MATTER NO. M06733

In the Matter of an Application by EfficiencyOne for Approval of a Supply Agreement for Electricity Efficiency and Conservation Activities between EfficiencyOne and Nova Scotia Power Inc., the establishment of a final agreement between the parties and approval of a 2016–2018 DSM Plan

DIRECT TESTIMONY OF

PAUL CHERNICK

ON BEHALF OF

THE CONSUMER ADVOCATE

Resource Insight, Inc.

JUNE 2, 2015

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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 PLC-1.

Q: Have you testified previously in utility proceedings?

A: Yes. I have testified nearly 300 times on utility issues before various regulatory, legislative, and judicial bodies, including utility regulators in thirty-five states and six Canadian provinces, and two U.S. Federal agencies.

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

A: Yes. I have testified in numerous proceedings on avoided costs, program scope, cost recovery, and related issues, 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 (Matter No. 01439)
- The proposed purchased-power agreement between Nova Scotia Power Inc. and a biomass project to be constructed at the NewPage Port Hawkesbury pulp and paper mill (Matter No. 01496)
- Nova Scotia Power's proposal to build the biomass project at NewPage Port Hawkesbury (Matter No. 02961)
- Heritage Gas's 2010 rate case (Matter No. 03454)
- Nova Scotia Power's proposal to increase production depreciation rates (Matter No. 03665)
- The Board's review of proposed feed-in tariffs for certain distribution-connected renewable projects (Matter No. 03632)

- The Nova Scotia Power 2012 General Rate Application (Matter No. 04104), with respect to cost allocation and rate design
- The Board's review of proposed a proposed load-retention tariff and rate (Matter No. 04175)
- The application of Efficiency Nova Scotia Corporation's Electricity Demand-Side Management Plan for 2013–2015 (Matter No. 04819).
- The application of Nova Scotia Power and Pacific West Commercial Corporation for a load-retention rate mechanism for the Port Hawkesbury paper mill (Matter No. 04862)
- Nova Scotia Power's 2013 Annual Capital Expenditure Plan (Matter No. 05339)
- The application of Nova Scotia Power for approval of the South Canoe Wind Project (Matter No. 05416)
- The Board's review of the Maritime Link proposal (Matter No. 05419).
- Nova Scotia Power's 2013 Cost of Service Study (Matter No. 05473)
- The Board's review of proposed feed-in tariffs for Development Tidal Arrays (Matter No. 05092).
- Nova Scotia Power Annual Capital Expenditure Plan for 2015 (Matter No. 06514)

I have also assisted the Consumer Advocate in preparing comments in the Board's reviews of Nova Scotia Power's Nuttby, Digby, and Point Tupper wind-project proposals (Matters Nos. 02195, 02763, and 02983), Nova Scotia Power's Renewable Energy Tax and Accounting Depreciation (Matter No. 03795), the Capital Expenditure Justification Criteria review (Matter No. 04600), the Renewable RFP (Matter No. 04838), the 2014 NS Power Integrated Resource Plan (Matter No. 05522), Port Hawkesbury Paper Load Retention Tariff Report (Matter No. 05803), the renewable-to-retail proceeding (Matter No. 06214), cases related to the NS Power transmission required to support exports to New Brunswick following operation of the Maritime Link (Matter Nos. 06525 and 06660), and the on-going stakeholder process on NS Power's 2014 cost allocation update (Matter No. 06555).

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 some aspects of the filing by EfficiencyOne (E1) in this proceeding, as well as the response by Nova Scotia Power (NS Power). Specifically, I address the following issues:

- Estimation of avoided costs (Board Issue 5d)
- Cost-effectiveness screening of DSM (Board Issue 5c)
- Strategic issues in portfolio design (Board Issue 5a)
- Measurement of affordability and bill effects (Board Issue 5b and 5e)

Q: Are there particular issues closely related to your testimony that you are not addressing?

A: Yes, in particular an evaluation of EfficiencyOne's proposed budget and savings. If NS Power is correct that more DSM can be implemented with lower expenditures in some programs, EfficiencyOne should modify those budgets down and those savings targets up. I have not seen any convincing evidence that EfficiencyOne has overstated the costs of its programs, but if more can be done for less without creating lost opportunities or introducing new inequities, so much the better. The same applies to the measures with TRC ratios less than 1.0;

if EfficiencyOne has no good reason for including them, they can be removed and the net benefits increased.[1]

III. Avoided Costs

Q: What are your concerns about the avoided costs used in screening the DSM programs?

A: I have identified problems in several aspects of the avoided costs developed by NS Power, which I have grouped into problems relating to (1) avoided generation costs, (2) avoided T&D costs, and (3) energy and peak loss factors.

A. Avoidable Generation Costs

Q: What avoided generation cost did EfficiencyOne use in its DSM screening?

A: EfficiencyOne used avoided costs developed by NS Power in its IRP for what NS Power calls the base-DSM scenario.

Q: How did NS Power estimate avoided generation cost?

A: Nova Scotia Power describes its approach as a partial revenue requirements method that includes the following steps:[2]

1. using the Strategist model to estimate total annual variable costs, generation additions, and generation-addition fixed revenue requirements for the load cases with and without the DSM portfolio;

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[1] As I discuss below, these measures may be justified as marketing measures, for simplification of program design, or by non-energy benefits that EfficiencyOne has not included in the TRC results. It remains the responsibility of EfficiencyOne to explain and justify its inclusion of each such measure.

[2] This process is sketched out in NS Power's "Review of DSM Scenarios, Avoided Costs and Associated Planning Analysis," February 2015 (hereinafter, "the NSPI presentation"), slide 4.

2. dividing the cost of new generation plant between energy and capacity based on projected capacity factor;
3. computing the difference in energy costs by year for between the DSM and no-DSM cases;
4. dividing the difference in annual energy costs by the difference in annual energy requirements between the DSM and no-DSM cases, to derive an avoided energy cost per MWh;
5. dividing the difference in annual nominal revenue requirements of new capacity-related plant additions by the difference in rated capacity of the resources in the DSM and no-DSM cases, to derive an avoided capacity cost per kW-year.

Q: What problems have you identified in NS Power's avoided generation cost estimates?

A: I have found the following problems in NS Power's avoided generation costs estimates:

- the lack of shaping of the energy decrement and time-differentiation of the avoided energy costs;
- failing to reflect some benefits of reduced energy load, including opportunities for increased steam plant layups, reduction in Port Hawkesbury biomass operation, and opportunities for selling excess renewable energy to New England;
- inappropriate treatment of the avoided Mersey expansion as a demand-driven capacity cost, rather than an avoided energy cost;
- failing to incorporate the potentially avoidable capacity costs of the steam plants, including stretching out maintenance cycles for lightly-used plants

(especially Trenton 5 and Lingan 1), and the possibility of retiring additional steam plants;

- using nominal annual ratemaking fixed revenue requirements for new resources, rather than the cost savings of deferral;
- computing avoided capacity cost per kW-year by dividing the avoided generation plant costs by the rated capacity of the plant rather than by the load reduction that allows deferral, and the related failure to reflect a required reserve margin in the avoided costs;
- ignoring the avoidable costs of new generation in or transmission to Halifax, to maintain reliability following the retirement of Tufts Cove capacity, starting in 2025;
- ignoring inflation after 2039.[3]

1. *Avoided Energy Costs*

Q: How should the DSM load shape be modeled in the computation of avoided energy costs?

A: The DSM-related reduction in energy load should be shaped over months, on- and off-peak periods, and hours in proportion to expected DSM savings, or (if the shape of the DSM load reductions have not been estimated) the average hourly energy requirement. Since operating costs tend to be higher with higher load (all else equal) and since NS Power's avoided energy costs tend to be highest in the winter, when gas prices increase marginal energy costs in many

[3] As shown in E-28(C) SBA IR-34 Attachment 1 Confidential & Electronic.xlsb, tab "Avoided Costs," the avoided capacity costs are constant after 2039, indicating an assumption of zero inflation.

hours, a load-weighted energy decrement will generally produce a higher avoided energy cost than a flat decrement.

Q: Why is it important to time-differentiate avoided costs?

A: As I described in the previous question, some savings are more valuable than others, due to differences in marginal energy price over months, periods, and hours. Therefore, DSM cost-effectiveness tests should be computed from avoided costs that reflect the greater value of saving a MWh of energy from, for example, space heating than from water heating.[4]

Q: Please elaborate on NS Power's failure to reflect some benefits of reduced energy load.

A: Reduced load would facilitate NS Power's ability to lay up steam plants over the summer, to reduce energy generation from the very expensive Port Hawkesbury biomass plant, and to sell excess renewable energy to New England.

Q: How would reduced energy load facilitate layup of steam plants over the summer?

A: Lower summer loads could reduce loads enough that one or more of the least-efficient units (at Lingan and Trenton 5) could be shut down during the summer without endangering reliability. NS Power has used this approach at Lingan 2 to reduce non-fuel operating costs; I do not see any reflection of that potential benefit in NS Power's avoided-cost estimates.

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[4]It is not clear whether EfficiencyOne has developed time-differentiated energy savings by measure. The response to (E1) NSPI IR-17 Attachment 2 indicates that EfficiencyOne assumed energy savings from residential lighting is equal in all 8,760 hours of the year, which is absolutely implausible. Hence, EfficiencyOne may have some work to do before it can assess the actual cost-effectiveness of its 2016–2018 programs, let alone screen appropriately for the 2019–2021 DSM plan.

