

**Matter No. M09191**

Nova Scotia Power Incorporated's 2019 Load Forecast Report

**DIRECT TESTIMONY OF**  
**PAUL CHERNICK**  
**ON BEHALF OF**  
**THE CONSUMER ADVOCATE**

Resource Insight, Inc.

**JULY 9, 2019**

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Exhibit PLC-1

*Professional qualifications of Paul Chernick*

1 **I. Identification**

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

3 A: I am Paul L. Chernick. I am the president of Resource Insight, Inc., 5 Water  
4 St., Arlington, Massachusetts.

5 **Q: Summarize your professional education and experience.**

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

12 I was a utility analyst for the Massachusetts Attorney General for more  
13 than three years, and was involved in numerous aspects of utility rate design,  
14 costing, load forecasting, and the evaluation of power supply options. Since  
15 1981, I have been a consultant in utility regulation and planning, first as a  
16 research associate at Analysis and Inference, after 1986 as president of PLC,  
17 Inc., and in my current position at Resource Insight. In these capacities, I  
18 have advised a variety of clients on utility matters.

19 A: My work has considered, among other things, the cost-effectiveness of pro-  
20 spective new electric generation plants and transmission lines, retrospective  
21 review of generation-planning decisions, ratemaking for plant under construc-  
22 tion, ratemaking for excess and/or uneconomical plant entering service, con-  
23 servation program design, cost recovery for utility efficiency programs, the  
24 valuation of environmental externalities from energy production and use,  
25 allocation of costs of service between rate classes and jurisdictions, design of

1 retail and wholesale rates, and performance-based ratemaking and cost  
2 recovery in restructured gas and electric industries. My professional qualifi-  
3 cations are further summarized in Exhibit PLC-1.

4 **Q: Have you testified previously in utility proceedings?**

5 A: Yes. I have testified more than 325 times on utility issues before various  
6 regulatory, legislative, and judicial bodies, including utility regulators in  
7 thirty-five states and six Canadian provinces, and two U.S. Federal agencies.  
8 This testimony has included the review of many utility-proposed power  
9 plants and purchased-power contracts.

10 **Q: Have you testified previously regarding energy-efficiency portfolio  
11 design?**

12 A: Yes. I have testified in numerous proceedings on the evaluation, timing, and  
13 other aspects of energy-efficiency portfolio design, as listed in my resume.

14 **Q: Have you previously testified before this Board?**

15 A: Yes. I testified in over 25 Board proceedings, as listed in my resume. I have  
16 also assisted the Consumer Advocate in preparing comments in more than a  
17 dozen other Board proceedings.

## 18 **II. Introduction and Summary**

19 **Q: On whose behalf are you testifying?**

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

21 **Q: What is the purpose of your testimony?**

22 A: I review aspects of the 2019 load forecast report prepared by NS Power.  
23 Specifically, I comment on NS Power's treatment of the following:

- 1 • The replacement of resistance electric and fossil fuel-based space heat with  
2 heat pumps.
- 3 • The conversion of oil and propane hot water to electric heat pumps.
- 4 • The forecast of behind-the-meter solar PV penetration and the resulting  
5 reduction in energy requirements.
- 6 • The forecast of the penetration of electric vehicles, their energy  
7 requirements and their effect on load shape.
- 8 • The effects on load shapes of rates and demand response programs enabled  
9 by the Advanced Metering Infrastructure (AMI) that NS Power is installing.
- 10 • The updating of DSM projections to reflect the 2020–2022 settlement (and  
11 eventually approved plan) and the results of the ongoing potential study.
- 12 • Lighting efficiency effects should be rethought to reflect historical large  
13 improvements, which will be slowing running out in the next several years.

14 In addition, it is important to recognize that the Integrated Resource  
15 Plan (IRP) process will affect many of these issues. Revised expectations  
16 may be reflected in an updated 2019 load forecast, the 2020 load forecast, or  
17 (in some cases) resources in the IRP.

### 18 **III. Forecasting Issues**

19 **Q: Does NS Power deal with some end uses and other adjustments to load**  
20 **outside of the main load forecasts?**

21 A: Yes. For several end uses, such as heat pumps, water heating, rooftop solar  
22 generation, and electric vehicles, NS Power has limited historical data or  
23 expects the future to differ from history, due to targeted programs and  
24 changing market conditions. Therefore, NS Power models these end uses

1 outside of the average-use intensities that drive most of the residential and  
2 commercial load forecasts.<sup>1</sup>

3 **A. *Space-Heating Heat Pumps***

4 **Q: How does NS Power deal with the load effects of the replacement of**  
5 **resistance electric and fossil-fueled space heat with heat pumps.**

6 A: NS Power estimates that residential heating shares in 2018 were about 5%  
7 heat pumps, 25% electric resistance, and 70% non-electric.<sup>2</sup> Rather than  
8 estimating the rate at which resistance-heating and non-electric heating  
9 dwellings will be converted to heat pumps, NS Power forecasts a total  
10 number of heat-pump conversions and allocates them 65% to non-heating  
11 and 35% to heating.<sup>3</sup>

12 Table 1 below outlines the estimated heat pump conversions by type  
13 based on NS Power's forecast:

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<sup>1</sup> Nova Scotia Power 2019 Load Forecast Report, p.25, lines 19-23.

<sup>2</sup> 2019 Load Forecast Report Synapse IR-06 Attachment 5.

<sup>3</sup> Nova Scotia Power 2019 Load Forecast Report, p. 27, lines 6-7.

1 **Table 1: Forecasted Heat Pump Conversions**

Year	Cumulative New Installs	% of Conversions from		Conversions from		Annual Conversion Rate		Remaining Units		
		% Non-Electric	% Electric	Non-Electric	Electric Resistance	Non-Electric	Electric Resistance	Non-Electric	Electric Resistance	Electric Heat Pump
	<i>a</i>	<i>b</i>	<i>c</i>	<i>d</i>	<i>e</i>	<i>f</i>	<i>g</i>	<i>h</i>	<i>i</i>	<i>j</i>
2016								285,323	97,208	20,469
2019	15,180	65%	35%	9,867	5,313	3.5%	5.5%	275,456	91,895	35,649
2020	28,173	65%	35%	18,312	9,861	3.0%	4.7%	267,011	87,347	48,642
2021	41,329	65%	35%	26,864	14,465	3.1%	5.0%	258,459	82,743	61,798
2022	54,540	65%	35%	35,451	19,089	3.2%	5.3%	249,872	78,119	75,009
2023	67,784	65%	35%	44,060	23,724	3.3%	5.6%	241,263	73,484	88,253
2024	81,078	65%	35%	52,701	28,377	3.5%	6.0%	232,622	68,831	101,547
2025	90,442	65%	35%	58,787	31,655	2.5%	4.5%	226,536	65,553	110,911
2026	94,957	65%	35%	61,722	33,235	1.3%	2.3%	223,601	63,973	115,426
2027	99,101	65%	35%	64,416	34,685	1.2%	2.2%	220,907	62,523	119,570
2028	102,977	65%	35%	66,935	36,042	1.1%	2.1%	218,388	61,166	123,446
2029	105,983	65%	35%	68,889	37,094	0.9%	1.7%	216,434	60,114	126,452

