such correlation. For each of the 38 days in 2011 and 2012 with a load swing of more than 550 MW, Figure 1 shows the change in wind output from the low-load hour to the daily peak hour.[18] Appendix 6.02, Table 3.3 assumes that wind generates at 100% of capacity at the minimum-load hour and drops to zero at the daily peak. To the contrary, on 23 of those days (to the right side of the figure), wind generation *increased* between the lowest-load hour and the peak hour of the day, offsetting the load swing. On another 11 days, wind output declined by less than one third of installed capacity. Four days had negative wind swings of about 40% of capacity, and just one had a downward swing of 60%. For the 785 MW wind case posited in Table 3.3, the difference between a wind swing of 100% and a swing of 60% is about 300 MW, or the load-following capacity of about three and a half committed coal units.

[18]The wind output in each hour is from Synapse IR-5, Attachment 1. Rather than try to estimate the capacity of wind installed and included in the hourly monitoring at various dates, I estimated the installed capacity as the maximum previously reported hourly output in each category (IPP, Digby, and Nuttby) reported in Synapse IR-5. Since the IPPs may not have operated at full capacity simultaneously, I may have underestimated the total wind capacity and hence overstated the percentage swing.

Figure 1: Wind-Output Swing Coincident with High Load Swings



Each bar corresponds to one of the 38 days.

While NSPI will need to improve its wind-output forecasting as wind penetration grows, and will continue to require some coal plants to operate off-peak to meet peak loads, the burden of managing plant commitment should be much lower than the Sponsor suggests in Figure 3.3 of Appendix 6.02.

Q: Does Appendix 6.02, Table 3.3, use a reasonable value for must-run thermal generation?

A: I have only reviewed the treatment of the Brooklyn and Port Hawkesbury biomass plants, which CA IR-46c lists as being “must-run for RES” at a total of 75 MW. These units do not need to run in every hour to meet the RES. If system conditions require it at high-wind, low-load periods, these units can be shut down for a few hours. This generation should not be dispatched if that would require curtailing wind generation or shutting down fossil units that may be required in the next day.

Q: What capacity values does the Sponsor assign to generation taking Energy Resource Interconnection Service (ERIS)?

A: The Sponsor gives zero capacity value to these resources (Appendix 6.02 at 10), which currently include the Port Hawkesbury biomass plant and the Nuttby, Dalhousie Mountain, and Glen Dhu wind plants.

Q: How does NSPI deal with wind plants served on ERIS?

A: When asked for "any information on any actual problems experienced due to the use of ERIS by wind projects," the Sponsor responded as follows:

> ERIS issues for wind projects east of Onslow are handled by out-of-merit redispatch of thermal generation in Cape Breton. Wind generation in the Digby area has been curtailed in periods of transmission line outages or high hydro generation availability in the western Annapolis Valley. (CA IR-33f)

The first sentence indicates that the ERIS status of two of the wind plants results in reduced operation of the coal plants on Cape Breton.[19] Since reliability problems would generally occur at times of high load and outages in some of the Cape Breton coal fleet, turning down coal when there is more than enough generation available would not normally be a reliability problem. The second sentence of the response does not appear to be related to ERIS, since the ERIS wind plants are not in the Digby area.

Q: Is it reasonable to assign those generators zero capacity value?

A: No. The ERIS transmission service is nominally non-firm. However, NSPI's experience indicates that these resources are rarely curtailed, and when they are

[19]The ERIS "wind projects east of Onslow" are Dalhousie Mountain and Glen Dhu. The Sponsor, in CA IR-89, adds Trenton to the coal plants that can be turned down in response to wind generation east of Onslow, and also clarifies that "out-of-merit" here means that NSPI would sometimes rather turn down gas generation than the coal generation, not that replacing coal energy with wind increases costs.

curtailed, it is due to excess generation using the same transmission facilities, and/or a lack of load. At the times at which the generation would be needed—high load periods, especially when other generation is out of service—the transmission system will not tend to be heavily loaded, allowing NSPI to deliver energy from the ERIS projects to load. As shown in CA IR-86, the curtailments of wind generation in 2011–2012 occurred at low-load periods, starting at 12:33 to 5:45 in the morning.

