RE: FortisBC Energy Inc. (FEI) Application for Approval of a Multi-Year Performance Based Ratemaking Plan for 2014 through 2018, including approvals sought pursuant to section 44.2(a) of the *Utilities Commission Act (UCA)* of an expenditure schedule for FortisBC Energy Utilities (FEU) for demand-side measures for 2014 through 2018	)	**BCUC Project No. 3698715**

and

RE: FortisBC Inc. (FBC) Application for Approval of a Multi-Year Performance Based Ratemaking Plan for 2014 through 2018, including approvals sought pursuant to section 44.2(a) of the UCA of an expenditure schedule for demand-side measures FBC for 2014 through 2018	)	**BCUC Project No. 3698719**

DIRECT TESTIMONY OF

JOHN PLUNKETT, GREEN ENERGY ECONOMICS GROUP, INC.

AND

PAUL CHERNICK, RESOURCE INSIGHT, INC.

ON BEHALF OF

BRITISH COLUMBIA SUSTAINABLE ENERGY ASSOCIATION AND

SIERRA CLUB BRITISH COLUMBIA

DECEMBER 20, 2013

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I. Introduction and Summary

A. Identification and Qualifications

Q: State your names, occupations, and business addresses.

A: We are John J. Plunkett and Paul L. Chernick. Plunkett is a partner in and president of Green Energy Economics Group, Inc., an energy consultancy he co-founded in 2005. His office address is 1002 Jerusalem Road, Bristol Vermont 05443. Chernick is the president of Resource Insight, Inc., 5 Water Street, Arlington, Massachusetts.

Q: Mr. Plunkett, summarize your qualifications.

A: I have worked for over thirty years in energy utility planning, concentrating on energy efficiency as a resource and business strategy for energy service providers. Throughout my career I have played key advisory and negotiating roles on all aspects of electric and gas utility demand side management ("DSM"), including residential, industrial, and commercial program design; implementation management and oversight; performance incentive design; and monitoring, verification, and evaluation. I have led, prepared, or contributed to numerous analyses and reports on the economically achievable potential for efficiency and renewable resources. Over the past two decades, I have been involved in the review or preparation of many gas and electricity DSM investment plans. I have worked on these issues throughout North America and in China on behalf of energy service providers, citizen and environmental groups, state consumer advocates, utility regulators, and government agencies at the local, state, provincial, and national levels.

I earned my B.A. in Economics with Distinction from Swarthmore College, where I graduated Phi Beta Kappa and was awarded the Adams Prize in Economics. My resume is attached as Exhibit JPPC-1.

Q. Mr. Chernick, summarize your qualifications.

A. I received an SB degree from the Massachusetts Institute of Technology in June 1974 from the Civil Engineering Department, and an SM degree from the Massachusetts Institute of Technology in February 1978 in technology and policy.

I have worked in utility regulation, ratemaking and planning since December 1977. My professional qualifications are further summarized in Exhibit JPPC-2.

Q: Have you testified previously in utility regulatory proceedings?

A: Yes. Plunkett has testified as an expert witness over two dozen times before regulators in a dozen states and three Canadian provinces. Chernick has testified roughly 300 times on utility issues, before regulators in five Canadian provinces, thirty U.S. jurisdictions, and two U.S. Federal agencies. His previous testimony is listed in my resume.

Q: Has either of you testified previously before the British Columbia Utilities Commission (the Commission)?

A: Yes, we both have. Plunkett presented evidence regarding energy efficiency resource acquisition before the Commission on six previous occasions. He provided evidence and testimony regarding BC Hydro's 2006, 2008, and 2012 energy efficiency resource acquisition plans (Project Nos. 3698419, 3698514, and 3698622, respectively). He submitted testimony concerning DSM plans by Terasen Gas in October 2008 (Project No. 3698512) and in November 2011 by Fortis Energy Utilities BC Gas (Project No. 3698627). He testified regarding FortisBC Electric's DSM Plan in March 2012 (Project No. 3698620).

Chernick presented evidence before the Commission regarding BC Hydro's 2005 resource-acquisition plan (Project No. 3698388) and BC Hydro's Large General Service rate application (Project No. 3698573).

Q: Mr. Plunkett, summarize your recent work on energy efficiency resource investment.

A: Most of my work over the last five years has been consulting on gas and electric energy-efficiency planning and implementation for energy service providers in the northeastern and midwestern U.S., and technical support for expanding efficiency resource acquisition in several southern states.

Since 2008, GEEG has been engaged by Philadelphia Gas Works ("PGW") to assist with development, regulatory review, and implementation of a five-year, $50 million DSM portfolio. I submitted testimony in support of PGW's plan with the Pennsylvania PUC, which was approved for implementation in 2010. In 2013, I also submitted testimony on behalf of Citizens for Pennsylvania's Future recommending that implementing a multi-year energy-efficiency portfolio should be a condition of the proposed merger of three gas utilities. In November the PUC approved a settlement containing a commitment by the new company to assess the economic feasibility of DSM programs for its service area, and to implement them if doing so is found to be cost-effective.

I have served as economic policy advisor since 2000 for Efficiency Vermont, the first statewide energy-efficiency utility administered under four successive three-year performance contracts administered by the Vermont Energy Investment Corporation (VEIC).[1] In this capacity I helped develop and implement economic policy and practice for guiding energy-efficiency investment. I testified in 2010 in the Vermont Public Service Board (VT PSB) proceeding that led to a twelve-year order of appointment for VEIC. The order of appointment includes non-electric energy efficiency investment. I led the technical analysis behind two long-range assessments by VEIC of the economically achievable electricity savings in Vermont in 2009, and again in 2011, from continued efficiency investment for twenty more years, under several scenarios. The 2011 analysis was instrumental in the VT PSB's decision establishing performance targets and budgets for 2012–14 and savings and spending targets for the subsequent 17 years. I am currently assisting VEIC with economic

[1] The efficiency utility model has been replicated in Canada by Efficiency Nova Scotia.

analysis of the next 20-year Demand Resources Plan (setting 2015–17 budgets and performance goals and expected results through 2024).

Over this period I have also occasionally worked with Vermont's utilities and regulators on geographically targeting energy efficiency retrofits to help relieve transmission and distribution capacity constraints. This year I developed a tool for estimating costs of expanding efficiency resource acquisition to relieve reliability constraints resulting from the arrival of large new loads. In support of the proposed acquisition of Vermont's largest utility, I testified on behalf of Green Mountain Power (GMP) and Gaz Metro on the economic merits of the proposal by the combined companies to invest $21 million on additional energy-efficiency in the acquired utility's service area, rather than refunding the same amount due those customers for prior emergency rate relief. For the last two years, GEEG has provided GMP with technical support in assessing and selecting projects for annual investments for its Community Energy Efficiency Fund.

GEEG was engaged in May 2011 by Shaw Engineering and Infrastructure to assist in the economic assessment and guidance of statewide gas and electric energy efficiency investment in its administration of Wisconsin's Focus on Energy (FOE) portfolio. Between 2008 and 2012, GEEG assisted Peoples Gas with economic analysis in the planning and implementation of its Chicagoland Natural Gas energy efficiency programs and portfolio. I testified on behalf of Peoples Gas before the Illinois Commerce Commission in 2010 regarding cost recovery of first-year program expenditures; I again submitted testimony in 2011 concerning the prudence of second-year expenditures.

GEEG has been providing technical support and expert testimony for the Sierra Club (U.S.) since 2011 on expanding energy-efficiency investment to substitute for coal-fired generation in several cases, including in Oklahoma in 2011 and in an ongoing rulemaking proceeding there on future efficiency resource acquisition performance standards. In 2011, I prepared comments on Maryland utilities' ability to scale up efficiency investment to meet that state's energy-efficiency resource standards (EERS). GEEG also prepared a report on achievable efficiency savings and costs in

Nevada for the Sierra Club in January of 2012. Sierra Club recently engaged us to assist with establishing EERS in Florida.

For the Alliance for Affordable Energy, GEEG conducted analysis and prepared comments in May of this year demonstrating the costs, savings, and benefits from increasing electric energy efficiency investment by Entergy New Orleans. GEEG also prepared a report for the City of Austin's consumer advocate recommending efficiency savings targets and budgets in 2012.

Q. Mr. Chernick, describe your work on valuing electricity and natural gas savings from demand management investments in Canada and the U.S. over the last few years.

A. I have been part of the consulting team that produced the biennial New England Avoided Energy Supply Cost report, used as the basis for DSM screening by utilities and other program administrators in all six New England states, in 2007, 2009, 2011, and 2013. Since 2008, I testified on the role of energy-efficiency efforts in resource planning and the costs avoided by DSM (marginal costs) in Arkansas, Ontario, Connecticut, Pennsylvania, Oklahoma, Manitoba, New Orleans, Nova Scotia and Kansas. I also testified on the effect of energy-efficiency programs on the need for transmission lines in western Massachusetts and southeastern Massachusetts. In addition, I have provided support on avoided-cost issues for a number of projects, including many of those listed by Mr. Plunkett.

Q: On whose behalf are you testifying?

A: Our testimony is sponsored by the British Columbia Sustainable Energy Association ("BCSEA") and the Sierra Club of British Columbia ("SCBC").

Q: What is the purpose of your direct testimony?

A: BCSEA/SCBC engaged us to assess the adequacy and reasonableness of the five-year gas demand-side management expenditure plan submitted for Commission review by the FortisBC Energy Utilities ("FEU") and the five-year electric demand-side management expenditure plan submitted for Commission review by FortisBC, Inc. ("FBC").

B. Summary

Q: Summarize your findings, conclusions, and recommendations.

A: On the whole, the gas DSM plan proposed by FEU is not unreasonable. It extends and refines existing programs at roughly similar levels of spending and savings. FEU's annual gas savings plans are behind industry leaders; its projected costs to achieve planned savings are in line with industry experience. Economic performance of FEU's portfolio can be improved by refocusing, consolidating, and integrating programs and re-allocating resources accordingly. Scaling up FEU's portfolio up to match leading industry performance by 2016 would further reduce the total resource costs of gas service to FEU's customers over the life expectancy of the efficiency measures installed as a result of the programs. The additional gas savings from expanding the portfolio would also eliminate additional amounts of greenhouse gas emissions over time.

Based on these findings and conclusions, we recommend that the Commission approve FEU's five-year expenditure plan, with modifications according to recommendations we develop in Sections II and III of this testimony. In particular, we recommend that FEU combine several of its separate program proposals to launch the next generation of the successful LiveSmart residential retrofit program. Consistent with recent findings from the LiveSmart stakeholder review, LiveSmart should be re-designed according to industry best practices to achieve deeper gas savings with comprehensive whole-house treatment integrating gas and electric efficiency savings among larger numbers of FEU's residential customers over time.

Our examination of FBC's electric DSM expenditure plan and supporting evidence leads us to opposite findings, conclusions and recommendations than those we reached regarding FEU's gas DSM plan. FBC plans to cut 2014-2018 electric efficiency program spending and savings by more than half compared to the 2013 level previously approved by the Commission. FortisBC seeks to justify this drastic course change by claiming that its long-run marginal cost (LRMC) has declined by a third and that the lower LRMC has rendered most of the previously planned electricity savings no longer cost-effective. Our analysis indicates neither proposition is true.

From FBC's workpapers, it appears that FBC's proposed portfolio reduces implementation of measures that are cost-effective even in FBC's screening. Using entirely FBC's own estimates (of avoided costs, measure costs, savings, and the like) and analysis tools, we were able to construct an alternative portfolio that cost-effectively maintains the spending and savings levels of the 2012 DSM expenditure plan.

In addition, FortisBC's new estimate of the long-run marginal supply cost avoided by demand management is understated due to several factual and methodological errors. Once these flaws are corrected, avoided supply costs should be expected to average about \$120/MWh levelized over 2014–24 and \$140/MWh levelized over 2014–43. The corrected LRMC is nearly three times FBC's estimate and substantially higher than the estimate used to value the existing DSM plan previously approved by the Commission.

Finally, our empirical analysis of costs and savings by other utilities indicates that it is economically feasible for FBC to scale up its existing programs to match savings performance achieved and planned by industry leaders. Doubling existing portfolio savings of roughly 1 percent to 2 percent of sales annually would eliminate the need for 150 MW in new capacity that the Company expects to need by 2030. We recommend that the Commission direct FBC to increase spending and savings to achieve 2 percent annual savings by 2016. Doing so would net British Columbia's economy another \$139 million in total resource cost reductions over the life of the additional measures installed in 2014–2018, and (at a marginal emission rate of 0.41 tonne CO_2e/MWh) reduce greenhouse gas emissions by 204 thousand tonnes through 2018.

Q: Has FBC justified its proposed replacement of DSM savings with market purchases?

A: No. The *Utilities Commission Act* s.44.1(2) requires that a public utility that intends to purchase energy to meet demand must explain "why the demand for energy to be served by the…purchases…are not planned to be replaced by demand-side measures." In its Application, FBC has proposed to move in the opposite direction, replacing DSM with spot market purchases. FBC has not provided any credible explanation for why the demand it proposes to meet with spot market purchases is not planned to be met with DSM.

Q: How does FBC's 2014–2018 DSM proposal compare with its approved 2012 Long-Term Resource Plan?

A: FBC's current DSM proposal is fundamentally inconsistent with its 2012 LTRP and the associated 2012 Long Term DSM Plan. The approved 2012 LTRP provides for substantial amounts of cost-effective DSM instead of market purchases. The current DSM proposal reverses that approach.

Q: How have you organized the rest of this testimony?

A: In Section II, we explain the principles of least-cost DSM resource acquisition planning and discuss industry-wide best practices in acquisition of DSM resources, including design, scale, integration and economic screening of programs and portfolios. We address integration of gas and electric DSM programs by FEU and FBC and provide a framework applying best industry practices for structuring BC's combined gas and electric DSM portfolios.

In Section III, we assess FEU's proposed gas DSM portfolio. We provide the results of our examination of the composition of FEU's portfolio, in particular regarding efficiency measures for heating equipment and relative cost-effectiveness of aiming early retirement compared to end-of-life opportunities. We make recommendations for improving the portfolio's economic performance in this respect. We go on to present recommendations on how FEU's DSM portfolio should be expanded to achieved industry-leading depth of savings. We outline the cost-effectiveness of this expanded gas DSM portfolio.

In Section IV, we summarize FBC's proposal to cut the electric DSM portfolio spending and savings by 60 percent. We provide information on the cost-effective DSM measures that are omitted or scaled back in FBC's proposed portfolio. We discuss FBC's failure to properly use DSM cost-effectiveness tests to build a portfolio that maximizes cost-effective savings from expenditure levels previously approved and included in its resource plan. We spotlight FBC's reliance on reducing rate impacts as a rationale for its proposed cuts in DSM spending. We provide figures for a rebalanced portfolio using FBC's own cost-effectiveness calculator. We show that FBC's unit costs of its reduced portfolio are low compared to industry benchmarks because of the drastic reduction of economies of scale. Next, we provide sector-level budgets and economic analysis showing that FBC can cost-effectively double its achievement of electric efficiency savings compared to the 2012–2013 plan.

In Section IV, we also examine FBC's avoided marginal cost of electric supply. We detail the ways in which FBC significantly underestimated its LRMC for DSM screening purposes. We examine the impact on FBC's short term marginal costs of the US–Canada exchange rate, firming the non-firm Mid-Columbia supply, shaping market prices to match DSM, wheeling rates, and transmission and distribution costs. We address FBC's longer-term marginal costs, including the incremental costs of firm generation energy and capacity, and the consequences for GHG emissions reductions and electricity self-sufficiency in BC.

Lastly in Section IV, we examine FBC's avoided marginal cost of electric supply. We detail the ways in which FBC significantly underestimated its LRMC for DSM screening purposes. We examine the impact on FBC's short term marginal costs of the US–Canada exchange rate, firming the non-firm Mid-Columbia supply, shaping market prices to match DSM, wheeling rates, and transmission and distribution costs. We address FBC's longer-term marginal costs, including the incremental costs of firm generation energy and capacity, and the consequences for GHG emissions reductions and electricity self-sufficiency in BC.

Section V contains our final conclusions and recommendations.

II. DSM Resource Acquisition Planning

A. Least-cost Efficiency Resource Acquisition

Q. What is the right amount of energy efficiency resources for gas and electric utilities such as FortisBC to plan to acquire over time?

A. Like any utility seeking to minimize the total resource cost of supplying safe and reliable energy service, FortisBC should plan to acquire all gas and electric demand-side resources achievable for less than the long-run marginal cost of avoided supply.

This least-cost imperative is illustrated graphically in Exhibit JPPC-3. The first panel shows the standard representation of the upward-sloping marginal cost curve for electricity supply, with Quantity on the horizontal axis in GWh/year, and Marginal Cost in $/MWh on the vertical. The area under the MC curve is the total cost of Q_{supply}.

Panel 2 shares the same horizontal axis for quantity, except the origin is on the right. It shows the marginal cost curve for electricity efficiency (labelled MC_{demand}). Looking from right to left, the marginal cost curve turns sharply upward roughly four-fifths of the way leftward to designate a theoretical maximum efficiency potential that is less than all of the amount of total energy demand. The shaded area under the efficiency cost curve represents the total cost of efficiency at any particular quantity.

Panel 3 combines the first two panels to illustrate that there are an infinite number of potential combinations of efficiency and supply to meet total requirements. In this illustration, resource allocation starts with S_1D_1. The horizontal axis shows that this particular resource allocation combines supply of S_1 and efficiency of D_1. The total resource costs of this initial resource allocation of supply and efficiency is the sum of the shaded area under the MC_{supply} curve at point S_1 and the shaded area under the MC_{demand} curve at point D_1. It can be seen that shifting the chosen allocation of supply and efficiency changes the shaded areas and hence the total cost of the particular resource allocation.

Panel 4 presents the least-cost resource allocation that results when efficiency resources are acquired until their marginal costs equal the marginal supply costs they avoid compared to the initial allocation. In the illustration, the horizontal axis shows a resource allocation of supply of S_2 and efficiency of D_2. This allocation is where the marginal cost of supply equals the marginal cost of efficiency. This occurs at the intersection of the supply cost curve and the efficiency cost curve, marked as point (S_2D_2). With the S_2 and D_2 resource allocation the marginal acquisition costs are the same for both supply and efficiency. Observe that the total shaded area under the efficiency and supply marginal cost curves is much smaller than under the initial resource allocation. Even without calculus it is visually apparent that no other combination of supply and efficiency can yield lower total resource costs.

Panel 5 illustrates the gain in economic welfare from acquiring all cost-effective efficiency resources. The shaded triangular area A shows the value (money saved) of moving from the initial resource allocation at (S_1D_1) to the optional resource allocation at (S_2D_2). Conversely, area A represents graphically the forgone welfare gain from not increasing the scale of cost-effective energy efficiency resource acquisition.

Q. Is the least-cost planning imperative you posit consistent with BC statutory and regulatory policy?

A. Yes. Our understanding is that public policy in BC requires FEU and FBC to pursue all cost-effective energy efficiency and conservation measures, and that cost-effectiveness is generally determined by the total resource cost test, subject to certain modifications in the DSM Regulation.

Q. Beyond pecuniary reasons, are there additional reasons to maximize the amount of cost-effective gas and electric efficiency resources FortisBC acquires over the 2014–18 performance period?

A. Yes. In BC, as in other jurisdictions, it is recognized that cost-effective energy conservation and efficiency measures are beneficial for various non-financial reasons, particularly by displacing energy production or generation and thereby avoiding increases in GHG emissions and conventional pollution.

B. Efficiency Portfolio Scale: Gas and Electric Industry Experience

Q: What evidence can you provide concerning the scale of gas and electric efficiency resource acquisition in the U.S.?

A: The American Council for an Energy Efficient Economy (ACEEE) issues an annual scorecard report on gas and electric DSM efforts. The most recent ACEEE State Energy Efficiency Scorecard came out in November 2013 and provided realized savings from 2011.[2] It reports that annual gas savings achieved by gas efficiency portfolios in 2011 ranged from 0.04% in Delaware to 1.25% in Minnesota and nearly 2.0% in Vermont. Program administrators acquired these savings over a range of USD$0.71 to USD$13.75 $/therm-yr (calculated as the budgeted dollar expenditure divided by the incremental amount of annual gas savings achieved from that year's expenditures).[3] Excluding outlier data from Oklahoma, the average savings as a percentage of retail sales for gas efficiency programs in the United States in 2011 was 0.42%, and the average cost was USD$4.97/therm-yr for the 29 states that the ACEEE reported data on. Table 1 highlights costs and savings for both the top ten and bottom ten states as ranked by savings as a percentage of sales in 2011.

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[2] http://aceee.org/research-report/e13k

[3] In order to compare 2011 gas savings with gas efficiency budgets from 2011, budget values from ACEEE's 2012 State Energy Efficiency Scorecard (http://aceee.org/research-report/e12c) were used. Oklahoma's costs of $98.33/therm-yr were an order of magnitude larger than any other state, so was considered an outlier, and not included in this analysis.

Table 1: 2011 Cost and Savings for Natural Gas DSM in the United States

	State	Savings as % of Sales	Budget US$/therm-year
	TOP 10 STATES		
1	Vermont	1.91%	$1.89
2	Minnesota	1.25%	$1.46
3	Michigan	0.80%	$2.05
4	Massachusetts	0.71%	$7.77
5	Iowa	0.69%	$5.24
6	Oregon	0.61%	$5.06
7	Wisconsin	0.56%	$0.71
8	New Hampshire	0.55%	$8.67
9	Washington	0.50%	$4.13
10	California	0.44%	$7.92
	Average	***0.80%***	***$4.49***
	Median	***0.69%***	***$4.49***

	State	Savings as % of Sales	Budget USD$/therm-year
	BOTTOM 10 STATES		
20	Illinois	0.23%	$3.42
21	Arizona	0.23%	$2.86
22	Arkansas	0.23%	$4.47
23	South Dakota	0.16%	$3.00
24	Nevada	0.12%	$4.85
25	Maryland	0.07%	$4.69
26	New Mexico	0.07%	$8.50
27	Idaho	0.06%	$7.86
28	Kansas	0.05%	$1.96
29	Delaware	0.04%	$13.75
	Average	***0.13%***	***$5.53***
	Median	***0.12%***	***$4.69***

Source: ACEEE 2012 State Energy Efficiency Scorecard

Q: Does ACEEE report on electric DSM savings and spending?

A: Yes. ACEEE includes figures for electric DSM in its annual scorecard. The 2013 State Energy Efficiency Scorecard found annual savings for electric energy efficiency programs ranged from 0.02% of retail sales in Louisiana, to 2.12% of retail sales in Vermont. Program administrators acquired these savings from a range of USD$0.06 to

USD$0.60 /kWh-yr (calculated as the budgeted electric efficiency expenditures for a given year divided by the net, incremental annual savings achieved in that year).[4] Excluding outlier data from Virginia, the average savings as a percentage of retail sales for electric efficiency programs in the United States in 2011 was 0.68% and the average cost was USD$0.25/kWh-yr for the 46 states that the ACEEE reported data on. Table 2 highlights costs and electricity savings for both the top ten and bottom ten states as ranked by savings as a percentage of sales in 2011.