Q: How could reduced energy load facilitate reduced energy generation from the Port Hawkesbury biomass plant?

A: The dispatch costs (mostly fuel) for the Port Hawkesbury plant are much higher than the costs for NS Power's other resources. Assuming that the province approves NS Power operating the Port Hawkesbury plant on an economic-dispatch basis, lower energy loads would reduce the need for renewable energy, allowing NS Power to generate less electricity from Port Hawkesbury. After 2019, every 100 MWh saved reduces NS Power's renewable-energy requirement by 40 MWh.

Q: How would reduced energy load facilitate sale of excess renewable energy to New England?

A: Again, lower load means lower renewable requirements, and hence more excess renewable energy available to sell to New England. Renewable energy certificates are currently selling for about $50/MWh, which is in addition to the market value of the energy. As NS Power increases its ability to export energy to New Brunswick, in conjunction with the Maritime Link, its ability to export renewable energy through New Brunswick to New England should also increase.

Q: Why is treatment of the avoided Mersey expansion entirely as a demand-driven capacity cost inappropriate?

A: The Mersey expansion is much more expensive per kilowatt than other capacity resources. Specifically, NS Power expects the expansion to cost $3,500/kW, compared to $1,100/kW for a 49 MW peaker (NS Power 2014 IRP Report Appendix B, pages 20 and 21).[5] When Strategist selects the expansion, the

[5]These prices are all in 2013 dollars, and may not include AFUDC, which would further increase the installed cost of the Mersey expansion, with its longer construction period.

program must have determined that the energy savings with the Mersey expansion cover its higher fixed costs.[6] Those energy savings are reflected in the avoided energy costs (since the running costs of the no-DSM case are reduced by the Mersey expansion, which does not occur in the low-DSM or base-DSM cases). NS Power's treatment of these costs understates the avoided energy costs and increases the avoided capacity costs.

Q: Does the same issue arise for other resources in the avoided-cost runs?

A: Yes. NS Power expects the high-efficiency 100-MW combustion turbines (presumably LMS-100 units) that it schedules for 2025 and 2033 to cost $1,600/kW and the combined-cycle plants that it schedules for 2035 and 2038 to cost $1,500/kW, respectively about 45% and 36% more than the pure peakers. Again, the higher fixed costs are justified by energy savings, which reduce NS Power's estimate of the avoided energy costs. For the combined-cycle units, NS Power avoids the misallocation of costs by a process it describes as ratioing the combined-cycle cost to the cost of a combustion turbine, which I assume means that NS Power treats the first $1,100/kW as being capacity-related and the remainder energy-related. That is an appropriate approach, which NS Power should also have applied to Mersey and the high-efficiency combustion turbines.

2. Avoided Demand-Driven Generation Costs

Q: What is wrong with NS Power using nominal annual ratemaking fixed revenue requirements for new resources?

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[6] Nova Scotia Power characterizes the expansion of the Mersey system in its Half-Low DSM case as being driven for economics, not for capacity (NS Power Presentation at slide 5).

A: The fundamental problem is that a load reduction that delays a plant's operation by one year does not avoid the first-year ratemaking costs. Rather, the load reduction delays a whole stream of revenue requirements. The normal approach to estimating avoided costs would be to compute the value of one year's deferral of the cost, and then another year, and so on. The result of this computation is a stream of revenue requirements that rise with inflation, or equivalently are levelised in real terms. The computation of that revenue requirements stream for each resource is very simple with normal Excel functions.[7]

Q: What effect does this error have on NS Power's estimates of avoided costs?

A: Depending on the measure life and timing of resource additions, NS Power's approach may over-estimate or under-estimate avoided costs in any given period.

Q: What problem arises from NS Power's computation of avoided capacity cost per kW-year by dividing the avoided fixed generation costs by the rated capacity of the avoided resources?

A: The fixed costs are avoided or deferred by a load reduction, which is usually significantly smaller than the capacity of the avoided resource, for two reasons. First, with a target reserve requirement of about 20%, each 50 MW of generation resource can support only about 42 MW of load, so no more than 42 MW of load reduction are required to avoid a 100-MW capacity resource. Second, if Strategist finds that NS Power would be slightly short of capacity in a year, it may add a 50-MW resource to cover a shortfall of only 10 or 20 MW. In these situations, a load reduction much smaller than the full load-carrying capacity of the resource would be sufficient to avoid the capacity resource.

[7]The revenue-requirements approach is appropriate for assessing annual rate and bill effects, but it does not provide a proper basis for screening DSM.

Whether avoiding the 50-MW resource would require a load reduction of 42 MW or a 10 MW, the avoided cost per kilowatt of load reduction is greater than NS Power estimates.

Q: Is there a simple fix for these problems with NS Power's approach?

A: There are two potential fixes. The comprehensive fix is to divide the avoided capacity cost by the load reduction required to avoid the capacity. A partial fix would be to add a reserve margin of 20% to the avoided capacity charge computed by NS Power (after correction for the other problems I list above). That partial fix would deal with the first problem, but not the second.

Q: Has NS Power added a reserve margin to its estimate of avoided capacity cost?

A: Not that I can find. Unfortunately, NS Power's documentation of its avoided-cost computation has been very limited in both its 2014 IRP and in the current proceeding.

Q: What costs may be avoidable through DSM as a result of the planned retirement of Tufts Cove 1 in 2025 and Tufts Cove 2 in 2032?

A: As I understand the current supply situation for the Halifax load center, the existing generation in the load center (Tufts Cove and the Burnside combustion turbines) and transmission south from Onslow are just about enough to supply the load center. With the load growth in the no-DSM case, and the retirement of Tufts Cove units, additional transmission and local generation might well be needed to reliably serve Halifax. NS Power did not recognize any transmission costs as avoidable and its avoided-cost estimates do not reflect any savings provided by lower load specifically in the Halifax region.[8]

B. Avoided Transmission and Distribution

Q: What transmission-and-distribution costs does NS Power include in its estimates of avoided costs?

A: None. NS Power excludes all load-related transmission and distribution from the avoided costs. NS Power recognizes that "these components do contribute in some part to the avoided costs," but claims that reflecting avoided T&D "introduces a complexity with limited benefit" and suggests that avoided T&D "can continue to be studied in the next contract period" (NS Power Presentation at slides 8, 11).[9]

Q: What is the level of the "limited benefit" that NS Power expects from reflecting avoided T&D in DSM screening, and how did NS Power determine the level of the benefit?

A: NS Power does not elaborate on either of those issues. Instead, NS Power defends its assertion of "limited benefit" by reciting a series of facts, some of

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[8]The IRP includes a commitment of further "thermal generation asset analysis work," with

> by the end of June 2015,…an initial thermal asset management plan," including "consideration of locational value of Tufts Cove plant, and flexible operating characteristics of gas- and oil-fired steam units compared to coal-fired units. There may be locational or system considerations that could give preference to sustaining capital or life extension expenditures at the Tufts Cove location compared to other plants. (NS Power 2014 IRP at 65)

[9]NS Power does not define the "next study period" in this context, but it may mean that it would ignore T&D until the next IRP, or until it is time to develop avoided costs for the next three-year DSM plan.

which do not appear to be related to the magnitude of T&D benefits and others of which discuss ways in which T&D costs are avoidable, as follows:

> The benefit of T&D avoided costs is restricted (or limited) by what has been a largely broad based roll out of efficiency programs in Nova Scotia. Program delivery has been directed at broad customer uptake, more so than power system requirements. (NSPI (CA) IR-15a)

While it is difficult to determine exactly what NS Power means by those sentences, it seems to be indicating the load reductions are widespread. Hence, a portion of load reductions would fall on otherwise overloaded transformers, distribution lines, substations, and transmission lines.

> Transformers that are replaced because of load rating, and have remaining useful operating life, are regularly repurposed on the power system. (NSPI (CA) IR-15a)

So NS Power acknowledges that it installs larger transformers due to high load levels, incurring the costs of removing the old transformer, plus purchase and installation of the new transformer (in addition to possibly higher fixed losses, depending on the age and design of the transformer being replaced), and salvages only the remaining life of the smaller transformer that has been replaced. Where the old transformer has already been subject to overloads, that remaining life may be short.[10] Installing a repurposed transformer in place of a new one also incurs the cost of an additional installation when the repurposed unit dies. In any case, the net credit from reusing the old transformer is likely to be a small fraction of the new transformer.

> Transformers replaced for reliability purposes (condition or age) may be replaced with a larger unit (incremental increase). (NSPI (CA) IR-15a)

[10] A transformer that is deteriorated due to loads or age may not be worth reusing, considering installation and removal costs, and may be scrapped.

In other words, high loads on transformers may require installation of larger, more expensive transformers, which is clearly a load-related and avoidable cost. In addition, the "condition" that requires replacement of the transformer may be deterioration of the internal insulation due to repeated overloads, so the need for replacement may also be load-related.

> Primary feeders rebuilt for reliability purposes may be reconductored with electrical conductor of a higher rating which could be in response to feeder loading or could reflect current construction standards. (NSPI (CA) IR-15a)

While NS Power does not specify the "reliability purposes" for which feeders may be rebuilt, this term could be limited to situation where the equipment is inadequate regardless of load, perhaps because the conductors are failing under wind and ice load, or the poles are rotting.[11] In those situations, NS Power acknowledges that it may need to increase the conductor size to carry the load on the feeder.[12]

Q: Has NS Power ever estimated avoided T&D costs?