Notes:

- a NS Power 2019 Load Forecast Report, Figure 10.
- b NS Power 2019 Load Forecast Report, Figure 10.
- c NS Power 2019 Load Forecast Report, Figure 10.
- d  $a \times b$
- e  $a \times c$
- f increase in  $d \div h$  previous year
- g increase in  $e \div i$  previous year
- h previous year –  $d$ ; 2016 data are from Synapse IR-06, Attachments 1 and 5
- i previous year –  $e$ ; 2016 data are from Synapse IR-06, Attachment 5
- j previous year +  $a$ ; 2016 data are from Synapse IR-06, Attachments 1 and 5

2 The market penetration of heat pumps in new construction is kept  
 3 constant at 25% throughout the forecast.

4 **Q: Are these estimates reasonable?**

5 A: That is difficult to say. Future conversion of other energy heating sources to  
 6 heat pumps are as dependent on policy and programs as on market behaviour  
 7 and customer interest. NS Power has a financing program to encourage the  
 8 conversion of fossil-fuel space heat to heat pumps, while EfficiencyOne

1 encourages conversion of resistance heat to heat pumps. The future of heat  
2 pumps should be considered as a set of decision variables in the IRP process.

3 **B. Water Heating**

4 **Q: What water-heating issues does NS Power address?**

5 A: NS Power says that it expects “that some customers who convert their oil  
6 heating systems to heat pumps will also convert their hot water supply to  
7 electric hot water tanks due to the annual operating savings.”<sup>4</sup>

8 **Q: What other water-heating issues should NS Power have addressed?**

9 A: NS Power appears to have overlooked the opportunity for encouraging  
10 existing and new water-heating customers to use heat-pump water heaters,  
11 which use less than half the energy.

12 **Q: Does NS Power address the peak load of existing and new water heaters?**

13 A: Yes. NS Power reports that “coincident system peak from water heaters  
14 shows that approximately one in five water heaters is on” at the peak hour.<sup>5</sup>

15 **Q: How does NS Power address options for reducing the contribution of  
16 water heating to peak load?**

17 A: NS Power notes that “the peak impact can potentially be mitigated through  
18 AMI enabled technology such as direct load control, the impact of which is  
19 currently being evaluated.”<sup>6</sup> NS Power does not estimate the effect on peak  
20 load of a system-wide program of controlling water heater storage. Direct

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<sup>4</sup> Ibid., p. 28, lines 5-7.

<sup>5</sup> Ibid., lines 13-14.

<sup>6</sup> Ibid., lines 15-16.



1 load control can be implemented very quickly, allowing water-heater loads to  
2 provide operating reserves and moderate ramping.

3 **Q: How should NS Power proceed with respect to water heating?**

4 A: NS Power should be working with EfficiencyOne to maximize the use of  
5 heat pumps for customers with electric water heating, both for existing water-  
6 heater installation and for conversions from oil (or propane). NS Power  
7 should also be preparing to implement load control for water heaters,  
8 including encouraging the installation of smart water heaters and running  
9 pilot programs for customers in areas in which AMI has been installed. Both  
10 of those issues should be addressed in the IRP process.

11 **C. *Behind-the-Meter Solar***

12 **Q: How does NS Power model the load effects of behind-the-meter solar  
13 installations?**

14 A: The load forecast only considers distributed small-scale solar installations  
15 that fall under NS Power's net metering program. These installations are  
16 mainly rooftop installations and reduce load primarily in the residential  
17 class.<sup>7</sup> There were 532 residential solar installations and 49 installations in all  
18 other customer classes through the net metering program as of 2018. The  
19 average installed capacity was 9.3kW and 16.8 kW for residential and non-  
20 residential customers, respectively, with an estimated 5.3 GWh of total  
21 annual net metering solar generation in 2018 based on a capacity factor of  
22 14%.<sup>8</sup>

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<sup>7</sup> Ibid., p. 31, lines 1-7.

<sup>8</sup> Ibid., lines 9-13.

1           Solar installations are anticipated to increase in the future due to  
2 initiatives like local Property Assessed Clean Energy (PACE) programs and  
3 the provincial SolarHomes rebate of \$1 per Watt of installed capacity.<sup>9</sup> The  
4 forecasted number of new residential installations was updated based on a  
5 study for the Canadian Solar Industries Association (CSIA) that modeled  
6 different solar uptake scenarios between 2019 and 2025. NS Power assumed  
7 that the SolarHomes rebate would continue through 2023 but gradually  
8 decline. In this projection, the CSIA study estimates that residential  
9 customers would add 42 MW by 2025; NS Power extends that forecast to  
10 170 MW by 2030.<sup>10</sup> NS Power added in non-residential installations, which it  
11 describes as “accounting for approximately 20 percent of total installed  
12 capacity.” NS Power estimates that these behind-the-meter solar installations  
13 will reduce load 56 GWh in 2025 and 178 GWh by 2030. NS Power says that  
14 “There is no anticipated impact to peak as generation occurs at times non-  
15 coincident with NS Power’s system peak (winter evenings).”<sup>11</sup>

16 **Q: What concerns do you have with NS Power’s projection of load**  
17 **reductions from behind-the-meter solar?**

18 A: This is another forecast component that is sensitive to policies, programs and  
19 rates. The NS Power projection seems reasonable, for the combination of net  
20 metering, PACE and the phase-out of the SolarHomes program, although  
21 installations will vary with the pricing of installed solar equipment. The IRP  
22 should consider whether the addition of behind-the-meter solar, especially

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<sup>9</sup> Ibid., lines 13-16.

<sup>10</sup> Ibid., lines 16-24.

<sup>11</sup> Ibid., p. 32, lines 4-12, which also notes that NS Power does not expect any significant amount of “solar/battery storage”.

1 with storage, would be cost-effective in avoiding generation costs, reducing  
2 distribution upgrades, and improving customer resilience in the inevitable  
3 outages of the delivery system.