[4] In order to compare 2011 gas savings with gas efficiency budgets from 2011, budget values from ACEEE's 2012 State Energy Efficiency Scorecard (http://aceee.org/research-report/e12c) was used. Virginia's cost of less than $0.01/kWh-yr was considered an outlier value and was excluded from this analysis

Table 2: 2011 Costs and Savings for Electric DSM in the United States

	State	Savings as a % of Sales	Budget USD$/kWh -year		State	Savings as a % of Sales	Budget USD$/kWh -year
	TOP 10 STATES				**BOTTOM 10 STATES**		
1	Vermont	2.12%	$0.35	37	Texas	0.20%	$0.20
2	Massachusetts	1.43%	$0.57	38	South Dakota	0.18%	$0.21
3	Arizona	1.38%	$0.12	39	Delaware	0.18%	$0.16
4	California	1.35%	$0.34	40	Mississippi	0.14%	$0.07
5	Connecticut	1.32%	$0.35	41	Arkansas	0.13%	$0.40
6	Hawaii	1.31%	$0.27	42	Georgia	0.11%	$0.14
7	Rhode Island	1.25%	$0.56	43	Wyoming	0.08%	$0.39
8	New York	1.25%	$0.60	44	Kansas	0.08%	$0.29
9	Ohio	1.22%	$0.07	45	Alabama	0.08%	$0.15
10	Minnesota	1.21%	$0.23	46	Louisiana	0.02%	$0.57
	Average	***1.38%***	***$0.35***		***Average***	***0.12%***	***$0.26***
	Median	***1.32%***	***$0.35***		***Median***	***0.12%***	***$0.21***

Source: ACEEE 2012 State Energy Efficiency Scorecard

Q: Does this mean that electric utilities spent 35 cents for each kWh they saved?

A: No. $0.35/kWh-yr is the average amount that program administrators in the top-10 list spent per annual kWh of savings achieved in 2011. Those savings are expected to last from 10 to 20 years on average, depending on the mix of programs within the portfolio and the mix of measures installed by customers participating in the program that year.

Computing the life-cycle or levelized cost of saved energy, by contrast, accounts for the longevity of DSM savings. The levelized cost of saved energy is a function of the discount rate and the life expectancy of the resulting savings. At an assumed average measure life of 15 years and a real discount rate of 5.5 percent, the unit cost of annual savings $0.35/kWh-yr translates to a levelized cost of $0.035/kWh over the expected lifetime of the savings.

Q: Is the levelized cost of saved energy directly comparable with the avoided marginal cost of energy supply?

A: Yes, so long as the load shapes and durations are comparable. Even if the timing of savings do not exactly match, comparing levelized costs and benefits can be helpful as a quick approximation of cost-effectiveness. BC Hydro, for example, routinely compares levelized DSM costs with levelized avoided supply costs. A levelized cost of $0.035/kWh over the lifetime of the savings is well below any reasonable estimate of FBC's long-run marginal costs and is even below FBC's estimate of the short-run variable costs of energy supply.

Q: Can the same comparison be done for the cost of natural gas energy efficiency to the avoided marginal cost of natural gas?

A: Yes. The same principles apply in calculating the levelized cost of gas DSM savings for comparison with avoided supply costs of gas supply. Using the average cost for natural gas programs reported by ACEEE of $4.97/therm-yr, gas DSM savings lasting an average of 15 years (again with a real discount rate of 5.5 percent) would translate into a levelized cost of $0.495/therm.

C. Best Practices in Energy-Efficiency Resource Acquisition

Q: What do you mean by best industry practices in energy-efficiency resource acquisition?

A: Best practices in energy-efficiency resource procurement have been developed based on lessons learned from over twenty years of experience with program design and implementation throughout North America. These lessons were documented by

Pacific Gas and Electric (PG&E) in collaboration with numerous electric and gas utilities over five years ago.[5] They can be distilled into the following guiding principles for maximizing achievement of cost-effective efficiency resources in long-range electric and gas energy-efficiency resource planning:

1) Scale up portfolio electricity and gas savings by choosing the pace, scale and target customer populations for discretionary efficiency resource investment that maximizes net economic benefits (calculated according to the total resource cost (TRC) test).

2) Avoid cream-skimming and the creation of lost opportunities by encouraging comprehensive treatment and deeper savings per participant.

3) Jointly design and implement gas and electric efficiency programs targeting building construction and retrofit, and standardize program designs across electric and gas utility service areas. This applies

    - to FEU and FBC together in territory they share;
    - to FEU in territory where customers are also served by BC Hydro; and
    - to FBC with respect to BC Hydro's programs targeting retail and wholesale purchases of electricity-using products, appliances, and equipment.

Q. Can you point to exemplary programs by industry leaders that embody these principles?

A. Yes. "Leaders of the Pack: ACEEE's Third National Review of Exemplary Energy Efficiency Programs" was released in June 2013.[6] The authors selected the best programs from around the U.S. targeting all major market segments in the residential

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[5] www.eebestpractices.com

[6] Seth Nowak, M. Kushler, P. Witte, and D. York, Leaders of the Pack: ACEEE's Third National Review of Exemplary Energy Efficiency Programs, Report No. U132, American Council for an Energy Efficient Economy: Washington, DC, June 2013. http://aceee.org/research-report/u132u132

and nonresidential sector. These programs exemplify best industry practices in energy-efficiency program design and implementation in terms of maximizing gas and electric savings and net economic benefits from DSM investment.

Q: What are discretionary efficiency resources?

A: Unlike market-driven efficiency opportunities that arise in new construction and new and end-of-life equipment replacement purchases, discretionary efficiency resources involve retrofits that can be timed to suit a utility's resource needs. Discretionary retrofits entail early retirement and replacement of existing inefficient equipment, and/or the installation of supplemental measures (such as insulation or controls).

Q: How can DSM program administrators maximize economic benefits by timing and targeting discretionary efficiency investment?

A: Program administrators can choose how long they want to take to reach the entire eligible population and realize the achievable potential for cost-effective electricity and gas savings they offer. They can target subsets of the total population offering the greatest potential for cost-effective electricity savings. One effective approach is to identify and target customers with the highest usage, since efficiency savings potential is highly correlated with total usage. For example, programs can target customers in the top usage quintile first, and then work down to the fourth quintile over the chosen investment period.

Another effective means of maximizing economic value from discretionary resource acquisition is to target retrofit investment geographically. Doing so lowers resource acquisition costs through improved efficiencies in the marketing and delivery of program services. Geographically targeting retrofit programs can also deliver electricity and gas savings where they are most valuable to the utility. For example, utilities can geographically target retrofit programs to deliver a particular amount of peak demand savings in areas of the system where load growth is expected to necessitate transmission and/or distribution capacity expansion. The avoided costs from deferring such investments add significantly to value of efficiency resources acquired in the targeted area. Vermont electric utilities have been working with the state's efficiency utility to plan "geo-targeted" efficiency investment for the past three years, and plan to continue doing so for a least the next three.

Q: What do you mean by "cream skimming?"

A: Cream-skimming occurs when an efficiency program captures some low-cost savings while deliberately or inadvertently leaving behind savings opportunities that would not be cost-effective on their own but that would have been cost-effective if they had been included in the program. An example of cream-skimming is installing equipment that is less efficient than economically optimal (e.g., early retirement of an inefficient central air conditioner and replacing it with one with an SEER of 15 rather than one with an 18 SEER if the latter would be cost-effective). The opportunity to achieve the savings from the efficiency upgrade at the relatively low incremental cost at the time of installation is lost for the life of the new inefficient equipment. This example illustrates how an energy-efficiency program could actually create lost opportunities for efficiency savings.

Q: How could poor DSM program design create lost opportunities for efficiency savings?

A: Consider the opportunity to achieve cost-effective residential lighting retrofit savings. It would almost certainly not be cost-effective for FortisBC Electric to field a program that only installed high-efficiency lamps in its customers' homes. However, a FortisBC Gas residential retrofit program could install high-efficiency lamps at the same time as conducting diagnostic and treatment visits. The incremental cost of installing the lamps would be relatively low and thus probably cost-effective. In this example, failing to integrate lighting direct installation with the FortisBC Gas residential retrofit program would create electric efficiency lost opportunities by "stranding" savings that could have been acquired cost-effectively.

Failure to capture such lost-opportunity efficiency resources needlessly raises the cost of energy service to the province's consumers, either by forfeiting cost-effective savings entirely – and over-allocating resources to more expensive supply – or by requiring programs to return for them later as higher-cost retrofits.

Q: How does uniformity in program designs between utilities help maximize cost-effective electricity savings?

A: With possible exceptions at the local level between FBC and BC Hydro territories, the Province's supply chains for efficiency products and services generally do not vary according to utility service area boundaries. Making suppliers and contractors learn and comply with different sets of financial incentives and minimum efficiency requirements between BC Hydro and FortisBC Electric raises the costs of and discourages participation in electric utility DSM programs. Combining programs under a single umbrella also heightens market awareness up and down the supply chain.

Wherever possible, FortisBC Electric should increase standardization of common program features with BC Hydro. This should include marketing, financial incentives, and eligibility requirements. It should apply in all markets, such as retail products, HVAC, lighting and other equipment replacement, and new construction. Uniform program design will help promote market demand for, and supply of, high-efficiency products, equipment and services. It will provide economies of scale in program administration and implementation, and will accelerate cost declines in premium-efficiency technologies.

D. Integration of Gas and Electric Efficiency Programs

Q: Why is it so important that utilities address electricity and gas savings from efficiency measures in combination?

A: Some residential efficiency upgrades save both gas and electricity, such as building shell improvements that save gas heating in the winter and electric cooling in the summer. Typically such measures are cost-effective when both (gas and electricity) savings are counted but not when examined separately. This applies in both residential new construction and residential retrofit. Failure to integrate electricity and gas savings into program design and delivery could easily lead to the false conclusion that efficiency investments are not cost-effective.

Having FortisBC Gas and FortisBC Electric operate two separate efficiency programs for the same customers simultaneously would result in higher program costs, lower market penetration and less comprehensive savings among participants. Some FortisBC Electric customers use electricity to cool and FBC Gas energy to heat their homes and businesses. Many efficiency retrofit opportunities involve efficiency measures that save both forms of energy. Dealing with separate programs poses a barrier to customer and supplier participation.

Conversely, addressing all of a customer's inter-related efficiency opportunities comprehensively makes participation and additional efficiency measures more attractive, maximizing the amount of cost-effective electricity and gas savings realized from efficiency portfolio investment. This is especially critical for residential retrofit programs and for BC Hydro programs targeting new construction in both sectors because opportunities to save both electricity and gas cost-effectively are so abundant in these markets.

Among larger customers, the primary concern is that the planning and execution of efficiency upgrades in both market-driven equipment replacement and efficiency-driven retrofits be coordinated with business capital budgeting cycles. Many retrofit projects produce both gas and electricity savings, so it is imperative that customized offers be made on the basis of cash flows they produce in combination. In this way FEU and FBC can both maximize combined customer contributions toward gas and electric efficiency investments, thereby minimizing the share of investment costs borne by their respective ratepayers and the savings that can be achieved by any fixed portfolio expenditures budget.

Best industry practice is to assess gas and electric efficiency cost-effectiveness jointly, and then formulate financial strategies and deliver program services to save both at the same time.

Q: How can FBC make sure that its electric DSM programs are sufficiently integrated with FEU's natural gas DSM programs?

A: Based on the best practices by efficiency industry leaders, the FortisBC utilities should field programs that jointly target both electric efficiency and natural gas efficiency under a single umbrella. Combined electricity and gas programs should be created for residential and nonresidential construction (both new and renovation) and for retrofits.

For *residential* programs, it makes sense for FEU (gas) to form the platform on which FBC electricity efficiency measure are "piggybacked." This is because FEU would already be incurring the relatively high cost of reaching residential customers, and cost-effective gas savings are likely larger than cost-effective electricity retrofit savings in homes in the FBC service area.

Conversely, for *nonresidential* programs, gas efficiency savings should piggyback on the electric efficiency program platform, since the magnitude and value of cost-effective electric efficiency savings will tend to outweigh gas savings in these settings.

Q: Based on these industry best practices, can you present a common framework showing how FortisBC gas and electric efficiency programs should fit together into an over-arching portfolio?

A: Yes. Table 3 contains a matrix identifying which efficiency market segments should be served by gas, electric, or combined programs. The delineation of responsibilities between utilities is consistent with the best practices described above, and with experience by industry leaders in serving these market segments, as documented in ACEEE's latest report on exemplary programs.

Table 3: Recommended Best-Practices Gas and Electric DSM Portfolio

Customer Sector	Efficiency Resource Type	Market	Segment	Program Design & Implementation		
				Separate		Joint
				FortisBC Gas (FEU)	FortisBC Electric (FBC)	Lead Utility
Residential	Market Driven	HVAC equipment purchases	End-of-life replacement and New purchases	Furnaces, Boilers, Water heaters	Heat pumps, Air conditioners, Water heaters	N/A
		Product and appliance purchases	End-of-life replacement and New purchases	Washers, Dryers, Stoves	Lighting, Washers, Dryers, Refrigerators, Freezers, Electronics	
		Construction	New homes and Rehabilitation	Building shell, HVAC equipment, Appliances, Lighting		FEU
	Discretionary Comprehensive retrofit		Supplemental measures and Early retirement		Lighting	
Commercial & Industrial	Market Driven	Products and equipment purchases	End-of-life replacement and New purchases	HVAC, Process	HVAC, Lighting, Motors, Process	N/A
		Construction	New construction, Renovation and Expansion	Building shell, HVAC Equipment, Process, Lighting		FBC
	Discretionary Customized Facility Retrofit		Supplemental measures and Early retirement		Lighting	

Q: Does this joint approach risk cross-subsidization between gas and electric ratepayers?

A: No. If both utilities correctly allocate common program costs in proportion to the benefits of their respective energy savings then there will be no cross-subsidization. It is common for separate electric and gas utilities to allocate program and fixed costs for measures that save both electricity and gas, in proportion to their respective shares of the present worth of total resource benefits derived from each.

Q: Is FEU already integrating its gas DSM programs with the electric DSM programs of FBC and BC Hydro?

A: BC's utilities have been heading increasingly in this direction. Full integration continues to lag, however, and considerable room for improvement remains. To minimize costs and maximize benefits the FEU gas and FBC and BC Hydro electric programs should be fully integrated for new construction and retrofits in all sectors in the 2014–2018 performance period, certainly by no later than 2016.

Q: What types of enhancements are needed to cost-effectively scale up FortisBC gas and electric discretionary DSM resource acquisition plans?

A: First, FEU should work with FBC and BC Hydro to redesign the low-income retrofit programs to incorporate best practices for achieving comprehensive electric and gas efficiency savings. Using programs in Connecticut, Long Island, Massachusetts, and New Jersey as models, the utilities should directly install all cost-effective efficiency measures, including equipment replacement, instrumented air- and duct-sealing, and cavity insulation. This approach will lead to deeper electricity savings and improve program cost-effectiveness.

Second, FortisBC Gas and FortisBC Electric should jointly develop and implement programs to promote comprehensive retrofit investment on the part of single-family residential, multi-family residential, and small to medium commercial and industrial customers. In particular, FortisBC Gas should consolidate its various residential retrofit programs into the next generation of LiveSmart whole-building retrofit program for residential customers. This next iteration should fully integrate all cost-effective electric efficiency retrofits, including lighting, appliances, and HVAC equipment.

These enhanced programs should be supported by improved financing mechanisms structured to provide customers with positive cash flow from their contribution toward their customized efficiency investment project.

E. Economic Screening of DSM Investment Portfolios

Q: How should utilities, program administrators and regulators evaluate the cost-effectiveness of DSM plans?

A: The basic cost-effectiveness test for DSM efforts is the total resource cost (TRC) test. The TRC test is the present value of all benefits of the DSM minus the present-value of all costs of the DSM, regardless of whether those costs and benefits are borne by participants, utility customers as a whole, or a broader group defined by the regulator. The DSM program passes the TRC test if the net benefit is positive. Among competing DSM portfolios, the one with the greatest net resource benefits is economically superior to its alternatives.

In addition, the utility cost test (UCT), which subtracts the present value of all DSM costs that flow through the utility from the present value of all DSM benefits that flow through the utility, is useful to confirm that the DSM is likely to reduce revenue requirements for utility customers.

The process of determining which competing DSM program portfolios are cost-effective and selecting between them is referred to as "screening." Programs that pass screening are generally incorporated into the DSM portfolio and investment plan, with consideration of necessary ramp-up periods for new and expanded efforts.

Q: What are the benefits of DSM?

A: The most readily quantifiable benefits of DSM are the avoided supply costs. In addition, various DSM programs have other benefits, such as enhanced comfort, aesthetics, and productivity. The avoided supply costs include the costs of acquiring generation resources for energy and capacity, subject to constraints imposed by legislative and regulatory policy, as well as the incremental costs of transmission and distribution.[7] Some electric avoided costs are naturally expressed in dollars per MWh, and others in dollars per kW-year. The value of avoided energy costs in any particular projection will generally vary over time: from year to year, among months, and among various periods of the day and week. The forecast of avoided capacity costs may similarly have different values in different years, and the avoided capacity costs may be distributed among high-load hours in the various seasons. For simplicity in exposition, analysts will sometimes reduce the variety of avoided costs to a single value, such as the levelized value per MWh of a particular load shape over a particular number of years. Such summary values should not be used in determining the cost-effectiveness of DSM with any other load shape or duration.

Q: In an appropriate economic screening process, how would the estimates of avoided costs affect the cost-effectiveness of DSM measures?

A: Higher avoided costs result in more DSM measures and programs having benefits higher than their costs, and thus passing under the TRC and UCT screening tests. As a result, it is crucial to accurately estimate the avoided costs, in order to identify and plan for all cost-effective DSM. As illustrated in Exh. JPPC-3, the optimal DSM plan is generally the one that maximizes TRC net benefits, when all costs and benefits are included in screening.

III. FortisBC's Gas DSM Plan

A. FEU's 2014–2018 Proposed Spending and Savings

Q: What are FortisBC Gas' (FEU) current plans for natural gas programs?

A: FEU's spending and savings goals for 2014 through 2018 are presented in Table 4.

[7] All of these avoided supply costs should be increased by marginal line losses, unless the savings estimates are increased for those losses to the generation level.

Table 4: FEU Planned Gas DSM for 2014 through 2018

Year	Spending ($ Million)	Incremental Annual Savings (GJ/yr)	$/GJ-yr	Savings as % of Sales
2014	$34.35	703,948	$48.80	0.40%
2015	$36.54	898,760	$40.65	0.50%
2016	$35.84	802,370	$44.67	0.45%
2017	$35.39	681,290	$51.94	0.38%
2018	$35.87	626,051	$57.30	0.35%
Total	**$177.99**	**3,712,419**	**$47.94**	

B. Composition of FEU's Proposed DSM Portfolio

Q: What does FEU propose for its 2014–2018 DSM portfolio?

A: Table 5 lists the planned spending by program for 2014–2018 and Table 6 lists the planned savings.

Table 5: FEU Planned Gas DSM Spending by Program ($000)

Program	2014	2015	2016	2017	2018
Residential	$10,558	$11,152	$11,110	$10,700	$11,383
Commercial	$11,132	$11,573	$10,972	$10,416	$10,051
Industrial	$1,912	$2,357	$2,662	$2,983	$2,983
Low Income	$2,629	$2,822	$3,042	$3,247	$3,483
Conservation Education and Outreach	$2,400	$2,400	$2,400	$2,400	$2,400
Innovative Technologies	$1,207	$1,218	$1,233	$1,218	$1,210
Enabling Activities	$4,515	$5,015	$4,420	$4,425	$4,365
Portfolio Total	**$34,353**	**$36,537**	**$35,839**	**$35,389**	**$35,875**

Table 6: FEU Planned Incremental Gas DSM Savings (GJ/year)

Program	2014	2015	2016	2017	2018
Residential	190,255	212,785	223,384	236,422	271,890
Commercial	367,794	444,502	364,129	283,918	229,511
Industrial	109,664	142,349	168,172	127,838	66,991
Low Income	26,357	26,919	27,747	27,768	28,190
Innovative Technologies	9,878	72,204	18,937	5,343	29,468
Portfolio Total	703,948	898,760	802,370	681,290	626,051

Q: Is this a reasonable portfolio of gas DSM programs?

A: For its size, FEU's proposed mix of DSM programs is reasonable. Taken together, the proposed programs cover the market segments listed in Table 3.

We also conclude, however, that portfolio economic performance would improve and net resource benefits would increase if program resources were re-allocated within the overall level of expenditures FEU proposes. The net benefits of this reallocation are separate and apart from those that would accrue from increasing the *scale* of FEU's expenditures and savings over the five-year period, as discussed in the next section.

Q: Why do you conclude that FEU's proposed portfolio would benefit from reallocating program resources?

A: Like most gas utility DSM portfolios, FEU targets the heating equipment market. The leading gas utility programs in the residential heating equipment market, featured in the ACEEE report, specifically target natural turnover of aging stock of existing residential heating equipment nearing the end of its rated life. However, FEU's program does not appear to do so. Instead, FEU targets heating systems with an average of five remaining years of service life and encourages early retirement with high-efficiency new equipment.

Q: Is it wrong for FEU to target early retirement of heating equipment?

A: No, not if it is cost-effective relative to competing alternatives – one of which is waiting until the end of life when people are in the market for a new furnace to replace the old one. Our concern with FEU's approach is about the extent to which early retirement is cost-effective relative to natural replacement, and how to ensure to maximization of the measure's cost-effectiveness and contribution to portfolio net benefits.

Q: Has FEU examined this issue?

A: Yes. According to FEU, early retirement provides greater net benefits than natural replacement, for several reasons. One is the value of the savings from replacing low-efficiency heating equipment stock. Another is the certainty of "locking in" new, more-efficient technology early. A third is that FEU finds that the incremental cost of high-efficiency equipment over minimum efficiency standards for new equipment is too high to be cost-effective.

Q: Have you examined the relative cost-effectiveness of intervening at the time of market driven replacement versus encouraging early retirement?

A: Yes.

Q: What did you find, and how do your findings differ from FEU's?

A: We analyzed the cost-effectiveness of early retirement employing a different algorithm to account for the value of permanently deferring the end-of-life replacement.[8] We found that end-of-life replacement and early retirement are more or less a wash in terms of net benefits. (Under the modified TRC, net benefits from early retirement of a standard efficiency furnace would be $288, versus $185 for end-of-life replacement.) However, the big difference is the amount of money required – both total resources and program budget – to get another $103 in net benefits from early retirement over end-of-life replacement. The results of these calculations are shown in Table 7, below.

[8] "Retrofit Economics 201: Correcting Common Errors in Demand-Side Management Cost-Benefit Analysis" (J. Plunkett, R. Brailove and J. Wallach) *IGT's Eighth International Symposium on Energy Modeling*, Atlanta, Georgia, April 1995.