A: No. (IR (NSPI) CA-15(c)). It is not clear why NS Power says that it can *continue* studying an avoided-cost component it appears to have never *started* studying.

Q: What would be the effect of deferring the analysis of avoided T&D costs to the next study period?

A: The analysis of the cost-effectiveness and bill effects of DSM programs in this matter will be distorted, understating the benefits of DSM and overstating the

[11]Rebuilds driven by "reliability" concerns that include the need to carry anticipated load would be load-related.

[12]If the feeder has been overloaded, the insulation and the mechanical strength of the conductor may be impaired, potentially leading to earlier reconductoring.

bill effects. In addition, NS Power partially justifies its proposed DSM savings target on the assertion higher savings would not defer any additional capital investments in the near term. I have already explained how some generation investments (and transmission into the Halifax load center) costs may be avoided by DSM; avoiding other transmission and distribution investments would further undermine NS Power's argument.

Q: Does NS Power have any rationale for its failure to estimate avoidable T&D costs?

A: In response to the question "Does NS Power agree that avoiding or deferring T&D investments would improve the affordability of a DSM portfolio?" NS Power responded as follows:

> Focused DSM programming could avoid, defer, or reduce some T&D investments; however, a high degree of coordination between utility planners and efficiency program designers would be necessary to achieve a material result. In addition, there would need to be a willingness to focus DSM investment in discrete geographic areas to match the power system topology rather than the current broad-based offerings across the province. IR (NSPI) CA-15(b)

Q: Is this a reasonable response?

A: No, for three reasons. First, the response avoids admitting the obvious reality that load reductions, targeted or otherwise, that avoid or defer T&D investments would reduce rates and bills, improving the affordability of the portfolio. NS Power's reluctance to agree with fundamental realities is disturbing.

Second, NS Power is incorrect in assuming that T&D costs can only be avoided by geographically targeted DSM. Even a DSM program that was uniform across the province would reduce load on some equipment enough to defer upgrades. In addition, the high-growth areas most likely to need T&D upgrades are likely to attract a disproportionate share of DSM savings, since that growth will usually be driven by new construction, rehabilitation, and addition of equipment, all of which should be covered by vigorous energy-efficiency programs. Areas with little pre-DSM load growth will also participate in energy-efficiency programs, but customers there will be limited to replacement of equipment on failure, and some retrofits.

Third, NS Power's unsupported assertions notwithstanding, geographical targeting of DSM to areas with particularly high avoided T&D costs (e.g., areas facing overloads of feeders, substations and subtransmission) is not particularly difficult. In Vermont, the efficiency utility has provided that service to the distribution utilities for many years.[13] The distribution utilities pay Efficiency Vermont for the additional costs of intensive marketing of retrofits in the targeted areas. The Vermont system load is about half that of NS Power's; so NS Power is clearly large enough to deal with targeted DSM to reduce revenue requirements further.

Q: If NS Power adopted geographically targeted DSM, would that eliminate the avoided costs for non-targeted DSM?

A: No. Some of the non-targeted DSM would still fall into the targeted areas with above-average avoided T&D costs, and some of the avoidable T&D costs (e.g., the overloading of scattered transformers) would not be targetable in the first place.

Q: How should NS Power estimate avoidable transmission and distribution capacity for DSM?

A: In general, it is not possible to directly compute the difference in T&D investment for the base and DSM cases, due to the lack of system planning

[13]While Vermont has experienced some consolidation of distribution utilities over the last couple decades, the state still has about 20 utilities.

models comparable to the system models used in generation planning. Hence, it is usually necessary to estimate T&D costs from historical (and perhaps projected) relationships between investments and the loads served by that investment, and between O&M and loads.

Q: Should avoided T&D costs include only the costs avoided by NS Power?

A: No. Regardless of where the customer's usage is metered—at transmission level or after secondary distribution—someone must provide distribution to the end use, which is almost always at secondary voltage. Hence, avoidable T&D should be computed to the secondary level for all customer classes.

Q: Have other utilities with little or no overall growth after DSM estimated avoided T&D costs?

A: Yes. The following table summarizes the avoided T&D costs estimated by New England states and utilities, in 2015 U.S. dollars.[14] All five of the states listed have experienced falling energy requirements and peak loads since the early 2000s (2003 to 2005, depending on the state and measure of load).

Table 1: Summary of New England Avoided T&D Estimates

State	Company	Transmission	Distribution	Total
CT	Connecticut L&P	$1.25	$32.19	$33.44
CT	United Illuminating	$2.74	$49.75	$52.49
MA	National Grid	$23.01	$124.28	$147.29
ME	Statewide			$81.67
RI	National Grid	$37.86	$162.47	$200.33
VT	Statewide	$50.45	$113.51	$163.96

I have previously reviewed the Connecticut estimates of avoided T&D and found that they exclude significant amounts of load-related expenditures.

[14]The source is Appendix G of "Avoided Energy Supply Costs in New England 2015 Report" 2015 study prepared for the Avoided-Energy-Supply-Component (AESC) Study Group.

Q: Do NSPI's investment plans include T&D projects due to load growth?

A: Yes. NS Power lists the ACE projects that it identifies as load-related in response to NSPI (CA) IR-17(a).

Q: Have there been T&D projects cancelled or delayed due to load growth lower than expected?

A: Yes. While NS Power lists only a couple such projects, it also notes that most projects deferred by DSM would never have appeared in an ACE filing, which identifies only short-term needs.

C. Line Losses

Q: Does NS Power include loss factors in its avoided cost estimates?

A: No. Indeed, NS Power appears to take the position that it does not need to estimate avoided losses, on the following grounds:

> The avoided generation capacity and energy costs are based on the revenue requirement to meet energy and capacity requirements, including losses. As such, demand and energy losses are inherent to the calculation and specific loss factors are not required. (IR (NSPI) CA-27)

Q: Is NSPI correct that avoided costs derived from revenue requirement method should not require specific loss factors?

A: No. For each kWh saved at the end-use, more than a kWh is saved at the generation level. The difference depends on the end-use voltage level and the load on the various portions of the T&D system from the generator to the end use. For residential loads, the vast majority of the losses occur on the utility system, while for a large industrial customer or a university campus, a significant portion of the losses may occur on transformers and conductors on the customer's side of the meter.

Q: Do you believe that NS Power has developed reasonable loss factor estimates that could be used for avoided costs?

A: No. As I stated in my testimony in Matter No. 05473 (at 96):

> NSPI acknowledged that its estimates of loss factors depended on too many undocumented judgmental inputs and has undertaken to re-estimate the loss factors based on hourly loads and engineering estimates of fixed and variable losses by voltage level.

Q: What line losses should be included in DSM avoided costs?

A: Marginal losses should be included for energy costs, recognizing the variation in marginal losses with load level. Losses rise as load rises (and hence as costs rise), and the incremental losses on an additional kWh of sales in any hour is roughly twice the average value of variable losses in that hour. Marginal energy losses should reflect the product of the various loss levels and energy costs, which vary over the course of the day and the year, rather than losses at the average load level. Just as energy costs should be differentiated by time of use and season, so should estimated losses.

Demand-related costs should include average losses at the peak load.

Like distribution costs, losses should be included to the end-use level, which is almost always secondary.

Q: Did EfficiencyOne use any line losses in its DSM screening?

A: Yes. EfficiencyOne appears to have used 11.8% line losses for all energy savings. It does not appear that EfficiencyOne included any demand losses.

Q: Is this a reasonable energy line-loss value?

A: Yes, at least in terms of general order of magnitude. The loss factor should be higher in high-load periods and lower in low-load periods, and should be based on an analysis of NSPI's system and losses to the customer's end use. Until NS

Power or some other party can develop reasonable estimates of marginal losses, the 11.8% value is a reasonable placeholder.

IV. Cost-Benefit Tests

Q: Which cost-benefit tests are at issue in this proceeding?

A: There are four such tests used or proposed in this proceeding: the Total Resource Cost (TRC) test, the Program Administrator Cost (PAC) test, various forms of Rate and Bill Impact Measure (RBIM), and the first-year cost per MWh.

Q: What are the positions of EfficiencyOne and NS Power regarding the roles of these tests?

A: The Board has established the TRC as the primary cost-effectiveness screening test for DSM. The Board considers a DSM program to be cost-effective if it passes the TRC overall, even if it includes measures that fail the TRC test. (Order Matter No. M03669, June 30 2011, at 31).

EfficiencyOne follows Board policy in developing its proposed DSM plan but requests that the UARB change that policy and approve the use of the PAC rather than the TRC as the primary screening test (EfficiencyOne Application at 56).

Nova Scotia Power accepts the use of the TRC for screening, but also advocates that the Board require EfficiencyOne to "provide results by Measure, Program and Portfolio for the TRC, PAC and RBIM tests" (NS Power Evidence at 51), and advocates using some sort of rate and bill impact measure (RBIM) and the first-year cost per MWh to further restrict the programs to be implemented, and thus effectively advocates that those tests override the TRC, so long as the result is a reduction in DSM spending.

Q: What rationale does EfficiencyOne offer for using the PAC as the primary screening test?