4 **D. *Electric Vehicles***

5 **Q: How does NS Power model the load effects of electric vehicles?**

6 A: NS Power’s forecast of electric vehicle penetration is similar to those in the  
7 2018 load forecast, with approximately 223 electric vehicles in Nova Scotia  
8 by the end of 2018 and no EV purchasing incentives in the province.<sup>12</sup> NS  
9 Power says that the current forecast considers future vehicle availability,  
10 vehicle battery range, Electric Mobility Canada’s forecasted growth of EV  
11 market in Canada, and other global forecasts.<sup>13</sup> Figure 13 of the Load  
12 Forecast Report shows additions of electric vehicles increasing from 195  
13 additional vehicles in 2019 to 8,854 additional vehicles in 2029, for a total of  
14 45,531 post-2018 vehicles by 2029. NS Power forecasts that the post-2018  
15 electric-vehicle load will increase from 2 GWh in 2020 to 147 GWh in  
16 2029.<sup>14</sup> NS Power also projects that electric vehicles would increase system  
17 peak by 65 MW in 2029<sup>15</sup>, but that “around half the EV contribution to peak  
18 is assumed to be mitigated in the peak forecast.”<sup>16</sup> NS Power describes the  
19 basis for that assumption as follows:

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<sup>12</sup> Ibid., p. 29, lines 5-8.

<sup>13</sup> Ibid., lines 10-12.

<sup>14</sup> Ibid., p. 30, lines 4-5.

<sup>15</sup> Ibid., p. 60, Figure 31.

<sup>16</sup> Ibid., p. 59, lines 5-6.

1           There are no specific peak mitigation programs taken into account for  
2           the forecast, with the exception of the peak contribution of EVs. EVs are  
3           expected to be similar to other jurisdictions for which there is some data  
4           on the impact of peak mitigation measures. Possibilities for peak  
5           mitigation include items such as direct load control (space heating, hot  
6           water heating, or EVs), integration of battery storage, or rate design  
7           (time of use, critical peak pricing or other rates enabled by an AMI  
8           deployment). Critical peak pricing, for instance, is expected to  
9           contribute as much as 26MW of savings on peak by 2022. Although  
10          combinations of the above are likely to be implemented within Nova  
11          Scotia in the next 5-10 years, the amount of uncertainty surrounding the  
12          specific combinations or impacts makes it difficult to estimate. As rate  
13          design initiatives progress, in particular with the possibilities provided  
14          by AMI deployment, estimates for peak reduction will be updated in  
15          future load forecasts.<sup>17</sup>

16       **Q: Is this an appropriate approach?**

17       A: No. NS Power’s description is difficult to follow, since it veers from the issue  
18       to the effect of electric vehicles to the possibilities of a suite of offsetting  
19       “peak mitigation measures,” which includes direct load control of electric  
20       vehicles as an offset to electric vehicles. The IRP should consider the other  
21       peak mitigation measures (direct load control, battery storage, and rate  
22       designs) as resources. Since EVs can both increase and decrease peak loads,  
23       they must be approached as both a forecasting and a planning issue,  
24       involving policy, incentives and rate design affecting the number of electric  
25       vehicles used in the province, their usage patterns, and their interactions with  
26       the electric system.

27       **Q: How might electric vehicles reduce peak loads?**

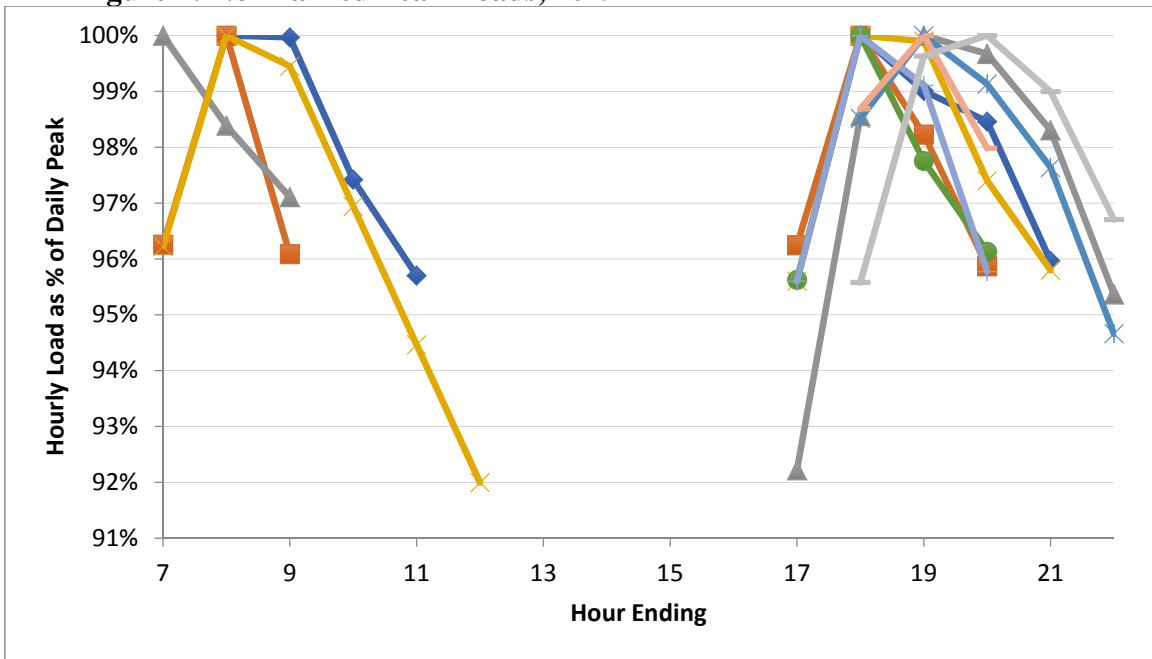
28       A: NS Power’s peak loads tend to occur in winter mornings and evenings, in  
29       blocks of up to five hours. Figure 1 shows the peak and near-peak loads on  
30       the thirteen highest-load days in January and February 2019. These days

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<sup>17</sup> Ibid., p. 57, lines 15-28

1 include the 34 highest-load hours, as well as any adjacent hours in the top  
2 100 hours. Each day had near-peak hours in the morning (four days), or in  
3 the evening (nine days), but not both. I normalized the loads to the daily  
4 peak; the hours I present cover all the hours within 5% of the daily peak load,  
5 and generally cover all the hours within about 100 MW of the daily peak.

6 **Figure 1: Normalized Peak Loads, 2019**



7  
8 A time-of-use rate, critical-peak pricing tariff, or other program to  
9 control the timing of electric vehicle charging could increase load in the  
10 midday, from about 11 AM to 4 PM, and again overnight, from 10 PM to 6 AM.  
11 Vehicles that are fully charged in the early morning could be used to feed  
12 energy back into the distribution system for at least parts of the morning  
13 peaks (for example, once a commuter gets to work and plugs in the vehicle).  
14 The same is true for vehicles that charge during the day and are plugged in  
15 during the evening (work vehicles that are parked in the business lot at the  
16 end of the day, or personal vehicles that are parked at home for the evening).