Table 7: Cost-Effectiveness of Retrofit vs Natural Replacement of Furnaces [redacted]

	Incremental Cost	Deferral Credit	Residual Value & Adjusted Future Baseline	PV Benefits (Gas & Electric)	PV Net Benefits
FEU TRC					
Early Retirement of Standard Effic (65%)	$4,365		$(2,768)	redacted	redacted
Early Retirement of Mid Effic (80%)	$4,365		$(2,768)	redacted	redacted
Natural Replacement	$312			redacted	redacted
FEU MTRC					
Early Retirement of Standard Effic (65%)	$4,365		$(2,768)	redacted	redacted
Early Retirement of Mid Effic (80%)	$4,365		$(2,768)	redacted	redacted
Natural Replacement	$312			redacted	redacted
JPPC TRC					
Early Retirement of Standard Effic (65%)	$4,365	$(2,609)		$944	$(812)
Early Retirement of Mid Effic (80%)	$4,365	$(2,609)		$555	$(1,201)
Natural Replacement	$401			$361	$(40)
JPPC MTRC					
Early Retirement of Standard Effic (65%)	$4,365	$(2,609)		$2,044	$288
Early Retirement of Mid Effic (80%)	$4,365	$(2,609)		$1,179	$(577)
Natural Replacement	$401			$586	$185

Q: What changes to FEU's approach to this market would improve the portfolio's economic performance?

A: First, FEU should re-design its portfolio to offer incentives to customers in the market for a new furnace or boiler for whatever reason, and offer financial incentives based on the incremental cost of premium efficiency equipment over standard efficiency new models. Second, FEU should bundle heating early retirement into a comprehensive, whole-house retrofit program, i.e., LiveSmartBC.

Q: How will these changes improve portfolio performance?

A: First, increasing the market penetration of high-efficiency furnace replacement sales will add net benefits comparable to those estimated for early retirement, but with lower expenditures per participant. Second, integrating early retirement into a comprehensive (whole building) approach will increase net benefits per retrofit project as fixed program costs are spread over more savings. Carefully targeting early retirement to applications most likely to be cost-effective will further increase net benefits from FEU's portfolio expenditures, such as by targeting LiveSmart to customers with annual gas usage in the top two quintiles.

Q. Is there evidence supporting your conclusion that incorporating early retirement into LiveSmart would increase participation and savings?

A. Yes. A November 2013 workshop was hosted by FEU on the status of the LiveSmart program. Information was presented that demonstrated the need to restore and strengthen financial incentives in order to increase program uptake and the depth of participant savings by encouraging installation of all recommended efficiency measures. Several slides from this workshop, prepared by Dunsky Energy Consulting, are attached as Exh. JPPC-4. See slides 12 through 14, showing close correlation between incentive levels and customer applications, and the decline of savings depths with customer adoption of fewer measures over time.

C. Recommended Spending and Savings for FEU

Q: Do you find that FEU can and should increase the scale of savings from its gas DSM portfolio?

A: Yes. As shown in Table 4, above, FEU's current 2014–2018 DSM Plan would save from 0.35% to 0.50% of sales ("depth of savings"). This depth of savings is in the middle of the pack for gas DSM administrators in the United States. The average depth of savings for gas DSM efficiency programs in the United States in 2011 was 0.42%, from ACEEE data[9] discussed in Section II.C.[10] A number of states have set more

[9] http://aceee.org/research-report/e13k
[10] The ACEEE report is available at http://aceee.org/research-report/e13k.

aggressive goals and are already achieving savings of over 1% of sales, including Vermont, Massachusetts, and Minnesota.

Q: What is the timing and approach you recommend for gas portfolio ramp-up by FEU?

A: FEU should expand DSM program activity as soon as possible, with an ultimate goal of achieving annual savings of one percent of sales starting in 2016 (year three of the five year performance period). This goal is in line with other leading natural gas program administrators. We recommend a five-year program period that follows the trajectory of savings as a percentage of sales outlined in Table 8.

Table 8: Incremental Savings as a Percentage of Forecast Sales for FEU

Year	Res	C&I	Total
2014	0.60%	0.60%	0.60%
2015	0.80%	0.80%	0.80%
2016	1.00%	1.00%	1.00%
2017	1.00%	1.00%	1.00%
2018	1.00%	1.00%	1.00%

Q: How much natural gas will the expanded DSM portfolio save?

A: Table 9 provides the annual incremental and cumulative gas savings expected to be achieved by the expanded portfolio. Projected annual incremental savings climb from 1.1 PJs in the first year, to 1.8 PJs in the fifth year, with cumulative savings of 7.9 PJs annually by the end of 2018.

Table 9: Projected Annual and Cumulative Gas Savings for FEU

Year	Incremental PJs			Cumulative PJs		
	Residential	C&I	Total	Residential	C&I	Total
2014	0.42	0.65	1.07	0.42	0.65	1.07
2015	0.56	0.87	1.43	0.97	1.52	2.49
2016	0.69	1.10	1.79	1.66	2.62	4.28
2017	0.69	1.11	1.80	2.35	3.73	6.08
2018	0.69	1.12	1.81	3.03	4.85	7.88

Q: How much CO_2 emissions reductions will the expanded DSM portfolio achieve?

A: As shown in Table 10, these natural gas savings will yield an estimated 7.1 million tonne reduction in CO_2 emissions over the lifetimes of the installed measures (which extend as long as 25 years for many measures).

Table 10: Projected CO_2 Emission Reductions for FEU

Year	Cumulative Tonnes CO_2		
	Residential	C&I	Total
2014	21,271	33,081	54,352
2015	49,578	77,616	127,194
2016	84,715	133,690	218,405
2017	119,738	190,232	309,971
2018	154,644	247,263	401,907
Lifetime	3,344,755	3,940,862	7,130,859

CO2 Emissions Factor for Natural Gas 0.051 Tonnes CO2/GJ

Q: How much will it cost FEU's ratepayers to acquire these additional gas savings?

A: Spending ramps up from $41 million in 2014, to $68 million in 2018 (in 2013 dollars). Table 11 shows the year-by-year total spending in the proposed portfolio

Table 11: Projected Spending by Year

Year	Budgets (Millions 2013$)		
	Residential	C&I	Total
2014	$25.47	$15.20	$40.67
2015	$33.91	$20.46	$54.37
2016	$42.33	$25.76	$68.09
2017	$42.28	$25.98	$68.26
2018	$42.22	$26.20	$68.42

Q: How do FEU's proposed program spending and savings compare with other utilities?

A: Table 12 and Table 13 compare sector-level projections for FEU's proposed spending with historical results and current projections for Vermont Gas (VT Gas), and the combined gas utilities in Massachusetts (MA Statewide). VT Gas is representative of a smaller utility achieving high savings as a percentage of sales even with a service territory with low population density. MA Statewide is an example of a large concerted effort by a nearby state to ramp up savings to one percent ("1%") of sales, securing a role as a nationwide leader in natural gas efficiency.

Table 12 shows the average cost per annual therm saved (in 2013 dollars) for each administrator.

Table 13 shows the average savings as a percentage of sales for each administrator. The average values in these tables take into account actual results starting in 2010, as well as recent projections if available.

Table 12: Comparison of Average Cost per Annual GJ (2013$)

Average 2013$/GJ-yr			
Admin	**Res**	**C&I**	**Total**
FEU	$60.72	$39.97	$45.78
VT	$47.97	$13.08	$25.45
MA	$74.17	$33.78	$69.22

Table 13: Comparison of Average Savings as a Percentage of Sales

Average Savings as a Percentage of Sales			
Admin	Res	C&I	Total
FEU	0.41%	0.42%	0.41%
VT	0.92%	1.03%	0.98%
MA*	0.70%	0.54%	0.89%

**MA Sector values are for historical data, while portfolio values include projections*

FEU's projected costs are lower than both VT and MA on the residential side, suggesting that spending more per GJ for more aggressive savings is entirely possible. On the nonresidential side, FEU's costs-projections are much higher than both VT and MA, suggesting that additional scale economies or additional programs for commercial and industrial customers may be possible. In the end, FEU's total portfolio projections come in slightly under MA and above VT.

We can also compare projected unit costs for FEU to the average unit costs of the top ten states in the United States in 2011 (as shown in Table 1). The top ten US gas states have an average unit cost of USD$4.49/therm, which converts to $45.57/GJ (2013 CAD$). This is lower than what FEU is projecting.

Looking at savings as a percentage of sales, FEU is achieving solid but not outstanding savings. FEU's projections of its depth of savings are below those of both MA and VT, but only slightly below the median of 0.69% of sales achieved by the top ten states in 2011. It is also important to note that FEU is projecting approximately the same savings levels for residential as non-residential, which should help keep overall portfolio costs lower as residential savings are typically more expensive to achieve (as shown in Table 12).

D. Benefits and Costs of Expanding FEU Gas DSM Investment Portfolio

Q: How did you develop your projections of annual DSM portfolio expenditures for expanded gas DSM savings?

A: To compute annual expenditures for the expanded portfolio, we multiplied the residential and non-residential spending per annual incremental GJ saved in the years 2014 through 2018 by the annual incremental savings by class shown in Table 9. The annual savings were calculated by multiplying forecast annual sales by the annual incremental percent savings projection for each year and sector. With the historical and planned savings and spending of industry leaders in mind, we used professional judgment to project both how much annual incremental savings FEU could achieve as a percentage of forecast sales, and how much they should be expected to spend per annual GJ saved to achieve them.

Q: How did you compare the benefits and costs of expanding FEU's gas DSM portfolio?

A: The benefits and costs of gas DSM investment were compared from two perspectives: total resource costs, and gas system costs (also known as program administrator costs). The primary test for DSM cost-effectiveness is the TRC test, which accounts for all the benefits and costs to the economy of the efficiency investment, regardless of who enjoys or pays for them. Costs consist of the efficiency measure costs and the costs of marketing, technical assistance, management, and other program functions that are more or less fixed with respect to the volume of program activity and/or the number of efficiency measures installed. The net benefits to the economy from cost-effective DSM investment are the difference between the present worth of benefits and costs of the programs over the lifetimes of all the measures installed as a result of the program.

The gas system perspective, by contrast, counts only those benefits and costs of DSM programs that fall within the sphere of costs paid by all gas system ratepayers. It indicates the extent to which a program or portfolio of programs benefits the group of ratepayers supporting the investment.

Q: What are the lifetime costs and benefits you estimate if FEU implemented the expanded DSM portfolio you recommend?

A: Table 14 summarizes the cost-effectiveness of the recommended portfolio under both the total resource cost test and the utility cost (UC) tests.

Table 14: FortisBC Gas DSM Program Budgets for 1% Annual Savings [11]

NPV	TRC Test	UC Test
Total Portfolio		
Costs	$430	$327
Benefits	$659	$603
Net Benefits	$230	$275
B/C Ratio	1.53	1.84
Residential		
Costs		$203
Benefits		$266
Net Benefits		$63
B/C Ratio		1.31
Nonresidential		
Costs		$124
Benefits		$336
Net Benefits		$212
B/C Ratio		2.71

Q: How did you estimate the total resource costs from your projections of program expenditures?

A: We approximated the amount of efficiency measure costs not included in the program and portfolio expenditures based on two assumptions about the structure of program costs, based on our knowledge of the program designs as recommended and our professional judgment. The first assumption concerns the share of portfolio

[11] TRC benefits and costs discounted at a real discount rate of 4.08%; PAC values discounted at the real discount rate of 4.93%.

expenditures that goes toward financial incentive as opposed to all the other, largely fixed, costs associated with administering the program, including marketing, technical assistance, management, reporting and evaluation. The second key assumption is what fraction of the total costs of efficiency measures installed through the program is defrayed by program spending on financial incentives. Based on a five-year outlook and in line with comparable DSM portfolios with which we am familiar, we assumed the same number for both, i.e., that financial incentives take up two thirds of the total portfolio budget, and that across programs, they cover the same percentage of incremental and installed efficiency measure costs.

Q: How much in additional net benefits would accrue to the British Columbia economy if the DSM were to be scaled up to the recommended 1% savings level?

A: By increasing the DSM spending and savings over the next 5 years, the British Columbia economy would reduce its net total resource costs by an additional $127 million.

IV. FortisBC's Electric DSM Plan

A. FBC's proposed 2014–2018 DSM expenditures and savings

Q: What is FBC's proposed DSM Plan?

A: FBC proposes to reduce spending and savings from the levels approved by the BCUC for 2012-13 by more than half. Table 15 compares FBC's proposed plan with the spending and savings from the previously approved plan, projected forward onto the years 2014–2018.

Table 15: Comparison of FBC Proposed and Previously Approved DSM

Year	Spending ($000s)	Savings (MWh)	Savings as % of Sales	$/kWh-yr
	FBC Proposed			
2014	$3,001	12,800	0.48%	$0.23
2015	$3,087	12,887	0.47%	$0.24
2016	$3,054	12,823	0.47%	$0.24
2017	$3,100	12,823	0.46%	$0.24
2018	$3,153	12,823	0.46%	$0.25
	FBC Previously Approved			
2014	$7,173	25,656	0.95%	$0.28
2015	$7,328	26,015	0.96%	$0.28
2016	$7,417	26,266	0.96%	$0.28
2017	$7,512	26,187	0.94%	$0.29
2018	$7,675	26,475	0.94%	$0.29

Q: What is the depth of savings associated with FBC's proposed DSM Plan?

A: Rather than achieving 0.9% energy savings, FBC now proposes to acquire only 0.5% energy savings.

Q: How does Fortis justify this proposed reduction in portfolio scale?

A: According to FBC, the estimated value of electricity savings from DSM programs has fallen by a third. This decline in value rendered the previous portfolio no longer sufficiently cost-effective under the Total Resource Cost test. FBC therefore removed efficiency measures and programs whose savings were no longer cost-effective at the lower avoided costs it now projects. The lower expenditures and their associated program savings were the result.

Q: Is it true that FBC's avoided long-run marginal costs are a third lower than projected when the Commission approved the 2012-13 DSM Plan?

A: No, as discussed in Section IV. E.

B. FortisBC's Screening of DSM

Q: How did FBC use the TRC and UCT in developing its proposed 2014–2018 DSM plan?

A: It does not appear that FBC actually used the TRC or UCT to design its proposed DSM portfolio. Table 16 lists the measures that pass the TRC test in FBC's screening, but for which FBC reduced the number of planned installations from the existing portfolio (FBC Exhibit B-12 Attachment 20.1.1) to the proposed portfolio (FBC Exhibit B-12 Attachment 20.1). Table 16 also lists the measures with TRC ratios greater than 1.0 that FBC chose not to include in either the original portfolio or the proposed portfolio.

Table 16: Cost-Effective Measures Curtailed in FBC Proposal

Measure	TRC B/C Ratio		Included Unit Count	
	Original Portfolio	Proposed Portfolio	Original Portfolio	Proposed Portfolio
Insulation: R0 Base	1.07	1.15	702,790	562,232
Insulation: R19 Base	1.45	1.50	1,210,526	968,421
Windows: Dual	3.30	3.30	0	0
Refrigerator: Pick-up	1.96	1.87	333	0
Freezer	1.67	1.16	1,517	0
Freezer: Pick-up	1.70	1.62	221	0
Consumer Electronics	2.42	2.42	0	0
HVAC Optimization	1.19	1.15	731,900	0
Building Optimization	1.66	1.89	423,132	0
Servers	3.62	2.94	15	0
Wastewater	2.16	2.08	1	0
Energy Management Systems	3.86	3.82	1	0

As indicated in Table 16, even where FBC finds a measure to be cost-effective, it has often reduced the proposed rate of implementation of that measure, or omitted the measure entirely. Many of FBC's reductions in proposed spending and saving are clearly not driven by its changes in its projected avoided costs. Even with FBC's low estimate of LRMC, it could design a cost-effective portfolio as large as the 2012 IRP portfolio.

Q: Has FBC demonstrated that previously approved expenditure levels could not produce cost-effective savings at the lower avoided costs FBC claims?

A: No, it has not.

Q. How did FBC construct its reduced 2014–2018 portfolio?

A: FBC calculated the benefits of savings produced by the program expenditures associated with extending the previous plan into the 2014–18 period at the (assumed) lower avoided costs. It found that the portfolio as constituted no longer produced sufficient resource benefits to satisfy the minimum performance requirement (i.e., MTRC). FBC changed the portfolio by removing measures and programs components that were not cost-effective until the portfolio achieved the minimum level of TRC cost-effectiveness. This exercise demonstrates that one way to improve net benefits of a portfolio is simply to delete its uneconomic or even less economic parts.

Q: What other options are available for improving portfolio economic performance in the face of lower avoided costs?

A: In place of or in addition to deleting program expenditures for program components, portfolio administrators can increase their positions in other program components that are relatively more cost-effective. For example, commercial/industrial electric efficiency investment is generally more cost-effective than residential because levelized costs per kWh saved are generally lower. A portfolio can be rebalanced within and between sectors and market segments to increase net benefits by shifting expenditures toward those more cost-effective savings sources.

Q. Did FBC conduct such an analysis?

A. No, it did not.

Q: Did FBC explain why not?

A: Not convincingly. Essentially, FBC said it did not do so because rebalancing the portfolio would favor large customers to the disadvantage of residential customers.

Q. Is a potentially adverse distributional outcome a valid reason for restricting the scale of a cost-effective efficiency portfolio?

A. No. Not according to accepted regulatory policy at this or any other commission we know of. Using putative distributional consequences to stop an economically superior resource investment would be unheard of, running contrary to least-cost resource planning as well as regulatory policy.

Q. Why is such reasoning invalid?

A. First, there is nothing inherently unfair about acquiring cost-effective efficiency resources disproportionately from large customers, especially not if portfolio costs are assigned and allocated to participating classes in proportion to their relative program spending and savings. Second, the prescribed method for evaluating the cost-effectiveness of DSM portfolios prohibits the Commission from approving a proposed DSM plan which has been restricted solely on the basis of rate impacts. Since a portfolio with greater savings will have greater net resource benefits than FBC's proposal, FBC in effect is screening out increased DSM exclusively on the basis of alleged adverse rate impacts (and without recognizing corresponding bill impacts).

Q. Is there other evidence that FBC is seeking to restrict cost-effective efficiency acquisition due to adverse rate impacts?

A. Yes. FBC states that it has not relied on the RIM test to discontinue any individual measures and claims that the "2.2% rate impact benefit is a byproduct of the condensed DSM Plan." [12] However, FBC also states explicitly that it rejected continuation of the previously approved DSM expenditures "in part because of the 2.2 per cent rate impact it creates."[13] FBC dismisses as "modest" and "not...significant" a 12 percent increase in DSM target savings from including all cost-effective (by its evaluation) measures.[14] When asked if an alternative DSM plan with higher spending and savings than FBC proposes could be cost-effective, i.e., produce higher net benefits under either the TRC, MTRC, or the Utility Cost test, FBC's response was that "FBC agrees that it is a

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[12] FBC Exhibit B-21, BCSEA IR 65.6; FBC Exhibit B-21, BCSEA IR 66.2
[13] FBC Exhibit B-12, BCSEA IR 21.2
[14] FBC Exhibit B-21, BCSEA IR 64.2.2

possibility, but such an alternative plan could also increase the rate impact and could restrict the range of programs across the customer classes."[15]

In short, while FBC may not have literally used a RIM test to screen out specific measures it certainly used rate impacts to support its drastic cut in the portfolio as a whole. This is a distinction without a difference.

Moreover, presenting rate impacts in the absence of corresponding bill impacts on customers is an error of omission; the former is meaningless without the latter.

Q: Do you have any evidence that the previously approved portfolio could be rebalanced to meet TRC cost-effectiveness requirements?

A: Yes. We rebalanced the portfolio using the cost-effectiveness calculator FBC provided in response to discovery. We found that it would be possible to move expenditures away from less cost-effective programs in favor of more cost-effective programs to produce enough total resource benefits to achieve sufficient cost-effectiveness from the previously approved annual expenditure levels over the 5-year portfolio. The results are shown in Tables 17 and 18.

[15] FBC Exhibit B-21, BCSEA IR 63.3.1, underline added

Table 17: FBC Rebalanced Portfolio Savings

Program Area	2014	2015	2016	2017	2018
	Plan Savings	Plan Savings	Plan Savings	Plan Savings	Plan Savings
Programs by Sector	*MWh*	*MWh*	*MWh*	*MWh*	*MWh*
Residential	10,121	9,910	9,862	9,882	9,902
General Service	17,113	17,364	17,660	17,324	17,577
Industrial	2,221	2,259	2,296	2,334	2,371
Total Programs:	**29,454**	**29,533**	**29,818**	**29,540**	**29,850**

Table 18: FBC Rebalanced Portfolio Cost and Cost-Effectiveness

-	2014 Plan			2015	2016	2017	2018
	Cost	TRC	TRC incl mTRC	Plan Cost	Plan Cost	Plan Cost	Plan Cost
Programs by Sector	$(000)	B/C ratio		$(000)	$(000)	$(000)	$(000)
Residential	2,438	1.2	1.2	2,317	2,301	2,293	2,286
General Service	3,326	1.3	1.5	3,403	3,485	3,464	3,545
Industrial	300	3.1	3.1	307	315	323	330
Sub-total Programs:	**6,064**	**1.3**	**1.4**	**6,027**	**6,101**	**6,080**	**6,161**
Supporting Initiatives	525			525	525	525	525
Planning & Evaluation	773	-	-	786	799	813	827
Total	7,362	**1.2**	**1.3**	7,338	7,425	7,418	7,513

Q: Is there other evidence that continuing with the previously approved FBC expenditure levels would be cost-effective in spite of avoided costs equal to only two thirds of the value used to justify the previous DSM plan?

A: Yes. Despite FBC's claim in its filing that results from recent program implementation "support" its proposed cut to DSM, on the contrary, the last year's worth of results indicate that as implemented the portfolio would still be almost cost-effective under the TRC. In fact, this simple re-statement of benefit/cost results clearly indicates that relatively modest shifts in the portfolio's composition would render it sufficiently cost-effective to meet Commission requirements.[16]

Q. What do you conclude with regard to FBC's assertion that lower avoided costs necessitate reductions in previously approved DSM portfolio expenditures?

A: There is absolutely no persuasive evidence to substantiate FBC's claim that previously approved DSM portfolio expenditures should be drastically reduced. The proposed curtailment of the portfolio should be rejected.

Q: How should FBC's portfolio be restructured?

A: No matter what level of expenditures the Commission approves for FBC, the portfolio should be organized according to the framework laid out in Table 3 in Section II.C, above, to align the constituent programs with best industry practice. The top priority is full integration with FEU gas DSM programs where indicated. In particular, FBC programs should

- "piggyback" on FEU programs targeting the residential retrofit, new construction, and renovation, and
- form the platform with FBC in the lead for nonresidential construction and retrofit programs targeting comprehensive electric and gas efficiency savings in building and facilities.

[16] FBC Exhibit B-12, BCSEA IR 21.1

In addition, FBC should standardize its program strategies with BC Hydro's programs targeting high-efficiency electric products, appliances, and equipment in retail and wholesale markets.

C. Benchmarking FBC's proposed expenditures and savings

Q: How much per kWh of annual energy savings does FortisBC propose to spend to acquire efficiency resources under its 5-year plan?

A: Dividing spending by annual incremental energy savings indicates that FortisBC plans to spend between $0.23 and $0.25 per first year annual kWh of electric energy savings. As discussed in Section II.B., this figure is not the same as the levelized cost of saved energy, which is a function of the life expectancy of the resulting savings and the discount rate. At an assumed average measure life of 15 years and a real discount rate of 6 percent, this translates to $0.0245/kWh saved, well below the Company's estimate of avoided supply costs of $0.05661/kWh.

Q: How does this unit cost compare with industry experience?