A: EfficiencyOne says that its

> primary concerns with the existing test…are accuracy (not all inputs are calculated appropriately), bias (there is a lack of inclusion of all appropriate customer benefits), and ratepayer value (the TRC is not an accurate reflection of ratepayer value). (EfficiencyOne Application at 57)

EfficiencyOne goes on to say that

> it is essential for the primary cost-effectiveness test…to ensure an accurate decision-making guide is in place…. The proposed shift from the traditional TRC test to the PAC test is a result of ENS's commitment to the accurate accounting of DSM costs and benefits" (EfficiencyOne Application at 57)

and further claims that

> The PAC test is inherently balanced. In this manner, the PAC requires no regulatory effort to balance appropriately, which could likely be significant for a modified TRC-based approach.
>
> The PAC is more reflective of a ratepayer value approach. In this manner, it allows fairer competition between supply-side and demand-side planning options.
>
> The PAC cost is consistent with a least-cost procurement view, which aligns with the Public Utilities Act. (EfficiencyOne Application at 57–58)

Q: What is EfficiencyOne's basis for these assertions?

A: EfficiencyOne relies on a report by Phillipe Dunsky (Appendix I of the Application). In that report, Dunsky chooses to focus on the inadequacies of the description of the TRC in the 32-year-old California Standard Practice Manual, rather than best practice in application of the TRC, even though Dunsky acknowledges,

> The extent of experimentation underway underscores a point that is often lost when considering the TRC: while it was borne of a Standard Practice Manual, its use today is anything but standardized. (Application Appendix I at 9)

Dunsky also criticizes specific jurisdictions (often not identified) for errors in applying the TRC, such as the following:

- Quebec's inclusion of the costs of measures implemented by free riders (but not the benefits),
- some jurisdictions not fully accounting for all avoided-cost components,[15]
- some "regions" ignoring spillover benefits and market transformation,[16]
- disagreements about "the rate at which future savings should be discounted,"[17]
- some jurisdictions oversimplify the estimate of measure lifetimes,
- "some regions have not adjusted their models" to reflect the reality that one LED lamp replaces 20 incandescent lamps (and associated labour costs) over its lifetime,
- some regions ignore some or all of the benefits of saved heating fuels and water, and
- "in some regions, planning models are limited in the number of years of analysis they can account for, and the benefits of measures with longer lifespans (e.g. new construction, envelope retrofits, ground source heat pumps) may literally be cut short as a result." (Application Appendix I at 10–12)

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[15]This criticism applies to NS Power's avoided cost, as I discuss in Section III.

[16]It is not clear what Dunsky means by a "region," since energy-efficiency screening rules are generally set by jurisdiction (state or province) or utility.

[17]Dunsky acknowledges that the choice of discount rate is an issue regardless of the choice of tests, so it is not clear why it is in his list of problems with the TRC.

Q: Do these concerns constitute adequate reasons to abandon the TRC?

A: No. Most of the issues—inappropriate treatment of free-rider costs, ignoring spillover, discount rate, understatement of avoided costs, misestimation of measure lives, truncation of avoided costs—apply equally to any cost-benefit test, including EfficiencyOne's preferred PAC test. Mr. Dunsky's concerns are all readily addressed and corrected, although NS Power has been very slow to deal with some of them.

Q: Does Mr. Dunsky raise any other objections to the TRC?

A: Yes. His major concern with the TRC (and the only concern that would conceivably justify a switch to the PAC) is that the TRC as employed in some places does not recognize non-energy benefits to participants, such as increased comfort and health of occupants, reduced O&M costs from longer-lived lamps (a point that Mr. Dunsky also included in his list of critiques of the TRC, as discussed above), and higher resale values for efficient homes.[18] As Mr. Dunsky acknowledges (at 15), other jurisdictions have estimated these benefits for use in program screening, so NS Power could as well.[19]

Q: Is the PAC a suitable measure of DSM net benefits?

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[18]In addition, Mr. Dunsky suggests that there are utility non-energy benefits (which generally sound like avoided costs, such as reduced fuel-price risk and load shape) and societal avoided costs (which are generally excluded from the TRC by design), particularly air emissions (largely internalized by Nova Scotia's emission caps) and regional macroeconomic effects (which Mr. Dunsky says have been estimated for Nova Scotia). These costs can be estimated and added to avoided costs or other benefits, if the Board desires.

[19]In reality, quantifying these benefits only matter for measures that would have failed screening without them. If a measure, or program, passes the TRC at a benefit-cost ratio of 1.4 without non-energy benefits, adding those benefits and raising the ratio to 1.9 will not change the cost-effectiveness determination.

A: No. By ignoring costs and benefits to participants, the PAC inherently distorts the value of DSM programs for ratepayers and Nova Scotia. In addition, the PAC cannot be used to guide optimization of DSM portfolio design, since it will indicate that a program is improved by reduction in incentives, even if those reduce participation and disproportionately increase participant costs.

Q: What is your overall assessment of EfficiencyOne's proposal to replace the TRC with the PAC?

A: The Board should push NS Power and EfficiencyOne to improve the estimates of avoided costs and non-energy benefits, and if necessary, instruct its consultants to fill in parts of the TRC analysis that the utilities have difficulty resolving. A comprehensive TRC is better than either a limited TRC or any version of the PAC (which would require the same improvement in the avoided costs as the TRC).

Q: What role should the PAC test play in constructing a DSM portfolio?

A: The PAC is useful in designing programs, particularly in determining whether participant incentive levels are excessive. If a measure passes the TRC but fails the PAC, that would indicate that EfficiencyOne (and hence ratepayers) would be paying the participant more than the avoided cost of the measure, which is generally unnecessary. The PAC should not be used to determine whether DSM measures or programs should be implemented.

Q: At what level of DSM portfolio design should the TRC be applied?

A: The program designers should attempt to maximize net TRC benefits, so in principle the TRC should guide every step of screening, from measure to program to sector to portfolio. It would generally be counter-productive to burden a program with TRC benefits greater than costs with an incremental measure that (without any allocation of fixed program costs or overhead) would fail the TRC. That said, there are probably measures that would fail the TRC on their own, but are worth including in a program. For example, if a measure is cost-effective for 97% of treated sites, it may be less expensive to just do it for the other 3%, rather than complicating training of installers and verification of installations, as well as explaining to some participants why they are not eligible for a popular measure that their neighbors received. Similarly, a measure whose direct TRC benefits do not cover its cost may be justified because it is inexpensive and very popular with participants, encouraging participation at low cost.[20] Furthermore, until Nova Scotia completes the quantification of non-energy benefits some measures that fail the incomplete TRC should be eligible for inclusion in programs, if EfficiencyOne can make a plausible case that the non-quantified benefits would be sufficient to make the measure cost-effective.

Q: Should the DSM portfolio be designed to maximize the TRC ratio of the portfolio?

A: No. Any DSM activity with TRC benefits in excess of costs is a net gain. Concentrating on TRC ratios encourages cream-skimming. The goal should be to maximize net TRC benefit (the present value of benefits minus costs), subject to any other constraints and objectives.

Q: What is NS Power's position regarding cost-effectiveness testing?

A: Nova Scotia Power supports continued use of the TRC test. However, NSPI's approach to program selection for its Alternative Plan is not consistent with its stated support of primary reliance on the TRC, since it uses the cost per first year savings to select programs or market segment to curtail. In doing so, NSPI

[20] An extreme example would be a cute refrigerator magnet that gets the installer into the house to install some LED lamps, check insulation levels and refrigerator age, and so one.

actually eliminated the end-use category with the second-highest average TRC ratio (the residential lighting program) (NSP Evidence, Appendix B).

In the longer term, NS Power appears to favour increased use of some unspecified rate and bill analysis, which it calls the RBIM, by measure, program and portfolio RBIM.

Q: Can you explain what NS Power means by the RIMB test?

A: Not entirely. On the one hand, NS Power appears to accept the portfolio-wide analysis of rate and bill changes for participants and non-participants presented in EfficiencyOne's Application (Appendix D), other than the omission of the effects of DSM on the allocation of fixed costs. On the other hand, NS Power proposes the computation of some sort of RBIM for every measure, which would be meaningless. The effect of any single measure on rates is almost certain to be de minimus. Certainly, the Board would not be able to determine whether any particular measure would increase or decrease the equity of program design

Nova Scotia Power has not explained what an RBIM would look like at any level other the portfolio, or why that test would be relevant.

Q: How should rate and bill analysis be applied to the review of DSM programs?

A: The rate and bill analysis should be expanded to reflect the allocation of costs (including the costs of new generation, transmission and distribution, as well as DSM) among the major rate classes. The resulting estimate of rate and bill changes from the no-DSM case and year-over-year should be reviewed to determine whether the effect on any particular class (including non-participants) is excessive.

V. Designing the Demand-Side-Management Portfolio

A. EfficiencyOne and Nova Scotia Power's Demand-Side-Movement Proposals

Q: How do the proposals of EfficiencyOne and NS Power differ?

A: EfficiencyOne proposes a DSM plan that it estimates will achieve a total energy savings of 405.9 GWh at a cost of $121.5 million over the three-year Contract Period. The plan is roughly equivalent to the Base Case from the IRP and the proposed annual budget is similar to the 2014 DSM expenditure level. NS Power contends that a much smaller expenditure on the order of $66 million would be more affordable and cost effective and still achieve a savings of 300 GWh.

