STATE OF NEW HAMPSHIRE

BEFORE THE PUBLIC UTILITIES COMMISSION

Liberty Utilities Least Cost	**)**	
Integrated Resource Plan	**)**	**Docket No. DG 17-152**
	)	
	)	

DIRECT TESTIMONY OF

PAUL CHERNICK

ON BEHALF OF

CONSERVATION LAW FOUNDATION

Resource Insight, Inc.

SEPTEMBER 6, 2019

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EXHIBITS

I. Identification & Qualifications

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

A: My name is Paul L. Chernick. I am the president of Resource Insight, Incorporated, 5 Water Street, Arlington, Massachusetts.

Q: Summarize your professional education and experience.

A: I received a Bachelor of Science degree from the Massachusetts Institute of Technology in June 1974 from the Civil Engineering Department, and a Master of Science degree from the Massachusetts Institute of Technology in February 1978 in technology and policy.

I was a utility analyst for the Massachusetts Attorney General for more than three years. I was involved in numerous aspects of utility rate design, costing, load forecasting, and the evaluation of power supply options. Since 1981, I have been a consultant in utility regulation and planning, first as a research associate at Analysis and Inference, after 1986 as president of PLC, Inc., and in my current position at Resource Insight since 1990. In these capacities, I have advised a variety of clients on utility matters.

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

Q: Have you testified previously in utility proceedings?

A: Yes. I have testified over three hundred times on utility issues before various regulatory, legislative, and judicial bodies, including utility regulators in thirty-seven states and six Canadian provinces, and three U.S. federal agencies. This previous testimony has included many reviews of the economics of power plants, utility planning, marginal costs, and related issues.

Q: On whose behalf have you worked?

A: A large percentage of my testimony has been filed on behalf of consumer advocates (e.g., the Massachusetts, New Mexico, Washington, and Illinois Attorney Generals; other official public consumer advocates in Connecticut, Maine, Massachusetts, New Hampshire, New Jersey, Pennsylvania, Illinois, Minnesota, Maryland, Ohio, Vermont, Indiana, South Carolina, Arizona, West Virginia, Utah, District of Columbia, and Nova Scotia; and such non-profit consumer advocates as AARP, East Texas Legal Services, Public Interest Research Groups, Alliance for Affordable Energy, citizens' groups, Ontario School Energy Group, Citizens Action Coalition, and Small Business Utility Advocates). I have also worked for regulatory bodies in Massachusetts, Connecticut, District of Columbia, and Puerto Rico, as well as the Vermont House of Representatives.

The remainder of my clients include investor-owned and municipal utilities, municipalities (New York City, Chicago, Cincinnati, several Massachusetts, New Hampshire and New York towns in various proceedings), large customers, power-plant developers and owners, labor unions, energy advocates and environmental groups.

II. Introduction

Q: On whose behalf are you testifying?

A: I am testifying on behalf of Conservation Law Foundation.

Q: What is the scope of your testimony?

A: I consider the following issues raised in Liberty's Least Cost Integrated Resource Plan (LCIRP), filed on October 2, 2017:

- The role of increased gas penetration in Liberty's load forecast.
- The imprudence of encouraging shifting energy load to gas.
- The uncertainty in future gas use and the resulting risk of commitment to new pipelines.
- The need to consider alternatives to the Granite Bridge Pipeline, the major project in Liberty's LCIRP (and the subject of Docket No. DG 17-198), and the upstream pipeline contracts that Liberty proposes to utilize Granite Bridge.

Q: Please summarize your conclusions and recommendations.

A: Liberty's LCIRP does not advance economically prudent or environmentally sound energy investments, and therefore is not consistent with New Hampshire's planning requirements.

Even with supplementary testimony required by the Commission's finding that the Company's LCIRP filing was incomplete, Liberty does not include an evaluation of alternatives to new natural gas infrastructure investments and commitments that it proposes will be borne by ratepayers.

The plan fails to recognize and incorporate the need to reduce fossil fuel use—including natural gas—to mitigate climate change and pollution impacts.

The plan fails to reasonably address future need in light of the availability of cleaner and lower cost resources, including electricity and high-performance air-source electric heat pumps.

There is significant risk that the plan will result in future stranded costs and higher customer costs, as New Hampshire transitions away from direct use of fossil fuels to cleaner energy resources.

Q: What is the global and national background to local decisions about natural gas use?

A: Natural gas use, in New Hampshire and nationally, must decline if we are to avoid the most severe consequences of global warming, as discussed in the testimony of CLF witness Elizabeth Stanton in this docket. About two dozen US regulatory jurisdictions have recognized this reality by establishing greenhouse-gas reduction targets, including California,[1] Connecticut, Massachusetts, Vermont, Maine, and New York. In order to minimize the economic burden of unsustainable long-term commitments, New Hampshire would be well advised to similarly reflect the carbon-constrained future in current decision-making.

Q: Does Liberty address the greenhouse-gas implications of its planned expansions of gas supply and sales?

A: In a sense. Mr. Killeen basically denies that Liberty needs to think about greenhouse gases at all, because the Company interpret[s] the requirement to assess the LCIRP's "integration and impact on state compliance with the Clean Air Act of 1990, as amended, and other environmental laws that may impact a utility's assets or customers," as required by RSA 378:38, V" in narrow terms:

> The goal of the Clean Air Act of 1990, as amended (the "Act"), is primarily to "curb three major threats to the nation's environment and to the health of millions of Americans: acid rain, urban air pollution, and toxic air emissions." (Killeen Direct at 7:14–20).

[1] Draft Results: Future of Natural Gas Distribution in California, CEC Staff Workshop for CEC PIER-16-011, June 6, 2019, available at https://ww2.energy.ca.gov/research/notices/2019-06-06_workshop/2019-06-06_Future_of_Gas_Distribution.pdf.

> To achieve these goals, and relevant here, the Act "requires states to make constant formidable progress in reducing emissions," through programs and policies that "promote[] the use of clean low sulfur coal and natural gas, as well as innovative technologies to clean high sulfur coal through the acid rain program [and] and create[] enough of a market for clean fuels derived from grain and natural gas to cut dependency on oil imports by one million barrels/day." *Id*.
>
> …the increased use of natural gas will have a positive contribution toward achieving New Hampshire's required emissions levels under the Act. Since the LCIRP describes how the Company can meet its growing customer demand over the planning period, and increased natural gas usage is specifically and favorably referenced in the Act (likely because natural gas most often displaces other more polluting fuels such as oil and propane for heating, as will likely be the case with most of EnergyNorth's new customers), the LCIRP would likely have a positive impact on New Hampshire's compliance with the Act.

Q: Is Mr. Killeen correct that only "acid rain, urban air pollution, and toxic air emissions" matter under the Act, and that the Act does not cover greenhouse gases?