A: On the basis of empirical analysis of DSM portfolio costs and savings across the industry (Exhibit JPPC-5), GEEG projects that at the savings level FBC plans, it should expect to spend $0.429/kWh-yr in 2014, increasing to $0.470/kWh-yr by 2018 for residential, and $0.351/kWh-yr in 2014, increasing to $0.392/kWh-yr by 2018 for non-residential. This is due to the reduced scale of FBC's planned efforts, which have low variable costs in relation to relatively high fixed program and portfolio infrastructure costs.

Q: How did FBC's unit cost projections for its previous level of savings compare with industry experience?

A: Our regression analysis showed that FortisBC's projections of expenditures per annual kWh of savings for 0.9% savings in its previous plans aligned closely with empirical cost predictions from industry experience.

D. Increasing FBC DSM savings

Q: Can FortisBC substantially increase its achievement of cost-effective electric efficiency savings compared to the previously approved plan?

A: Yes. As Plunkett testified in the last FBC DSM expenditure review, FBC can cost-effectively double its achievement of electric efficiency savings compared to the 2012–2013 plan. The primary reason is that leading North American electric efficiency portfolio administrators have been and plan to continue saving two percent of total retail electric energy sales annually for half the long-run marginal costs of supply they avoid. FortisBC could do likewise by following industry best practices in scaling up participation and savings and thereby doubling portfolio savings.

Q: What industry experience supports your finding that industry leaders have achieved or plan to achieve savings in the two-percent range?

A: This experience is documented in a report prepared by GEEG for BCSEA, *et al*[17]. It contains annual spending and savings by selected North American efficiency portfolio administrators going back as far as 2001 and in several jurisdictions future projections for up to 20 years. Exhibit JPPC-5 provides information for portfolios with the highest percentage of annual savings as well as others with lower savings. On the basis of results and plans of leading jurisdictions, the report projects the annual expenditures FortisBC would need to make to achieve annual savings equal to two percent of electric energy sales.

Q: What do you find from your data on industry DSM savings performance?

A: Portfolio performance falls into a range spanning four savings tiers.

Tier 1(≥1.5%): In the top tier, states are achieving at or near two percent (2%) of sales. It contains eight program years of experience, including California for the

[17] Exhibit JPPC-5, Expanding Energy Efficiency Resource Acquisition for FortisBC Electric

past four of the five years, Vermont for the past three years, as well as Connecticut as of last year.

Tier 2 (≥0.67% and <1.5%): States in the second tier are saving at or near one percent (1%) of annual sales, with annual savings ranging from two-thirds (2/3) of one percent to 1.5 percent of sales. In addition to earlier years' performance by California, Vermont, and Connecticut, this group also includes 60program years of experience from efficiency portfolios in Iowa, Maine, Massachusetts, Nevada, New York, Rhode Island, Hawaii, the Pacific Northwest, British Columbia, and Nova Scotia.

Tier 3 (≥0.33% and <0.67%): States with savings at or near 0.5% of sales fall into the third tier. This group contains 25 program years of results, and includes savings in even earlier years for states in the first two tiers, plus Arkansas, New Jersey, and Wisconsin.

Tier 4 (<0.33%): All other states with savings less than one-third (1/3) of a percent of sales fall into the lowest tier. This group saved around 0.25% of sales and includes earlier results for some states with performance in Tier 3, as well as Texas, and Arkansas

Q: Into which performance tier does FortisBC's DSM Plan fall?

A: FortisBC's previously approved savings plan of 1.0% of annual sales places it squarely in the second-to-top performance tier. Its current proposal put it in Tier 3 if it actually achieves its expected savings at its proposed budget. More likely, however, is that savings resulting from its proposed budget will be less than planned. At acquisition costs predicted by industry experience, adhering to its proposed budget would probably land FBC in the bottom savings tier.

Q: Describe results and characteristics of portfolios in the top two performance tiers.

A: Portfolio administrators in thirteen jurisdictions report 69 program-years of collective experience since 2001 achieving savings ranging from 0.67 percent to 2.53 percent of sales. These leading efficiency portfolios are located in British Columbia, California, Connecticut, Hawaii, Iowa, Maine, Massachusetts, Nevada, Nova Scotia, and Vermont. Some of these jurisdictions are continuing to pursue savings around 2% of sales annually in the years ahead, including California, Massachusetts, Nova Scotia, the Pacific Northwest, Rhode Island, and Vermont.

The geographic, socio-economic, and climatic diversity of these results and plans strongly suggests that *where* a portfolio is located has little bearing on whether it can be reasonably expected to achieve top-tier energy savings. This is because almost all electric end-uses have cost-effective savings potential, no matter where they are. For example Vermont, Hawaii and California have quite different geographic, socio-economic and climatic situations, but efficiency program administrators within each state plan to continue to achieve savings in the 2% range.

Such successful experience under such diverse conditions elsewhere leaves little doubt that FBC can scale up to top-tier efficiency portfolio performance. From this experience it is possible to predict how much it will cost to apply best industry practices to increase participation and savings per participant in order to scale up portfolio savings.

Q: How do energy-efficiency resource costs change as portfolios scale up efficiency resource acquisition?

A: The cost of acquiring efficiency resources is subject to two opposing economic forces: economies of scale and diminishing marginal returns. Some portfolio administration costs are fixed with respect to the level of participation and savings actually achieved, like development, planning, marketing, and management. Beyond a certain level of participation, fixed program costs are spread over more savings and tend to level off or decline gradually.

Q: What about prospects for diminishing returns as FortisBC scales up its efficiency portfolio to achieve double its currently-planned electricity savings?

A: As efficiency portfolios scale up activity levels and savings, the law of diminishing returns can increase the acquisition costs of efficiency savings in two mutually reinforcing ways. First, available efficiency opportunities become more expensive as the depth of savings increases at the measure and project level. Second, experience shows that higher financial incentives are required to achieve participation rates in the 75–90 percent range, especially for more costly efficiency measures with deeper savings. These two factors can interact to raise the cost to portfolio administrators of acquiring additional savings. The upshot is that FortisBC's electric efficiency resource supply curve will eventually become progressively steeper as the portfolio invests in acquiring more of its service area's achievable efficiency potential.

Q: Have you estimated what it would cost for FortisBC to scale up its portfolio to achieve annual electricity savings of 1.0 percent in 2014, 1.5 percent in 2015, and 2 percent of sales by 2016 and in subsequent years?

A: Yes. Table 19, below, presents annual projection of annual program budgets and incremental annual energy savings for the residential and nonresidential sectors. In my opinion, these values provide a reasonable basis for setting budgetary expectations for scaling up FortisBC's electric efficiency resource acquisition, starting in 2014.

Q. How did you develop these projections?

A: We did so using a two-stage process. The first stage is to estimate portfolio administrator costs of achieving the savings goals we recommend, expressed in terms of expenditures per annual kWh saved (i.e., unit costs). Next I translated unit acquisition costs by sector to sector-level budgets.

Q: Explain how you developed your projections of FBC's future efficiency resource acquisition costs for reaching the savings targets you recommend.

A: As explained in Exh. JPPC-5, Section II.B (pp. 6-8), GEEG has developed an empirical model based on data on historical and planned performance that predicts acquisition costs based on several explanatory variables. These include savings as a percentage of sales; residential vs. nonresidential sector; maturity of the portfolio; starting year for projections; and geographic location. The coefficients of this equation were estimated using ordinary least squares regression analysis on the historical and planned data presented in Exh. JPPC-5. Tables 3 and 4 of Exh. JPPC-5 show that the estimated coefficients and the entire equation are highly statistically significant. All coefficients are statistically significant, with confidence levels beyond 99 percent; the regression equation accounts for 87 percent of the variance in the dependent variable, portfolio administrator cost per annual kWh saved.

Q: What did your regression analysis reveal about the relationship between efficiency resource acquisition costs and the explanatory variables you examined?

A: Three findings stand out. First, the estimated equation is a polynomial function of savings depth that reveals the influence of both scale economies at savings depths below 2.5% and diminishing returns beyond that (see the cost curve depicted Figure 3, p. 8 of Exh. JPPC-5). Second, costs increase as a function of the maturity of the portfolio, the starting year of the prediction, and whether the period covered by the prediction applies to plans for the future (as opposed to predicting historical performance). Taken together, results indicate a secular trend of increasing efficiency resource acquisition costs over time, independent from the depth of savings. Third, certain locations matter—specifically, efficiency portfolios in California and New England tend to be more expensive than elsewhere, all else equal.

Q: What unit costs of efficiency resource acquisition does the model predict for FortisBC?

A: According to Exh. JPPC-5, Table 8, p. 11, "residential costs start at CAD$0.32/kWh-yr, falling to as low as CAD$0.22/kWh-yr by 2016, and then rising monotonically thereafter to CAD$0.28/kWh-yr by 2023. Non-residential costs start at CAD$0.24/kWh-yr range, falling to CAD$0.14/kWh-yr, and ending up near CAD$0.20/kWh-yr."

Q: How did you translate these unit costs into sector-level DSM budgets for FortisBC?

A: Multiplying these sector-level unit costs of energy savings ($/kWh-yr) by annual MWh savings representing two percent of forecast service-area sales for residential and nonresidential customers provides annual budgets for FortisBC by year. Table 19 shows projected FortisBC electric DSM program budgets yielding scaling up to 2% depth of savings in 2016, and then maintaining that level through 2023, for a 10 year analysis period. The derivation of the values in Table 19 is detailed in Exh. JPPC-5.

Table 19. FortisBC Electric DSM Program Budgets for 2% Annual Savings

	Budgets (Millions 2013$)			Incremental GWh		
Year	**Residential**	**C&I**	**Total**	**Residential**	**C&I**	**Total**
2014	$4.51	$3.04	$7.55	14.2	12.8	26.9
2015	$5.36	$3.31	$8.68	21.4	19.4	40.8
2016	$6.28	$3.62	$9.90	28.8	26.2	55.0
2017	$6.59	$3.90	$10.49	29.0	26.5	55.5
2018	$6.92	$4.20	$11.12	29.2	26.9	56.1
2019	$7.24	$4.50	$11.75	29.5	27.2	56.7
2020	$7.57	$4.81	$12.39	29.7	27.6	57.3
2021	$7.91	$5.13	$13.04	29.9	27.9	57.8
2022	$8.25	$5.45	$13.70	30.2	28.3	58.4
2023	$8.59	$5.78	$14.37	30.4	28.6	59.0

Q: Have you calculated the levelized costs per kWh of savings associated with the annual budgets you estimate?

A: Yes. As explained earlier, levelized costs are a function of the discount rate and the average life expectancy of portfolio savings, which depends in turn on the composition of the efficiency measure mix within and between the residential and nonresidential sectors. Given that high-efficiency lighting and HVAC equipment will predominate in both sectors, and that solid-state lighting will increase the longevity of residential lighting savings, average savings lifetimes of 10 and 15 years are reasonable assumptions for each respective sector. Applying these lifetimes to the residential and nonresidential costs of annual savings yields estimates of levelized cost of saved energy for the residential sector of between 3.05 to 4.11 cents/kWh and 1.50 to 2.28 cents/kWh for the commercial/industrial sectors. On a sales-weighted basis, this translates into an average acquisition cost of roughly 2.31 to 3.24 cents/kWh for the entire portfolio (in constant 2013 dollars, using the Company's residential-nonresidential sales split and a real discount rate of 4.93 percent).

Q: Should the Commission expect these additional savings and spending levels to be cost-effective?

A: Yes. On a levelized basis, the life-cycle costs of achieving the higher savings I recommend are roughly one third the long-run marginal costs of electricity energy and capacity that Mr. Chernick derives in his testimony below.

Q. Q: What discount rate did you use for the cost-effective analysis?

A: We used a 4.93% real discount rate for the program administrators cost (PAC) test and 4.08% for the total resource cost (TRC) test.

Q: On what did you base these discount rate assumptions?

A: They were based on weighted average cost of capital, using 40% equity at 9.15% and 60% debt at 5.79% (averaging 7.13%), from FBC Exhibit B-1, pp 236-237 and a 2% interest rate. The 7.13% nominal discount rate was then converted to the 4.93% real discount rate by using 2.1% inflation from Attachment H. Reducing the debt rate by the 25% corporate tax rate produces a 4.08% rate used for the TRC test.

Q: What discount rate did FBC use in its portfolio cost-effectiveness analysis?

A: FortisBC used an 8% real discount rate in for its cost-effectiveness analysis.

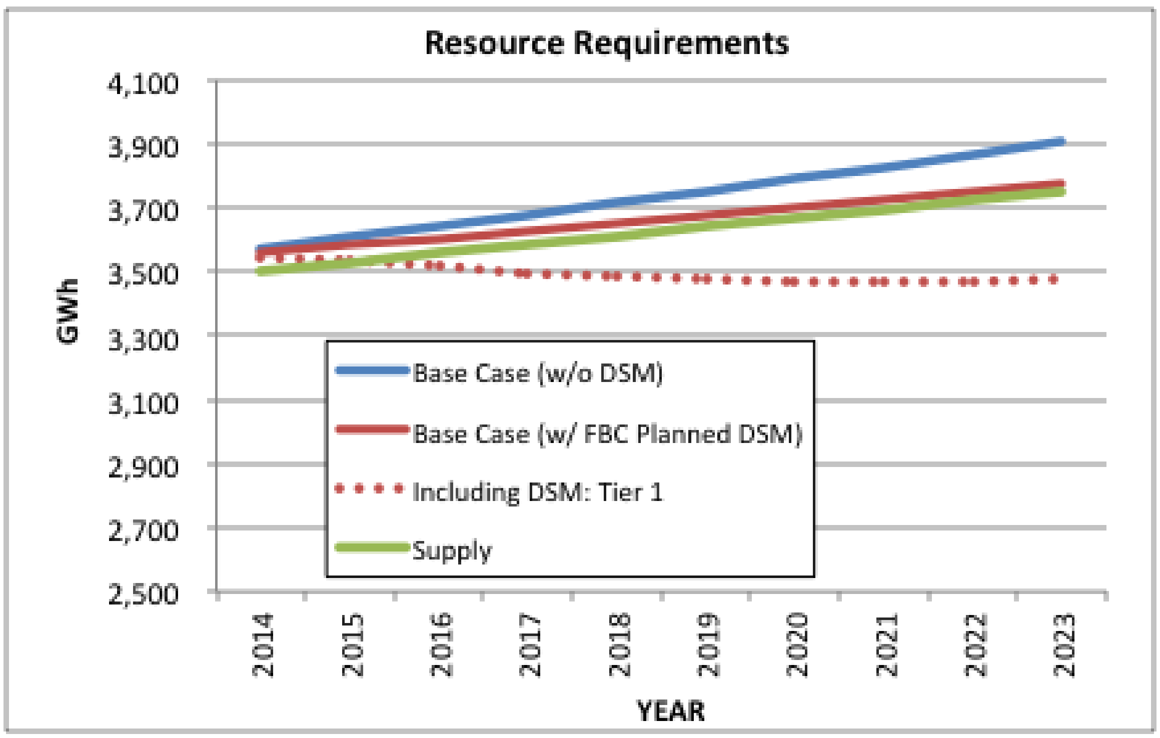
Q: What difference does it make whether one uses a higher discount rate?

A: Using a higher discount rate decreases the benefits and will lead to lowering the cost-effectiveness. In other words, FBC has understated the present worth of future benefits resulting from its proposed DSM portfolio, and from the continuation of expenditures under the previously approved portfolio.

Q: Is there any evidence that increasing cost-effective efficiency resource acquisition beyond FBC's current plans would have other benefits?

A: Yes. Comparing projected sales without DSM, with FBC's planned DSM, and with the higher amount of DSM we recommend, as in Figure 1, shows that the higher levels of DSM would mitigate needs for additional supply side resources that exist in the other two scenarios.

Figure 1: Sales Forecasts for FBC Compared to Supply Resources



Q: Would acquiring so much more efficiency resources benefit British Columbia's economy?

A: Acquiring energy efficiency resources equivalent to two percent of FortisBC's total electricity sales so much more cheaply than supply will be a powerful stimulus to the economy the Company serves in the years ahead. The present worth of the net benefits from the efficiency portfolio investment over the next decades is $251 million using FBC's avoided supply costs.

Q: How does this compare to FBC's proposed DSM spending?

A: Increasing the spending to acquire 2% savings would lower the net total resource costs to the British Columbia economy by an additional $139 million, compared to FBC's proposed spending.

E. FBC's Avoided Long-Run Marginal Cost of Electric Supply

Q: Does FBC estimate avoided costs in its application in this proceeding?

A: Yes. An estimate of avoided generation costs is developed in Exhibit B-1-1, Appendix H, Attachment H4. FortisBC simplifies its avoided energy costs to a single levelized dollar-per-MWh value over the period 2014–2043 and usually refers to that value as its long-run marginal cost or LRMC.[18] In discovery, FortisBC also describes an avoided T&D capacity cost of $35/kW-year, which it refers to as a Deferred Capital Expenditure. (FBC Exhibit B-7 BCUC 1.238.1) This value is included as a benefit in the screening spreadsheet (FBC Exhibit B-12 Attachments 20.1, 20.1.1)

Q: How does FBC estimate its long-run marginal cost for screening DSM programs?

A: FortisBC assumed that its long-run marginal cost would be the average annual spot price at the Mid-Columbia trading hub, plus transmission to the BC border at the BPA wheeling rate for 2014 of $1.917 USD/MWh and transmission losses of 1.90%.

FortisBC's LRMC forecast used "the Midgard methodology outlined in the 2012 Resource Plan, but assuming BC Hydro's low-gas, low carbon forecast, updated by

[18] As we discuss in the remainder of this section, DSM avoids several types of costs, and efficiency measures with different load shapes will have different avoided costs. While we follow standard terminology in BC by referring to a utility's "marginal cost," it is important to remember that no one cost is appropriate for screening all DSM.

Midgard June 15, 2013 BC Wholesale Market Energy Curve update." (FBC Exhibit B-12 BCSEA 1.11.5)

Q: How did Midgard estimate the Mid-Columbia price?

A: Midgard multiplied a gas price forecast times assumed equivalent heat rates for high-load and low-load hours, and added an estimate of the effect of greenhouse gas regulation. "Historic pricing data from the Intercontinental Exchange (ICE) is used to derive the historic heat rate (ratio of cost of electricity over cost of natural gas) between Henry Hub natural gas prices and Mid-C day-ahead electricity prices." (Exhibit B-1-1, Appendix H, Attachment H4, Step 2a)

Q: Does FBC's LRMC estimate accurately express FBC's actual long-run marginal cost?

A: No. Rather than a true long-run marginal cost, FBC actually estimates only a series of *short*-run marginal energy costs. FortisBC assumes that the only costs that will vary as a result of DSM are spot energy purchases. While that may be a reasonable approximation for generation costs for 2014, it is not realistic for 2020 and preposterous for the end of FBC's forecast in 2043.

Q: Does FBC acknowledge that additional costs may be avoidable due to DSM?

A: Yes. As we point out below, FortisBC acknowledges that it may need to acquire firm resources, obtain more capacity, and progress toward self-sufficiency and reduce GHG emissions, but it declines to include those costs in its estimate of "LRMC," at least until the next Resource Plan in 2016. FortisBC acknowledges that the LRMC should include "the reduction in transmission, distribution, generation, and capacity costs valued at marginal cost" (FBC Exhibit B-12 BCSEA 11.8), but it includes no generation capacity or any fixed generation costs, and its position on transmission and distribution costs is ambiguous.

Q: Does FBC assert that the energy supply avoided by DSM would be the modeled purchases from the Mid-Columbia trading hub?

A: No. FortisBC is very vague about what resources would actually be avoided by DSM (e.g., FBC Exhibit B-12 BCSEA 32.2, FBC Exhibit B-21 BCSEA 42.1). The Company presents the forecast Mid-C prices as a proxy for the value of avoided electricity purchases, wherever those may originate.

Q: What specific problems in FBC's analysis will you discuss?

A: We first discuss the problems in FBC's estimation of its short-run marginal cost, and then discuss the additional costs that should be included in the LRMC beyond the short run.

1. FBC's Under-Estimation of Short-term Marginal Cost

Q: What portions of FBC's estimate of short-run marginal cost do you discuss?

A: We describe the following problems:

1. Failure to account for the exchange rate from US dollars to Canadian dollars.
2. Use of non-firm market purchases as a proxy for reductions in firm load.
3. Use of average energy prices instead of prices at the times corresponding to DSM savings.
4. Understatement of short-term non-firm transmission charges from the Mid-Columbia market to FortisBC's service territory.
5. Understatement of avoided T&D costs.

a) Failure to account for Foreign Exchange Rate

Q: How does FBC convert the US dollars in which the Mid-Columbia prices are quoted to Canadian dollars?

A: FortisBC assumes parity between US and Canadian dollars for 2014 to 2043 (Exhibit B-1-1, Appendix H, Attachment H4).

Q: Is that assumption consistent with FBC's assumption in its 2012 Long Term Resource Plan?

A: No. "In its 2012 Long Term Resource Plan (Appendix B - Energy and Capacity Market Assessment), FBC used a USD to CAD conversion rate defined 'as a linear trend starting at 1 USD = 1 CAD in 2011 and ending at 1 USD = 1.25 CAD in 2040'" (FBC Exhibit B-12 BCSEA 4.2). This assumption was equivalent to a decline in the Canadian dollar from $1 US in 2011 to $0.80 US in 2040.

Q: What is FBC's rationale for changing this assumption?

A: FortisBC ordered Midgard to discard Midgard's own forecast in favor of the parity projection. "The GLJ January 1, 2013 forecast also included an exchange rate forecast which Midgard was directed to use because it was an independent publically available forecast." (FBC Exhibit B-12 BCSEA 4.4) Even though FBC depended on Midgard for the exchange-rate forecast in the Resource Plan, FBC did not solicit or receive any opinion from Midgard regarding the use of the GLJ projection (FBC Exhibit B-21 BCSEA 49.3, 49.4).

Q: Is the GLJ exchange rate "an independent publically available forecast"?

A: No, not in any meaningful sense of the term "forecast." Each GLJ quarterly forecast simply assumes that the exchange rate will be constant through the end of the forecast at the rate for the current quarter. For example:

- In January 2006, GLJ projected an exchange rate of 0.850 (US$/Can$) for the first quarter of 2006 and forever after.
- In July 2008, GLJ projected an exchange rate of 1.000 for the first quarter of 2006 and forever after.
- In April 2011, GLJ projected an exchange rate of 0.980 for the second quarter of 2011 and forever after.
- In January 2013, GLJ projected an exchange rate of 1.000 for the first quarter of 2013 and forever after.

- In October 2013, GLJ projected an exchange rate of 0.970 for the fourth quarter of 2013 and forever after.

That is hardly a serious forecasting approach.

Q: Does FBC claim that the GLJ assumption is a serious forecast?

A: Yes. In FBC Exhibit B-21 BCSEA 48.1, FBC quotes a general statement from GLJ regarding its methodology for its "price and market forecasts," which does not mention the exchange-rate projection.

Oddly, FBC defends the GLJ projection by citing two short-term projections of exchange rates, both of which show lower exchange rates than GLJ's projection (FBC Exhibit B-21 BCSEA 48.1).

Q: Did FBC ask GLJ how it consistently determines that exchange rates will remain constant?

A: No. FBC did not ask GLJ how it developed the projection (FBC Exhibit B-21 BCSEA 49.4).

Q: Does FBC provide any support for the accuracy of the GLJ parity assumption, rather than the futures prices?