As the Sponsor concedes,

> All wind curtailment events were due to reaching minimum safe generation levels, except for two Glen Dhu curtailments—[starting at] 2012-08-31 00:33 and 2012-09-01 05:45—which were due to transmission system constraints. (CA IR 86b)

Consequently, ERIS projects do not appear to be significantly less valuable for serving peak load than other similar resources served on network service. As a result, the Sponsor has understated the capacity value of existing wind resources and has overstated the cost of integrating future wind resources.

V. Assessment of Maritime Link Net Benefits for Nova Scotia Ratepayers

Q: Has the Sponsor demonstrated that its proposal meets the standard that "the project represents the lowest long-term cost alternative for electricity for ratepayers in the Province," as required by the Maritime Link Cost Recovery Process Regulations?

A: No. The numerous problems in the Sponsor's analysis, including those I describe above and those described in the evidence of Levitan & Associates on behalf of the Consumer Advocate and Small Business Advocate, make it impossible to reach that conclusion. Even in that analysis the difference in present value among the alternatives is quite low. Since the Sponsor's analysis is biased toward the Maritime Link project by a substantial but not quantified amount, the Board cannot determine whether the bias accounts for all of the apparent net benefit of the Maritime Link.

As demonstrated in the evidence of Levitan & Associates, correcting the Sponsor's errors indicates that the alternatives (indigenous wind and imports from Hydro Quebec) would be less expensive than the Maritime Link as proposed. The important corrections include reduced gas prices, reduced capacity requirements in the "Low" load wind case, elimination of double-counting of wind curtailments and integration costs, and including the costs of pumped storage without including the energy and capacity benefits of pumped storage.

VI. Options for Improving the Economics of Maritime Link for Nova Scotia Ratepayers

Q: Have you identified options for reducing the burden of the Maritime Link on Nova Scotia ratepayers, if the Board accepts NSPML's application?

A: Yes. Four such options would be the following:

- ensuring NSPI access to specific levels of energy above the NS Block, at fixed prices,
- splitting the sales revenues from Nalcor generation flowing through the NSPI transmission system,
- excluding the Labrador Transmission Assets from the allocation of costs to NSPI,
- building the Maritime Link as a merchant project, with guaranteed cost recovery from Nova Scotia consumers.

A. Guaranteed Pricing of Economy Energy

Q: How much energy would Nova Scotia consumers receive in exchange for the share of the project costs for which they will be charged?

A: As proposed by NSPML, in consideration for its assuming 20% of the costs of the Maritime Link, NSPI would receive from Nalcor an average of 153 MW for sixteen hours daily (including weekends) for 895 GWh annually for 35 years (the NS Block) and about 200 MW of Supplemental Energy in the off-peak hours for about 254 GWh annually for the first five years. Any additional energy that NSPI receives from Nalcor would be priced at the market value of the energy, which may be high at some times and low at others.

Q: How much economy energy does the Sponsor assume NSPI will receive from the Maritime Link?

A: In the Application, the Sponsor assumes that, under its "Base" forecast, NSPI would purchase an average of about 1,300 GWh annually in economy energy over the Maritime Link during the period of the Supplemental Energy block, rising to about 1,530 GWh in 2023 and 2024, to about 1,600 GWh in 2025 (when NSMPL assumes that transmission upgrades will allow Nova Scotia to increase its take from Nalcor from 300 MW to 500 MW), and to more than 1,700 GWh after 2035, in addition to purchases of about 500 GWh from New Brunswick.[20] This magnitude would require NSPI to take an average of about 280 MW from the Maritime Link around the clock prior to 2025 (and more later), increasing NSPI's requirement for operating reserves.