To support its claim that a more-affordable but still effective-plan could be designed under this reduced budget, NS Power derived an Alternative Plan from the EfficiencyOne plan.[21]

Q: How did NS Power derive the Alternative Plan?

A: NS Power eliminated the end-use categories with unit cost above FY $300/MWh (Evidence, p. 38 and Appendix B—NSPI Alternate DSM Plan). Appendix B indicates that the Alternative Plan retains a portion of the RES-HVAC/Shell category, but at a much lower unit cost of $260/MWh in 2016.With the exception of the RES-HVAC/Shell category, NS Power's estimates of the DSM costs and MWh savings for its Alternative Plan match EfficiencyOne's estimates by end-use.

[21]The Company proposed that DSM expenditures be reduced to about $22 million per year, but has not yet developed an actual alternative DSM portfolio. Its Alternative Plan is more in the nature of a scenario.

Q: How did NS Power "adjust" the RES-HVAC/Shell category?

A: It appears that in the Alternative Plan, the RES-HVAC/Shell category remains in name only. In the EfficiencyOne plan, the RES-HVAC/Shell category consists mostly of DSM measures for existing homes and the RES-Package measures target new construction. In NS Power's Alternative Plan, RES-HVAC/Shell category targets new construction, not retrofits (Evidence at 38):

> While it is among the more expensive programs, NS Power included a portion of this [RES-HVAC/Shell] category in each of the three years of the Contract Period. This was included to recognize that there could be some DSM opportunity lost by not addressing projects in the residential new home construction market. The amount included (4,600 MWh at a cost of $1.2 million) is based on the 2014 Evaluation Report regarding new homes.

It would more accurate to say that NS Power eliminated both Efficiency-One's RES-HVAC/Shell and Res-Package programs and replaced them with a new residential-construction placeholder,

B. Demand-Side-Management Portfolio Strategy

Q: Why does NS Power believe that an annual budget of about $22 million would be a more-appropriate level of DSM expenditure?

A: That is not clear. NS Power strongly suggests that it is proposing very large reductions in the EfficiencyOne DSM program to maintain short-term affordability, asserting that its proposed reduction in the budget and savings target would:

> …provide the best balance between affordability in the short-term and overall cost effectiveness out beyond 2030 for the following reasons:
>
> > (a) it aligns with near-term utility requirements for energy and capacity;

> (b) it recognizes greater confidence in near-term forecasts;[22] and
>
> (c) it is most economic at years 2025 and 2030, and the cross-over point (where it becomes less cost-effective than the higher DSM option) is not until 2034.
>
> The delay required for a DSM plan to become economic indicates that a more moderate level of DSM should be undertaken to mitigate near-term rate pressure for customers, while not sacrificing the future. (Evidence, pp. 31–32)

Nova Scotia Power does not appear to have developed the $22 million budget or the savings target to meet any specific measure of affordability, let alone developed a demonstration that the short-term rate effects of the EfficiencyOne plan would outweigh its long-term cost-effectiveness.

Q: Is developing a DSM portfolio to meet a pre-set budget a good approach?

A: No. The preferable approach would start by identifying a set of programs that would achieve the following:

- Capture as much as possible of the cost-effective lost opportunities in new construction, renovation, remodeling, process change, purchases of new equipment and replacements for failed or otherwise inadequate equipment.
- Maintain the integrity of the energy-efficiency infrastructure of contractors (and their employees) and relationships with other trade allies.
- Produce a well-balanced portfolio, offering energy-efficiency benefits to as broad as possible a cross-section of customers.

If that initial portfolio has unacceptable rate or bill effects, it should be redesigned to increase the equity of the portfolio, using the tools I discuss in SectionVI.B.

[22] I have not found anyplace other than this one clause where NS Power mentions this point about forecasting, let alone explains how NS Power's forecasting uncertainties would support its proposed reduction in the EfficiencyOne plan.

1. Prioritization of Lost-Opportunity Measures

Q: Please explain what you mean by "lost-opportunity" resources.

A: "Lost-opportunity" DSM resources are market-driven and can only be captured as they come available. Lost opportunities occur during new construction, expansion, industrial process change, equipment replacement, and efficiency upgrades (since a mediocre efficiency improvement may preclude higher-efficiency installations). Lost-opportunity DSM should be captured whenever cost-effective, since it cannot be deferred.

Q: What DSM options can be deferred without incurring too high a cost?

A: Funding for early replacement of inefficient appliances can be reduced without sacrificing lost opportunities, so long as programs are available to capture appliances that are being retired and maximize the efficiency of their replacements. To the extent that EfficiencyOne is in a position to determine the model of older appliances in conjunction with other programs, it should retain that data so that early replacement can be targeted to the least-efficient units.

Q: In proposing a much lower level of DSM expenditure, does NS Power still recognize the importance of capturing lost opportunities?

A: Sometimes. As noted above, the Alternative Plan includes $1.2 million per year for DSM in new residential construction to address lost-opportunity resources. On the other hand, NS Power's proposed elimination of all residential HVAC programs for existing residential customers would likely result in lost opportunities since there would be no program for replacement of failing HVAC equipment with higher efficiency systems.[23] The same is true for building-shell

[23] In addition, with any HVAC upgrades, whether a replacement or a retrofit, there may an opportunity to downsize the equipment by installing shell measures to reduce thermal loads. If the

measures in renovation and remodeling, as well as replacement of windows and doors for aesthetic, convenience and comfort. NS Power proposes to eliminate completely all residential lighting efforts, including incentives for new fixtures that may last decades and be impossible to retrofit with LEDs.[24]

2. *Maintenance of Energy-Efficiency Infrastructure*

Q: What do you mean by energy-efficiency infrastructure?

A: EfficiencyOne (or any other utility) cannot deliver DSM entirely on its own. It needs contractors to implement retrofit projects; architects and engineers to participate in new-construction, renovation and process modification programs; wholesalers and retailers (in plumbing, HVAC equipment, appliances, lighting, and other areas) to stock equipment so that it will be available and affordable; and plumbers and HVAC contractors to recommend high-efficiency equipment to clients and to participate in equipment-replacement programs.

Q: How could erratic changes in DSM spending damage this infrastructure?

A: If Nova Scotia DSM programs are dramatically curtailed, contractors to EfficiencyOne will have to downsize, laying off employees, and some of them will probably leave the energy-efficiency business entirely. This is particularly

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customer defers these envelope improvements, the HVAC upgrade will be oversized, creating a lost opportunity.

[24]I personally have some fixtures purchased in 1995 that have bases or size constraints that preclude retrofitting with LEDs or CFLs, and would be hard (not to mention expensive) to replace with fixtures that would coordinate with other nearly design features in my home (including light fixtures can retrofitted). I underestimated the time for dimmable efficient lamps to become available in the sizes and styles that I need. A utility incentive program for LED fixtures would help tomorrow’s renovators avoid my misfortune.

true if programs serving entire market segments are eliminated, as NS Power suggests. Wholesalers and retailers may be left with stocks of highly efficient equipment that sells poorly without the programs. Architects, engineers, plumbers, and HVAC contractors who have trained their staff to participate in the programs will have wasted their time and may have added staff (in support of participation in the programs) that are now redundant.

Q: Why is maintenance of the energy-efficiency infrastructure important?

A: EfficiencyOne (or any other program administrator) is unlikely to be able to reconstitute fully functional province-wide DSM support quickly or inexpensively after several years' hiatus, because of the following three factors:

- the time required for recruiting staff that have been laid off and even left the field,
- the time (and cost) required for training contractors and trade allies who have not looked at the DSM procedures for years and may have been operating under very different business models,
- the suspicion that will undoubtedly linger after the contractors, employees and trade allies that perceive EfficiencyOne (or the Board, or the Province, depending on the particular party's perspective) pulled the rug out from under them.[25]

I am not suggesting that EfficiencyOne or the NS Power ratepayers owe any DSM contractor or ally a living. Keeping those parties engaged with the DSM programs must be justified by benefits to ratepayers.

Q: How does the need to maintain DSM infrastructure affect the extent to which existing programs can be ramped down temporarily?

[25] In the words of an American President, "Fool me once, shame on you; fool me twice…won't get fooled again."

A: There is undoubtedly a range in which EfficiencyOne can reduce spending on specific DSM programs; that is part of the operational flexibility of DSM.[26] But just as with many of NS Power's steam plants, ramping the programs down too quickly or too far may limit the extent to which they can be ramped back up when needed.

VI. Affordability Issues

Q: How should the Board deal with affordability of the DSM portfolio?

A: The concern with affordability requires a two-step process. First, the Board (or parties working under the Board's guidance) must determine whether a proposed DSM portfolio would result in excessive rate and bill effects to some class or group of customers. Second, if such excessive effects are identified, the equity of the portfolio should be improved by changing cost allocation, increasing cost-effective DSM services to underserved customer groups, and/or reducing spending and/or savings in ways that do not create lost revenues and that minimize the reduction in net benefits.

A. Assessing Rate and Bill Effects

Q: Has NS Power demonstrated that EfficiencyOne's DSM plan would have unacceptable short-term rate effects?

A: No. NS Power simply contends that EfficiencyOne's rate and bill impact analysis (which NS Power calls RBIM) is an inadequate basis for evaluating affordability.

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[26]Other aspects of the flexibility are the natural tendency of some programs (such as new construction) to ramp up when load grows, and the increased savings for many measures under unusually high-load conditions (e.g., extreme cold or heat).