1           Not every vehicle will be able to operate in that manner every day.  
2           Some vehicles will be on the road, or otherwise away from charging  
3           facilities, during the peak periods. Other vehicles may have operating  
4           schedules that force them to charge in the peak periods. The mix of use cases  
5           (the general term describing the use of the vehicles and their schedules)  
6           within the Nova Scotia electric vehicle fleet will depend on the purchasing  
7           behaviour of consumers and businesses, as well as the incentives (such as  
8           financing of charging stations) and rates offered by NS Power. If NS Power  
9           offers packages of incentives and rates that are attractive to long-haul  
10          truckers (who may have limited flexibility in recharging schedules), the net  
11          effect may be an increase in peak loads. If the programs are attractive to  
12          commuters and to businesses whose vehicles can be charged overnight or  
13          midday (and be available to discharge during at least some of the peak  
14          hours), the peak and near-peak loads can be decreased. Since those peak and  
15          near-peak hours must account for a large portion of NS Power's risk of  
16          unserved energy, those load reductions would improve reliability, reduce the  
17          need for new capacity, and facilitate retirement of expensive existing  
18          generation.

19       **Q: How should NS Power proceed with respect to its forecast of electric**  
20       **vehicle loads?**

21       A: This issue should be further considered in the IRP. NS Power should also be  
22       working toward development of rates and other programs that will encourage  
23       the most valuable uses of electric vehicles.

1 **E. Advanced Metering Infrastructure**

2 **Q: How does NS Power deal with the load effects of AMI-enabled rates and**  
3 **programs?**

4 A: The Load Forecast Report mentions AMI in only two instances:

5 In the case of hot water heaters, the peak impact can potentially be  
6 mitigated through AMI enabled technology such as direct load control,  
7 the impact of which is currently being evaluated.<sup>18</sup>

8 There are no specific peak mitigation programs taken into account for  
9 the forecast, with the exception of the peak contribution of EVs. EVs are  
10 expected to be similar to other jurisdictions for which there is some data  
11 on the impact of peak mitigation measures. Possibilities for peak  
12 mitigation include items such as direct load control (space heating, hot  
13 water heating, or EVs), integration of battery storage, or rate design  
14 (time of use, critical peak pricing or other rates enabled by an AMI  
15 deployment). Critical peak pricing, for instance, is expected to  
16 contribute as much as 26MW of savings on peak by 2022. Although  
17 combinations of the above are likely to be implemented within Nova  
18 Scotia in the next 5-10 years, the amount of uncertainty surrounding the  
19 specific combinations or impacts makes it difficult to estimate. As rate  
20 design initiatives progress, in particular with the possibilities provided  
21 by AMI deployment, estimates for peak reduction will be updated in  
22 future load forecasts. The impact of any of these initiatives, at least  
23 within the 10 year timeframe of this forecast, is likely to fall within the  
24 sensitivity analysis provided in Section 11.<sup>19</sup>

25 On discovery, Synapse asked “What are current plans for rolling out  
26 AMI-based load control for water heaters?”<sup>20</sup>. NS Power responded by  
27 reference to its response to a related question in the 2018 Load Forecast  
28 Report review, “The AMI business case did not include benefits for load  
29 control of water heaters specifically; however it included benefits associated

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<sup>18</sup> Ibid., p. 28, lines 14-16.

<sup>19</sup> Ibid., p. 57, lines 15-28.

<sup>20</sup> 2019 Load Forecast Report Synapse IR-08, part d.

1 with an illustrative critical peak pricing program. NS Power will look into  
2 ways to leverage the system for demand response related initiatives as part of  
3 the review of time-varying pricing tariffs.”<sup>21</sup>

4 **Q: Is this response adequate?**

5 A: No. In approving the AMI investment over a year ago, the Board noted the  
6 importance of implementing a critical-peak pricing (CPP).

7 NSPI estimated that an opt-in CPP tariff targeting peak period load  
8 reductions during the winter could produce savings of \$27.0 million in  
9 the net present value of revenue requirement over a 20-year period. That  
10 estimate was based on avoiding capital investment associated with 26  
11 MW of generation capacity additions. The estimate assumed that 15% of  
12 residential customers would be enrolled onto the CPP tariff by 2022, and  
13 would collectively reduce their winter peak demand by 12.5%.<sup>22</sup>

14 The Board also quoted NS Power’s response to complaints that it had  
15 not yet devised a rate design to produce demand reductions from the AMI  
16 project.

17 For the purpose of this Application, it is largely irrelevant whether the  
18 forecast capacity savings is ultimately achieved through a CPP program  
19 or some other price offering or indeed, a suite of new time-of-use based  
20 price offerings across classes. Parties can be confident that by  
21 implementing the AMI system, the capacity benefits forecast in the  
22 Application will be realized. The Company’s evidence demonstrates it is  
23 more likely that this forecast capacity benefit will be exceeded  
24 significantly, as opposed to not fully realized.

25 Pending the Board’s approval of this capital project, the Company will  
26 develop its pricing plans and execute these in full collaboration with its  
27 customers and their representatives and other stakeholders.<sup>23</sup>

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<sup>21</sup> 2019 Load Forecast Report NSUARB IR-02 Attachment 1, p. 13.

<sup>22</sup> Board Decision, Matter No. M08349, June 11, 2018, ¶93, p. 29

<sup>23</sup> NSPI Reply to Closing Submissions, p. 15, quoted in Board Decision, Matter No. M08349, June 11, 2018, ¶101.



1           Since NS Power is committed to the considerable investment necessary  
2           to implement AMI, it has the opportunity to use the new meters and other  
3           infrastructure to minimize revenue requirements, including reducing and  
4           shifting loads through the implementation of CPP, time-of-use rates, feeder  
5           balancing, and voltage optimization. NS Power’s load forecast should also be  
6           reflecting projections of the load effects of these programs.

7   **Q: Is “the impact of any of these initiatives... likely to fall within the**  
8   **sensitivity analysis,” and if so, why should NS Power be thinking about**  
9   **the load effects of AMI-enabled programs?**

10 A: The impact of AMI-enabled initiatives are indeed likely to fall within the  
11 range of forecasts NS Power presents in Section 11 of the Load Forecast  
12 Report. But that range of forecasts is quite large.<sup>24</sup> By 2026, the high  
13 sensitivity would require (including 20% reserves) about 200 MW more  
14 capacity than the base case, or the equivalent of one-and-a-third of NS  
15 Power’s steam units. The low sensitivity, with more aggressive DSM, would  
16 require about 300 MW less capacity, or about two steam units.

17           While it is important to be aware that economic, technological, policy,  
18           and climatic conditions will vary among years and that anticipated long-term  
19           average trends may vary from current expectations, and to have contingency  
20           plans for higher and lower loads, NS Power cannot simultaneously plan for a  
21           vast range of future outcomes. Existing generation units are either sustained

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<sup>24</sup> I have not fully examined the derivation of NS Power’s sensitivity range, but it appears to conflate short-term variation in weather and economic conditions (which may be important in preparing for excursions of annual load from long-term trends) with uncertainty in the underlying long-term conditions. Hence, the spread from the Low Band to the High Band is essentially constant over time. I do not see any explicit allowance for secular multi-year changes in climate, economic trends, technology, or policy.