A: No. To the contrary, FBC acknowledges that it "does not have a view on which data provides a 'better estimate' of future exchange rates." (FBC Exhibit B-21 BCSEA 49.5) The only basis on which FBC can defend its use of the parity assumption is that it appears in the same document as the GLJ natural gas commodity price forecast (*ibid*.).

Q: How has the exchange rate varied over the last decade?

A: Table 20 shows the exchange rate annually since 1994 and quarterly in 2013. The average exchange rate has been $0.807 US per dollar Canadian. The exchange rate has been falling consistently since December 2012.

Table 20: History of US-Canadian Currency Exchange Rate

Year	Exchange Rate $US/$Cdn
1994	0.732
1995	0.729
1996	0.733
1997	0.722
1998	0.675
1999	0.673
2000	0.673
2001	0.646
2002	0.637
2003	0.721
2004	0.768
2005	0.826
2006	0.882
2007	0.935
2008	0.943
2009	0.880
2010	0.971
2011	1.012
2012	1.001
1Q2013	0.991
2Q2013	0.977
3Q2013	0.963
4Q2013	0.956

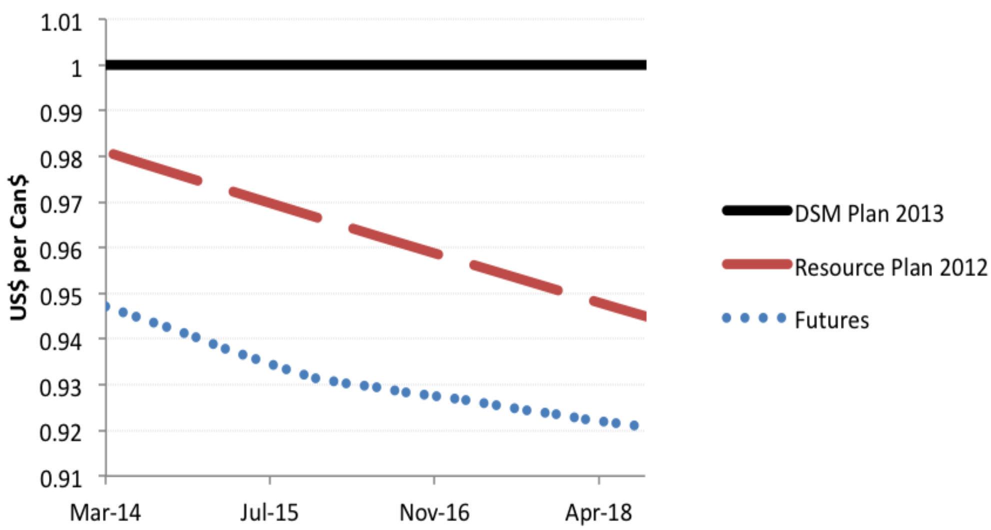
Sources: Crude Oil and Natural Gas Liquids, GLJ Petroleum Consultants, January 2006 and October 2013. 4Q2013 from Bank of Canada for Nov 15, 2013.

Q: How do expectations for future exchange rates compare to the projections in FBC's 2012 Resource Plan and the current DSM Plan?

A: FortisBC provided exchange rate futures through December 2017 (FBC Exhibit B-12 BCSEA 4.5). The exchange rate futures at August 29, 2013 were US$0.9471 per Can$ for 2014 falling to $0.9266 in 2017. Since then, futures have fallen further, and futures for December 2018 are now available, at $0.9122 as of December 6.

Figure 2 compares the exchange rates from the 2012 Resource Plan, the current DSM Plan, and the futures markets.

Figure 2: Comparison of Exchange Rates

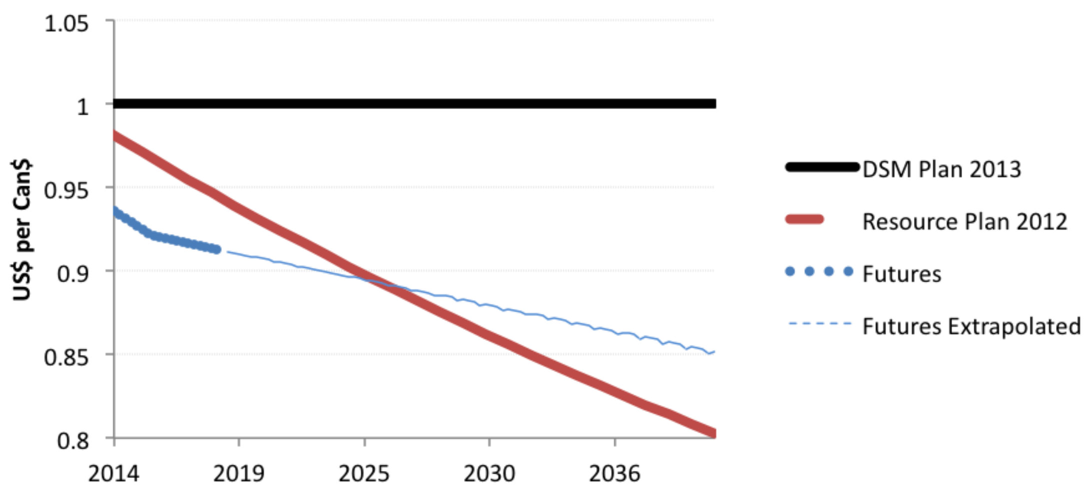


Q: What is the implication of the differences between the 1.00 exchange rate that FBC used in the DSM filing and the market exchange rates, both recent and future?

A: FortisBC's parity exchange rate assumption underestimates the Mid-C prices in Canadian dollars and therefore understates the cost of electricity purchases avoided by DSM. If the resulting understated avoided costs were used in screening DSM, the resulting DSM portfolio would likely exclude some cost-effective DSM.

Assuming that the futures continue to decline at the relatively gentle slope of the 2017–2018 futures, they would be higher than the Midgard forecast in the 2012 Resource Plan after 2025, as shown in Figure 3, below. Using the extrapolated futures would increase the levelized value of FBC's LRMC over the next 30 years by 12%.

Figure 3: Extrapolated Exchange-Rate Futures



b) Firming the Non-firm Mid-Columbia Supply

Q: Is FBC's LRMC estimate based on the savings from avoiding firm purchases?

A: No. The Mid-C spot supply used in Midgard's estimate is generally non-firm until the day before delivery, when the price is fixed. In addition, the transmission cost that FBC adds to the Mid-C price is non-firm.

Q: Is this treatment appropriate?

A: No. Once DSM investments are in place, the savings are firm, and should be valued at the benefit of obtaining less firm supply or selling existing firm supply into the market. If FBC were to firm up the supply price long in advance, there would likely be costs of credit guarantees, hedging or similar costs.

Q: Does FBC recognize that DSM is a firm resource?

A: Oddly enough, FortisBC takes the position that "DSM is not regarded by FBC as firm" (FBC Exhibit B-12 BCSEA 7.5) and "not all DSM savings FBC realizes can be considered firm" (FBC Exhibit B-21 BCSEA 14.1). We do not understand how FBC can consider efficiency measures, once implemented, to be less firm than its load. In most cases, if an efficiency measure fails (the motor of an efficient refrigerator burns out), load falls rather than rising. While the savings from some efficiency measures, such as setback thermostats, can vary with customer behaviour, so will pre-DSM load, so even those measures that require human interaction are no less firm than FBC's load.

Q: Does FBC actually meet all its short-term requirements by purchasing non-firm spot energy?

A: No. Fortis admits that "A typical market contract for FBC has in the past been contracting for short-term supplies of firm power to be delivered to FortisBC during the on-peak hours during the peak demand months of December, January, and/or February." (FBC Exhibit B-12 BCSEA 7.5) These are typically the highest-cost periods of the year.

Q: Does FBC consider market purchases, such as those modeled by Midgard, to be reliable resources on peak?

A: No. "FBC agrees that it is risky to rely on the market to meet energy…needs during periods of peak demand." (FBC Exhibit B-12 BCSEA 8.2) While Fortis believes that off-peak energy will be available from the market, "over the longer term as FBC's requirements grow, it may be prudent to consider other options due to price risk. The 2016 Resource Plan will re-examine the best resource options for FBC to meet customer capacity and energy and stand alone energy needs at that time." (*Ibid*)

Q: Is it prudent to ignore the need for firm supplies until after the 2016 Resource Plan?

A: No. FortisBC is proposing to waste five years of DSM implementation that would reduce FBC's need for additional firm energy acquisition.

Q: Are you aware of any other estimation processes that use spot-market price forecasts and adjust them to reflect the costs of firm supply?

A: Yes. The biennial New England Avoided Energy Supply Cost projections (sponsored by and covering the investor-owned utilities and/or their regulators in all six states) start with projections of market prices for several regional hubs, and then add 10% to reflect the costs of firming that supply.

Q: Has FBC provided any information regarding the incremental cost for firm purchases, over the spot price at Mid-Columbia?

A: In FBC Exhibit B-21 BCSEA 56.2, FBC indicates that it does not track its purchase costs from the US. However, FBC does track its combined hourly purchase costs from the US and BC, and reports that it paid an average of about $5/MWh more than the Mid-Columbia price in the same hour over October 2011 to October 2013. While FBC attributes about $4/MWh to “transmission charges and other ancillary services” (even though it includes less than $2/MWh in its avoided costs), leaving only about $1/MWh to cover the costs of firm supply, this is likely to underestimate the firming costs. A substantial portion of FBC’s market purchases (about one third in 2012) are from entities in BC, presumably when the costs of those sources are lower than the Mid-Columbia price.

c) Shaping the Market Prices to Match DSM

Q: For what load shape is FBC’s LRMC computed?

A: Midgard computed FBC’s LRMC as the average of forecasts of price in high-load hours (HLH) and low-load hours (LLH), weighted by the number of hours in each period: 55% HLH, 45% LLH (Exhibit B-1-1, Appendix H, Attachment H4, Step 3a). In effect, Midgard assumed that DSM savings would be spread evenly over all hours of the day, all days of each month, and all months of the year.

As FBC acknowledges, “The proxy for LRMC of market purchases calculated from Midgard’s 2013 BC Market Price Curve Update is an annual average price. No time of delivery shaping factors have been applied to the LRMC.” (FBC Exhibit B-12 BCSEA 7.5.1)

Q: Is that a reasonable assumption?

A: No. The load reductions from most efficiency measures occur when the affected end use would have been used. As FBC says, "DSM savings will generally follow FBC's time of day and seasonal load profile." (FBC Exhibit B-12 BCSEA 7.5)

Q: How different would the avoided costs be for "FBC's time of day and seasonal load profile" than for Midgard's assumed even distribution of savings over the year?

A: The differences would be substantial. While FBC ignores time of day and seasonal price variations in its LRMC determination, it does provide a summary of estimates from BC Hydro of the ratio of the price in each period to the annual average (FBC Exhibit B-12 BCSEA 6.1), reproduced in Table 21, with the addition of a column for the all-hours price in each month.

Table 21: BC Hydro Estimate of Ratio of Mid-C Prices to Annual Average

Month	HLH	LLH	All Hours
Jan	116%	105%	111%
Feb	111%	102%	107%
Mar	104%	96%	100%
Apr	95%	89%	92%
May	89%	81%	85%
Jun	90%	82%	86%
Jul	105%	91%	99%
Aug	113%	97%	106%
Sep	102%	94%	98%
Oct	107%	95%	102%
Nov	111%	101%	107%
Dec	116%	106%	112%
Average	104.9%	94.9%	

Q: How different are the BC Hydro estimates of period prices from FBC's assumption of uniform avoided costs throughout the year?

A: In BC Hydro's estimates, the winter prices average about 10% more than the annual prices, and the HLH prices average about 5% more than the annual prices.

Q: Does FBC reflect these differentials in its screening, applying higher avoided costs for space heating and on-peak end uses than for other DSM measures?

A: No. The Company ignores these differentials.

Q: Are the BC Hydro estimates reasonable approximations of the daily and seasonal variation of market prices?

A: No, at least not over the last three years. Table 22 shows the ratio of the average Mid-C price in each period to the average annual price, averaged over the three years 2010 through 2012, using data provided by FBC in FBC Exhibit B-12 BCSEA Attachment 7.1. The differentials from the average are much greater than the BC Hydro estimates. Winter prices have been about 25% higher than the annual average, and peak prices average about 13% higher than average. The actual temporal variations in market prices have been over twice the BC Hydro estimates.[19]

Table 22: Historical Mid-Columbia Price Ratios, 2010–2012

Month	HLH	LLH	All Hours
Jan	141%	125%	134%
Feb	129%	104%	118%
Mar	98%	78%	89%
Apr	92%	57%	76%
May	89%	48%	70%
Jun	64%	17%	43%
Jul	104%	50%	80%
Aug	125%	89%	109%
Sep	128%	111%	120%
Oct	127%	114%	121%
Nov	132%	115%	124%
Dec	123%	108%	116%
Average	112.6%	84.6%	

[19] We do not know why BC Hydro's estimate of the spread in Mid-C market prices is so much lower than the historical data indicate.

Source: from FBC Exhibit B-12 Attachment 7.1

Q: How would these variations in avoided energy costs affect the cost-effectiveness of DSM measures?

A: If the avoided cost estimate took into account the hourly and seasonal price differentials, then the avoided costs for typical measures would be higher and more DSM would pass screening. This effect would be largest for space-heating measures and commercial programs targeting HLH reductions. Some off-peak summer measures would be less likely to screen.

Q: Has FBC offered any basis for assuming that it would purchase market energy at lower prices than the market prices weighted by FortisBC's load?

A: Not directly, but FortisBC does offer some indirect arguments on this issue. "The advantage of [FBC's] procurement method is that FortisBC has flexibility with regard to contract timings, quantity of contracts and contract durations." (FBC Exhibit B-12 BCSEA 7.3, 8.5) This appears to be a quote from Midgard's 2011 FortisBC Electricity Market Assessment. The next sentence of that report reads "The disadvantage of this strategy is that FortisBC may misread the market and either pay a high price for the firm power or be unable to secure the quantity and quality of firm power that FortisBC is seeking." (FBC Exhibit B-12 Attachment BCSEA 4.1)

FortisBC also argues that "there are many times during which there is significant surplus generation [in the BPA region] because of wind and run of river hydro conditions. Indeed it is often these times where FBC is able to take advantage of the market because the flexibility of its storage resources allow it to shape the timing of its market purchases." (FBC Exhibit B-21 BCSEA 45.11; see also FBC Exhibit B-21 BCSEA 45.13)

Q: Has FBC provided data supporting its claim that its operational flexibility allows it to purchase energy at particularly low-priced times?

A: No. The data that FBC has provided on the timing of its purchases and imports since 2010 (FBC Exhibit B-12 Attachment BCSEA 7.6.1 and FBC Exhibit B-21 BCSEA

51.2) indicate that FBC's purchase patterns includes large purchases in the high-load hours and in high-cost months.[20]

In addition, in its 2012–2013 Revenue Requirements Application, FBC forecast that its spot market purchases for energy in 2013 would average $60/MWh (BCUC Project No. 3698620, FortisBC Exhibit B-1, Table 4.1.2.2-9).[21] FortisBC's forecast of incremental spot energy purchase prices does not reflect low-cost off-peak purchases.

d) Wheeling Rates

Q: What transmission rate would apply to wheeling energy from the Mid-Columbia generation pool to the British Columbia border?

A: FortisBC provided the following information regarding the Bonneville Power Authority (BPA) transmission rate:

> The rate that would apply to transmitting energy from Mid-C to Teck Metals Line 71 would be BPA's Hourly Firm and Non-Firm transmission service rate, under the Point to Point Rate, currently 3.74 mills per kilowatthour. Additionally, BPA's Scheduling, System Control and Dispatch Service would apply at 0.59 mills per kilowatthour and Regulation and Frequency Response Service at 0.13 mills per kilowatthour. In total, the rate for wheeling energy from Mid-C to Teck Metals Line 71 would be 4.46 mills per kilowatthour, <u>equivalent to $4.46 per MWh</u>. (FBC Exhibit B-12 BCSEA 8.4.1, underline added)

Those wheeling rates would be in US dollars and would need to be adjusted upward to reflect the exchange rate. In addition, FBC would incur losses of 1.9%. (FBC Exhibit B-12 BCSEA 8.4.1)

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[20] In FBC Exhibit B-12 BCSEA Attachment 7.7.1, FBC provides hourly market-purchase data for April 2102 to July 2013. These data are inconsistent with the summary data in FBC Exhibit B-12 Attachment BCSEA 7.6.1 and FBC Exhibit B-21 BCSEA 51.2, for much of the period in which the datasets overlap.

[21] This cost estimate reflects only FortisBC's additional energy requirements, excluding low-cost spot purchases to back out more expensive energy from BC Hydro, and is thus comparable to the incremental energy that would be required by FortisBC's proposed reduction in DSM implementation.

Q: What is the wheeling rate for the Teck Metals line from the US into the FBC service territory?

A: FortisBC reports that the rate is $0.2/MWh (FBC Exhibit B-21 BCSEA 55.1).

Q: What is the cost of wheeling energy from the BPA area through BC Hydro to FBC?

A: The tariff rate would be over $6/MWh (FBC Exhibit B-12 BCSEA 8.9), plus losses of 6.28%.

Q: What cost is included in FBC's estimated LRMC for transmission of energy over the BPA system and the Teck Metal transmission line?

A: Midgard added $1.917/MWh Canadian in 2014, escalating at 1% annually. This is under 40% of the current wheeling rate of $4.46/MWh US. FortisBC excluded the Teck Metal wheeling rate entirely, because "the exclusion of the wheeling cost for Teck Metals Line 71 in the Midgard study is not material." (FBC Exhibit B-12 BCSEA 8.6).

In FBC Exhibit B-21 BCSEA 56.2, FBC estimates that the costs of transmission and other ancillary services from Mid-C to the Teck Metals line have total about $4/MWh over the last two years, twice the wheeling cost in FBC's avoided costs.

Q: Are there any additional costs of wheeling energy from Mid-Columbia?

A: Yes. FortisBC acknowledges that the BPA system is congested at some times, leading to higher prices for delivery to Teck Metals.

Q: Does FBC include these costs in its LRMC?

A: No. "The consequences of transmission congestion are highest for FBC and its customers during on peak hours during the winter peak.…Given DSM is a broad measure to generally reduce load (as opposed to time of use rates which target peak loads), transmission congestion was not included in the assessment of FBC's avoided cost." (FBC Exhibit B-12 BCSEA IR 8.3) In other words, FBC seems to be saying that because not all energy purchases avoided by DSM would include congestion charges, FBC ignored all congestion charges. That is not a reasonable position.

Q: Is the delivery of the energy to FBC firm?

A: No. FortisBC explains the situation as follows:

> The firm transmission from Mid-C to the BC/US border (which includes Teck Metals Line 71) is fully subscribed. However, BPA routinely makes additional transmission available on a non-firm basis. …On an hourly basis, it is expected that there will be a certain amount of this non-firm transmission available, but no guarantee that there will be enough to fully meet the demand.…Therefore, if transmission can be obtained, it is expected that BPA will deliver the power but there is no guarantee. (FBC Exhibit B-12 BCSEA 8.7)
>
> FBC has not reserved any firm transmission capacity from Mid-C to Teck Metals Line 71. (FBC Exhibit B-12 BCSEA 8.7.1)

e) Transmission and Distribution Costs

Q: What was FBC's estimate of marginal transmission and distribution costs?

A: The LRMC Avoided Cost Derivation in Attachment H4 does not mention T&D costs. Nor does the remainder of Appendix H. On discovery, FBC claimed that it "has no T&D avoided cost analyses to provide" (FBC Exhibit B-12 BCSEA 15.1) and that, with respect to "the potential avoided or deferred costs of new transmission/distribution infrastructure through the use of DSM…, then FBC has not conducted any formal studies" (FBC Exhibit B-12 BCSEA 15.2). The latter response also expresses skepticism that DSM would avoid any local T&D, and that "On the basis of this conclusion …, FBC does not consider there to be a basis on which to conduct further marginal cost studies."

Nonetheless, FBC indicated on discovery that it had included a $35/kW-year "Deferred Capital Expenditure factor, based on plan kW savings, to represent incremental Transmission & Distribution capital costs." (FBC Exhibit B-7 BCUC 1.238.1, Attachment BCUC 1.248.02)

Q: How did FBC estimate those incremental transmission and distribution costs?

A: The documentation of FBC's derivation is limited to some cryptic inputs in BCSEA IR 2.59.1. From that response, it appears that FBC divided some amount of growth-related T&D investments (probably $223 million, from 2013 through 2019) by 279 MW of load growth and annualized the investment per kW over 30 years at a 6% debt rate, net of 2% inflation.

Q: Does that computation appear to be correct?

A: No. The load growth from winter 2012/13 through winter 2019/20 is only 65 MW (FortisBC 2012–2013 Revenue Requirements Application, Appendix 3A, Tab 3, Table A-3). Also, FBC's cost of capital in nominal terms is about 7.13%, or 8.35% with a 25% income tax rate, and thus 6.13% in real terms. Using these corrected inputs, we estimate load-growth incremental costs of $233/kW-year, or about $46/MWh for the average load shape and higher for weather-sensitive on-peak loads. This compares to the $35/MWh figure used by FBC, referred to above.

2. Longer-term Marginal Cost

Q: How would the marginal costs in the longer term differ from the short-run costs that FBC includes in its estimate of the benefits of DSM?

A: Truly long-run marginal cost would include avoidable incremental costs of firm generation energy and capacity, in addition to local transmission and distribution capacity. Given public policy in British Columbia, the incremental generation resource would need to be primarily or entirely renewable, and located in British Columbia, to meet British Columbia's commitments to renewable energy development, greenhouse-gas mitigation and self-sufficiency.

Q: Do the values that FBC lists as its LRMC in this proceeding include any of the long-run generation cost components?

A: No. As discussed above, FBC recognizes that it will need to deal with the supply of firm energy in the 2016 Resource Plan, but chooses to ignore firm-energy requirements in DSM planning. As discussed in the next section, FBC also recognizes that it faces a need for capacity within the life of most of the DSM measures that would be installed in 2014–2018, but also chooses to ignore that cost in DSM planning. Rather than an in-province renewable resource, FBC values DSM at the costs of non-renewable, carbon-emitting fossil-fueled energy sourced from the Mid-Columbia market hub.

Q: Does FBC acknowledge that its proposed cut-back in DSM would contradict provincial GHG policies?

A: No. FortisBC argues that it is not required to consider BC policies regarding greenhouse-gas emissions in its DSM planning; that its purchases from Mid-Columbia hub are much cleaner than the marginal generation in the Northwest; and that it is complying with BC policy by proposing to substantially reduce its DSM savings.

Q: How will you discuss the long-run avoided-cost issues?

A: We discuss generation capacity and then the costs of Greenhouse-gas mitigation and self-sufficiency.

a) Generation Capacity

Q: Does the FBC estimate of marginal costs include any avoidable capacity costs?

A: No.

Q: What is FBC's basis for excluding capacity costs from the LRMC?