A: No. The Supreme Court addressed a similar issue in the context of EPA's refusal to treat greenhouse gas emissions as pollutants and found that:

> The harms associated with climate change are serious and well recognized. The Government's own objective assessment of the relevant science and a strong consensus among qualified experts indicate that global warming threatens, inter alia, a precipitate rise in sea levels, severe and irreversible changes to natural ecosystems, a significant reduction in winter snowpack with direct and important economic consequences, and increases in the spread of disease and the ferocity of weather events….
>
> Because greenhouse gases fit well within the Act's capacious definition of "air pollutant," EPA has statutory authority to regulate emission of such gases….That definition—which includes "any air pollution agent… including *any* physical, chemical, …substance…emitted into…the ambient air…," §7602(g) (emphasis added)—embraces all airborne compounds of whatever stripe. Moreover, carbon dioxide and other greenhouse gases are undoubtedly "physical [and] chemical… substance[s]."[2]

[2] U.S. Supreme Court, Massachusetts v EPA, Decided April 2, 2007, Docket #05-1120.

The Supreme Court has found that the Act covers greenhouse gases. Mr. Killeen's attempt to rewrite the law is ill-founded.

Q: What portions of the Act was Mr. Killeen quoting in the section of his testimony that you copied above?

A: None that I could find. He cites to an EPA web page that purports to be a summary on the Clean Air Act. Neither Mr. Killeen nor the EPA web page cites to the actual Act. The language that Mr. Killeen cites does not appear in the January 17, 2017 snapshot of the site.[3]

Q: Where does the Act "specifically and favorably reference" increased natural gas usage, as Mr. Killeen claims?

A: He does not cite to the Act. Again, he misrepresents the recent EPA gloss as if it were the Act. I found three references to "natural gas" in Title V of the Act; two were involved in determining allowance assignments, and the third describes extra allowances allocated to a municipal or state utility that "furnishes electricity, electric energy, steam, and natural gas within an area consisting of a city and 1 contiguous county." The closest I find to an endorsement of natural gas is in the definition of "clean alternative fuel" to mean "any fuel (including methanol, ethanol, or other alcohols (including any mixture thereof containing 85 percent or more by volume of such alcohol with gasoline or other fuels), reformulated gasoline, diesel, natural gas, liquefied petroleum gas, and hydrogen) or power source (including electricity) used in a clean-fuel vehicle that complies with the standards and requirements applicable to such vehicle…" (42 U.S.C. §7581; §7554 has similar language with regards to urban buses).[4]

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[3] https://19january2017snapshot.epa.gov/clean-air-act-overview/clean-air-act-text.html.

[4] The Energy Independence and Security Act of 2007 (Title II.A) amended the renewable fuels standards in the Clean Air Act and mentioned natural gas in the contexts of setting efficiency standards for gas-fired ethanol plants and exempting ethanol plants fueled by natural gas or biomass from greenhouse gas emissions standards for a transition period in 2008 and 2009.

Q: Did Mr. Killeen establish that increased gas use will help mitigate New Hampshire greenhouse gas emissions, as required by the Supreme Court's finding that those emissions are covered by the Act?

A: No. He concentrates on criteria pollutants and compares natural gas only to dirtier fuels, not to cleaner electric energy from renewables or even high-efficiency gas. The analysis of "potential environmental, economic, and health-related impacts of each option proposed in the LCIRP" (Killeen Direct Testimony at 12:4–5) remains inadequate.

III. Gas Promotion in Liberty's Load Forecast

Q: What is Liberty's justification for Granite Bridge and the associated supply contracts?

A: Mr. Killeen explains that the Company's claimed need for Granite Bridge arises from forecast load growth:

> Q. Is the Company's existing delivery capacity sufficient to meet the forecasted demand requirements of its customers?
>
> A. No. The Company's design day demand during the planning period will exceed its capacity on the Concord Lateral, and there is no more capacity available on the Concord Lateral…(Killeen Direct at 7:5–8).

He similarly explains that forecast load growth drives the need for the new supply contracts:

> Q. Is the Company's existing gas supply sufficient to meet the forecasted demand?
>
> A. No. Although the Company currently has sufficient supplies to use all the available capacity on the Concord Lateral, the Company does not have the incremental supply to meet the forecasted increase in demand. Specifically, the Company requires incremental supply during the development of the Granite Bridge Pipeline, and to utilize the capacity of the Granite Bridge Pipeline once it is placed into service.

In other words, load growth drives Liberty's case for both Granite Bridge and the new long-term supply contracts.

Q: How much of Liberty's projected load growth would result from its promotion of conversion from other fuels to natural gas?

A: Table 1 reproduces Liberty's forecast based on historical trends (which would include some fuel-switching from other fuels to natural gas) and Liberty's total forecast, including the results of Liberty's fuel-switching efforts.[5]

Table 1: Effect of Fuel-Switching Promotion on Liberty Load Forecast (BBtu)

	Residential		C&I		Total
	Heating	Non-Heating	Heating	Non-Heating	
From LCIRP Table 20: Econometric Demand Forecast					
2017/18	6,025	68	6,242	1,984	14,319
2018/19	6,089	66	6,332	1,979	14,466
2019/20	6,168	64	6,422	1,963	14,617
2020/21	6,235	62	6,484	1,942	14,722
2021/22	6,308	59	6,568	1,922	14,858
From LCIRP Table 23: Demand Forecast Including Promotion					
2017/18	6,302	68	6,670	2,102	15,142
2018/19	6,427	66	6,871	2,119	15,483
2019/20	6,568	64	7,107	2,147	15,885
2020/21	6,733	62	7,375	2,192	16,360
2021/22	6,908	59	7,655	2,228	16,851
Promotional Load Growth					
2017/18	277	-	428	118	823
2018/19	338	-	538	140	1,017
2019/20	400	-	684	184	1,268
2020/21	498	-	891	250	1,638
2021/22	600	-	1,088	305	1,993

Q: Please describe Liberty's promotional efforts.

A: The difference between the model results in LCIRP Table 20 and the enhanced forecast in LCIRP Table 23 is due to the effect of two Liberty programs, as estimated by EnergyNorth's Sales and Marketing Group:

[5] The values in both LCIRP Table 20 (before the load-promotion efforts) and Table 23 (with load promotion) are both prior to the inclusion of energy efficiency.

> Two out-of-model adjustments were made to the econometric forecast to account for additional growth that is not reflected in the historical billing data. Those out-of-model adjustments were related to: (1) expected increases in the number of customers in the Company's existing service territory related to increasing sales and marketing efforts; and (2) estimates of the number of customers in new service territories in which the Company is expanding. (LCIRP, pages 21–22).

The additional natural gas use by new customers resulting from Liberty's planned promotion efforts accounts for 68% of the load growth that Liberty projects over the forecast period. Without these new heating customers, Liberty's forecast would fall from 2.7% annually to 0.9%.

Q: What are the implications of the large role of fuel-switching in Liberty's forecast?

A: If Liberty were not promoting the shifting of customer loads from other fuels to natural gas, its need for additional resources would be dramatically reduced. Liberty's case for acquiring additional gas supplies is driven by Liberty's own plans to increase sales, but Liberty has not shown that such increases in natural gas combustion are in the public interest. Thus, the LCIRP is neither integrated nor least-cost.

IV. Shifting Energy Load Among Fuels

Q: Does Liberty consider whether shifting customer energy use to gas would have environmental effects?