1 or allow to wear out and retire, new resources are either ordered or cancelled,  
2 distribution facilities are added or rebuilt to accommodate expected loads.  
3 Avoided costs must be computed for specific conditions.<sup>25</sup>

4 NS Power's base forecast should include the load effects it expects from  
5 its AMI investments. The uncertainties in those load effects can be included  
6 in the sensitivity band.

7 **Q: How should NS Power improve its treatment of the load effects of AMI-**  
8 **enabled programs?**

9 A: The IRP process should examine options for AMI programs and their effects  
10 on loads, costs and the need for new and continuing resources. In addition,  
11 and in coordination with the IRP, NS Power should be planning for  
12 implementation of its AMI-enabled programs, starting with pilot programs as  
13 necessary, and developing rates for the rate-related programs.

14 ***F. Energy-Efficiency Program Effects***

15 **Q: How does the load forecast reflect the effects of energy-efficiency**  
16 **programs?**

17 A: The Load Forecast Report says "Beyond 2019, DSM savings equal the base  
18 DSM scenario from the 2014 Integrated Resource Plan.... because the  
19 average annual savings in the base DSM forecast best match the expected  
20 average annual DSM savings from the 2017 to 2019 period."<sup>26</sup>

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<sup>25</sup> DSM options can be screened against avoided costs that reflect the average of multiple futures, but even those futures should be centered on the most likely case.

<sup>26</sup> Ibid., p. 38, lines 7-11.

1 **Q: Is this approach appropriate?**

2 A: This approach may have been reasonable at the time NS Power was  
3 developing the load forecast. As NS Power points out, “It is expected that the  
4 DSM forecast will be adjusted for the 2020 load forecast with inputs from the  
5 upcoming 2020-2022 DSM agreement, and any other relevant regulatory  
6 processes.”<sup>27</sup> I agree that the DSM forecast for 2020–2022 should be  
7 updated.

8 In addition, the IRP should consider the long-term role of energy-  
9 efficiency programs, for inclusion in future load forecasts.

10 **G. *Lighting Efficiency***

11 **Q: How does NS Power address trends in lighting efficiency?**

12 A: When asked about “the types of lighting technologies NS Power includes in  
13 its forecasting model and saturation by class (i.e., CFL, LED, etc.), NS  
14 Power replied that “Lighting types are not included explicitly in the forecast;  
15 however, the impact of increasingly efficient lighting can be seen in the  
16 change in efficiency and saturation over time.”<sup>28</sup>

17 I assume that NS Power means that the changing lighting efficiency  
18 over time is included in the *OtherIndex* variable of its residential SAE model:

19 
$$OtherIndex = g(\text{Other Appliance Saturation and Efficiency Trends})^{29}$$

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<sup>27</sup> Ibid., lines 11-13.

<sup>28</sup> 2019 Load Forecast Report CA IR-28.

<sup>29</sup> Ibid., p. 73, line 29.

1 **Q: Is this approach adequate?**

2 A: I do not see how it could capture the changes in the lighting efficiency over  
3 time.

4 If NS Power did not estimate the changing mix of lighting technologies  
5 over the historical period, it is not clear how the OtherIndex variable could  
6 have captured those trends in the historical residential data.<sup>30</sup> And if NS  
7 Power did not forecast the change in lighting energy intensity, it is not clear  
8 how the forecast could reflect future changes in the trends.

9 While this criticism could be applied to other portions of the SAE  
10 model, it is particularly serious for lighting. Lighting technology has changed  
11 dramatically over the last decade or so, with CFL lamps replacing  
12 incandescent lamps and then LEDs replacing the remaining incandescents,  
13 the CFLs and older fluorescent lighting. Much of that transition was captured  
14 in the estimated DSM savings, with some driven by regulation and market  
15 choices (driven by falling prices for CFLs and LEDs, greater familiarity and  
16 wider availability). As the market comes to dominate improvements in  
17 lighting efficiency, reducing the claimed lighting savings from DSM  
18 programs, pre-DSM load growth may be suppressed. But as the installed  
19 lighting mix moves closer to 100% LED, the incremental reductions will  
20 slow down. Without considering where Nova Scotia is in this transition and  
21 assuming some consistent trend in efficiency, NS Power may be overstating  
22 load in the near term, and perhaps understating load in the longer term.

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<sup>30</sup> Lighting saturation is generally treated as 100%, so the saturation trends would not affect lighting, unless NS Power were including some measure of the number of lamps, total lumens, and/or usage hours.

1 **Q: Why do you highlight the lighting part of efficiency trends?**

2 A: The lighting changeover has been more rapid than changes in other end uses,  
3 due to the short life of incandescent lamps, the ease of replacement, and the  
4 relatively low cost of the new lamps. An incandescent bulb may burn out  
5 after a year or so of use, creating an opportunity to screw in an LED  
6 replacement that only costs a few dollars more. Even unscrewing a  
7 functioning incandescent and throwing it away is not a large financial or  
8 logistical undertaking. Appliances tend to have longer lives and be more  
9 difficult and expensive to replace. Building shells (and replaceable  
10 components, such as windows) have even longer lives and major  
11 modifications are expensive and usually require the use of contractors and  
12 specialized vendors. It is not a great leap to assume that the turnover of older  
13 appliances and windows for newer, more efficient ones in the next decade  
14 will resemble that rate in the last decade. That would be an unrealistic  
15 assumption for lighting.

16 **Q: How does the NS Power load forecast account for changing efficiency of**  
17 **non-residential lighting?**

18 A: The commercial models are structured similarly to the residential models.  
19 The projections appear to be based on US EIA projections of commercial  
20 lighting use, which should include the effects of energy-efficiency programs  
21 and efficiency standards in areas without Nova Scotia's history of vigorous  
22 energy-efficiency programs. It is difficult to determine how well the  
23 commercial SAE models incorporate realistic changes in commercial lighting  
24 energy use.

1 **Q: How should NS Power improve this part of its load forecast?**

2 A: The historical lighting data should be harmonized with the treatment of  
3 baselines and free-ridership in the evaluations of EfficiencyOne (and earlier,  
4 NS Power) energy-efficiency programs. The forecast lighting efficiency  
5 should be harmonized with the baselines developed as part of the  
6 EfficiencyOne potential study. These activities could be pursued in the  
7 ongoing IRP process.