[20]The Application suggests that the New Brunswick purchases arise from the Maritime Link project. (Application at 92) It is not clear why that should be true. The purchases from New Brunswick that the Sponsor assumes with the Maritime Link are orders of magnitude higher than the purchases that NSPI projected for 2013 and 2014 in the 2013 GRA.

Q: How would the availability of additional fixed-price surplus energy from Nalcor aid Nova Scotia electric customers?

A: The Application simply assumes that large surplus-energy purchases will be available from Nalcor and that they will be priced below the costs of wind energy for the first several years of Maritime Link operation.[21] Neither Nalcor nor the Sponsor has offered any assurance that these quantities or prices will actually be available.

If Nalcor provides NSPI with a call option for specific quantities of energy at specific prices that would be competitive with current forward prices, ratepayers would have much greater assurance of receiving benefits from the economy energy, particularly if future market prices for natural gas and electricity are higher than currently expected.

Q: The evidence of Levitan & Associates suggests that much more Supplemental Energy should be included in the Maritime Link package, at no additional charge to Nova Scotia ratepayers. Would that change accomplish the same end as the call option you have described?

A: Yes. Increasing the number of years during which NSPI receives the Supplemental Energy block, as the Levitan Panel suggests, would improve the economics of the Maritime Link package for Nova Scotia ratepayers.

[21] The power prices by month and pricing period (on- and off-peak) are provided in NSUARB IR-37, Attachment 1.

B. Sharing Nalcor Revenues on Sales through Nova Scotia

Q: What benefit would NSPI customers receive from Nalcor sales wheeled through the Maritime Link and Nova Scotia to New Brunswick and beyond to New England?

A: The electric consumers would receive no direct benefits from these transactions. All else equal, the transmission revenues from the Nalcor wheeling would reduce the allocation of transmission costs to Nova Scotia customers, but NSPI will also need to invest in additional transmission to allow Nalcor to make those sales, so the net effect is likely to be near zero. If New Brunswick does not expand internal transmission sufficiently to allow Nalcor to deliver to New England all the potential throughput of the Maritime Link, NSPI would be required to buy the additional stranded energy from Emera at a price calculated to eliminate any net benefit to NSPI, including the benefit of RES and environmental compliance (Application p. 146, Appendix 8.01, and CA IR-71 and IR-97).[22]

Q: How would sharing of Nalcor's revenues on sales wheeled through the Maritime Link and Nova Scotia benefit NSPI customers?

A: I see three benefits of Nalcor paying the Sponsor for this use of the Maritime Link, so long as the revenues are passed on to NSPI ratepayers. First, the additional revenues would reduce the net cost of the Maritime Link Project, making it more competitive with the alternatives. Second, if Nalcor sales to New England rise, diverting energy away from sales to Nova Scotia, the shared revenues would increase, offsetting some of the lost benefits to Nova Scotia. Third, even a small revenue share (e.g., a few percent of revenue) would

[22] As a result, NSPI may be charged more for stranded energy than it would pay for negotiated purchases of surplus energy.

encourage Nalcor to maximize sales to Nova Scotia by reducing the price offered to NSPI.

C. Exclusion of Labrador Transmission Assets from NSPI Rates

Q: What are the Labrador Transmission Assets?

A: The Labrador Transmission Assets (LTA) comprise two overhead 315-kV AC transmission lines from Muskrat Falls to Churchill Falls, via Gull Island, along with associated switchyards at Churchill Falls and Muskrat Falls. (Filing, at 96; MHI Study, App. 5.01, at 55)

Q: What is the cost of the LTA?

A: The guaranteed capital cost of the LTA is $700 million, of which NSPML's share is $140 million.[23] (Filing, p. 97) Based on the revenue requirements for the Maritime Link in Synapse IR-16 Attachment 1, I estimate the annual carrying charge rate to be about 8.5%, which for the LTA would be about $12 million annually.