Q: What problem has NS Power identified with EfficiencyOne's rate and bill impact analysis?

A: EfficiencyOne understates the increase in rates due to DSM by omitting the effect the reduction in sales due to the portfolio. Therefore, in NS Power's view:

> the current version of the RBIM is incomplete and should be disregarded by the Board and stakeholders. It fails to consider critical customer cost impacts and therefore provides an inaccurate portrayal of the potential rate and bill impacts. (Evidence at 44)

Q: Has NS Power identified any other problems with EfficiencyOne's RBIM?

A: No. NS Power does not dispute EfficiencyOne's analysis of revenue requirements and average bills.[27] Nor does the Company claim that EfficiencyOne's results indicate excessive bill impacts or inequities. Nova Scotia Power's recommendation to the Board rests in large part on the implicit speculation that a comprehensive analysis would show excessive effects for some group, presumably non-participants.

Q: Do you agree with NS Power that the Board should reject EfficiencyOne's DSM proposal on the basis of the weaknesses in its RBIM?

A: No, for at least two reasons. First, NS Power does not actually present any evidence that EfficiencyOne's plan has excessive rate impacts. NS Power's recommendation that the Board reject EfficiencyOne's DSM plan because of a hypothetical problem is inappropriate. If NS Power had reason to be concerned about rate effects, it could have done its own analysis. In fact, NS Power is in a

[27]While NS Power suggests that it found other flaws in the EfficiencyOne rate and bill analysis (NS Power Evidence at 44), I have not been able to identify any other specific problem claimed by NS Power that EfficiencyOne has not addressed in the current version of the analysis. Indeed, EfficiencyOne appears to have overestimated rate and bill effects by ignoring the difference between the avoided fuel and purchased-power cost and the lower average cost of fuel.

better position than EfficiencyOne to conduct ratemaking analyses, since it better understands regulatory and tax accounting for various cost categories (e.g., generation, T&D, DSM) and class cost allocation (both current and proposed).[28]

Second, rejecting an entire cost-effective DSM portfolio based on the possibility of excessive rate impacts over a few years is inconsistent with the treatment of supply-side investment decisions. Utilities routinely raise rates and bills to some or all customers to reduce total revenue requirements. If utilities worried about rate impacts in supply planning, they would avoid baseload resources because of short-term effects. When a utility brings a major new supply into service, it typically increases bills and rates in the short term, to reduce them in the long term. This reduction in total costs comes at a considerable price for the elderly, economically marginal businesses, and other customers who may not remain on the system long enough to experience the long-term benefits.[29] Depending on the cost allocation methods used, adding a least-cost supply resource may raise rates for some customers while reducing rates for other.

Q: Are you suggesting that rate effects of DSM should be ignored?

A: Not at all. The ratepayer effects of the DSM portfolio should be examined to flag any equity problems or excessive rate impacts. And these equity effects

[28]That analysis should include the avoided T&D that NS Power has ignored, the additional avoidable energy costs I discuss in Section III.A, and the difference between avoided energy costs and the FAM rate.

[29]NS Power did not appear to be troubled by its finding that the Maritime Link investment could raise rates on a present-value basis from 2018 through 2029 (NSPML Application at 133).

should be evaluated for the portfolio as a whole both among and within classes and over time.

Unfortunately, the Board does not have before it a complete rate and bill analysis in the current proceeding. There is no basis for finding that the effects of EfficiencyOne's proposed portfolio are excessive, and thus no reason to reduce DSM spending drastically and forgo system-wide DSM benefits and bill savings, as NS Power suggests.

Q: Once a reasonably complete rate and bill analysis is available, how should the Board determine whether rate or bill effects are excessive?

A: There is no simple answer to this question. Acceptable levels of rate increases due to DSM depend on such factors as the starting level of rates, base-case rate increases without DSM, the distribution of DSM offerings (i.e., what percentage of customers can participate), the distribution of DSM savings (e.g., such as the percentage of customers with declining bills), provisions to prioritize DSM to vulnerable customers (low-income, at-risk businesses), and the average level of customer bills.

Q: If DSM results in rates higher than they might be otherwise, does this imply that the rates are excessive or unfair, or that they endanger the Nova Scotia economy?

A: No. The economic attractiveness of Nova Scotia for business, and the disposable income of households, depends on bills, not rates. As long as DSM is cost-effective, it will decrease the costs of energy services and bolster the local economy. Whether a difference in rates between two DSM plans is a matter for concern depends on how much average bills are reduced, how widely the benefits of DSM are distributed, how rates would otherwise be moving, and how much risk is reduced, as well as the magnitude of the rate difference.

B. Improving Affordability and Equity of a DSM Portfolio

Q: How can concerns about affordability be addressed in DSM portfolio development?

A: One of the best solutions is to have a well-balanced portfolio of DSM programs that gives all customers an opportunity to reduce their electricity usage.

Q: In deriving its $22 million DSM budget and Alternative Plan, did NS Power take into consideration the importance of developing a well-balanced portfolio?

A: No. Despite NS Power's concern about affordability, 75% of the end-use-specific DSM expenditures that it eliminated from EfficiencyOne's plan were in residential end-use categories. While NS Power reported in its 2014 compliance cost-of-service study that the residential class constituted 47% of energy load and 53% of revenues, NS Power's proposes to spend only 25% of the DSM budget on the residential class and would deliver only about 27% of the DSM savings to that class. The NS Power proposal is thus heavily tilted toward the commercial and industrial customers.

In contrast, EfficiencyOne proposes to spend 48% of the DSM budget on residential customers and get 43% of the portfolio energy savings from that class; these values are much closer to the residential share of NS Power's load and revenues.

Q: Other than designing a well-balanced DSM portfolio, what can be done to minimize any identified rate impacts and bill inequities?

A: Several mechanisms are available for minimizing rate or bill problems, such as the following:

- Removing market barriers, minimizing cash requirements, and targeting marketing efforts to increase the ability of vulnerable customers (low income residentials, marginally viable commercial and industrial firms) to participate and reduce their bills.

- In some situations, careful program design may be able to overcome market barriers while charging participants a substantial portion of measure costs, either at the time of installation or through energy-service charges.
- If rate effects are excessive in early years, with low avoided costs, the timing of retrofit programs can be stretched out (but not suspended) to coincide with higher avoided costs in later years.

The last two options should be undertaken only with great caution, since sloppy exercise of these options may reduce DSM savings, result in lost opportunities and increase the cost of energy services.

VII. Conclusions and Recommendations

Q: Please summarize your conclusions.

A: My major conclusions are as follows:

- NS Power's estimates of avoided costs are generally understated and have other problems with timing, errors in allocation between energy and capacity, and failure to time-differentiate avoided costs.
- The problems in NS Power's avoided costs probably cause the TRC ratios reported by EfficiencyOne to be understated (although some specific measures may be overstated), and in the revenue-requirements increases estimated by EfficiencyOne being overstated.
- EfficiencyOne should time-differentiate the energy savings of its measures, so that it can reflect the differences in the value per MWh of various measures and programs.

- The TRC should be the primary test for cost-effectiveness, at the program level and (to the extent feasible) the measure level.
- The PAC should be used as a rough guide to the maximum incentive levels that EfficiencyOne should be paying on a program level.
- The RBIM should be a comprehensive analysis of the rate and bill effects at the portfolio level, as a check on inter-class equity and effects on customers who choose not to participate in any programs.
- EfficiencyOne has not produced a comprehensive rate and bill analysis.
- Nova Scotia Power has not demonstrated any inequity or excessive bill increase resulting from the EfficiencyOne proposal.
- Nova Scotia Power's Alternative DSM Proposal is not a full-fledged plan, but as presented by NS Power it would be inequitable to residential customers, create lost opportunities, undermine the residential energy-efficiency retrofit sector in Nova Scotia and contractors' confidence in the stability of province-wide efficiency policy.
- Were there compelling evidence that EfficiencyOne's proposal created significant inequities and should be scaled back, those reductions should be shaped to minimize lost opportunities, reductions in DSM net benefits and the damage to the province-wide DSM infrastructure.

Q: Does this conclude your testimony?

A: Yes, at this time. I am still reviewing NS Power's confidential responses (to which I did not have access until May 29) and may file supplemental testimony based on that review.

Exhibit PLC-1

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SUMMARY OF PROFESSIONAL EXPERIENCE

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

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

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

EDUCATION

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

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

HONORS

Chi Epsilon (Civil Engineering)

Tau Beta Pi (Engineering)

Sigma Xi (Research)

Institute Award, Institute of Public Utilities, 1981.

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"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.

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EXPERT TESTIMONY

1. **Mass. EFSC** 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. **Mass. EFSC** 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. **Mass. EFSC** 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. **Mass. DPU** 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 Susan Geller.

5. **Mass. DPU** 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. **U.S. ASLB** NRC 50-471, Pilgrim Unit 2; 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 Susan Geller.

7. **Mass. DPU** 19845, Boston Edison time-of-use-rate case; Massachusetts Attorney General. December 4 1979. (Not presented)

   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 Susan Geller.

8. **Mass. DPU** 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. **Mass. DPU** 20248, petition of Massachusetts Municipal Wholesale Electric Company 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. **Mass. DPU** 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. **Mass. EFSC** 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. **Mass. DPU** 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. **Mass. EFSC** 79-1, Massachusetts Municipal Wholesale Electric Company Forecast; Massachusetts Attorney General. November 5 1980.