8 **Q: Does this conclude your testimony?**

9 A: Yes.

## Exhibit PLC-1

### PAUL L. CHERNICK

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#### SUMMARY OF PROFESSIONAL EXPERIENCE

- 1986–Present* **President, Resource Insight, Inc.** Consults and testifies in utility and insurance economics. Reviews utility supply-planning processes and outcomes: assesses prudence of prior power planning investment decisions, identifies excess generating capacity, analyzes effects of power-pool-pricing rules on equity and utility incentives. Reviews electric-utility rate design. Estimates magnitude and cost of future load growth. Designs and evaluates conservation programs for electric, natural-gas, and water utilities, including hook-up charges and conservation cost recovery mechanisms. Determines avoided costs due to cogenerators. Evaluates cogeneration rate risk. Negotiates cogeneration contracts. Reviews management and pricing of district heating systems. Determines fair profit margins for automobile and workers' compensation insurance lines, incorporating reward for risk, return on investments, and tax effects. Determines profitability of transportation services. Advises regulatory commissions in least-cost planning, rate design, and cost allocation.
- 1981–86* **Research Associate, Analysis and Inference, Inc.** (Consultant, 1980–81). Researched, advised, and testified in various aspects of utility and insurance regulation. Designed self-insurance pool for nuclear decommissioning; estimated probability and cost of insurable events, and rate levels; assessed alternative rate designs. Projected nuclear power plant construction, operation, and decommissioning costs. Assessed reasonableness of earlier estimates of nuclear power plant construction schedules and costs. Reviewed prudence of utility construction decisions. Consulted on utility rate-design issues, including small-power-producer rates; retail natural-gas rates; public-agency electric rates, and comprehensive electric-rate design for a regional power agency. Developed electricity cost allocations between customer classes. Reviewed district-heating-system efficiency. Proposed power-plant performance standards. Analyzed auto-insurance profit requirements. Designed utility-financed, decentralized conservation program. Analyzed cost-effectiveness of transmission lines.
- 1977–81* **Utility Rate Analyst, Massachusetts Attorney General.** Analyzed utility filings and prepared alternative proposals. Participated in rate negotiations, discovery, cross-examination, and briefing. Provided extensive expert testimony before various regulatory agencies. Topics included demand forecasting, rate design, marginal costs, time-of-use rates, reliability issues, power-pool operations, nuclear-power cost projections, power-plant cost-benefit analysis, energy conservation, and alternative-energy development.

## EDUCATION

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

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

## HONORS

Chi Epsilon (Civil Engineering)

Tau Beta Pi (Engineering)

Sigma Xi (Research)

Institute Award, Institute of Public Utilities, 1981.

## PUBLICATIONS

“Price Effects as a Benefit of Energy-Efficiency Programs” (with John Plunkett), *2014 ACEEE Summer Study on Energy Efficiency in Buildings* (5) 57–5-69. 2014.

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“Conservation Potential in the State of Minnesota,” (with Ian Goodman) Minnesota Department of Public Service, June 16 1988.

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## **PRESENTATIONS**

“Rethinking Utility Rate Design—Retail Demand and Energy Charges,” Solar Power PV Conference, Boston MA, February 24, 2016.

“Residential Demand Charges - Load Effects, Fairness & Rate Design Implications.” Web seminar sponsored by the NixTheFix Forum. September 2015.

“The Value of Demand Reduction Induced Price Effects.” With Chris Neme. Web seminar sponsored by the Regulatory Assistance Project. March 2015.

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

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

“Distributed Utility Planning.” With Steve Litkovitz. Presentation to the Vermont Distributed-Utility-Planning Collaborative. November 1999.

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

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

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## **ADVISORY ASSIGNMENTS TO REGULATORY COMMISSIONS**

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

Austin City Council, Austin Energy Rates, March to June 2012.

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## EXPERT TESTIMONY

1. **Mass. EFSC 78-12/MDPU 19494, Phase I; Boston Edison 1978 forecast; Massachusetts Attorney General. June 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 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 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 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 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 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 1979.**

Critique of utility marginal cost study and proposed rates; principles of marginal cost principles, cost derivation, and rate design; options for reconciling costs and revenues. Joint testimony with 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 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 1980.

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

10. **Mass. DPU 200**, Massachusetts Electric Company rate case; Massachusetts Attorney General. June 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 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 1980.

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

13. **Texas PUC 3298**, Gulf States Utilities rates; East Texas Legal Services. August 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 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 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 1981 and February 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 1981.

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 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. DC PSC FC785**, Potomac Electric Power rate case; DC Peoples Counsel. July 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 DE 81-312**, Public Service of New Hampshire supply and demand; Conservation Law Foundation et al. October 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. CC 82-0026**, Commonwealth Edison rate case; Illinois Attorney General. October 1982.

Review of Cost-Benefit Analysis for nuclear plant. Nuclear cost parameters (construction cost, O&M, capital additions, useful life, 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 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 Consumer Advocate. November 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 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 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 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 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 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 1985 and October 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 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 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 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 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 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 1986.

Recommendations for power-plant performance standards for Palo Verde nuclear units 1, 2, and 3.

- 53. Ill. CC 86-0325**, Iowa-Illinois Gas and Electric Co. rate investigation; Illinois Office of Public Counsel. August 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 1986.

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 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 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 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 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 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 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 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 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 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 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 1988.

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

- 68. Mass. DPU 88-123**, petition of Riverside Steam & Electric; Riverside Steam and Electric Company. May 1988 and November 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 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 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 1988, supplemented August 1988; Losses and Expenses, September 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 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 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 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 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 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 rates; Massachusetts Energy Office. June 1989.

Prudence of decision to spend \$400 million from 1986–88 to return Pilgrim nuclear 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 1989. Rebuttal, October 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 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 1989. Surrebuttal February 1990.

Analysis of a proposed 20-year power purchase. Comparison to efficiency investment. Critique of conservation potential analysis. Analysis of Vermont electric energy supply. Planning risk of large supply additions. Valuation of environmental externalities. Identification of possible improvements to proposed contract.

- 81. Mass. DPU 89-239**, inclusion of externalities in energy-supply planning, acquisition, and dispatch for Massachusetts utilities. Boston Gas Company. 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 1990.

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

- 83. Ill. CC 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 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 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. URC**, integrated-resource-planning docket; Indiana Office of Utility Consumer Counselor. November 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 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 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 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**, commission investigation; Southern Environmental Law Center. March 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 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 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 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 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 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 1991.

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

- 96. Mass. DPU 91-131**, update of externalities values adopted in Docket 89-239; Boston Gas Company. October 1991. Rebuttal, December 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 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 1991.

Obligation to pursue integrated resource planning, 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 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 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 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 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. UC E-100 Sub 64**, integrated-resource-planning docket; Southern Environmental Law Center. September 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 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 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 1992.