A: FortisBC's explanation is difficult to summarize, so we quote it below:

> FBC is calculating the annual average LRMC of firm spot market energy, which if purchased on an hourly basis is firm for the hour and therefore has implicit capacity costs embedded in the hourly spot price. FortisBC can also buy a short-term firm blocks of energy from a third party such as power marketer (e.g. Morgan Stanley, Shell, Powerex, etc.) for up to a year (or possibly longer), with the price indexed to the spot market price. Again since these are firm blocks they have implicit capacity costs built into the price. (FBC Exhibit B-12 BCSEA 14.1)

> Spot market power is only sold on a dollars per MWh basis and the value of the capacity is not broken out from the value of the energy. Therefore, the LRMC used by FBC includes the value of the capacity as part of the dollar per MWh price. (FBC Exhibit B-21 BCSEA 58.1)

Q: Is this a valid argument?

A: No. While FBC could purchase firm capacity along with firm energy, the Midgard energy-price forecast does not include any premium for firmness. Capacity, as a commodity distinct from energy, represents the ability to produce energy in whatever hour it is needed, due to changes in load and the availability of other resources. FortisBC's description of purchases of specific amounts of energy in specific hours, a year or more in the future, is not a substitute for capacity.

Indeed, "FBC agrees that it is risky to rely on the market to meet energy and capacity needs during periods of peak demand." (FBC Exhibit B-12 BCSEA 8.2)

Q: When does FBC expect to need additional capacity?

A: Figure 1.2.5-A of the 2012 Resource Plan shows a need for additional capacity in 2020, if only half the then-planned DSM is implemented. Since FBC is now proposing to cut its DSM savings by about 67%, or about 45 MW, the shortfall would be considerably greater than those shown in the 2012 Resource Plan.

Notwithstanding its acknowledgment of the risk of depending on the market for capacity, FBC argues that in "the 2012 Long Term Resource Plan…the 2020 June and December exposure is limited to only 4% of the super peak hours in both months, or about 4 hours per month." (FBC Exhibit B-12 BCSEA 14.3.1) Nonetheless, the 2012 Resource Plan showed a shortfall with half the then-planned DSM savings, and the shortfall would increase in subsequent years if load is allowed to grow.

Q: How does FBC propose to deal with capacity costs in the LRMC?

A: FortisBC says that "The most appropriate resources to meet FBC's long term load will be examined in the 2016 Resource Plan" (FBC Exhibit B-12 BCSEA 14.3.1).

Q: Would that approach be prudent?

A: No. Ignoring avoidable capacity costs in DSM planning over the next five years could result in FBC needing to acquire more-expensive resources in 2019 and 2020.

b) Greenhouse-Gas Mitigation

Q: Does FBC accept that the incremental energy that it purchases from the US Northwest would be primarily fossil-fueled, increasing greenhouse-gas emissions?

A: No. While it is often vague about the sourcing of its spot energy purchases (e.g., FBC Exhibit B-12 BCSEA 32.2, FBC Exhibit B-21 BCSEA 2.1), FBC says that "FBC's purchases of energy at the Mid-C would be sourced from the generation resources available in the [Northwest] region," accompanied by a graph showing that total energy supply to the US Northwest is typically about 60% hydro, 20% coal and 10% gas (FBC Exhibit B-12 BCSEA 1.2.2)

FortisBC also argues that the additional energy purchased at the Mid-Columbia hub to replace lost DSM savings should be characterized by annual average generation sources rather than by the marginal generation sources (FBC Exhibit B-21 BCSEA 43.1). FortisBC expands on this assertion, as follows:

> FBC agrees that it is likely that a decrease in load will result in displacement of whatever generation is the marginal resource at the time. Often, this will be a thermal resource, but the flexibility of the FBC system enables energy to be purchased at times when non-thermal resources such as water and wind are the marginal resource…. FBC continues to believe that using the average of CO_2e emission rate related to its market purchases is the most appropriate measure. (FBC Exhibit B-21 BCSEA 45.13)

Q: Is this explanation borne out by the available data?

A: No. The graph in FBC Exhibit B-21 BCSEA 44.1 shows that some gas is operating in Washington on most days, and coal is operating in almost as many. Even when no coal or gas is operating in Washington, the coal units may be operating elsewhere in the Northwest (in Montana, Oregon, Idaho Power's coal plants in Nevada and Wyoming). The Northwest Power and Conservation Council (NPCC) explains the nature of the marginal units as follows:

> "In the Northwest, the average marginal CO_2 production is substantially higher than the average CO_2 production from all electricity generation. This is because hydroelectricity and wind, which have low operating costs and no CO_2 emissions are brought on-line before coal-fired or natural gas-fired generating units. Because only the marginal plants would be displaced by conservation, it would not be proper to use the average of CO2 emissions from all power generation to estimate the CO2 saved through conservation." ("Marginal Carbon Dioxide Production Rates of the Northwest Power System," Northwest Power and Conservation Council, June 13, 2008, p. 1)

Clearly, additional imports of energy by FBC that increases US energy generation will result in increased coal and/or gas operation in almost all hours.

Q: Does FBC agree with this assessment?

A: No. When asked if it agrees with NPCC, FBC responded as follows:

> FBC agrees that the average marginal CO_2 production is likely to be higher than the average CO_2 production given the nature of the generation resources in the Pacific Northwest. However FBC does not fully agree with the explanation provided by NCCP because there are other factors in place that sets the marginal generation in any hour that FBC maybe purchasing market power. Indeed there are many hours of the year where coal and gas are generating because they are must-run facilities or contracted to provide baseload supply (i.e. are not dispatched in response to market), and there are many times during which there is significant surplus generation because of wind and run of river hydro conditions. Indeed it is often these times where FBC is able to take advantage of the market because the flexibility of its storage resources allow it to shape the timing of its market purchases. It is not reasonable to assume that FBC market purchases are all being made at times when the marginal generator is thermal. (FBC Exhibit B-21 BCSEA 45.12)

Q: Is this explanation consistent with the data?

A: No. When the Northwest has surplus wind and hydro energy, so that the alternative to selling the energy to British Columbia is curtailing wind or spilling hydro, the spot market energy price would be zero or negative. From the data FBC has provided, it appears to purchase substantial amounts of energy at high-cost, high-load periods. The Northwest experiences those conditions primarily in the low-load hours in the spring, during period of high runoff. Significant portions of FBC's market purchases (including those from the US) occur in high-load hours and in the summer, fall and winter, when the Northwest is operating coal and gas plants to meet its load.[22] While "it is not reasonable to assume that FBC market purchases are all being made at times when the marginal generator is thermal," it is reasonable to assume that fossil generation is on the margin in most hours.

In any case, FBC's assertion that it can purchase some energy in hours with lower GHG emissions would argue for a different weighting of the marginal emissions rates over the year, not the use of average emissions.

Q: Does FBC acknowledge that its DSM proposal is inconsistent with Provincial policy?

A: No. When asked whether "increasing relatively carbon-intensive market imports and decreasing zero-carbon DSM savings the proposed 2014–2018 DSM Plan does not support the objective of reducing GHG emissions and would tend to increase rather than reduce GHG emissions", FBC answered that

> FBC considers that the combination of the proposed DSM plan and the RCR conservation rates results in an offset of more than 50 percent of load growth and is therefore overall tending to reduce GHG emissions. (FBC Exhibit B-21 BCSEA 39.1)

Q: Is that a reasonable interpretation of the mandate to reduce GHG emissions?

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[22] The assertion that any significant fossil output in the Northwest results from having "must-run" status strains credibility. The gas-fired simple-cycle and combined-cycle combustion turbines ramp up and down quickly, and would only be on must-run status during very specific conditions of transmission and generation outages. Coal units may occasionally be forced to operate at night because they cannot ramp up and down rapidly enough to shut down over night and serve load the next day, but these conditions appear to be rare in the Northwest. As for FBC's assertion that fossil plants "are not dispatched in response to market" prices, such operation would be highly inefficient and uneconomic, and FBC offers no evidence that it occurs.

A: No. FortisBC's response attempts to pass off a reduction of the growth rate in GHG emissions as a decrease in emissions. The proper comparison is between the GHG emissions consequences of FBC's proposed 2014–2018 DSM plan and the GHG emissions consequences of a 2014–2018 DSM plan that included all cost-effective DSM. With FBC's proposed truncated DSM proposal, its load, its purchases of fossil-fueled energy, and its contribution to GHG emissions would rise over time.

c) Self-sufficiency

Q: Does FBC accept some responsibility for meeting Provincial goals for self-sufficiency?

A: Yes. FortisBC's 2012 Integrated System Plan says that "The BC Energy Plan sets forth several goals and objectives, including…Achieving self-sufficiency to meet electricity need by 2016" (p. 7) and that the "Clean Energy Act sets forth 'British Columbia's energy objectives,'" including "achieve electricity self-sufficiency." (p. 8)

Q: Would FBC's proposal to reduce its DSM efforts and increase imports conflict with these policies?

A: Yes. Section 6(4) of the Clean Energy Act states that "A public utility, in planning…for…energy purchases, must consider British Columbia's energy objective to achieve electricity self-sufficiency."

FortisBC claims that it can ignore this mandate, because "the "electricity self-sufficiency" concept can be applied to a public utility…in two specified circumstances: '(a) the construction or extension of generation facilities, and (b) energy purchase.' DSM programs and expenditures do not fall under either circumstance, and thus are not directly related to the objective of achieving 'electricity self-sufficiency'." (FBC Exhibit B-12 BCSEA 1.3)

Q: Is FBC's argument reasonable?

A: No. In planning to reduce its DSM efforts, FBC is committing itself to additional market purchases, at least until it commits to some other construction or purchase.

Hence, FBC is planning for energy purchases, and should not ignore British Columbia's objective to achieve electricity self-sufficiency.

Q: Does FBC acknowledge that it will eventually need to deal with the Province's self-sufficiency goal?

A: Yes. FortisBC says that "the 2016 Resource Plan will re-examine the best resource options for FBC to meet customer capacity and energy and stand alone energy needs at that time." (FBC Exhibit B-21 BCSEA 8.2)

Q: Is that delay reasonable?

A: No. The loss of DSM savings in 2014–2018 would reduce British Columbia's self-sufficiency and may require more expensive resources to catch up.

V. Conclusions and Recommendations

Q: What are your main conclusions regarding the 2014-18 gas and electric DSM expenditure plans proposed by the two Fortis utilities serving British Columbia?

A: The scale of energy savings proposed over the next five years by both plans falls short of both industry leaders elsewhere in North America. FBC's proposed electric savings fall further behind industry leaders than do FEU's planned gas savings. Proposed savings also fall short of their potential cost-effective contributions toward British Columbia's energy and environmental policy goals, which are among the continent's most ambitious.

With annual gas savings at 0.4% of sales, FEU's DSM plan is in the middle of the pack of industry performance, with industry leaders' savings being 1.0% or more annually. FBC's plan to cut DSM expenditures 60% from levels previously approved by the Commission and contained in its resource plan would probably land it in the bottom tier of DSM portfolios, based on our empirical analysis of industry experience and plans. Extending the previously approved FBC DSM plan savings at 0.85% of sales would keep FBC at half the savings performance of industry leaders, which are achieving 2 percent annual savings or more. This would keep FBC within the second performance tier among its peers.

Despite successful execution of its previously approved DSM programs, FBC's proposed DSM expenditures represents a complete failure in demand-side resource planning. FBC has provided no valid evidentiary support for its proposal to gut its previously approved electric DSM portfolio. It did not analyze alternative scenarios for rebalancing programs and program components in its previous portfolio to improve cost-effectiveness under the allegedly lower avoided costs. Its stated reasons for not doing so are invalid and contrary to least-cost resource planning. FBC's forecasts of long-run marginal supply costs are systematically biased downward. Moreover, the 8 percent real discount rate it used to analyze the cost-effectiveness of DSM expenditures is excessive, understating their present worth and further biasing FBC's findings.

Evidence we presented here demonstrates conclusively that it would be cost-effective to scale up both FEU and FBC DSM portfolio savings to match industry leaders at 1% and 2% respectively. These additional savings would also bring BC closer to meeting its environmental and sustainability goals.

Scale aside, the composition of the portfolios of DSM programs proposed by FEU and FBC is not as aligned with industry best practices as it can and should be. First and foremost, it is time for full integration of gas and electric DSM programs in key residential and nonresidential market segments in British Columbia including new construction and retrofit. Consolidating several FEU programs under more comprehensive umbrellas will also improve program and portfolio cost-effectiveness through broader participation and deeper savings per project, as detailed in Section III.

If there is a "poster child" for consolidating gas and electric efficiency programs in BC, it would be reviving LiveSmartBC as a scaled-up, whole-house residential retrofit program. Doing so would be indisputably cost-effective, given the favorable economics of the individual FEU programs that would be folded into it. Since the majority of benefits from whole-house retrofits come from natural gas savings, it is logical for FBC to follow industry best practice and take the lead in implementing this and residential new construction programs. FBC and BC Hydro can piggyback cost-effective electric efficiency measures on these programs, and help defray fixed program costs in proportion to the electric benefits produced (e.g., efficient lighting, air-conditioning, appliance retrofits). Table 3 in Section II provides the framework under which individual FEU and FBC gas and electric DSM programs should be consolidated and integrated to align more closely with best industry practices in portfolio design and implementation.

Q: What are your recommendations?

A: We recommend that the BCUC approve FEU's 2014–18 DSM expenditure plan, with modifications as to scale and composition discussed earlier in this testimony. We further recommend that the Commission direct FEU to submit a revised schedule of expenditures and savings by program by year in compliance with the approval within 180 days of its order in this proceeding.

As for FBC, we recommend rejection of the proposed electric DSM plan. At a minimum, we recommend that FBC continue operating under its previously approved DSM plan, i.e., its annual expenditures and savings. We further recommend that within 180 days FBC file a new 2014–18 plan containing expenditures and savings consistent with those developed in this testimony (and detailed in Exh. JPPC-5). The compliance plan should consist of programs that follow best industry practices in accord with the framework presented in Table 3, including full integration with FEU programs where indicated.

Q: When FBC files a new electric DSM plan, correcting the errors you describe above, how should it develop avoided costs?

A: In its corrected plan, FBC should screen DSM programs using avoided costs based on corrections to its short-run marginal costs in 2014–2016 and on long-run avoided costs from 2017 on. The corrections to the short-run marginal costs should include the following features:

- Increasing the non-firm spot market price to reflect firm supply.
- Weighting the spot energy prices to reflect the pattern of DSM savings over the day, week and year.
- Including the cost of congestion on the BPA system.
- Including the full cost of wheeling.
- Using a realistic currency exchange rate.
- Including the costs of short-term capacity purchases, plus 5% for the required contribution to the planning reserve margin.
- Increasing the avoided T&D costs to the full value indicated by FBC's data, or about $233/kW-year.

We estimate that, with these corrections, the avoided cost in 2014–2020 would be about $90–$100/MWh, rough twice FBC's estimates for this period (combining the LRMC reported in the Application with the $35/kW-year reported in FBC discovery responses). The long-term marginal cost should be based on the costs of building or purchasing renewable resources in British Columbia, plus the avoided T&D costs. The BC Hydro 2013 IRP (Figure 5.9) indicates that incremental BC renewables will cost on the order of $120/MWh, plus any required transmission upgrades. With the local T&D costs the total avoided cost would be about $165/MWh, about three times FBC's estimate of avoided costs. Assuming that the marginal source of energy supply is entirely spot market purchases through 2019, and entirely new renewables from 2020 onward, with no incremental generation capacity cost before 2020, the levelized LRMC over 2014–2043 would be about $140/MWh, compared to FBC's estimate of about $50/MWh.

Q: Does this complete your direct testimony?

A: Yes, it does.

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Trained as an economist, John Plunkett has worked for over 30 years in energy utility planning, concentrating on energy efficiency and renewables investments as resource and business strategies for energy service providers. He has played key advisory and negotiating roles on all aspects of electric and gas utility demand-side management (DSM), including residential, industrial and commercial program design, implementation, oversight, performance incentives, and monitoring and evaluation, and its role in business, regulatory, ratemaking, resource planning and policy decisions. He has led, prepared or contributed to numerous analyses and reports on the economically achievable potential for efficiency and renewable resources, and led the development of spreadsheet-based tools to quantify the economic and financial value of green energy investment to regulators, portfolio administrators, and individual end users.

Plunkett has worked throughout North America and in three Chinese provinces. He has testified as an expert witness before regulators in Connecticut, Delaware, the District of Columbia, Florida, Illinois, Indiana, Louisiana, Maine, Maryland, Massachusetts, New Jersey, New York, North Carolina, Oklahoma, Pennsylvania, and Vermont, as well as in the Canadian provinces of British Columbia, Ontario, and Quebec.

EMPLOYMENT HISTORY

2005-present
Partner and co-founder, **Green Energy Economics Group, Inc**., Bristol, VT
Consultancy specializing in valuing and planning electricity and natural gas utility energy-efficiency resource portfolio investments. Technical and strategic assistance with program development, design, economic and financial analysis, budgeting and planning, administration, implementation management, performance oversight, verification and evaluation; design of performance incentive and pricing mechanisms; regulatory and ratemaking treatment of DSM expenditures. Recent work applying empirical research and analysis of longitudinal data on DSM program administrators spending and savings for benchmarking future efficiency portfolio budget planning.

1996 – 2005
Partner and co-founder, **Optimal Energy, Inc.**, Bristol, VT.
Lead consultant for Natural Resources Defense Council on demand-side management portfolio design and economic analysis in two Chinese provinces. Lead witness on testimony recommending revamped performance incentive for Connecticut efficiency program administrators. Led statewide resource potential study for New York and efficiency potential study for Vermont. Economic advisor on efficiency portfolios administered by the Long Island Power Authority, to non-utility parties in Massachusetts and New Jersey DSM collaboratives, and for Northeast Energy Efficiency Partnerships on regional market transformation initiatives.

<u>1990 – 1996</u>
Senior Vice President, **Resource Insight, Inc.**, Middlebury, VT.
Provided analysis of DSM resource planning/acquisition and integrated resource planning in numerous states. Investigated regulatory and planning reforms needed to integrate demand-side resources with least-cost planning requirements by public utility commissions. Prepared, delivered and/or supported testimony on wide variety of IRP, DSM, economic, cost recovery and other issues before regulatory agencies throughout North America. Consulted and provided technical assistance regarding utility filings. Responsible for presentations and training seminars on DSM planning and evaluation.

<u>1984 – 1990</u>
Senior Economist, **Komanoff Energy Associates**, New York, NY.
Directed consulting services on integrated utility resource planning. Testified on utility resource alternatives, including energy-efficiency investments and independent power. Examined costs and benefits of resource options in over twenty-five proceedings. Supported major investigation into utility DSM investment and integrated resource planning. Designed and co-wrote microcomputer software for evaluating the financial prospects of customer-owned power generation. Wrote and spoke widely on integrated planning issues. Contributed to least-cost planning handbooks prepared by the National Association of Regulatory Utility Commissioners and by the National Association of State Utility Consumer Advocates.

<u>1978 – 1984</u>
Staff Economist, **Institute for Local Self-Reliance**, Washington, D.C.
Project development and management for a non-profit consulting firm specializing in energy and urban economic development. Project manager and economist for an investigation into the economic impact on small generators from electric utilities' grid-interconnection requirements. Coordinated research by three electrical engineers, and analyzed the impact of interconnection costs on wind, hydroelectric and cogeneration projects in seven utility service areas in New York. Provided technical coordination in cases before the District of Columbia Public Service Commission involving gas and electric utility demand management investment, non-utility generation pricing, both for the D.C. Office of People's Counsel.

<u>1977-78</u>
Energy Project Director, **D.C. Public Interest Research Group**, Washington, D.C. Led energy research and advocacy on campuses of Georgetown and George Washington Universities.

EDUCATION

B.A., Economics, with Distinction, *Phi Beta Kappa*, Swarthmore College, Swarthmore, PA, 1983. Awarded departmental Adams Prize in Economics for econometric analysis of nuclear plant capital costs.

(Georgetown University School of Foreign Service, Washington, DC, 1975-1977.)

PROJECT EXPERIENCE

ONGOING AND PAST ASSIGNMENTS (GEEG) -- 2006-PRESENT

Vermont

Senior Policy Advisor to Efficiency Vermont, the world's first Energy Efficiency Utility created to deliver statewide energy-efficiency programs for the customers of Vermont's electric utilities. Responsibilities involved economic, policy, and evaluation research, analysis and advice. Senior management team member from 2000 through 2007; led program development and planning, 2000-2002. Contract negotiation team member advising on performance goals and incentive mechanism for four successive contracts, 2000-11. Testified in support of 12-year order of appointment granted by the PSB December 2010. Lead author and technical director of 20-year forecasts in 2009 and 2011 of electricity savings under alternative investment scenarios used by the PSB to establish long-range portfolio savings and investment goals. Technical support on efficiency resource planning, 2012-present.

Program design and regulatory support for Green Mountain Power on 5-year investment of $9 million Energy Efficiency Fund. 2007 – 2010. Rebuttal testimony on achievable value from increasing energy-efficiency investment in utility service area, on behalf of Green Mountain Power in two merger applications in Dockets 7213 and 7770. December 2006-January 2007; January-April 2012. Technical assistance and regulatory support for assessing and selecting competive proposals for energy-saving investments under Community Energy Efficiency Development Fund, November 2012 – March 2013. Emprical forecasting of geographically targeted efficiency retrofit costs for non-transmission alternatives study group, 2012-March 2013.

Pennsylvania

DSM program design, implementation planning, and regulatory support, for Philadelphia Gas Works. August 2008 – present. Testimony before the Pennsylvania Public Utility Commission in Docket R-2009-2139884, December 2009 and April 2010.

Analysis and report on costs and benefits of meeting all statewide load growth with energy-efficiency investment, for Citizens for Pennsylvania's Future (Pennfuture). September 2007.

Direct and surrebuttal testimony for Citizens for Pennsylvania's Future (Pennfuture) on appropriate levels of efficiency portfolio investment in a gas merger case and in two rate cases before the Pennsylvania Public Utility Commission: Docket Nos. A-2013-2353647, et al re Equitable and Peoples Gas; 00061366 and 00061367 re Metropolitan Edison Company and Pennsylvania Electric Company; and Docket No. R-00061346 re Duquesne Light Company. July and September 2013; May - August 2006.

Wisconsin

DSM cost-effectiveness calculator development and application assistance for Shaw Engineering and Infrastructure, administrator for Wisconsin's Focus On Energy gas and electric energy efficiency investment portfolio. June 2011 – present.

Louisiana

Empirical costs projections and cost-effectiveness analysis of alternative energy-efficiency resource acquisition scenarios for Entergy New Orleans, prepared for the Alliance for Affordable Energy and submitted as comments to the City Council. April-May 2013.

Texas

Cost analysis, comments, and presentation on proposed Public Utility Commission rules for utilities pursuing statutory DSM savings goals, on behalf of the Sierra Club. May-June 2012.

Analysis of and report on achievable savings and costs for Austin City Council consumer advocate, "Energy Efficiency Resource Acquisition Options for Austin Energy." April 2012.

Illinois

Cost-effectiveness calculator development, oversight of cost/benefit analysis, and regulatory support for 3-year energy-efficiency portfolio for Peoples Gas. September 2008 – June 2012.

Rebuttal and surrebuttal testimony opposing disallowances recommended by ICC Staff for Peoples Gas. April – September 2010; December 2011.

Maryland

Comments, report, and recommendations on Maryland electric utilities' 2012-14 DSM plans, submitted to the Public Service Commission, Case Nos. 9153-57, on behalf of the Sierra Club, et al. October 2011.