A: Yes, to some extent. That position is presented in the testimony of Paul J. Hibbard, who states that:

> Meeting customer service needs can result in local and regional health impacts. This is because the combustion of fuel to meet home and business heating (and other service needs) is a source of harmful pollutants - including NOx, SO2, PM, Hg, and CO2. CO2 (and other GHGs involved in energy production and use, such as methane) contribute to the risks associated with climate change. The rest of the pollutants can have local and regional impacts, and can lead to or exacerbate premature deaths, asthma, and other major health problems for the state's residents" (Hibbard Direct 23:3-19)

> The use of natural gas to meet [heat, hot water, and cooking] needs can reduce the emissions that otherwise would occur if they were met with alternative fuels. To the extent meeting service needs with natural gas avoids using alternative and higher-emitting fuels, it can reduce public health and environmental impacts. (Ibid, 25:15–26:3)

Q: Do you agree with Mr. Hibbard's assertions?

A: Only partially. The burning of almost any fuel produces pollutants and greenhouse gases. Natural gas burns more cleanly at the burner tip than some other fuels (particularly oil). On the other hand, methane (the major component of natural gas) is a very potent greenhouse gas and contributes much more to climate change than CO_2 per molecule or gram of gas emitted. Depending on the amount of methane leaked to the atmosphere in extraction, processing, transportation and distribution, natural gas can actually result in more global warming per MMBtu of delivered energy than oil.[6]

The only significant sources of mercury (which is the Hg in Mr. Hibbard's list) in energy supply result from burning coal and waste materials. Coal heats only about 0.2% of New Hampshire homes and is vanishing from the New England electric generation system.

Q: Does the Company's witness Killeen also address environmental impacts of natural gas?

A: Mr. Killeen purports to provide the Company's assessment of the environmental, economic and health impacts of the options considered in the LCIRP, but he fails to adequately do so for several reasons.

First, he admits that the company only identified three resource options: two pipeline delivery options and LNG purchases (Killeen Direct at 7). The Company failed to consider additional options to balance natural gas demand and supply, including

[6] Methane gradually breaks down in the atmosphere, to its climate-forcing effects are strongest in the first couple decades after it is emitted. Unfortunately, the next few decades have been recognized as being critical to determining whether the most severe consequences of global warming can be avoided.

suspension of the promotional efforts and enhanced energy-efficiency programs. Nor did the Company test cases with lower demand and smaller supply options. As a result, he simply provides a cursory comparison of these two very limited options, and concludes that of the two, Granite Bridge is superior. He does the same for the gas supply sources, again failing to analyze other available energy resources.

Second, Mr. Killeen makes conclusory statements (without any supporting analysis) about the increased use of gas in the state having positive contributions to achieving selected aspects of the Clean Air Act. As I note above, his argument does not address the breadth or actual language of the Clean Air Act. He also fails to consider any other environmental laws. For these reasons, his testimony does not address the gaps in the LCIRP identified by the Commission.

Q: Is natural gas the preferred energy choice for space and water heating?

A: No. Compared to natural gas combustion at the end use, electricity can provide energy services while emitting less greenhouse gases, so long as it is either (1) sourced largely from renewable resources, including wind, solar and hydro or (2) produced and used in a manner that is more efficient than direct gas use at the end use.

Q: Is electric heat-pump space heating as efficient as gas heating?

A: Yes. Heat pumps are much more efficient than gas furnaces, boilers and water heaters. Modern high-efficiency heat pumps have a seasonal performance factors in the range of 9.5 to 12 Btu/kWh, which means that they provide 2.8 to 3.5 units of usable heat for each unit of input electric energy.[7] In other words, they are 280% to 350% efficient. A very efficient gas furnace or boiler might be in the 90%–95% range. The heat pump is thus three to four times as efficient as the gas space heating appliance. So unless the electricity for the heat pump comes from a mix of power plants that emit three or four times more

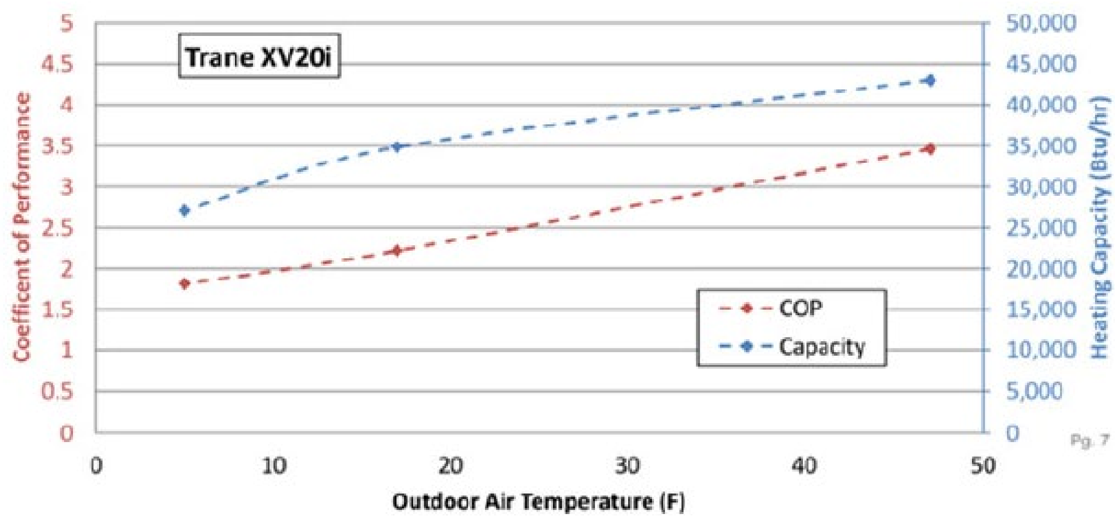
[7] The ratio of heat output to electric energy input is called the coefficient of performance, or COP.

CO_2 than direct gas combustion per unit of energy delivered to the home, emissions will be less with the heat pump than with a gas furnace or boiler. As I show below, the emissions of the New England electric system are far below those levels, so using electricity rather than natural gas will almost always reduce annual carbon emissions.

Q: Is that true for heat-pumps, even at New England winter temperatures?

A: Yes. Figure 1 shows the efficiency and capacity of a relatively inefficient heat-pump (HSPF 10) as a function of temperature. Both the COP and the heating capacity of the heat pump fall at low outdoor temperatures, but at the average January temperature in Manchester, in the low 20s, the COP is still about 2.5.

Figure 1: Example Heat-Pump Efficiency and Capacity[8]



Q: What sources would serve loads shifted to electricity?

A: The emissions associated with electricity depend on the type of generator that provides the energy. Additional wind, solar and hydro added to serve the loads have nearly zero emissions. The New Hampshire RPS requires that 8.8% of energy load be met with Class I non-thermal and Class II renewables in 2019, rising to 13.5% in 2025. Additional New

[8] ACEEE. Field Assessment of Cold Climate Air Source Heat Pumps, Ben Schoenbauer, et al. https://aceee.org/files/proceedings/2016/data/papers/1_700.pdf.

Hampshire electric load would thus be met about 10% with clean resources over the next several years.

The portion of new load that is not offset with new renewable resources is served by the marginal energy supply on the ISO-NE system. According to the 2018 Annual Markets Report from the ISO Internal Market Monitor (May 23, 2019), the real-time marginal energy supply was from natural gas over 70% of the time, with nearly another 20% from pumped storage (which generally would be refilled by energy from natural gas) and 2% from other hydro (which was probably be mostly storage hydro that would otherwise have saved the water to generate at a later hour, competing displacing gas). The remaining 7% or so of marginal supply was provided by about equal parts oil, coal, wind, and unspecified. New England coal is rapidly being retired.