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

- 108. N.C. UC E-100 Sub 64**, analysis and investigation of least cost integrated resource planning in North Carolina; Southern Environmental Law Center. November 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 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 1993; rebuttal February 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 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. CC 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. UC 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. UC E-2 Sub 669. December 1995.**  
Need for new capacity. Energy-conservation potential and model programs.
- 136. Arizona CC 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 incentive mechanisms in rates for the Consumers Gas Company.
- 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.

- Proposed power-supply arrangements between APS's potential 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. UC 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. URC 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 to October 2013.**

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 August 2006 to October 2013.**

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 M01439**, 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 M01496**, 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. Also filed and presented in **MA EFSB 08-02**, February 2010.
- 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. UC 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 M02961**, 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 M03665**, 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 M03665**, 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 M03632**, 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 M04104**; 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 M04175**, 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. CC 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. CC 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 M04819**, 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 CC 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 M04862**, 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. UC** 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. Conn. PURA** Docket No. 14-01-01, Connecticut Light and Power Procurement of Standard Service and Last-Resort Service. July and October 2014.
- Proxy for review of bids. Oversight of procurement and selection process.
- 288. Conn. PURA** Docket No. 14-01-02, United Illuminating Procurement of Standard Service and Last-Resort Service. January, April, July, and October 2014.
- Proxy for review of bids. Oversight of procurement and selection process.
- 289. 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.
- 290. 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.
- 291. 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.

- 292. 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.
- 293. 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.
- 294. 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.
- 295. 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.
- 296. Québec Régie de L'énergie** R-3867-2013 phase 1, Gaz Métro cost allocation and rate structure; ROEE. 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.
- 297. Conn. PURA** Docket No. 15-01-01, Connecticut Light and Power Procurement of Standard Service and Last-Resort Service. February and July 2015.
- Proxy for review of bids. Oversight of procurement and selection process.
- 298. Conn. PURA** Docket No. 15-01-02, United Illuminating Procurement of Standard Service and Last-Resort Service. February, July, and October 2015.
- Proxy for review of bids. Oversight of procurement and selection process.
- 299. Ky. PSC** 2014-00371, Kentucky Utilities electric rates; Sierra Club. March 2015.
- Review basis for higher customer charges, including cost allocation. Design of time-of-day rates.



- 300. Ky. PSC 2014-00372**, Louisville Gas and Electric electric rates; Sierra Club. March 2015.
- Review basis for higher customer charges, including cost allocation. Design of time-of-day rates.
- 301. Mich. PSC U-17767**, DTE Electric Company rates; Michigan Environmental Council, Sierra Club, and Natural Resource Defense Council. May 2015.
- Cost effectiveness of pollution-control retrofits versus retirements. Market prices. Costs of alternatives.
- 302. N.S. UARB M06733**, supply agreement between Efficiency One and Nova Scotia Power; Nova Scotia Consumer Advocate. June 2015.
- Avoided costs. Cost-effectiveness screening of DSM. Portfolio design. Affordability and bill effects.
- 303. Penn. PUC P-2014-2459362**, Philadelphia Gas Works DSM, universal-service, and energy-conservation plans; Philadelphia Gas Works. Direct, May 2015; Rebuttal, July 2015.
- Avoided costs. Recovery of lost margin.
- 304. Ont. Energy Board EB-2015-0029/0049**, 2015–2020 DSM Plans Of Enbridge Gas Distribution and Union Gas, Green Energy Coalition. Evidence July 31, 2015, Corrected August 12, 2015.
- Avoided costs: price mitigation, carbon prices, marginal gas supply costs, avoidable distribution costs, avoidable upstream costs (including utility-owned pipeline facilities).
- 305. PUC Ohio Case No. 14-1693-EL-RDR**, AEP Ohio Affiliate purchased-power agreement, Sierra Club. September 2015.
- Economics of proposed PPA, market energy and capacity projections. Risk shifting. Lack of price stability and reliability benefits. Market viability of PPA units.
- 306. N.S. UARB Matter No. M06214**, NS Power Renewable-to-Retail rate, Nova Scotia Consumer Advocate. November 2015.
- Review of proposed design of rate for third-party sales of renewable energy to retail customers. Distribution, transmission and generation charges.
- 307. PUC Texas Docket No. 44941**, El Paso Electric rates; Energy Freedom Coalition of America. December 2015.
- Cost allocation and rate design. Effect of proposed DG rate on solar customers. Load shapes of residential customers with and without solar. Problems with demand charges.

- 308. N.S. UARB** Matter No. M07176, NS Power 2016 Capital Expenditures Plan, Nova Scotia Consumer Advocate. February 2016.

Economic evaluation of proposed projects, including replacement energy costs and modeling of equipment failures. Treatment of capitalized overheads and depreciation cash flow in computation of rate effects of spending plan.

- 309. Md. PSC** Case No. 9406, BGE Application for recovery of Smart Meter costs, Maryland Office of People’s Counsel. Direct February 2016, Rebuttal March 2016, Surrebuttal March 2016.

Assessment of benefits of Smart Meter programs for energy revenue, load reductions and price mitigation; capacity load reductions and price mitigation; free riders and load shifting in peak-time rebate (PTR) program; cost of PTR participation; effect of load reductions on PJM capacity obligations, capacity prices and T&D costs.

- 310. City of Austin TX**, Austin Energy 2016 Rate Review, Sierra Club and Public Citizen. May 2016

Allocation of generation costs. Residential rate design. Geographical rate differentials. Recognition of coal-plant retirement costs.

- 311. Manitoba PUB**, Manitoba Hydro Cost of Service Methodology Review, Green Action Centre. June 2016, reply August 2016.

Allocation of generation costs. Identifying generation-related transmission assets. Treatment of subtransmission. Classification of distribution lines. Allocation of distribution substations and lines. Customer allocators. Shared service drops.

- 312. Md. PSC** Case No. 9418, PEPCo Application for recovery of Smart Meter costs, Maryland Office of People’s Counsel. Direct July 2016, Rebuttal August 2016, Surrebuttal September 2016.

Assessment of benefits of Smart Meter programs for energy revenue, load reductions and price mitigation; load reductions in dynamic-pricing (DP) program; cost of DP participation; effect of load reductions on PJM capacity obligations, capacity prices and T&D costs.

- 313. Md. PSC** Case No. 9424, Delmarva P&L Application for recovery of Smart Meter costs, Maryland Office of People’s Counsel. Direct September 2016, Rebuttal October 2016, Surrebuttal October 2016.

Estimation of effects of Smart Meter programs—dynamic pricing (DP), conservation voltage reduction and an informational program—on wholesale revenues, wholesale prices and avoided costs; estimating load reductions from the DP program; cost of DP participation; effect of load reductions on PJM capacity obligations, capacity prices and T&D costs.

- 314. N.H. PUC** Docket No. DE 16-576, Alternative Net Metering Tariffs, Conservation Law Foundation. Direct October 2016, Reply December 2016.