Oklahoma

Technical support and comments on rulemaking for energy efficiency resource standards; ongoing; Analysis, technical assistance and expert testimony on potential for energy-efficiency investment to substitute for fossil generation in proceedings before the Oklahoma Commerce Commission on behalf of the Sierra Club, May - December 2011.

New York

Advisor on energy-efficiency portfolio design and implementation, for the Economic Development Corporation of the City of New York, in three proceedings before the New York Public Service Commission. One is the PSC's investigation into an energy-efficiency portfolio standard for meeting statewide energy savings goals of 15% by 2015. The second is a collaborative effort with Consolidated Edison's gas division to design a portfolio of gas efficiency programs. The third is evaluation and future redesign of Con Ed Electric's $125 million network-targeted demand-side program. July 2007-December 2008.

Connecticut

Testimony regarding long-range energy-efficiency procurement plan of the Energy Conservation Management Board, on behalf of the Connecticut Office of Consumer Counsel. Fall 2008.

Florida

Direct testimony on the effect of economically achievable energy efficiency on the need for new coal-fired generation, on behalf of the Sierra Club and other environmental intervenors, Florida Public Service Commission Docket No. 070098-EI. March-April 2007.

U.S.

Economic analysis and consulting support on regulatory policy regarding energy efficiency resource acquisition, for the Regulatory Assistance Project. 2011-present.

British Columbia, Canada

Testimony on adequacy of BC Hydro's 2012-14 DSM Plan, submitted to the British Columbia Utilities Commission, BCUC Project No. 3698592**,** on behalf of the BC Sustainable Energy Association and Sierra Club (BC Chapter). August 2011 – May 2012.

Direct testimony on reasonableness of gas DSM Plan by Fortis Energy Utilities before the British Columbia Utilities Commission, BCUC Project No. 3698627**,** on behalf of the BC Sustainable Energy Association and Sierra Club (BC Chapter), May – November 2011.

Direct testimony and technical support on assessment of FortisBC Electric's long-term DSM plan, before the BCUC, on behalf of BCSEA/SCBC, August 2011 – March 2012.

Direct testimony and technical support on assessment of BC Hydro's long-term DSM plan, before the BCUC, on behalf of BCSEA/SCBC, November 2008 – March 2009; October 2011 - present.

Direct testimony on assessment of Terasen Gas conservation plans before the BCUC, on behalf of BCSEA/SCBC. October 2008.

Direct testimony on energy-efficiency investment spending and savings, British Columbia Hydro and Power Authority, 2006 Integrated Electricity Plan and Long Term Acquisition Plan, Project No. 3698419; and F2007/F2008 Revenue Requirements Application, Project No. 3698416, on behalf of BCSEA/SCBC et al. September 2006 – January 2007.

People's Republic of China

Central Government

Technical and policy advice and material preparation for regulators on clean energy investment on behalf of the Regulator Assistance Project's Global Power Sector Best Practices Project. June 2011 – present. Drafted sections of a "blueprint" for Chinese regulators on oversight of grid company administration of DSM programs, including cost-effectiveness analysis, reporting, and monitoring, verification and evaluation. May-July 2012.

Consulting team member on a project developing a national DSM implementation manual for China, sponsored by the National Development and Reform Commission, led by the Natural Resources Defense Council, in cooperation with California's investor-owned utilities, and funded by the international Renewable Energy and Energy Efficiency Programme (REEEP). Wrote chapters concerning performance indicators and cost-effectiveness analysis. 2007-Spring 2008. Manual approved by NDRC May 2009 and issued May 2010.

Guangdong Province

Consultant for the Institute for Sustainable Communities to assist Chinese experts with technical, economic, and financial assessments of industrial retrofit projects. Economic and financial assessment of efficiency retrofits to a ceramics manufacturing plant. 2007-2008. Training and technical assistance to Chinese trainers on economic and financial assessment of energy-efficiency and renewable investment projects in Guangdong and Jiangsu provinces. 2009-2010.

Team leader for Chinese and international consultants on a pre-feasibility analysis for the Asian Development Bank of a 24-year loan to support a $120 million demonstration Efficiency Power Plant (EPP) project in Guangdong province, focusing on industrial, commercial and institutional retrofits. June 2006 – 2007. ADB Board of Directors unanimously approved the loan and its first tranche of projects in June 2008.

Jiangsu Province

Consulting team leader on development, assessment, and implementation of demand-side management investment portfolios for China, for the Natural Resources Defense Council (July 2003 – 2007). Responsible for program implementation planning and support (2005-2007). Led modification and application of US-based program and portfolio economic analysis tool for DSM planning. Assisted Jiangsu Province with design and planning for first-stage implementation of Efficiency Power Plant (EPP) programs investing $12 million annually on high-efficiency retrofits to industrial motors and drives and commercial lighting and cooling. Directed economic and financial analysis of industrial retrofits for several manufacturers to determine financial incentives offered by the program. October 2005 – 2007. Training and technical support on economic and financial analysis of industrial retrofit projects for structuring and negotiating financial incentive offers to customers (2007-2008).

PRIOR ASSIGNMENTS (OPTIMAL ENERGY) -- 1996-2005

- Policy and economic advisor for Massachusetts energy efficiency collaboratives, focusing on regulatory, cost-effectiveness, shareholder incentives and other policy issues and strategies, on behalf of Massachusetts Collaborative Non-Utility Parties. (January 1999 – 2005)

- Co-author (with Optimal Energy and Vermont Energy Investment Corporation), Comments on Efficiency Maine's 2006-2008 Program Plan, on behalf of Maine's Office of Public Advocate. September 2005.

- Team leader providing technical assistance supporting rulemaking to implement energy-efficiency provision of renewable portfolio standard for Pennsylvania, on behalf of Citizens for Pennsylvania's Future (PennFuture). Lead consultant on development of protocols for measuring savings from energy-efficiency investments as tradable credits toward the electricity resource portfolio standard. Protocols adopted by the Pennsylvania Public Utilities Commission. 2005. (February – September 2005)

- Leader of analysis of economically achievable potential for energy-efficiency resources to offset loss of output in the event of early retirement of the Indian Point nuclear generation station, on behalf of the National Academy of Sciences. May-October 2005.

- Co-author (with Paul Chernick) of testimony assessing planned energy-efficiency investments by British Columbia Hydro, on behalf of the British Columbia Sustainable Energy Association and British Columbia Sierra Club, August 2005.

- Written testimony recommending energy-efficiency portfolio investment levels and savings goals in utility merger application before the Pennsylvania Public Utility Commission, Joint Application of PECO Energy Company and Public Service Electric and Gas Company for Approval of the Merger of Public Service Enterprise Group with and into Exelon Corporation, on behalf of the Pennfuture Parties, June 28, 2005.

- Co-author of and expert witness supporting "Getting Results: Review of Hydro Quebec's Proposed 2005-2010 Energy Efficiency Plan," before the Quebec Energy Board, on behalf of a coalition of business, municipal, and environmental groups (January-March 2005)

- Testimony (with Ashok Gupta) before the New York Public Service Commission supporting joint settlement proposal for 300 MW of additional efficiency investment in Con Edison territory, on behalf of the Natural Resources Defense Council, Pace Energy Project, and the Association for Energy Affordability (December 2004 – January 2005).

- Report and testimony on performance incentives for administrators of conservation and load management programs in Connecticut, on behalf of Connecticut Office of Consumer Counsel. (February 2003 – August 2004). DPUC adopted recommended performance incentive mechanism for 2006 program year.

- Project leader, including report and testimony, for consulting team projecting potential for demand-side resources to defer the need for the Northwest Reliability Project, a major transmission upgrade, on behalf of Vermont Electric Power Company. (November 2001 – December 2004)

- Report and testimony on Opportunities for Accelerated Electrical Energy Efficiency in Québec 2005 – 2012, on behalf of Regroupement National des Conseils Régionaux de L'environnement du Québec, Regroupement des Organismes Environnementaux en Energie and Regroupement pour la Responsabilité Sociale des Entreprises. (March – June 2004)

- Project leader for consulting team assessing technical, achievable and economic potential for energy-efficiency and renewable resources in New York State and five sub regions over 5, 10 and 20 years, on behalf of New York State Research and Development Authority. (January 2002 – August 2003)

- Project leader for consulting team updating statewide projection of economically achievable efficiency potential for state of Vermont, on behalf of the Vermont Department of Public Service. (October 2001 – 2003)

- "A Conservation Contingency Plan for Indian Point: Using California's Success Beating Blackouts to Replace Nuclear Generation Serving Greater New York," prepared for the Natural Resources Defense Council, October 2003.

- "The Achievable Potential for Electric Efficiency Savings in Maine." Projected and compared 10-year C&I costs, savings and benefits (based on technical potential analysis prepared by Exeter Associates). Expert testimony on behalf of the Office of Public Advocate, before the Maine PUC. (October 2002)

- Project leader for consulting team supporting utilities in targeting demand-side resources to optimize distribution investment planning in statewide distributed utility planning collaborative, on behalf of the Vermont Department of Public Service. (September 2001 – December 2002) Led development of DSM scoping tool, an MS Excel spreadsheet for preliminary analysis of the economically achievable potential for energy-efficiency to defer or displace planned distribution investments.

- Advisor on economic analysis for program planning and implementation of multi-year statewide energy-efficiency programs in the New Jersey Clean Energy Collaborative involving all the state's electric and gas utilities and the Natural Resources Defense Council. (April 2000 – June 2003, on behalf of NRDC). Co-directed collaborative work on program development, planning, and implementation for Conectiv. (November 1996 – 2000)

- Analysis and testimony before the Connecticut Siting Council on integrating potential demand reductions from targeted demand-side resources into need assessment for transmission upgrades, on behalf of the Connecticut Office of Consumer Counsel. Docket No. 217. (February 2002 – February 2003)

- Advice and negotiation on policy and scope of utility activities regarding targeted DSM to optimize distribution investment planning, involving Consolidated Edison, PECO Energy, and Orange and Rockland Utilities, on behalf of the Natural Resources Defense Council (Con Ed and PECO) and Pace Energy Project (O&R). (1999 – 2000)

- "Examining the Potential for Energy Efficiency in Michigan: Help for the Economy and the Environment," for American Council for an Energy-Efficient Economy (ACEEE). Analysis and report projecting costs and benefits of aggressive energy-efficiency investment. (January 2003)

- Led consulting team in the preparation of detailed recommendations for implementing strategic plan for acquiring clean power resources for the Jacksonville Electric Authority. (May – September 2001)

- Consultant to Citizens Utilities Corporation, supporting planning and management of investments pursuing maximum achievable levels of optimally cost-effective energy-efficiency in its Vermont Electric Division. (1997 – 2001)

- Consultant to PEPCo Energy Services on building energy-efficiency into retail service offerings. (2000 – 2001)

- Consultant to California Board for Energy-Efficiency, the agency responsible for administering wires-charge funded statewide energy-efficiency programs. Technical service consultant on nonresidential program design. (1997 – 1999)

- Lead consultant on energy product development for consumer energy cooperative, on behalf of Vermont Energy Futures, a non-profit organization spearheading development of a consumer-owned energy cooperative that will bundle electricity with energy-efficiency, renewables, and fossil fuels for residential, low-income, and small non-residential customers. One of key team members who prepared grant application to federal Health and Human Services Department for $800,000 grant supporting development of the co-op. (1997 – 2000)

- Led feasibility analysis and prepared preliminary business plan for bundling electricity, fuel, efficiency services, and green power initially targeting low-income and environmentally-conscious consumers, on behalf of the Energy Coordinating Agency and Conservation Consultants, Inc. (July – December 1997). Consultant on energy and business strategy and planning for Energy Cooperative Association of Pennsylvania, a buyers' cooperative offering electricity, fuel oil, energy-efficiency, and renewable energy to residential and non-profit consumers in eastern and western Pennsylvania. (1998 – July 1999)

- Lead consultant on energy efficiency program design and planning for Maryland Office of People's Counsel and Maryland Energy Administration. Led research, analysis, and program descriptions and budgets for use in restructuring workshops and legislative development on efficiency and renewable programs supported by system benefits charge. (1998)

- Lead consultant for the Vermont Department of Public Service regarding energy-efficiency investment during and after the transition to electricity restructuring. Lead author of *The Power to Save: A Plan to Transform Vermont's Efficiency Markets*, the DPS filing which called for development of centrally delivered statewide core programs by an efficiency utility. Provided written and oral testimony, on behalf of the Vermont Department of Public Service in Docket 5980. (1997 – 1999)

- Technical support to the Burlington (VT) Electric Department in developing energy efficiency programs and policies as part of their resource and business planning. (November 1996 – May 1997)

- Consultant to Vermont Senate Natural Resources and Finance Committees on efficiency and renewable policies in restructuring legislation passed by the Senate but not adopted by the House. Provided technical assistance to support drafting and passage of utility restructuring legislation (S.62). (1997)

- Support to the Vermont Department of Public Service in assessing the performance and expenditures of Green Mountain Power's commercial and industrial DSM programs. Also provided support to the DPS in the evaluation of GMP's actions surrounding the Vermont Joint Owners contract with Hydro Quebec including prudence. (1997).

- Direct testimony and cross-examination relating to the future of DSM under the proposed BG&E/PEPCo utility merger. Case No. 8725 In the matter of Application of BGE, PEPCo & Constellation Energy Corporation for Merger. (1996)

- Written report to the Ontario Energy Board assessing the 1997 DSM Plan filed by Union and Centra Gas LTD in light of prior OEB decisions, as well as specific program plans for residential and non-residential customers. The report also addressed potential changes in gas DSM regulation, cost recovery, and incentives. [*Assessment of the Centra/Union Gas Fiscal 1997 DSM Plan*, Plunkett, Hamilton, and Mosenthal, August 30, 1996.] Testimony before the OEB concerning the report's findings and recommendations. Union/Centra Rate Case, EBRO 493/494. Also prepared a report and testified on Union Gas's DSM program design in EBRO 496/94/95. (July 1996 – November 1996)

PRIOR ASSIGNMENTS (RESOURCE INSIGHT) – 1990-1996

- Consultant on energy-efficiency program design, planning, and policy issues for Maryland utilities including Potomac Electric, Baltimore Gas and Electric, Potomac Edison, Delmarva Power and Light, Southern Maryland Electric Cooperative, Washington Gas, on behalf of Maryland Office of People's Counsel. Coordinator and lead negotiator on DSM collaboratives for Washington Gas, Potomac Electric, Baltimore Gas and Electric, Delmarva Power and Light and Potomac Electric. Projects have included resource planning and allocation, program design, policy, cost recovery, mechanism design, and monitoring and evaluation planning. (1989 – 1997)

- Prepared testimony and supported settlement negotiations concerning the DSM Plan of Jersey Central Power and Light on behalf of the Mid Atlantic Energy Project and New Jersey

Public Interest Research Group. Analyzed DSM policy and commercial and industrial programs. Docket No. EE9580349 In the matter of Consideration and Determination of Jersey Central Power and Light Company's Demand Side Management Resource Plan filed pursuant to N.J.A.C. 14:12. (1995)

- Support to the Iowa Office of Consumer Advocate with the review and analysis of MidAmerican's, Interstate Power's and Iowa Electric Services' existing energy efficiency plans. Developed proposals for changes to and modifications of the utilities commercial and industrial energy efficiency programs. (1995 – 1996)

- Testimony and technical support for the Iowa Office of Consumer Advocate in settlement negotiations re IES Utilities C/I DSM programs. Docket No. EEP-95-1. (February 1996)

- Technical support to Florida Power Corporation on development of alternative DSM programs for commercial and industrial customers. (1995 – 1997)

- Supported development of testimony and negotiations regarding DSM program alternatives for Carolina Power & Light, on behalf of the Southern Environmental Law Center. Docket No. 92-209-E. (1995 – 1996)

- Reviewed and commented on Consumer Gas' C/I DSM programs on behalf of the Green Energy Coalition. (1995)

- Support to the Vermont Department of Public Service in negotiation settlement with Green Mountain Power regarding DSM program design and planning, focusing on target retrofits in load centers under T&D capacity constraints, and increased participation and comprehensiveness of lost-opportunity programs. (1995)

- Consulting services and expert testimony on behalf of the Green Energy Coalition concerning Ontario Hydro's DSM plans and acquisition of lost-opportunity resources. Before Ontario Energy Board H.R. 22. re: Ontario Hydro 1995 Rates and Spending. (1994) and re: Ontario Hydro's Bulk Power Rates for 1993. Ontario Energy Board HR-21. (1992)

- Reviewed Tennessee Valley Authority programs and environmental planning for the Tennessee Valley Energy Reform Coalition. (November 1994 – July 1995)

- Prepared and defended direct testimony on gas and electric Demand-Side Management/Integrated Resource Planning guidelines before the North Carolina Public Utilities Commission. Docket No. E-100, SUB 64A in the matter of Request by Duke Power Company for Approval of a Food Service Program, Docket E-100, SUB 71 In the matter of Investigation of the Effect of Electric IRP and DSM Programs on the Competition Between Electric Utilities and Natural Gas Utilities. (1994)

- Prepared and defended expert testimony and led analyses of demand-side management and fuel switching opportunities in Central Vermont Public Service territory, on behalf of the Vermont Department of Public Service. Project involved detailed analysis of measure costs, savings, and cost-effectiveness. Vermont Public Service Board, Docket 5270-CVPS-1&3. (1994)

- Prepared and defended expert testimony for the Vermont Department of Public Service on prudence of demand-side management in CVPS rate case. Vermont Public Service Board, Docket 5724. (May – August 1994)

- Directed and supported the preparation of joint testimony for Enersave, an efficiency service provider. Before the New York Public Service Commission, Case No. 94-E-0334. (September 1994)

- Joint testimony with Jonathan Wallach for the New York Public Utility intervenors reviewing 1994 LILCo DSM Plan. Before the New York Public Service Commission. P.S.C. Case No. 93-5-1123. (May 1994)

- Contributed to the critique of PECO Demand-Side Management Plan for the Nonprofits Energy Savings Investment Program. (February 1994)

- Provided direct testimony in a proceeding to investigate restrictions on DSM that could give one utility (gas or electric) an unfair competitive advantage over another (electric or gas, respectively). Before the Louisiana Public Service Commission Docket No. U-20178 Re: Louisiana Power & Light Company Least Cost Resource Plan. (1994)

- Provided expert testimony in support of PEPCo's DSM implementation. Before the Public Service Commission of the District of Columbia. Case No. 929. (1993)

- Prepared written testimony for the Maryland Office of People's Counsel analyzing potential for demand-side resources to offset need for power for proposed coal-fired plant. Delmarva Power & Light Company Dorchester Power Plant Certificate of Public Convenience and Necessity. Maryland PSC Case No. 8489. (January 1993)

- Coordinated testimony assessing the planning process, screening analyses, and cost-recovery proposals of the Detroit Edison Company for its demand-side management programs. Estimated potential levels of savings; identified improvements to the utility's proposed cost-recovery, lost-revenue, and incentive mechanisms; and recommended regulatory signals consistent with least-cost planning. Provided economic and regulatory advice, consulting services, and oversaw preparation of testimony. Michigan PSC Case No. U-10102. (1992)

- Economic and regulatory advice, consulting services, and supervision of testimony preparation. Provided technical services encompassing demand-side management program monitoring and evaluation, cost recovery, and review of second efficiency plans. Before the Iowa Utilities Board, Iowa Power and Light Docket No. EEP-91-3 and Interstate Power Company Docket No. EEP-91-5. (1992)

- Consulting on policy and resource-allocation issues on behalf of the Vermont Department of Public Service as part of DSM-program-design collaboratives with Vermont Gas. (1990 –

1991), Citizens Utilities (1990 – 1991), Central Vermont Public Service Corporation (1990) and Green Mountain Power. (1990)

- Comprehensive assessment of Ontario Hydro's 25-year resource plan. Directed work by over a dozen consultants. The study encompassed load forecasting; assessing DM potential and costs; resolving DM-implementation, resource-integration, and institutional issues; assessing all resource costs, including externalities; assessing costs of all supply resources, including non-utility generators; and estimating avoided costs. (1990 – 1992)

- Support to the Pennsylvania Energy Office in its evaluation of Pennsylvania electric utility demand-management plans by preparing testimony and co-authoring a comprehensive, five-volume study of all aspects of demand management. This document surveys issues related to integration of demand-management resources into utility planning, and reconciling least-cost planning objectives with rate-impact constraints; discusses strategies for utility intervention to remove market barriers to energy conservation; evaluates cost-recovery mechanisms for demand-management expenditures by utilities; explores issues related to the screening demand-management measures and programs; and examines direct costs, risk, and externalities avoidable through demand management. (1991 – 1993)

- Provided analysis of 1991 - 1992 New York electric utility DSM plans, and support for the analysis of 1993 - 1994 DSM Plans on behalf of Pace University Center for Environmental and Legal Studies, and Vladeck, Waldman, Elias & Engelhard, P.C., Counsel for the Class of LILCo Ratepayers in County of Suffolk *et al*. v. LILCo *et al*. Proceeding to Inquire into the Benefits to Ratepayers and Utilities from Implementation of Conservation Programs that will reduce Electric Use, New York Public Service Commission Case No. 28223. (1990, 1992, 1994)

- Reviewed Demand Side Management regulations and DSM compliance filings of four New Jersey utilities on behalf of the New Jersey Division of Rate Counsel. Demand Side Management Resource Plan of Jersey Central Power & Light Company. Docket No. EE-92020103. (1992)

- Identified energy-efficiency resources missing from FPL's resource plan that could provide economical substitutes for proposed power supply option. Expert testimony also addressed environmental costs avoided by DSM. Florida PSC Docket No. 920520-EG, In Re: Joint Petition of Florida Power and Light and Cypress Energy Partners, Limited Partnership for Determination of Need. (1992)

- Technical assistance and expert testimony for the Indiana Office of Utility Consumer Counselor, In the matter of the Petition of Indianapolis Power & Light Company for a Certificate of Public Convenience and Necessity for the Construction by it of Facilities for the Generation of Electricity and Submission and Request for Approval of Plan to meet future needs for Electricity. Cause No. 39236. (August 1991 – May 1992)

- Technical assistance and expert testimony for the Indiana Office of Utility Consumer Counselor. In the matter of the Petition of PSI Energy, Inc. Filed Pursuant to the Public Service Commission Act, as Amended, and I.C. 8-1-8.52 for the Issuance of Certificates of

Public Convenience and Necessity to Construct Generating Facilities for the Furnishing of Electric Utility Service to the Public and for the Approval of Expenditures for such Facilities. Cause No. 39175. (June 1991 – February 1992)

- Testimony and surrebuttal for the Delaware PSC Staff. Before the Delaware Public Service Commission Staff, In the Matter of the Application of Delmarva Power & Light Company for Approval of 48 MW Power Purchase Agreement with Star Enterprise, PSC Docket No. 90-16. (January 1991)

- Prepared comments on IRP principles and objectives for the Southern Environmental Law Center. Commonwealth of Virginia State Corporation Commission Order Establishing Commission Investigation to Consider Rules and Policy Regarding Conservation and Load Management Programs, Case No. PUE900070. (1991)

PRIOR ASSIGNMENTS (KOMANOFF ENERGY ASSOCIATES) – 1984-1990

- Advisor to the Vermont Public Service Board. Assisted with formulating issues, conducting hearings, deciding policy, and drafting opinions and orders on DSM planning programs, and ratemaking. Advised the Board's hearing officer on numerous decisions concerning policy and process, including cost-benefit analysis, design and coverage of utility energy-efficiency programs and integrated planning requirements. Investigation into Least-Cost Investments, Energy Efficiency, Conservation, and Management of Demand for Energy, Docket No. 5270. (1988 – 1990)

- Technical advisor to the Public Utility Law Project of New York. Recommended economic principles for planning utility DSM investment for low-income customers in New York. Proceeding on Motion of the Commission to Determine Whether the Major Gas and Combination Gas and Electric Utilities Subject to the Commission's Jurisdiction Should Establish and Implement a Low-Income Energy Efficiency Program, Case 89-M-124. (1990).