Hence, the energy for a marginal electric load, like a new heat pump, would come mostly from clean renewables or from natural gas.

Q: Will coal continue to be a significant contributor to New England electricity supply?

A: No. Since 2011, about 66% of New England coal capacity has retired. The largest remaining coal unit, Bridgeport Harbor 3 (42% of the remaining capacity), is committed to retire in 2021, while Schiller 4 has not cleared in the capacity market for 2021/22 or 2022/23 and Schiller 6 has dropped from clearing its full 47.8 MW for 2020/21, to 30 MW in 2021/22 and 14.5 MW in 2022/23. Schiller 4 and 6 have been running at very low capacity factors (8% and 7% in 2017, 11% and 15% in 2018, 6% and 8% in January–May 2019), which are unlikely to cover the costs of keeping them in service. Once those three units are gone, New England will be left with only Merrimack 1 and 2, which have run very little in recent years: 9% and 5% in 2017, 17% and 13% in 2018, and 14% and 8% so far in 2019. Since the first part of the year includes most of the winter conditions in which coal and oil plants are most likely to operate, the decline in operation from the coal plants is even more striking. Output for the first five months is down 54% from 2018 to 2019 for Merrimack 1, 63% for Merrimack 2, and 67% for Schiller 4 and 6.[9]

Q: How do the emissions from natural gas combustion for electricity compare to the emission from natural gas combustion for space heating?

A: From the EIA 923 database for 2018, I calculate that the average natural gas heat rate (MMBtu of fuel per MWh of output) for New England was 7.4 MMBtu/MWh, or 46% efficient. Some of the energy generated is dissipated as heat in the transmission and distribution system, and the marginal gas heat rate may be higher than average heat rate, but the delivered efficiency is still over 40%. So long as the electricity is converted to heat at an efficiency of more than about 2.5 (= 95% high-efficiency gas boiler ÷ 40% generation and T&D efficiency), electric space heating uses less gas than highly efficient direct gas combustion at the end use. Since some 10% of the electric energy would be from clean renewables, the gas used for electric heating would be less than that for gas heating, at an even lower electric space heater efficiency.

Q: How does that comparison work out for water heating?

A: Heat-pump water heaters (HPWH) are less efficient than heat-pump space heaters. A 2016 report of HPWH performance in the Northeast, presumably using a mix of older heat pumps, reported both rated Efficiency Factor (measured using a particular set of temperature and usage parameters) and measured coefficient of performance (COP) in Massachusetts and Rhode Island.[10] Table 2 shows the results of those studies, along with an extrapolation to current EF ratings.

9 The poor performance of Merrimack is not surprising, since its operating costs (just fuel and O&M from the FERC Form 1, p. 402, excluding capital additions and overheads, such as insurance, taxes, and employee benefits) were 9.0¢/kWh in 2016, 11.5/kWh in 2017, and 14.9¢/kWh in 2018. Schiller 4 and 6 were reported with wood-fired Schiller 5 in PSNH's FERC Report, so I do not have similar data for those units.

10 Field Performance of Heat Pump Water Heaters in the Northeast, Carl Shapiro and Srikanth Puttagunta, Consortium for Advanced Residential Buildings, National Renewable Energy Laboratory, February 2016, available at https://www.nrel.gov/docs/fy16osti/64904.pdf.

Table 2: HPWH Efficiency

		pre-2016		2019	
Model	**Capacity (gal)**	**Rated Energy Factor**	**Average New England COP**	**Rated Energy Factor**	**Extrapolated New England COP**
		a	*b*	*c*	*d*
GE	50	2.35	1.82	3.25	2.52
A,O. Smith	60/80	2.33	2.12	3.24	2.95
Stiebel Eltron	80	2.51	2.32	3.05	2.82

a Shapiro and Puttagunta, Table 3
b Shapiro and Puttagunta, Table 1
c https://mozaw.com/heat-pump-water-heater-reviews/
d b ÷ a × c

Gas-fired water heaters have rated efficiencies of 0.65 to 0.93.[11] So electric heat-pump water heating is 2.7 times as efficient as gas water heating (comparing the best gas storage water heater to the worst HPWH in Table 2), so less gas is used for HPWH than for the best gas water heaters. And as more of the electric supply is provided by renewables over time, the advantage of the electric equipment increases.

Q: What are the implications of the higher efficiency of electricity, as opposed to direct gas combustion, for space and water heating?

A: Since using electricity reduces gas use, it reduces greenhouse gas emissions, reduces pollutants (assuming the same emissions per therm burned), and could help relieve regional concerns about winter availability of gas capacity and supplies by freeing up space in existing pipelines to deliver gas to gas-fired generators in New England. In addition, since the gas-fired generation has emission controls and closer operational control than gas-fired end-use appliances, the emissions per therm from the power plants will tend to be lower than emissions from the gas appliances, and whatever pollutants are released are not in buildings or as near them as for gas appliances.

[11] https://www.energystar.gov/productfinder/product/certified-water-heaters/.

Q: Does electricity have advantages over natural gas in terms of pollutants, other than greenhouse gases?

A: Yes. Natural gas combustion emits NOx, CO, and (depending on combustion conditions) particulates. Burning gas for space heating, water heating and clothes drying emits the pollutants close to occupied building space (or in it, if the equipment is not working properly), while gas cooking emits pollutants inside those buildings. Non-combustion renewables produce none of those pollutants. Burning gas to produce electricity is not benign, but it produces little CO or particulates, and most gas-fired power plants have controls to reduce NOx emissions. And whatever NOx is emitted by electric generation is not in (or usually adjacent to) occupied buildings.

Q: Has electricity always been preferable to direct fossil-fuel heat sources environmentally or in terms of efficiency, for New England energy users?

A: No. In the late 1980s and early 1990s, I testified to the economic and environmental benefits of switching New England electric end-uses to burn gas.[12] At that point, the New England electric system was largely fueled with high-sulfur heavy fuel oil, which produced much more CO_2, sulfur, NOx, particulate and other pollutants than modern gas-fired combined-cycle units. Solar and wind were not significant parts of the incremental power supply, and renewable portfolio standards were not yet in place. In addition, cold-climate heat pumps had not been developed, so electric heating used much more energy than today's new efficient heating systems.

[12] Any gas appliances installed as a result of those analyses would be nearing the end of their useful lives.

Q: Are cold-climate heat pumps economically competitive with oil heat, from the consumer's perspective?

A: Yes. Several analyses have found that the lifecycle costs of heat pumps are lower than those of oil and propane heat.[13]

Q: Have other jurisdictions determined that fossil end uses should be shifted to high-efficiency electric equipment?