Framework for evaluating rates for distributed generation. Costs avoided and imposed by distributed solar. Rate design for distributed generation.

- 315. Puerto Rico Energy Commission** CEPR-AP-2015-0001, Puerto Rico Electric Power Authority rate proceeding, PR Energy Commission. Report December 2016.

Comprehensive review of structure of electric utility, cost causation, load data, cost allocation, revenue allocation, marginal costs, retail rate designs, identification and treatment of customer subsidies, structuring rate riders, and rates for distributed generation and net metering.

- 316. N.S. UARB** Matter No. M07745, NS Power 2017 Capital Expenditures Plan, Nova Scotia Consumer Advocate. January 2017.

Computation and presentation of rate effects. Consistency of assumed plant operation and replacement power costs. Control of total cost of small projects. Coordination of information-technology investments. Investments in biomass plant with uncertain future.

- 317. N.S. UARB** Matter No. M07746, NS Power Enterprise Resource Planning project, Nova Scotia Consumer Advocate. February 2017.

Estimated software project costs. Costs of internal and contractor labor. Affiliate cost allocation.

- 318. N.S. UARB** Matter No. M07767, NS Power Advanced Metering Infrastructure projects, Nova Scotia Consumer Advocate. February 2017.

Design and goals of the AMI pilot program. Procurement. Coordination with information-technology and software projects.

- 319. Québec Régie de l'énergie** R-3867-2013 phase 3A; Gaz Métro estimates of marginal O&M costs; ROEÉ. March 2017.

Estimation of one-time, continuing and periodic customer-related operating and maintenance cost. Costs related to loads and revenues. Dealing with lumpy costs.

- 320. N.S. UARB** Matter No. M07718, NS Power Maritime Link Cost Recovery, Nova Scotia Consumer Advocate. April 2017.

Usefulness of transmission interconnection prior to operation of the associated power plant.

- 321. Mass. DPU** 17-05, Eversource Rate Case, Cape Light Compact. Direct April 2017, Rebuttal May 2017.

Critique of proposed performance-based ratemaking mechanism. Proposal for improvements.

- 322. PUCO 16-1852**, AEP Ohio Electric Security Plan, Natural Resources Defense Council. May 2017.
- Residential customer charge. Cost causation. Effect of rate design on consumption.
- 323. Iowa Utilities Board RPU-2017-0001**, Interstate Power and Light rate case, Natural Resources Defense Council. Direct August 2017, Reply September 2017.
- Critique of proposed demand-charge pilot rates for residential and small commercial customers. Defects of demand rates and shortcomings of IPL experimental proposal design.
- 324. N.S. UARB Matter No. M08087**, NS Power 2017 Load Forecast, Nova Scotia Consumer Advocate. Direct August 2017.
- Review of forecast methodology, including extrapolation of drivers of commercial load from US national data; treatment of non-firm and competitive loads; behind-the-meter generation and controlling peak-load growth.
- 325. Québec Régie de l'énergie R-3867-2013 phase 3B**; Gaz Métro line-extension policy; ROÉÉ. September 2017.
- The costs of adding new load. Estimating the durability of revenues from line extensions.
- 326. Mass. EFSB 17-02**; Eversource proposed Hudson-Sudbury transmission line; Town of Sudbury. October 2017.
- Accuracy of ISO New England regional load forecasts. Potential for distributed solar, storage and demand response.
- 327. Manitoba PUB**, Manitoba 2017/18 & 2018/19 General Rate Application; Green Action Coalition. October 2017.
- Marginal costs. Rate design. Affordability rate design for low-income and electric-heating customers. Design of residential inclining blocks. Problems with demand charges and demand ratchets. Cost-of-service study improvements.
- 328. N.S. UARB Matter No. M08383**, NS Power 2018 Annually Adjusted Rates; Consumer Advocate. January 2018.
- Projection of incremental dispatch cost. Computing administrative charges. Methodological issues.

- 329. N.S. UARB** Matter No. M08349, NS Power’s Advanced Metering Infrastructure Proposal; Consumer Advocate. January 2018.

Estimation of AMI benefits: load balancing among feeders, critical peak pricing, avoided costs of meters for distributed generation. NS Power’s claims of benefits from accounting credits (AFUDC, overheads, and converting write-offs to reduced revenue) and shifting costs to customers (earlier billing, higher recorded usage). Realistic AMI meter life. Excessive charge for customers who opt out of AMI.

- 330. N.S. UARB** Matter No. M08350, NS Power 2018 Annual Capital Expenditures Plan; Consumer Advocate. February 2018.

Overlap between ACE projects and AMI project. Hydro project planning and valuation of lost hydro energy output.

- 331. Conn. PURA** Docket No. 08-01-01RE05, Proposed Amendment to Peaker Contracts; Connecticut Consumers Counsel. May 2018.

Dividing increased revenues from ISO-NE’s Pay-for-Performance mechanism between contract generators and ratepayers.

- 332. Kansas CC** Docket No. 18-WSEE-328-RTS, Westar Rate Case; Sierra Club. Direct June 2018. Rebuttal June 2018. Supplement July 2018.

Costs and benefits of running Westar coal plants. Costs of renewables and other alternatives. Recommendation regarding planning, coal retirement schedule, and acquisition of leased capacity.

- 333. Cal. PUC** Application 17-09-006; Pacific Gas and Electric Gas Cost Allocation Proceeding; Small Business Utility Advocates. Direct June 2018.

Allocation of gas distribution system costs. Allocation of costs of energy-efficiency programs.

- 334. N.S. UARB** Matter No. M08670, NS Power 2018 Load Forecast, Nova Scotia Consumer Advocate. Direct July 2018.

Review of forecast methodology, including treatment of future energy-efficiency programs, treatment of third-party supply and behind-the-meter generation.

- 335. Iowa Utilities Board** RPU-2018-0003, MidAmerican Energy Request for Approval of Ratemaking Principles for Wind XII; Sierra Club. Direct August 2018.

Cost and benefits of continued operation of six MidAmerican coal-fired units.

- 336. Cal. PUC** A.18-02-016, 03-001, 03-002; 2018 Energy Storage Plans; Small Business Utility Advocates. Direct, Rebuttal and Supplement, August 2018.

Excessive reliance on substation-sited storage. Need for increased emphasis on customer-sited and shared storage. Maximizing benefits, total and for small business. Oversizing of SDG&E proposed installations. Cost recovery. Storage technology diversity.

- 337. La. PSC** U-34794; Cleco Corp Purchase of NRG Assets and Contracts; Sierra Club. Direct, September 2018.

Economics of NRG generation resources, Cleco Power coal plants and wholesale sales contracts. Risks of the proposed transaction.

## ACRONYMS AND INITIALISMS

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