Q: Is Nalcor installing the Labrador Transmission Assets for the purposes of supplying the NS Block?

A: No. While the Sponsor asserts that "The Labrador Transmission Assets are required to complete the transactions in totality including the performance of all contractual provisions regarding the supply of the NS Block" (CA/SBA IR-20a), it does not explain why or how that would be true. the Sponsor also acknowledges that "The Labrador Transmission Assets allow for energy swaps between

[23]According to the MHI Study, the cost estimate for the LTA "increased significantly with Decision Gate 3" as a result of a decision to include 735 kV equipment at the Churchill Falls switchyard "which had previously been attributed to the Gull Island Generating Station Project" (MHI Study, at 55).

the Upper Churchill power house and Muskrat Falls to maximize energy production from the Churchill River system" (CA/SBA IR-20a), which appears to be a benefit primarily for Nalcor and Hydro Quebec. The LTA also appears to be useful for Nalcor to fully access its entitlement in Churchill Falls (currently the 300 MW recall block and after 2041 the entire 5,400 MW of the project). While these interconnections might make more economy energy available to Nova Scotia over the Maritime Link, the LTA would also allow Nalcor to wheel surplus energy from Muskrat Falls (and, presumably, future generation at Gull Island) through Hydro Quebec to Ontario, New York, and New England, potentially reducing energy available to Nova Scotia and increasing the price of whatever energy is available.[24]

In short, the Sponsor has not shown that Nalcor is investing in the LTA in order to provide for the supply of NSPML's 20% share of Muskrat Falls generation or NSPML's allocation of Supplemental Energy from Muskrat Falls.

Q: Would the Labrador Transmission Assets benefit Nova Scotia power consumers?

A: There are no assurances that NSPI customers would reap any tangible benefits from the LTA. While the LTA may increase the availability of surplus energy for purchase by NSPI at market prices, there is no guarantee regarding the quantity or pricing of any such future transactions. Indeed, by opening up the route through HQ to Ontario and the US, the LTA may reduce the amount of economy

[24]The Application (at 25) also claims that the LTA will connect Nova Scotia to Hydro Quebec and thereby complete a "new regional electricity loop that gives access to competitive energy markets" in New England. However, the Sponsor has not offered any evidence of the impact of this electricity loop on the availability or pricing of market-priced power in Nova Scotia or of any tangible benefits to NSPI customers from completing this loop with the LTA.

energy available to Nova Scotia and increase the price of power available to Nova Scotia.

Q: Should the costs of the LTA be recovered from NSPI retail customers?

A: No. The Labrador Transmission Assets are not required to deliver the NS Block to NSPI load. Moreover, there is no guarantee that investment in the LTA will increase the availability, or lower the cost, of surplus energy to NSPI load.

Recovering 20% of the LTA investment from NSPI customers can be viewed as distorting the "20 for 20" concept upon which the cost allocation for the whole suite of investments is based. Under that approach, Nova Scotia would receive 20% of the Muskrat Falls output in exchange for paying 20% of the total cost of Muskrat Falls and the facilities necessary to deliver Muskrat Falls output to Newfoundland and Nova Scotia. Since power can be generated at Muskrat Falls and delivered to Newfoundland and Nova Scotia without the Labrador Transmission Assets, including the LTA in the "20 for 20" computation would charge NSPI retail customers inappropriately. Thus, it would be more equitable and logical to exclude Nova Scotia consumers for paying any part of the LTA capital and O&M costs as part of the Maritime Link.[25]

Q: Would excluding recovery of the costs of the LTA from NSPI retail customers require revision in the suite of contracts and other agreements between the Sponsor and Nalcor?

A: I do not believe so. The division of costs and responsibilities between the parties can remain the same as currently proposed. The only difference would be that the Sponsor would recover its share of the LTA costs from tariff arrangements with Nalcor, as the latter uses the LTA to transfer energy between Muskrat Falls

[25]Were the Maritime Link package clearly in the best interest of ratepayers, the justification for the deal would be of limited relevance.

and Churchill Falls and to integrate Gull Island, rather than from the Nova Scotia ratepayers.