A: Yes. For example, the Draft 2019 New Jersey Energy Master Plan found that:[14]

> Over the next ten years, the state should prioritize buildings with the lowest cost, and the most pollution, for electrification by incentivizing electrification for existing oil or propane-fueled buildings. NJBPU should also provide incentives for natural gas-fueled properties to transition, as well as *terminate existing programs that incentivize the transition from oil heating systems to natural gas heating systems.* (emphasis added)
>
> **Goal 4.2.1: Incentivize transition to electrified heat pumps, hot water heaters, and other appliances**. New Jersey should prioritize buildings with oil and propane heating systems for electrification given the cost benefits and pollution reduction potential. … In addition, since the heat pump can also provide high-efficiency air conditioning, there is also an electricity savings. NJBPU should develop a program to ease the financial burden of making this one-time upgrade.
>
> Prioritizing the transition away from oil and propane for residential and commercial buildings is an aggressive but achievable goal with a low-cost impact and a noticeable gain in carbon reductions. It will also set the stage for the more complicated transition away from natural gas in the out years.

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[13] See, *e.g.,* Energy Savings, Consumer Economics, and Greenhouse Gas Emissions Reductions from Replacing Oil and Propane Furnaces, Boilers, and Water Heaters with Air-Source Heat Pumps, Steven Nadel, July 2018, American Council for an Energy-Efficient Economy, Report A1803, available at https://aceee.org/research-report/a1803; Ductless Heat Pump Meta Study, Faesy, R., et al, Northeast Energy Efficiency Partnerships, November 13, 2014, available at https://neep.org/neep-ductless-heat-pump-meta-study-report.

[14] Draft 2019 New Jersey Energy Master Plan, Policy Vision to 2050, June 10, 2019. "statewide, multi-agency effort is led by New Jersey Board of Public Utilities (NJBPU)." https://nj.gov/bpu/pdf/publicnotice/EMP Press Release 610_Revised.pdf.

> Additionally, NJBPU should offer financial incentives for natural gas-heated properties to upgrade to electric heating and cooling now, and *ramp down approval of new subsidies that incentivize building owners to retrofit from oil heating systems to natural gas heating systems*. ,,, (emphasis added)
>
> **Goal 4.2.2: Develop a transition plan to a fully electrified building sector….** It is expected that heat pumps will become more economically attractive in colder regions as technology continues to improve and becomes more efficient. …NJBPU expects that beyond 2030, state policy will have to aggressively target existing natural gas-heated buildings.
>
> An interagency task force should be established to work in close coordination with relevant stakeholders to establish a roadmap through 2050 that transitions existing building stock away from fossil fuels.[15]

Analysis for the California Energy Commission found that "Building electrification was shown to be one of the lower cost GHG mitigation strategies." "Replacing gas equipment with electric equipment upon burnout lowers the societal cost of achieving California's climate policy goals."[16]

The Massachusetts Comprehensive Energy Plan repeatedly cites the benefits of "fuel switching, both electrification and biofuels" and recommends in "Policy Priorities and Strategies" that the Commonwealth "Increase electrification of the thermal sector by providing program incentives for air source heat pumps for heating. Promote fuel switching in the thermal sector from more expensive, higher carbon fuels to lower cost, lower carbon fuels such as electric air source heat pumps and biofuels."[17] The Plan also finds that "the Aggressive Conservation and Fuel Switching scenario most significantly reduces 2030 greenhouse gas emissions" and also produces the lowest household energy costs.

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[15] Draft NJ EMP at 71–72.

[16] Aas, D, et al, Draft Results: Future of Natural Gas Distribution in California, CEC Staff Workshop for CEC PIER-16-011, Energy and Environmental Economics, June 6, 2019), available at https://ww2.energy.ca.gov/research/notices/2019-06-06_workshop/2019-06-06_Future_of_Gas_Distribution.pdf, at 3, 6.

[17] Massachusetts Comprehensive Energy Plan, Commonwealth and Regional Demand Analysis, Massachusetts Department of Energy Resources, December 12, 2018, available at https://www.mass.gov/files/documents/2019/01/10/CEP%20Report-%20Final%2001102019.pdf.

The Québec 2030 Energy plan shows electricity backing out oil and coal, without expansion of natural gas use.[18]

The New York PSC approved a Con Edison proposal to avoid a pipeline expansion by, among other things, accelerating gas energy-efficiency efforts and shifting gas and oil heating load to electric heat pumps:[19]

> The planned programs …include the installation of: (1) ground-source heat pumps at 8,800 single-family residences in Westchester County; (2) air-source heat pumps at over 1,000 small and mid-sized multi-family buildings that currently use fuel oil for heating in the Bronx and other areas of the Company's natural gas service territory; and, (3) heat pumps to pre-heat boiler return water at more than 1,000 small commercial and large residential facilities throughout the Company's natural gas service territory.[20]

Even in Con Edison's territory, with very high costs for electric energy, generation capacity and transmission and distribution capacity, the heat pump program was expected to have a benefit-cost ratio of 1.7.[21]

Q: What lessons do you draw from these four jurisdictions?

A: Jurisdictions that have thought through the process of addressing the environmental and economic impacts of energy supply and investments, to get to a post-carbon energy economy have concluded that efforts to increase natural gas use should end and that fossil end uses (including gas) should be shifted to electricity. New Hampshire would almost certainly reach the same conclusion if it were to model a future with major carbon emission reductions.

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[18] https://mern.gouv.qc.ca/english/energy/strategy/pdf/Highlights-The-2030-Energy-Policy.pdf.

[19] Many of the oil-heated building would be required to switch fuels by 2030. NY PSC Case 17-G-0606, Petition of Consolidated Edison Company of New York, Inc. for Approval of the Smart Solutions for Natural Gas Customers Program, Order Approving with Modification the Non-Pipeline Solutions Portfolio, February 7, 2019.

[20] *Id.*

[21] *Id.* at 8.

Increasing natural gas use, and committing to long-term contracts to support increasing (or even current) gas loads, will just increase the cost of transitioning away from fossil fuels.

V. Risks of Pipeline Commitments

Q: To what risks are ratepayers exposed as a result of Liberty investing in a major supply pipeline?

A: Liberty has not demonstrated that the planned investments and commitments will be beneficial to customers, even in the near term. There is a significant risk that the resources will not remain economic through their expected terms of service. The Granite Bridge Pipeline would be in place and available for several decades, with maintenance expenditures and investments that will need to be recovered from ratepayers, but Liberty is unlikely to need the delivery capacity for very long, leaving its customers vulnerable to having to pay for stranded assets.

Q: Have other jurisdictions recognized the likelihood that natural gas use must decline?

A: Yes. In California, analysis of options for meeting greenhouse gas goals found that the least-cost pathway would require a relatively rapid transition of new and replacement heating equipment to electricity. Even once the vast majority of new equipment installed in homes and businesses is electric, the slow turnover in appliances means that many gas furnaces, once installed, are likely to operate for decades longer, as illustrated in Figure 2.