    Cost comparison methodology; nuclear cost estimates; cost of conservation, cogeneration, and solar.

15. **Mass. DPU** 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. **Mass. DPU** 535; regulations to carry out Section 210 of PURPA; Massachusetts Attorney General. January 26 1981 and February 13 1981.

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

17. **Mass. EFSC** 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. **Mass. DPU** 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. **Mass. DPU** 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. **D.C. PSC** FC785, Potomac Electric Power rate case; D.C. 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. **N.H. PSC** 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. **Mass. 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. **Ill. 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. **N.M. 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. **Conn. DPUC** 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. **Mass. DPU** 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. **Mass. 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. **Conn. DPUC** 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. **Mass.** **EFSC** 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. **Mich.** **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. **Mass.** **DPU** 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. **Mass.** **DPU** 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. **Mich.** **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. **Mass.** **DPU** 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. **Penn.** **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. **N.H.** **PSC** 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. **Mass. Division of Insurance,** hearing to fix and establish 1986 automobile insurance rates; Massachusetts Attorney General. November 1984.

    Profit-margin calculations, including methodology and implementation.

40. **Mass.** **DPU** 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. **Mass. DPU** 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. **Vt. 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. **Mass. DPU** 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. **Mass. DPU** 85-121, investigation of the Reading Municipal Light Department; Wilmington (Mass.) 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. **Mass. 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. **N.M. 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. **Penn. 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. **Mass. DPU** 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. **Penn. 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. **N.M. 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. **Ill. 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. **N.M. 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. **Mass. 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. **Mass. DPU** 87-19, petition for adjudication of development facilitation program; Hull (Mass.) 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. **N.M. 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. **Mass. DPU** 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. **Mass. 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.

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

62. **Minn. 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. **Mass. 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. **Mass. DPU** 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. **Mass. 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. **Mass. 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. **Mass. DPU** 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. **Mass. DPU** 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. **Mass. DPU** 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. **R.I. PUC** 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. **Mass. 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. **Vt. 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. **Vt. 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. **Mass. DPU** 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. **Vt. 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. **Mass. DPU** 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. **Mass. DPU** 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. **Mass. DPU** 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. **Vt. 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. **Mass. DPU** 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. **Ill. Commerce Commission** 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. **Md. 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. 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. **Ind. 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. **Mass. DPU** 89-141, 90-73, 90-141, 90-194, 90-270; preliminary review of utility treatment of environmental externalities in October qualifying-facilities 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. **Mass. EFSC** 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. **Va. SCC** 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. **Mass. DPU** 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 New England Solid Waste Compact plant. Fuel price and avoided cost projections vs. realities.

92. **Vt. 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. **S.C. PSC** 91-216-E, cost recovery of Duke Power's DSM expenditures; South Carolina Department of Consumer Affairs. Direct, September 13 1991; Surrebuttal October 2 1991.

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

94. **Md. 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 (Maine) 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. **Mass. DPU** 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. **Fla. 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. **Fla. 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. **Penn. 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. **S.C. 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. **Mass. DPU** 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. **S.C. 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. **N.C. 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. **Ont. EAB** Ontario Hydro Demand/Supply Plan Hearings, *Environmental Externalities Valuation and Ontario Hydro's Resource Planning* (3 vols.); Coalition of Environmental Groups. 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 BEP,** 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. **Md. 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. **N.C. 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. **S.C. PSC** 92-209-E, in re Carolina Power & Light Company; South Carolina Department of Consumer Affairs. November 24 1992.

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

110 **Fla. DER** 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. **Md. PSC** 8487, Baltimore Gas and Electric Company electric rate case. Direct, January 13 1993; rebuttal, 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. **Md.** **PSC** 8179, 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. **Mich.** **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.

Demand-side-management planning, program designs, potential savings, and avoided costs.

115. **Mich.** **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. **Ill. Commerce Commission** 92-0268, electric-energy plan for Commonwealth Edison; City of Chicago. Direct, 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. **Vt.** **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. **Fla.** **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. **Vt. 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. **Mass. DPU** 94-49, Boston Edison integrated-resource-management plan; Massachusetts Attorney General. August 1994.

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

122. **Mich. 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. **Mich. 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. **N.J. BRC** 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. **Mich. 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. **Mich. 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. **N.C. 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. **D.C. PSC** FC917 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. **Ont. Energy Board** EBRO 490, DSM cost recovery and lost-revenue–adjustment mechanism for Consumers Gas Company; Green Energy Coalition. April 1995.

Demand-side-management 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. **Mass. DPU** 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. **Md. 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. **N.C. 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 **Vt. PSB** 5835, Central Vermont Public Service Company rates; Vermont Department of Public Service. February 1996.

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

139. **Md. 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. **Mass. 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. **Mass. DPU** 96-70, Essex County Gas Company rates; Massachusetts Attorney General. July 1996.

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

142. **Mass. DPU** 96-60, Fall River Gas Company rates; Massachusetts Attorney General. Direct, July 1996; surrebuttal, August 1996.

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

143. **Md. PSC** 8725, Maryland electric-utilities merger; 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. **N.H. 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. **Ont. 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** 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. **Vt. 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. **Mass. DPU** 96-23, Boston Edison restructuring settlement; Utility Workers Union of America. September 1997.

Performance incentives proposed for the Boston Edison company.

149. **Vt. 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. **Mass. DPU** 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. **Mass. DTE** 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. **N.H. 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. **Md. 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. Vt. 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. Mass. DTE 98-89, purchase of Boston Edison municipal street lighting; Towns of Lexington and Acton. Affidavit, August 1998.

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

157. Vt. 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. Mass. DTE 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. Md. 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. Md. 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. Md. 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. **Conn. 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. **Conn. 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. **Wash. 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. **Conn. 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. **Conn. 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. Va. 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. **Ont. 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. **Conn. 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. **Conn. Superior Court** CV 99-049-7239, Connecticut Light and Power Company stranded costs; Connecticut Office of Consumer Counsel. Affidavit, December 1999.

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

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

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

173. **Ont. 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. **Conn. 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. **Ont. 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. **N.Y. 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. **Mass.** **EFSB** 97-4, Massachusetts Municipal Wholesale Electric Company gas-pipeline proposal; Town of Wilbraham, Mass. June 2000.

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

180. **Conn.** **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. **Conn.** **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. **Mass.** **DTE** 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. **Conn.** **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. **Vt.** **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. **N.J.** **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. **N.J.** **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. **Conn. 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. **N.J. 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. **N.Y. 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. **Mass. DTE** 01-56, Berkshire Gas Company; Massachusetts Attorney General. October 2001.

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

191. **N.J. 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. **Vt. PSB** 6545, Vermont Yankee proposed sale; Vermont Department of Public Service. 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. **Conn. 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. **Vt. 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. **Conn. 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. **Conn.** **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. **Ont. Energy Board** RP-2002-0120, review of transmission-system code; Green Energy Coalition. October 2002.

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

198. **N.J.** **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. **Conn.** **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. **Conn.** **DPUC** 03-07-01, CL&P transitional standard offer; AARP. November 2003.

Application of rate cap. Legislative intent.

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

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

203. **N.Y.** **PSC** 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. **N.Y. 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. **Ont. Energy Board** 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. **Mass. DTE** 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. **N.Y. 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. **N.Y. 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. **Md. 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. **B.C. Utilities Commission** 3698388, British Columbia Hydro resource-acquisition plan; British Columbia Sustainable Energy Association and Sierra Club of Canada BC Chapter. September 2005.

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

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

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

212. **Conn. DPUC** 03-07-01RE03 & 03-07-15RE02, incentives for power procurement; Connecticut Office of Consumer Counsel. Direct, September 2005; Additional, 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. **Conn. 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. **Ont. 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. **Ont. Energy Board** 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. **Ind. Utility Regulatory Commission** 42943 and 43046, Vectren Energy DSM proceedings; Citizens Action Coalition. Direct, June 2006.

Rate decoupling and energy-efficiency goals.

217. **Penn. PUC** 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. **Penn. PUC** 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. **Conn. 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 quarterly since September 2006.

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

220. **Conn. 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 quarterly since August 2006.

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

221. **N.Y. 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. **Conn. 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. **Ohio PUC** PUCO 05-1444-GA-UNC, recovery of conservation costs, decoupling, and rate-adjustment mechanisms for Vectren Energy Delivery of Ohio; Ohio Consumers' Counsel. February 2007.

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

224. **N.Y. PSC** 06-G-1332, Consolidated Edison Rates and Regulations; City of New York. March 2007.

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

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

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

226. **Conn. DPUC** 07-04-24, review of capacity contracts under Energy Independence Act; Connecticut Office of Consumer Counsel. Direct (with Jonathan Wallach), 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. **N.Y. PSC** 07-E-0524, Consolidated Edison electric rates; City of New York. September 2007.

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

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

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

230. **Conn. DPUC** 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. **Ont. Energy Board** 2007-0905, Ontario Power Generation payments; Green Energy Coalition. 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. July 2008

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

233. **Ont. Energy Board** 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. **N.Y. PSC** 08-E-0596, Consolidated Edison electric rates; City of New York. 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. **Conn. DPUC** 08-07-01, Integrated resource plan; Connecticut Office of Consumer Counsel. 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. **Man. PUB** 2008 MH EIIR, Manitoba Hydro intensive industrial rates; Resource Conservation Manitoba and Time to Respect Earth's Ecosystem. November 2008.