D. Merchant Development of Maritime Link

Q: How might the Maritime Link be developed on a merchant basis?

A: Rather than committing Nova Scotia ratepayers to paying for the Maritime Link on a cost-of-service basis, without any assurance that the project will provide benefits commensurate with those costs, Nalcor, Emera, or a third party could pay the costs and recover them through sales of energy and capacity to NSPI, New Brunswick, or New England. Nova Scotia could purchase the amount of energy that it needed and that was cost-effective, given actual load growth and the costs of alternatives. That approach would relieve the Board of the need to approve the economics of the project, which would be the responsibility of the sponsors.

Q: Might the merchant approach create any regulatory complications?

A: Yes. If Emera owns a portion of a merchant facility selling power to NSPI, the Board would need to enforce its rules carefully regarding affiliate transactions. Since NSPI's planning decisions could affect Emera's unregulated earnings, the Board would have to be particularly vigilant in reviewing any NSPI proposal regarding resource planning, generation operation, and even transmission planning. Regulating NSPI will be easier if Emera is not an owner of the merchant Maritime Link facilities.

Does this conclude your testimony?

A: Yes.

Exhibit PC-1

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SUMMARY OF PROFESSIONAL EXPERIENCE

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

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

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

EDUCATION

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

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

HONORS

Chi Epsilon (Civil Engineering)

Tau Beta Pi (Engineering)

Sigma Xi (Research)

Institute Award, Institute of Public Utilities, 1981.

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

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"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.

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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; Supplemental, October 2010; Reply, October 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. **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.

251. **N.S. UARB** P128.10, Port Hawkesbury Biomass Project; Nova Scotia Consumer Advocate. Direct, June 2010.

Least-cost planning and renewable-energy requirements. Feasibility versus alternatives. Unknown or poorly estimated costs.

252. **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.

253. **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.

254. **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.

255. **N.S. UARB** NG-HG-R-10, Heritage Gas rates; N.S. Consumer Advocate. Direct, October 2010.

Cost allocation. Cost of capital. Effect on rates of growth in sales.

256. **Manitoba PUB** Case No. 17/10, Manitoba Hydro rates; Resource Conservation Manitoba and Time to Respect Earth's Ecosystem. Direct, December 2010

Revenue-allocation and rate design. DSM program.

257. **N.S. UARB** NSPI-P-891, Nova Scotia Power depreciation rates; N.S. Consumer Advocate. Direct, February 2011.

Depreciation and rates.

258. **New Orleans City Council** No. UD-08-02, Entergy IRP rules; Alliance for Affordable Energy. Direct, December 2010

Integrated resource planning: Purpose, screening, cost recovery, and generation planning.

259. **N.S. UARB** Docket BRD-E-R-10, Renewable Energy Community Based Feed-in Tariffs; N.S. Consumer Advocate. Direct, March 2011.

Cost of projects. Rate effects of feed-in tariffs. Consideration of community in computing costs.

260. **Mass. EFSB** 10-2/ D.P.U. 10-131, 10-132, NStar transmission; Town of Sandwich, Mass. Direct, May 2011; Surrebuttal, June 2011.

Need for new transmission; errors in load forecasting; probability of power outages.

261. **Utah PSC** Docket No. 10-035-124; Rocky Mountain Power rate case; Utah Office of Consumer Services. June 2011

Load data, allocation of generation plants, scrubbers, power purchases, and service drops. Marginal cost study: inclusion of all load-related transmission projects, critique of minimum- and zero-intercept methods for distribution. Residential rate design.

262. **N.S. UARB** Docket NSPI P-892; Nova Scotia Power general rate application; N.S. Consumer Advocate. August 2011.