Figure 2: Projected California Residential Heating Transition[22]

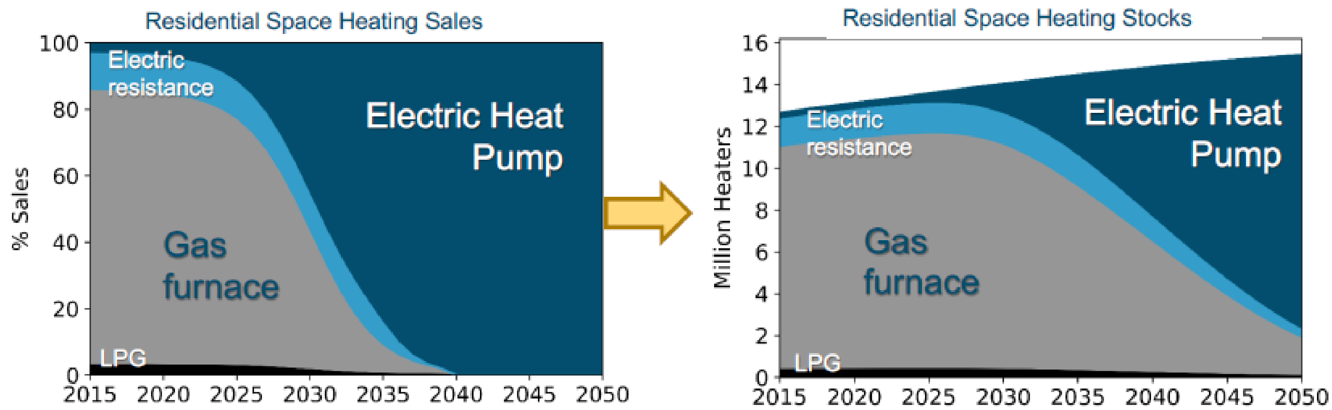
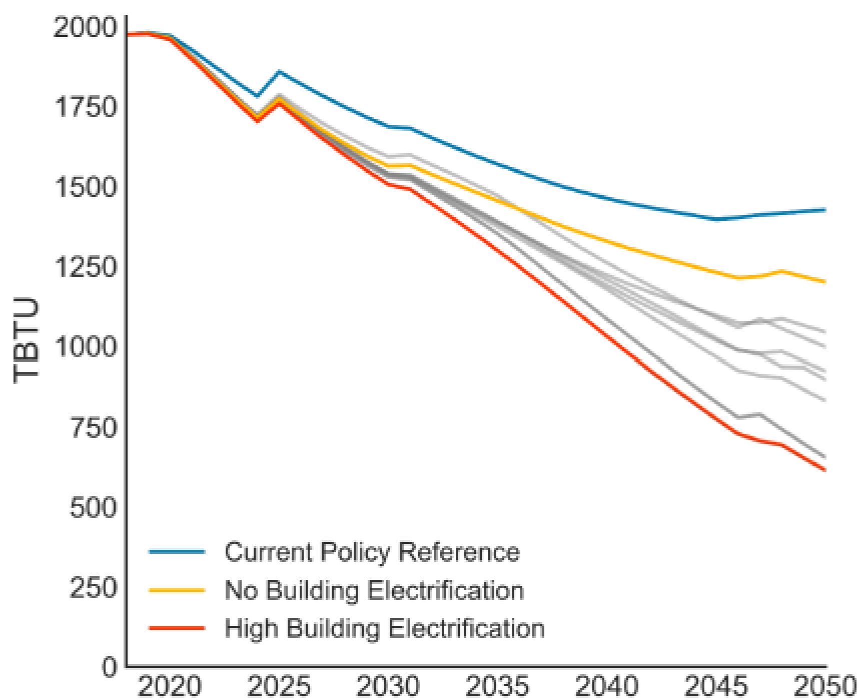


Figure 3 shows the projected deliveries of natural gas (along with biogas and other renewable gas) under the range of approaches considered in the study. The High Building Electrification case is the lowest-cost option.

Figure 3: California Gas Distribution Futures[23]



[22] Aas, et al., 2019 (op cit) at 48.

[23] Aas, et al., 2019 (op cit) at 52.

Q: How are these California results relevant to New Hampshire?

A: New Hampshire's climate and energy use mix differ from California's, so the optimal decarbonization trajectory will not be identical for the two states. But the general relationships are likely to be similar. A low-carbon future for New Hampshire and the region requires replacement of fossil-fueled space-and water-heating with electric appliances, as well as increased energy efficiency.

Q: What would a shorter useful life of Granite Bridge Pipeline mean for Liberty and its customers?

A: Either the near-term recovery of the pipeline cost would need to be accelerated, such as through a higher depreciation rate, or Liberty and the Commission will need to deal with recovering the stranded costs in the out years, spreading the costs over a falling sales base. The same would be true for associated supply contracts that are no longer needed or economic as regional gas load falls; Liberty would need to accelerate contract cost recovery through creation of a regulatory liability, creating a fund to pay down contract costs in the last years of the contract, rather than burdening the declining customer base with the full annual costs of the contracts.

Q: If Liberty does not need its full contract capacity during the life of the new supply contracts and the Granite Bridge Pipeline, could Liberty balance its supply by allowing other contracts to expire?

A: Yes, but at a significant cost. As Liberty witness William Killeen says, "The Company's existing gas supply portfolio consists of various legacy contracts for pipeline capacity and storage that can move gas to the Company's city gates along the Concord Lateral. Bates 038–041. These existing contracts have favorable terms that could not be obtained in today's market." (Killeen Direct Testimony at 8:12–15) So ratepayers would be stuck paying for the new supply contracts and Granite Bridge, while giving up lower-cost existing contracts.

Q: Are there regulatory precedents for these situations?

A: Yes. A number of electric utilities have found that continued operation of their coal plants—which were typically being depreciated over a 60-year life—would be uneconomic in the near future. For example, a plant might be 30 years old, with its original investment half depreciated and subsequent capital additions (for example, for environmental retrofits, perhaps including some very recent ones). When the falling cost of renewables and market power prices means further operation would increase rates, the utility is faced with a decision as to how to recover the remaining investment. Some utilities have accelerated the depreciation of these plants in their final years, while others have promptly retired the uneconomic assets and requested recovery of the investment balance through a regulatory asset. In either case, customers wind up paying more than if the utility had never built the plant or had retired it prior to large recent retrofits. The same was true for the above-market power purchases at the time of restructuring; there is a substantial risk of similar outcomes for new long-term gas contracts and pipeline construction.

VI. Alternatives to the Granite Bridge Pipeline

Q: What alternatives does Liberty have to balance load and capacity, without prohibiting new gas uses?

A: Most of the demand growth that Liberty has proposed would be eliminated by ceasing Liberty's efforts to promote new gas space and water heating (and some other end uses). For meeting the remainder of the load, above current supply, Liberty's options include energy conservation, including facilitating the penetration of heat pumps; a limited expansion of LNG supply in its service territory as needed to cover needle peaks; and (if necessary during a transition period) limited imports of LNG. The LCIRP notes that Liberty has been purchasing LNG and associated vapor from ENGIE.

A. Energy Efficiency

Q: Does the LCIRP include an aggressive energy-efficiency effort?

A: No. The LCIRP shows only minimal amounts of energy-efficiency load reductions. Table 3 shows the energy-efficiency savings that Liberty reports in its load forecast. LCIRP Table 24 subtracts the energy-efficiency column from the total pre-efficiency forecast to derive the total net forecast, so the data must be cumulative. Hence, I added a column for the incremental energy-efficiency savings in each year.