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

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

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

238. **Vt. 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. **N.S. UARB** 01439, Nova Scotia Power DSM and cost recovery; Nova Scotia Consumer Advocate. May 2009.

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

240. **N.S. UARB** 0496, 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. **Conn. Siting Council** 370A, Connecticut Light & Power transmission projects; Connecticut Office of Consumer Counsel. 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** 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** 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** R-2009-2139884, Philadelphia Gas Works energy efficiency and cost recovery; Philadelphia Gas Works. December 2009.

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

246. **B.C. Utilities Commission** 3698573, British Columbia Hydro rates; British Columbia Sustainable Energy Association and Sierra Club British Columbia. February 2010.

Rate design and energy efficiency.

247. **Ark. PSC** 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.

248. **Ark. PSC** 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.

249. **Ark. PSC** 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.

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** 02961, Port Hawkesbury biomass project; Nova Scotia Consumer Advocate. 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. 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. **Md. PSC** 9230, Baltimore Gas & Electric rates; Maryland Office of People's Counsel. 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. **Ont. Energy Board** 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** Matter No. 03454, Heritage Gas rates; Nova Scotia Consumer Advocate. October 2010.

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

256. **Man. PUB** 17/10, Manitoba Hydro rates; Resource Conservation Manitoba and Time to Respect Earth's Ecosystem. December 2010.

Revenue-allocation and rate design. DSM program.

257. **N.S. UARB** 03665, Nova Scotia Power depreciation rates; Nova Scotia Consumer Advocate. February 2011.

Depreciation and rates.

258. **New Orleans City Council** UD-08-02, Entergy IRP rules; Alliance for Affordable Energy. December 2010.

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

259. **N.S. UARB** NSPI-P-892, depreciation Rates of Nova Scotia Power; Nova Scotia Consumer Advocate. February 2011.

Steam-plant retirement dates, post-retirement use, timing of decommissioning and removal costs.

260. **N.S. UARB** 03632, renewable-energy community-based feed-in tariffs; Nova Scotia Consumer Advocate. March 2011.

Adjustments to estimate of cost-based feed-in tariffs. Rate effects of feed-in tariffs.

261. **Mass. EFSB** 10-2/DPU 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.

262. **Utah PSC** 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.

263. **N.S. UARB** 04104; Nova Scotia Power general rate application; Nova Scotia 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.

264. **N.S. UARB** 04175, Load-retention tariff; Nova Scotia Consumer Advocate. August 2011.

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

265. **Ark. PSC** 10-101-R, Rulemaking re self-directed energy efficiency for large customers; National Audubon Society and Audubon Arkansas. July 2011.

Structuring energy-efficiency programs for large customers.

266. **Okla. Corporation Commission** 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.

267. **Nevada PUC** 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.

268. **La. PSC** R-30021, Louisiana integrated-resource-planning rules; Alliance for Affordable Energy. Comments, October 2011.

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

269. **Okla. Corporation Commission** 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

270. **Ky. PSC** 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.

271. **N.S. UARB** 04819, demand-side-management plan of Efficiency Nova Scotia; Nova Scotia Consumer Advocate. May 2012.

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

272. **Kansas Corporation Commission** 12-GIMX-337-GIV, utility energy-efficiency programs; The Climate and Energy Project. June 2012.

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

273. **N.S. UARB** 04862, Port Hawksbury load-retention mechanism; Nova Scotia 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.

274. **Utah PSC** 11-035-200, Rocky Mountain Power Rates; Utah Office of Consumer Council. June 2012.

Cost allocation. Estimation of marginal customer costs.

275. **Ark. PSC** 12-008-U, environmental controls at Southwestern Electric Power Company's Flint Creek plant; Sierra Club. Direct, June 2012; rebuttal, August 2012; further, March 2013.

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.

276. **U.S. EPA** 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.

277. **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.

278. **Vt. PSB** 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.

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

Estimation of marginal costs. Fuel switching.

280. **N.S. UARB** M05339, Capital Plan of Nova Scotia Power; Nova Scotia Consumer Advocate. January 2013.

Economic and financial modeling of investment. Treatment of AFUDC.

281. **N.S. UARB** M05416, South Canoe wind project of Nova Scotia Power; Nova Scotia Consumer Advocate. January 2013.

Revenue requirements. Allocation of tax benefits. Ratemaking.

282. **N.S. UARB** 05419; Maritime Link transmission project and related contracts, Nova Scotia Consumer Advocate and Small Business Advocate. Direct, April 2013; supplemental (with Seth Parker), November 2013.

Load forecast, including treatment of economy energy sales. Wind power cost forecasts. Cost effectiveness and risk of proposed project. Opportunities for improving economics of project.

283. **Ont. Energy Board** 2012-0451/0433/0074, Enbridge Gas Greater Toronto Area project; Green Energy Coalition. June 2013, revised August 2013.

Estimating gas pipeline and distribution costs avoidable through gas DSM and curtailment of electric generation. Integrating DSM and pipeline planning.

284. **N.S. UARB** 05092, tidal-energy feed-in-tariff rate; Nova Scotia Consumer Advocate. August 2013.

Purchase rate for test and demonstration projects. Maximizing benefits under rate-impact caps. Pricing to maximize provincial advantage as a hub for emerging tidal-power industry.

285. **N.S. UARB** 05473, Nova Scotia Power 2013 cost-of-service study; Nova Scotia Consumer Advocate. October 2013.

Cost-allocation and rate design.

286. **B.C. Utilities Commission** 3698715 & 3698719; performance-based ratemaking plan for FortisBC companies; British Columbia Sustainable Energy Association and Sierra Club British Columbia. Direct (with John Plunkett), December 2013.

Rationale for enhanced gas and electric DSM portfolios. Correction of utility estimates of electric avoided costs. Errors in program screening. Program potential. Recommended program ramp-up rates.

287. **Man. PUB** 2014, need for and alternatives to proposed hydro-electric facilities; Green Action Centre. Evidence (with Wesley Stevens) February 2014.

Potential for fuel switching, DSM, and wind to meet future demand.

288. **Utah PSC** 13-035-184, Rocky Mountain Power Rates; Utah Office of Consumer Services. May 2014.

Class cost allocation. Classification and allocation of generation plant and purchased power. Principles of cost-causation. Design of backup rates.

289. **Minn. PSC** E002/GR-13-868, Northern States Power rates; Clean Energy Intervenors. Direct, June 2014; rebuttal, July 2014; surrebuttal, August 2014.

Inclining-block residential rate design. Rationale for minimizing customer charges.

290. **Cal. PUC** Rulemaking 12-06-013, electric rates and rate structures; Natural Resources Defense Council. September 2014.

Redesigning residential rates to simplify tier structure while maintaining efficiency and conservation incentives. Effect of marginal price on energy consumption. Realistic modeling of Consumer price response. Benefits of minimizing customer charges.

291. **Md. PSC** 9361, proposed merger of PEPCo Holdings into Exelon; Sierra Club and Chesapeake Climate Action Network. Direct, December 2014; surrebuttal, January 2015.

Effect of proposed merger on Consumer bills, renewable energy, energy efficiency, and climate goals.

292. **N.S. UARB** M06514, 2015 capital-expenditure plan of Nova Scotia Power; Nova Scotia Consumer Advocate. January 2015.

Economic evaluation of proposed projects. Treatment of AFUDC, overheads, and replacement costs of lost generation. Computation of rate effects of spending plan.

293. **Md. PSC** 9153 et al., Maryland energy-efficiency programs; Maryland Office of People's Counsel. January 2015.

Costs avoided by demand-side management. Demand-reduction-induced price effects.

294. **Québec** Régie de L'énergie R-3876-2013 phase 1, Gaz Métro cost allocation and rate structure; Regroupement des organismes environnementaux en énergie and Union des consommateurs. February 2015

Classification of the area-spanning system; minimum system and more realistic approaches. Allocation of overhead, energy-efficiency, gas-supply, engineering-and-planning, and billing costs.

ACRONYMS AND INITIALISMS

APS	Alleghany Power
ASLB	Atomic Safety and Licensing Board
BEP	Board of Environmental Protection
BPU	Board of Public Utilities
BRC	Board of Regulatory Commissioners
CMP	Central Maine Power
DER	Department of Environmental Regulation
DPS	Department of Public Service
DQE	Duquesne Light
DPUC	Department of Public Utilities Control
DSM	Demand-Side Management
DTE	Department of Telecommunications and Energy
EAB	Environmental Assessment Board
EFSB	Energy Facilities Siting Board
EFSC	Energy Facilities Siting Council
EUB	Energy and Utilities Board
FERC	Federal Energy Regulatory Commission
ISO	Independent System Operator
LRAM	Lost-Revenue-Adjustment Mechanism
NARUC	National Association of Regulatory Utility Commissioners
NEPOOL	New England Power Pool
NRC	Nuclear Regulatory Commission
OCA	Office of Consumer Advocate
PSB	Public Service Board
PBR	Performance-based Regulation
PSC	Public Service Commission
PUC	Public Utility Commission
PUB	Public Utilities Board
PURPA	Public Utility Regulatory Policy Act
SCC	State Corporation Commission
UARB	Utility and Review Board
USAEE	U.S. Association of Energy Economists
UTC	Utilities and Transportation Commission

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