Cost allocation: allocation of costs of wind power and substations. Rate design: marginal-cost-based rates, demand charges, time-of-use rates.

263. **N.S. UARB** Docket NSPI P-202; Load-retention tariff; N.S. Consumer Advocate. August 2011.

Marginal cost of serving very large industrial electric loads; risk, incentives and rate design.

264. **Okla. Corporation Commission** Cause No. PUD 201100077; Current and pending federal regulations and legislation affecting Oklahoma utilities; Sierra Club. comments July, October 2011; presentation July 2011.

Challenges facing Oklahoma coal plants; efficiency, renewable and conventional resources available to replace existing coal plants; integrated environmental compliance planning.

265. **Nevada PUC** Docket No. 11-08019; Integrated analysis of resource acquisition; Sierra Club. Comments September 2011; Hearing October 2011

Scoping of integrated review of cost-effectiveness of continued operation of Reid Gardner 1–3 coal units.

266. Okla. Corporation Commission Cause No. PUD 201100087; Oklahoma Gas and Electric Company electric rates; Sierra Club. November 2011.

Resource monitoring and acquisition. Benefits to ratepayers of energy conservation and renewables. Supply planning

267. Ky. PSC Case No. 2011-00375; Kentucky utilities' purchase and construction of power plants; Sierra Club and National Resources Defense Council. December 2011.

Assessment of resources, especially renewables. Treatment of risk. Treatment of future environmental costs.

268. N.S. UARB Docket NSUARB-E-ENSC-R-12; DSM plan of Efficiency Nova Scotia; N.S. Consumer Advocate. May 2012.

Avoided costs. Allocation of costs. Reporting of bill effects.

269. N.S. UARB Docket NSUARB-NSPI-P-203; Utility-sponsored energy-efficiency programs; N.S. Consumer Advocate. June 2012.

Effect on ratepayers of proposed load-retention tariff. Incremental capital costs, renewable-energy costs, and costs of operating biomass cogeneration plant.

270. Utah PSC Docket No. 11-035-200; Rocky Mountain Power Rates; Utah OCC. June 2012.

Cost allocation. Estimation of marginal customer costs.

271. Ark. PSC Docket No. 12-008-U; Environmental controls at Southwestern Electric Power Company's Flint Creek plant; Sierra Club. Direct, June 2012, Rebuttal, August 2012.

Costs and benefits of environmental retrofit to permit continued operation of coal plant, versus other options including purchased gas generation, efficiency, and wind. Fuel-price projections. Need for transmission upgrades.

272. U.S. EPA Docket EPA-R09-OAR-2012-0021, Air Quality Implementation Plan; Sierra Club, September 2012.

Costs, financing, and rate effects of Apache coal-plant scrubbers. Relative incomes in service territories of Arizona Coop and other utilities.

273. Arkansas PSC Docket No. 07-016-U, Entergy Arkansas' integrated resource plan; Audubon Arkansas. Comments, September 2012.

Estimation of future gas prices. Estimation of energy-efficiency potential. Screening of resource decisions. Wind costs.

274. Vt. PSB Docket No. 7862, Entergy Nuclear Vermont and Entergy Nuclear Operations petition to operate Vermont Yankee; Conservation Law Foundation, October 2012.

Effect of continued operation on market prices. Value of revenue-sharing agreement. Risks of underfunding decommissioning fund.

275. **Manitoba PUB** 2012–13 GRA, Manitoba Hydro rates; Green Action Centre. November 2012

Estimation of marginal costs. Fuel switching.

276. **Kansas CC** Docket No. 12-GIMX-337-GIV, Utility energy-efficiency programs; The Climate and Energy Project, December 2012.

Cost-benefit tests for energy-efficiency programs. Collaborative program design.

277. **N.S. UARB** Matter No. M05339; Capital Plan of Nova Scotia Power; N.S. Consumer Advocate. January 2013.

Economic and financial modeling of investment. Treatment of AFUDC.