Table 3: Energy-efficiency Savings in Liberty LCIRP Forecast (BBtu)

Year	Pre-Efficiency Forecast	Energy Efficiency	Forecast net of Energy Efficiency	New Energy Efficiency	Energy Efficiency as % Load
	a	b	c	d	e
2017/18	15,142	108	15,034		
2018/19	15,483	114	15,369	6.2	0.04%
2019/20	15,885	122	15,763	8.2	0.05%
2020/21	16,360	127	16,234	4.7	0.03%
2021/22	16,851	131	16,720	3.9	0.02%

a, b, c LCIRP Table 24 MMBtu ÷ 1,000
d *b* minus *b* previous year
e *d* ÷ (*a* - *b* previous year)

Q: How do the forecast energy efficiency savings compare to Liberty's reported past energy efficiency savings?

A: Table 4 shows the historical energy efficiency savings that Liberty claims for each year, from LCIRP Appendix 2, Table 2-1. Liberty describes these as annual savings, and they bounce up and down, so they appear to be the new savings each year.

Table 4: Historical Energy-Efficiency Savings in Liberty LCIRP (BBtu/year)

Year	Annual Savings
2003	38
2004	73
2005	76
2006	84
2007	153
2008	97
2009	121
2010	78
2011	76
2012	148
2013	115
2014	117
2015	144
2016	110
Cumulative	1,430

Liberty witness Eric M. Stanley provides an estimate of Liberty's 2018 incremental annual savings of 130 BBtu, or 0.73% of 2018 sales.

Q: Does Liberty explain why it projects its savings to fall from about 100 BBtu/year annually to less than 10 BBtu, as you compute in Table 3?

A: No.

Q: You assumed that the energy-efficiency values in your Table 3 and LCIRP Table 24 are cumulative values from some unspecified starting year. Is it possible that Liberty intended that those values be interpreted as incremental annual savings, as in LCIRP Table 2-1?

A: That interpretation would mean that Liberty incorrectly computed the post-energy-efficiency forecast in LCIRP Table 24. Table 5 computes the net-of-energy-efficiency forecast, assuming that Liberty intended the energy-efficiency values in LCIRP Table 24 to be annual.

Table 5: Alternative Interpretation of Liberty LCIRP Energy-efficiency Savings (BBtu)

Year	Pre-Efficiency Forecast	Annual Energy Efficiency	Cumulative Energy Efficiency	Forecast net of Energy Efficiency	Energy Efficiency as % Load
	a	*b*	*c*	*d*	*e*
2017/18	15,142	108	108	15,034	
2018/19	15,483	114	222	15,261	0.7%
2019/20	15,885	122	344	15,541	0.8%
2020/21	16,360	127	471	15,889	0.8%
2021/22	16,851	131	602	16,249	0.8%

a, b Table 24
c *b* plus *c* previous year
d *a* minus *c*
e *d* ÷ (*a* - *c* previous year)

This correction would reduce the forecast for 2021/22 by 471 BBtu, or 28% of the post-energy-efficiency forecast load growth from Table 3.

Q: If this interpretation of Liberty's energy efficiency plan is correct, what would be the effect of this energy efficiency plan on the load forecast without Liberty's vigorous fuel-switching plans?

A: Table 6 subtracts the cumulative energy-efficiency savings (under the alternative interpretation in Table 5) from Liberty's load forecast without the promotional program, from Table 3.

Table 6: Liberty Forecast without Promotion (BBtu)

	Pre-Efficiency Demand	Post-2016/17 Efficiency	Post-Efficiency Demand
2017/18	14,319	108	14,211
2018/19	14,466	222	14,244
2019/20	14,617	344	14,273
2020/21	14,722	471	14,251
2021/22	14,858	602	14,256

Eliminating the promotional efforts and maintaining the energy-efficiency savings would essentially eliminate Liberty's load growth.

Q: Are Liberty's energy efficiency programs particularly aggressive?

A: No. Taken literally, LCIRP Table 24 reports very small savings. Under the alternative interpretation, Liberty would be conserving 0.7% or 0.8% of energy use annually, just about enough to offset non-promotional load growth, and the LCIRP load forecast would need to be adjusted downward. Mr. Stanley's testimony supports that alternative interpretation, that Liberty intended to include much more energy efficiency in its forecast.

The Massachusetts Joint Statewide Electric and Gas Three-Year Energy Efficiency Plan 2019–2021 (October 31, 2018) includes gas savings of 1.25% of statewide sales.[24] The most recent ACEEE scorecard (which analyzes 2017 savings) shows gas savings of 1.35% of sales in Minnesota, 1.1% in Massachusetts, and 1% in Rhode Island and Michigan. It appears likely that Liberty could do more, cost-effectively, than the 0.8% it reports in the LCIRP.[25]

Q: Does Liberty witness Stanley's testimony address the failures of the LCIRP to adequately consider demand-side alternatives?

A: No. Mr. Stanley largely defends the Company's current gas efficiency programs, which are approved in a separate docket. While those programs might well be the most cost-effective programs to meet the state's minimum Energy Efficiency Resource Standard, Liberty has failed to consider whether additional cost-effective demand-side programs warrant investment as a more prudent way to meet its customers' needs in the future. Indeed, my understanding is the LCIRP law includes a hierarchy of resources that places demand reduction and energy efficiency at the top. Mr. Stanley's supplemental testimony fails to address whether enhanced demand reduction would contribute to reducing the cost of balancing supply and demand.

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[24] http://ma-eeac.org/plans-updates/.

[25] https://aceee.org/research-report/u1808

B. LNG

Q: Does New England have adequate LNG import capacity?

A: Yes. The Liberty LCIRP notes as much:

> Although the New England region continues to have certain volumes of imported LNG, those volumes have been variable and are becoming winter season focused. …[T]he two off-shore LNG importation facilities (i.e., Northeast Gateway and Neptune LNG) had limited activity since commencing service in 2009 and 2010, respectively, and ENGIE's Distrigas LNG facility has experienced a declining trend in LNG import volumes since 2009. (LCIRP, p. 45)

> The volume of LNG imported into the region is influenced by various factors, including…the need for the New England market to pull the supply by contracting for imported LNG volumes." (LCIRP, p. 46)

While the LCIRP may be painting the lack of demand for LNG in the New England market as some sort of problem, it is in fact an advantage for gas buyers, since import (and associated storage) capacity is readily available.

By the end of 2018, domestic gas liquefaction and shipping capacity, along the Gulf and the Southeast, was expected to more than double in 2019, from 4.9 Bcf/day to about 10 Bcf/day.[26] As of July 31, 2019, 13 Bcf/day of supply was in operation, in commissioning or under construction.[27] Additional LNG supply is under construction in Canada, Australia, Indonesia, Russia, Mozambique, Malaysia, Senegal and Argentina, with more projects proposed.[28]

If New England needs some supplemental gas, before the regional transition to electricity reduces gas load below the capacity of the existing pipeline system, LNG should be available. Of course, LNG is still natural gas, with its carbon emissions from

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26 https://www.eia.gov/todayinenergy/detail.php?id=37732.

27 https://www.eia.gov/naturalgas/U.S.liquefactioncapacity.xlsx.

28 https://www.igu.org/sites/default/files/node-news_item-field_file/IGU%20Annual%20Report%202019_23%20loresfinal.pdf.

combustion and methane emissions from leaks, so New England should not be planning on using large amounts of LNG for the long term. However, using small amounts of LNG in the near term would avoid the build-out of infrastructure and associated capacity contracts that lock in high costs to consumers, with a substantial risk of eventually being stranded costs.

VII. Conclusions

Q: Please briefly summarize your recommendations.

A: Liberty's LCIRP and supplementary filings are not consistent with New Hampshire's planning requirements, failing to include the necessary analysis of very real alternatives to new natural gas infrastructure projects that the Company insists are the only options for meeting Liberty's need to balance supply and demand.

The LCIRP fails to assess how Liberty can meet future needs through cleaner and lower cost resources that are currently available, including electric options such as high-performance air-source electric heat pumps. That approach is becoming common throughout North America.

If Liberty's proposed supply plan is implemented, there is significant risk that it will result in future stranded costs and higher customer bills, as New Hampshire customers transition away from fossil fuels to cleaner electric resources, but continue to pay for imprudent natural gas investments far into the future.

Q: Does this conclude your testimony?

A: Yes.

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SUMMARY OF PROFESSIONAL EXPERIENCE

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

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

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

EDUCATION

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

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

HONORS

Chi Epsilon (Civil Engineering)

Tau Beta Pi (Engineering)

Sigma Xi (Research)

Institute Award, Institute of Public Utilities, 1981.

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“Review of Jersey Central Power & Light’s 1992 DSM Plan and the Demand-Side Management Rules” (with Jonathan Wallach et al.); Report to the New Jersey Department of Public Advocate, June 1992.

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

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.

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

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

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

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

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

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

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

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

"Least Cost Planning and Gas Utilities." Demand-Side Management and the Global Environment Conference; Washington, D.C. April 22 1991.

Conservation Law Foundation Utility Energy Efficiency Advocacy Workshop; Boston, February 28 1991.

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

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

New England Gas Association Gas Utility Managers' Conference. Woodstock, Vermont, September 10 1990.

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

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

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

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

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

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

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

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

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

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

ADVISORY ASSIGNMENTS TO REGULATORY COMMISSIONS

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

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

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

Puerto Rico Energy Commission, Puerto Rico Electric Power Authority, rate design issues, September 2015 to present.

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 like, capacity factor), risks, discount rates, evaluation techniques.

24. **N.M. PSC** 1794, Public Service of New Mexico application for certification; New Mexico Attorney General. May 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 M**03632, renewable-energy community-based feed-in tariffs; Nova Scotia Consumer Advocate. March 2011.

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

261. **Mass. EFSB** 10-2/**DPU** 10-131, 10-132; NStar transmission; Town of Sandwich, Mass. Direct, May 2011; Surrebuttal, June 2011.

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

262. **Utah PSC** 10-035-124, Rocky Mountain Power rate case; Utah Office of Consumer Services. June 2011.

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

263. **N.S. UARB** 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; ROEÉ. 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; ROEÉ. 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.

Reliance on substation-sited storage. Need for increased emphasis on customer-sited and shared storage. Maximizing benefits, total and for small business. Oversized SDG&E proposed projects. 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.

338. **Cal. PUC** A.18-11-005; Southern California Gas Demand-Response Proposal; Small Business Utility Advocates. Direct March 2019, Rebuttal April 2019.

Potential benefits of gas demand response and SoCalGas failure to identify potential benefits from its programs. Program design. Cost allocation.

339. **Cal. PUC** A.18-11-003; Pacific Gas & Electric Electric Vehicle Rate; Small Business Utility Advocates. Direct April 2019, Rebuttal May 2019.

Critique of subscription demand charge. Time-of-use periods. Outreach to small business. Time-of-use price differentials.

340. **Cal. PUC** A.18-07-024; Southern California Gas and San Diego Gas & Electric Triennial Cost Allocation Proceeding; Small Business Utility Advocates. Direct April 2019.

Core commercial declining blocks. Computation of customer charges. Embedded versus marginal cost allocation. Marginal cost computation. Allocation of self-generation incentives.

341. **Vt. PUC** Case No. 19-0397-PET; Screening Values for Energy-Efficiency Measures; Conservation Law Foundation. Direct May 2019.

Conceptual basis for including price-suppression benefits to consumers. Avoided T&D costs. Avoided externalities with a renewable energy standard. Risk mitigation.

342. **N.S. UARB** Matter No. M09096; EfficiencyOne Application for 2020–2022 DSM Plan; Consumer Advocate. May 2019

Evaluate NS Power critique of EfficiencyOne proposal. Comparability of efficiency budgets. Affordability. Energy-efficiency programs and resource planning.

343. **N.S. UARB** Matter No. M09191; NS Power 2019 Load Forecast Report; Consumer Advocate. July 2019.

Review load-forecast treatment of energy efficiency, fuel switching, electric vehicles, behind-the-meter solar, AMI-enabled programs, and the changing trend in lighting efficiency.

344. **Iowa Utilities Board** RPU-2019-001; Interstate Power and Light Rate Case; Sierra Club. August 2019

Economics of continued operation of five coal units: fuel, O&M, capital additions, overheads, market revenues, and cost of renewable resources. Recommend retirement of all units.

345. **Maine PUC** 2019-00101; Unitil Precedent Agreement for Westbrook Xpress, Conservation Law Foundation. August 2019

The role of fuel convserions in Unitil's load forecast. Mandates for reducing greenhouse gas emissions. Efficient electric end uses as alternatives to gas system expansion. Risks of and alternatives to new pipeline supply.

346. **Maine PUC** 2019-00105; Bangor Natural Gas Precedent Agreement for Westbrook Xpress, Conservation Law Foundation. August 2019

Mandates for reducing greenhouse gas emissions. Efficient electric end uses as alternatives to gas system expansion. Risks of and alternatives to new pipeline supply.

347. **Wisconsin PSC 6690-UR-126**; Wisconsin Public Service Corporation 2020 Rate Case, Sierra Club. August 2019

Economics of continued operation of four coal units: fuel, O&M, capital additions, overheads, market revenues, and cost of renewable resources. Recommend retirement of uneconomic units.

348. **Wisconsin PSC 05-UR-109**; Wisconsin Electric Power Company 2020 Rate Case; Sierra Club. August 2019

Economics of continued operation of six coal units: fuel, O&M, capital additions, overheads, market revenues, and cost of renewable resources. Recommend retirement of uneconomic units.

349 **N.S. UARB Matter No. M09277**; NS Power Maritime Link Cost Recovery, Nova Scotia Consumer Advocate. August 2019

Benefits of the Maritime Link transmission line prior to operation of associated power supply and connecting transmission facilties.

350. **Colorado PUC Proceeding AL19-0268E**; Public Service of Colorado Rate Case, Sierra Club. September 2019

Prudence of PSCo regarding need to replace Comanche 3 superheater in fifth year. Economics of coal plants nationally. Regulatory responses to deteriorating coal economics.

351. **N.H. PUC** DG 17-152; Liberty Utilities Least Cost Integrated Resource Plan; Conservation Law Foundation. September 2019

Integrated planning for gas utilities in an era of carbon constraints. Heat pumps as alternative to expansion of gas distribution system. Risk of long-term supply contracts. Availability of LNG imports

ACRONYMS AND INITIALISMS

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

PLC 9/6/2019