- Technical assistance and advice on behalf of the South Carolina Department of Consumer Affairs on all aspects of Integrated Resource Planning and DSM planning including cost-effectiveness tests for South Carolina PSC investigation into Electric Utility Least-Cost Planning, Docket No. 87-223-E. (1987 – 1992)

- Prepared and defended expert testimony for the Indiana Office of Utility Consumer Counselor on potential for DSM to defer need for new generating capacity. Petition of Southern Indiana Gas and Electric Co. for Approval of Construction and Cost of Additional Electric Generation and for Issuance of a Certificate of Need Therefore, Indiana Utility Regulatory Commission, Cause No. 38738. (September 1989)

- Prepared and defended expert testimony for the Illinois Citizens Utility Board on adequacy of Commonwealth Edison's DSM efforts. Rulemaking Implementing Section 8-402 of the Public Utilities Act, Least-Cost Planning, Illinois ICC Docket No. 89-0034. (July 1989)

- Supported the Vermont Public Service Board with analysis, findings, and conclusions regarding the need for power based on potential DSM resources. Application of Twenty-Four

Electric Utilities for a Certificate of Public Good Authorizing Execution and Performance of a Firm Power and Energy Contract with Hydro-Quebec and a Hydro-Quebec Participation Agreement, Docket No. 5330. (1989 – 1990)

- Cost-benefit analysis for the City of Chicago examining alternatives to the renewal of Commonwealth Edison's franchise. (1989)

- Co-author (with J. Wallach) of *The Power Analyst*, integrated spreadsheet-based software for projecting the economic and financial performance of renewable and cogeneration projects, for the New York State Energy Research and Development Authority. Project manager, economic analysis. (1989)

- Advisor for the South Carolina Department of Consumer Affairs. Assessed costs and benefits of long-term power contract. In the Matter of Duke Power Company, Federal Energy Commission, Docket No. ER89-106-000. (January 1989 – March 1990)

- Analyzed and provided expert testimony on the economic potential for cost-effective DSM to substitute for capacity and energy from a combined cycle generating plant. Application of Potomac Electric Power Company for Certificate of Public Convenience and Necessity for Station H, Maryland PSC Docket No. 8063 Phase II. (1988)

- Examined, compared, and recommended appropriate cost-effectiveness tests for the DSM portion of the Massachusetts Department of Public Utilities investigation into the Pricing and Ratemaking Treatment to Be Afforded New Electric Generating Facilities Which Are Not Qualifying Facilities. Docket No. 86-36. (1988)

- Testimony for the District of Columbia Office of People's Counsel on electric and gas utility least-cost planning. Application of the Potomac Electric Power Company for Changes to Electric Rate Schedules, D.C. PSC Formal Case 834 Phase II. (April and June 1987)

- Cross-examination for the Connecticut Division of Consumer Counsel to defend KEA's financial assessment of CL&P's ability to withstand Millstone 3 disallowance. Investigation into Excess Generating Capacity of Connecticut Light & Power Company, Connecticut DPUC Docket No. 85-09-12. (April 1986)

- Cross examination for the Connecticut Division of Consumer Counsel to defend financial and statistical model supporting KEA's findings of CL&P construction imprudence. Retrospective Audit of the Prudence of the Construction of Millstone 3, Connecticut DPUC Docket 83-07-03. (March 1986)

- Cross-examination for the Pennsylvania Office of Consumer Advocate, defended quantification of imprudence findings by O'Brien/Kreitzberg & Associates regarding PECO's construction management of the Limerick 1 project. Pennsylvania PUC v. Philadelphia Electric Company Docket R-850152. (February 1986)

- Prepared and defended direct and surrebuttal testimony for the Pennsylvania Office of Consumer Advocate critiquing utility conservation and cogeneration assumptions and presented alternative 20-year electricity sales projection. Pennsylvania PUC Limerick 2 Investigation Docket I-840381. (April 1985)

PRIOR ASSIGNMENTS (INSTITUTE FOR LOCAL SELF-RELIANCE) – 1978-1983

- Technical and economic analysis of small-generator grid interconnection of seven New York electric utilities for the New York Energy Research and Development Authority. Project manager, economic analysis. (1983)

- Written testimony on behalf of the Alaska Public Interest Research Group implementing PURPA 210. Before the Alaska PUC. (1981)

- Written and oral testimony in oversight hearings on state implementation of the Public Utility Regulatory Policy Act of 1978 (PURPA). U.S House of Representatives Subcommittee on Energy Conservation and Power. (1981)

- Written and oral testimony in rulemaking for the Public Utility Regulatory Policy Act of 1978 (PURPA) on behalf of ILSR, before the Federal Energy Regulatory Commission. (1979)

PUBLICATIONS/PRESENTATIONS

"An Empirical Model for Predicting Electric Energy Efficiency Resource Acquisition Costs in North America: Analysis and Application", with T. Love and F. Wyatt. 2012 *Summer Study on Energy Efficiency in Buildings,* American Council for an Energy Efficient Economy, Pacific Grove, California, August 2012.

"Expanding Energy Efficiency for BC Hydro: Lessons from Industry Leaders," Webinar presentation for BC Sustainable Energy Association, June 19, 2012.

"'Walking the Walk' of Distributed Utility Planning: Deploying Demand-Side Transmission and Distribution Resources in Vermont, Part Dieux" with Bruce Bentley 2008 *Summer Study on Energy Efficiency in Buildings,* American Council for an Energy Efficient Economy, Pacific Grove, California, August 2008.

"Demand-Side Management Strategic Plan for Jiangsu Province, China: Economic, Electric and Environmental Returns from an End-Use Efficiency Investment Portfolio in the Jiangsu Power Sector," with Barbara Finamore and Francis Wyatt, 2006 *Summer Study on Energy Efficiency in Buildings,* American Council for an Energy Efficient Economy, Pacific Grove, California, August 2006.

"'Walking the Walk' of Distributed Utility Planning: Deploying Demand-Side Transmission and Distribution Resources in Vermont's 'Southern Loop,'" with Bruce Bentley and Francis Wyatt, 2006 *Summer Study on Energy Efficiency in Buildings,* American Council for an Energy Efficient Economy, Pacific Grove, California, August 2006.

"Comparative Performance of Electrical Energy Efficiency Portfolios in Seven Northeast States," with Glenn Reed and Francis Wyatt, 2006 *Summer Study on Energy Efficiency in Buildings,* American Council for an Energy Efficient Economy, Pacific Grove, California, August 2006.

"Charting New Frontiers with Vermont's Deployment of Demand-Side Transmission and Distribution Resources," ACEEE National Conference on Energy Efficiency as a Resource, Berkeley, CA, September 27, 2005.

"Energy Efficiency and Renewable Energy Resource Potential In New York State: Summary of Potential Analysis Prepared For the New York State Energy Research and Development Authority", invited presentation to the National Academy of Sciences Committee On Alternatives to Indian Point, Washington, DC, January 2005.

"Estimating and Valuing Energy-Efficiency Resource Contributions: Toward a Common Regional Protocol," presented at the Northeast Energy Efficiency Partnerships conference on regional efficiency policy, November 2004.

"The Economically Achievable Energy Efficiency Potential in New England," presented at the Northeast Energy Efficiency Partnerships conference on regional efficiency policy, November 2004.

"Rewarding Successful Efficiency Investment In Three Neighboring States: The Sequel, the Re-Make and the Next Generation (In Vermont, Massachusetts and Connecticut)," (with P. Horowitz and S. Slote), 2004 *Summer Study on Energy Efficiency in Buildings,* American Council for an Energy Efficient Economy, Pacific Grove, California, August 2004.

"Measuring Success at the Nation's First Efficiency Utility" (With B. Hamilton), 2002 *Summer Study on Energy Efficiency in Buildings,* American Council for an Energy Efficient Economy, Pacific Grove, California, August 2002.

"New Jersey's Clean Energy Collaborative: Model or Mess?" (with D. Bryk and S. Coakley), 2002 *Summer Study on Energy Efficiency in Buildings,* American Council for an Energy Efficient Economy, Pacific Grove, California, August 2002.

"Yes, Virginia, You Can Get There From Here: New Jersey's New Policy Framework For Guiding Ratepayer-Funded Efficiency Programs" (with S. Coakley and D. Bryk), *2000 Summer Study on Energy Efficiency in Buildings,* American Council for an Energy Efficient Economy, Pacific Grove, California, August 2000.

"Integrated Market-Based Efficiency and Supply for Small Energy Consumers: The Consumer Energy Cooperative" (with B. Sachs and E. Belliveau) *2000 Summer Study on Energy Efficiency in Buildings,* American Council for an Energy Efficient Economy, Pacific Grove, California, August 2000.

"Comprehensive Energy Services At Competitive Prices: Integrating Least-Cost Energy Services to Small Consumers through a Retail Buyer's Cooperative" (with B. Sachs), *1998 Summer Study on Energy Efficiency in Buildings,* American Council for an Energy Efficient Economy, Pacific Grove, California, August 1998.

"Capturing Comprehensive Benefits from Commercial Customers: A Comparative Analysis of HVAC Retirement Alternatives" (with P. Mosenthal and M. Kumm), *1996 Summer Study on Energy Efficiency in Buildings*, American Council for an Energy Efficient Economy, Pacific Grove, California, August 1996. 5.169.

"Joint Delivery of Core DSM Programs: The Next Generation, Made in Vermont" (with S. Parker), *1996 Summer Study on Energy Efficiency in Buildings*, American Council for an Energy Efficient Economy, Pacific Grove, California, August 1996. 7.127.

"Retrofit Economics 201: Correcting Common Errors in Demand-Side Management Cost-Benefit Analysis" (with R. Brailove and J. Wallach) *IGT's Eighth International Symposium on Energy Modeling*, Atlanta, Georgia, April 1995.

"DSM's Best Kept Secret: The Process, Outcome and Future of the PEPCo-Maryland Collaborative" (with R. D. Obeiter and E. R. Mayberry), *Proceedings of the ACEEE Summer Study on Energy Efficiency in Buildings*, Monterey, California, August 1994. 10.199.

Louisville Gas and Electric Company. Invited to make presentation on commercial program design. March 10, 1994.

"DSM for Public Interest Groups," Seminar coordinator and presenter. DSM Training Institute, Boston, Massachusetts, October 1993.

DSM Training Institute - *Training for Ohio DSM Advocates: Effective DSM Collaborative Processes*. Seminar co-presenter. Cleveland, Ohio, August 1993.

"Demand-Management Programs: Targets and Strategies," Vol. 1 of "Building Ontario Hydro's Conservation Power Plant" (with J. Wallach, J. Peters, and B. Hamilton), Coalition of Environmental Groups, Toronto, ONT, November 1992.

"DSM Program Monitoring and Evaluation: Prospects and Pitfalls for Consumer Advocates," *Proceedings from the Mid-Year NASUCA Meeting,* Saint Louis, Missouri, June 8, 1993.

"Twelve Steps To Comprehensive Demand-Management Program Development: A Collaborative Perspective", *Proceedings from the IRP Workshop: The Basic Landscape, NARUC-DOE Fourth IRP Conference*, Burlington Vermont, September 1992. 45.

"Demand-Side Cost Recovery: Toward Solutions that Treat the Causes of Utility Under-Investment in Demand-Side Resources" (with P. Chernick), *Proceedings from the Third NARUC Conference on Integrated Utility Planning*, Santa Fe, New Mexico, April 1991.

"Demand-Side Bidding: A Viable Least-Cost Resource Strategy?" (with P. Chernick and J. Wallach), *Proceedings from the Seventh NARUC Biennial Regulatory Information Conference*, Columbus, Ohio, September 1990.

"Where Do We Go From Here? Eight Steps for Regulators to Jump-Start Least-Cost Planning" (with M. Dworkin), *Proceedings from the Seventh NARUC Biennial Regulatory Information Conference*, Columbus, Ohio, September 1990.

"A Utility Planner's Checklist for Least-Cost Efficiency Investment" (with P. Chernick) *Proceedings from the Seventh NARUC Biennial Regulatory Information Conference,* September 1990. Also published in *Proceedings from the Canadian Electric Association's Demand-Side Management Conference*, St. John, Nova Scotia, September 1990.

"Carrots and Sticks: Do Utilities Need Incentives to Do the Right Thing on Demand-Side Investment?", *Proceedings from the National Association of State Utility Consumer Advocates* Santa Fe, New Mexico, June 1990.

"New Tools On the Block: Evaluating Non-Utility Supply Opportunities with the Power Analyst" (with J. Wallach), *Proceedings from the Fourth National Conference on Microcomputer Applications in Energy*, Phoenix, AZ, April 1990.

"Breaking New Ground in Collaboration and Program Design," *The Rocky Mountain Institute Competitek Forum* (Moderator), Aspen, Colorado, September 1989.

"Lost Revenues and Other Issues in Demand-Side Resource Evaluation: An Economic

Reappraisal" (with P. Chernick), *1988 Summer Study on Energy Efficiency in Buildings*, American Council for an Energy Efficient Economy, Pacific Grove, California, September 1988. "Pursuing Least-Cost Strategies for Ratepayers While Promoting Competitive Success for Utilities", *Proceedings from the Least-Cost Planning Conference, National Association of Regulatory Utility Commissioners,* Aspen, Colorado, April 1988.

"Balancing Different Economic Perspectives in Demand-Side Resource Evaluation", Workshop on Demand-Side Bidding, Co-sponsored by New York State PSC, ERDA, and Energy Office, Albany, New York, March 1988.

"There They Go Again: A Critique of the AER/UDI Report on Future Electricity Adequacy through the Year 2000" (with C. Komanoff, H. Geller and C. Mitchell), Presentation NASUCA (also debated AER/UDI co-author before NARUC annual meeting), New Orleans, Louisiana, November 1987.

"Saying No to the No-Losers Test: Correctly Assessing Demand-Side Resources to Achieve Least-Cost Utility Strategies", *Proceedings from the Mid-year NASUCA meeting*, Washington, D.C., June 1987.

"The Economic Impact of Three Mile Island" (with C. Komanoff), *Proceedings from the American Association for the Advancement of Science symposium*, May 1986.

"Facing the Grid" (with D. Morris), *New Shelter*, May - June 1981.

PAUL L. CHERNICK

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SUMMARY OF PROFESSIONAL EXPERIENCE

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

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

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

EDUCATION

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

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

HONORS

Chi Epsilon (Civil Engineering)

Tau Beta Pi (Engineering)

Sigma Xi (Research)

Institute Award, Institute of Public Utilities, 1981.

PUBLICATIONS

"Environmental Regulation in the Changing Electric-Utility Industry" (with Rachel Brailove), *International Association for Energy Economics Seventeenth Annual North American Conference* (96–105). Cleveland, Ohio: USAEE. 1996.

"The Price is Right: Restructuring Gain from Market Valuation of Utility Generating Assets" (with Jonathan Wallach), *International Association for Energy Economics Seventeenth Annual North American Conference* (345–352). Cleveland, Ohio: USAEE. 1996.

"The Future of Utility Resource Planning: Delivering Energy Efficiency through Distributed Utilities" (with Jonathan Wallach), *International Association for Energy Economics Seventeenth Annual North American Conference* (460–469). Cleveland, Ohio: USAEE. 1996.

"The Future of Utility Resource Planning: Delivering Energy Efficiency through Distribution Utilities" (with Jonathan Wallach), *1996 Summer Study on Energy Efficiency in Buildings*, Washington: American Council for an Energy-Efficient Economy 7(7.47–7.55). 1996.

"The Allocation of DSM Costs to Rate Classes," *Proceedings of the Fifth National Conference on Integrated Resource Planning*. Washington: National Association of Regulatory Utility Commissioners. May 1994.

"Environmental Externalities: Highways and Byways" (with Bruce Biewald and William Steinhurst), *Proceedings of the Fifth National Conference on Integrated Resource Planning*. Washington: National Association of Regulatory Utility Commissioners. May 1994.

"The Transfer Loss is All Transfer, No Loss" (with Jonathan Wallach), The *Electricity Journal* 6:6 (July 1993).

"Benefit-Cost Ratios Ignore Interclass Equity" (with others), *DSM Quarterly*, Spring 1992.

"ESCos or Utility Programs: Which Are More Likely to Succeed?" (with Sabrina Birner), *The Electricity Journal* 5:2, March 1992.

"Determining the Marginal Value of Greenhouse Gas Emissions" (with Jill Schoenberg), *Energy Developments in the 1990s: Challenges Facing Global/Pacific Markets, Vol. II,* July 1991.

"Monetizing Environmental Externalities for Inclusion in Demand-Side Management Programs" (with E. Caverhill), *Proceedings from the Demand-Side Management and the Global Environment Conference,* April 1991.

"Accounting for Externalities" (with Emily Caverhill). *Public Utilities Fortnightly* 127(5), March 1 1991.

"Methods of Valuing Environmental Externalities" (with Emily Caverhill), *The Electricity Journal* 4(2), March 1991.

"The Valuation of Environmental Externalities in Energy Conservation Planning" (with Emily Caverhill), *Energy Efficiency and the Environment: Forging the Link*. American Council for an Energy-Efficient Economy; Washington: 1991.

"The Valuation of Environmental Externalities in Utility Regulation" (with Emily Caverhill), *External Environmental Costs of Electric Power: Analysis and Internalization*. Springer-Verlag; Berlin: 1991.

"Analysis of Residential Fuel Switching as an Electric Conservation Option" (with Eric Espenhorst and Ian Goodman), *Gas Energy Review*, December 1990.

"Externalities and Your Electric Bill," *The Electricity Journal*, October 1990, p. 64.

"Monetizing Externalities in Utility Regulations: The Role of Control Costs" (with Emily Caverhill), in *Proceedings from the NARUC National Conference on Environmental Externalities,* October 1990.

"Monetizing Environmental Externalities in Utility Planning" (with Emily Caverhill), in *Proceedings from the NARUC Biennial Regulatory Information Conference*, September 1990.

"Analysis of Residential Fuel Switching as an Electric Conservation Option" (with Eric Espenhorst and Ian Goodman), in *Proceedings from the NARUC Biennial Regulatory Information Conference*, September 1990.

"A Utility Planner's Checklist for Least-Cost Efficiency Investment" (with John Plunkett) in *Proceedings from the NARUC Biennial Regulatory Information Conference*, September 1990.

Environmental Costs of Electricity (with Richard Ottinger et al.). Oceana; Dobbs Ferry, New York: September 1990.

"Demand-Side Bidding: A Viable Least-Cost Resource Strategy" (with John Plunkett and Jonathan Wallach), in *Proceedings from the NARUC Biennial Regulatory Information Conference*, September 1990.

“Incorporating Environmental Externalities in Evaluation of District Heating Options” (with Emily Caverhill), *Proceedings from the International District Heating and Cooling Association 81st Annual Conference*, June 1990.

“A Utility Planner’s Checklist for Least-Cost Efficiency Investment,” (with John Plunkett), *Proceedings from the Canadian Electrical Association Demand-Side Management Conference*, June 1990.

“Incorporating Environmental Externalities in Utility Planning” (with Emily Caverhill), *Canadian Electrical Association Demand Side Management Conference*, May 1990.

“Is Least-Cost Planning for Gas Utilities the Same as Least-Cost Planning for Electric Utilities?” in *Proceedings of the NARUC Second Annual Conference on Least-Cost Planning*, September 10–13 1989.

“Conservation and Cost-Benefit Issues Involved in Least-Cost Planning for Gas Utilities,” in *Least Cost Planning and Gas Utilities: Balancing Theories with Realities*, Seminar proceedings from the District of Columbia Natural Gas Seminar, May 23 1989.

“The Role of Revenue Losses in Evaluating Demand-Side Resources: An Economic Re-Appraisal” (with John Plunkett), *Summer Study on Energy Efficiency in Buildings, 1988*, American Council for an Energy Efficient Economy, 1988.

“Quantifying the Economic Benefits of Risk Reduction: Solar Energy Supply Versus Fossil Fuels,” in *Proceedings of the 1988 Annual Meeting of the American Solar Energy Society*, American Solar Energy Society, Inc., 1988, pp. 553–557.

“Capital Minimization: Salvation or Suicide?,” in I. C. Bupp, ed., *The New Electric Power Business*, Cambridge Energy Research Associates, 1987, pp. 63–72.

“The Relevance of Regulatory Review of Utility Planning Prudence in Major Power Supply Decisions,” in *Current Issues Challenging the Regulatory Process*, Center for Public Utilities, Albuquerque, New Mexico, April 1987, pp. 36–42.

“Power Plant Phase-In Methodologies: Alternatives to Rate Shock,” in *Proceedings of the Fifth NARUC Biennial Regulatory Information Conference*, National Regulatory Research Institute, Columbus, Ohio, September 1986, pp. 547–562.

“Assessing Conservation Program Cost-Effectiveness: Participants, Non-participants, and the Utility System” (with A. Bachman), *Proceedings of the Fifth NARUC Biennial Regulatory Information Conference*, National Regulatory Research Institute, Columbus, Ohio, September 1986, pp. 2093–2110.

“Forensic Economics and Statistics: An Introduction to the Current State of the Art” (with Eden, P., Fairley, W., Aller, C., Vencill, C., and Meyer, M.), *The Practical Lawyer*, June 1 1985, pp. 25–36.

“Power Plant Performance Standards: Some Introductory Principles,” *Public Utilities Fortnightly*, April 18 1985, pp. 29–33.

“Opening the Utility Market to Conservation: A Competitive Approach,” *Energy Industries in Transition, 1985–2000*, Proceedings of the Sixth Annual North American Meeting of the International Association of Energy Economists, San Francisco, California, November 1984, pp. 1133–1145.

“Insurance Market Assessment of Technological Risks” (with Meyer, M., and Fairley, W) *Risk Analysis in the Private Sector*, pp. 401–416, Plenum Press, New York 1985.

“Revenue Stability Target Ratemaking,” *Public Utilities Fortnightly*, February 17 1983, pp. 35–39.

“Capacity/Energy Classifications and Allocations for Generation and Transmission Plant” (with M. Meyer), *Award Papers in Public Utility Economics and Regulation*, Institute for Public Utilities, Michigan State University 1982.

Design, Costs and Acceptability of an Electric Utility Self-Insurance Pool for Assuring the Adequacy of Funds for Nuclear Power Plant Decommissioning Expense, (with Fairley, W., Meyer, M., and Scharff, L.) (NUREG/CR-2370), U.S. Nuclear Regulatory Commission, December 1981.

Optimal Pricing for Peak Loads and Joint Production: Theory and Applications to Diverse Conditions (Report 77-1), Technology and Policy Program, Massachusetts Institute of Technology, September 1977.

REPORTS

“Avoided Energy Supply Costs in New England: 2013 Report” (with Rick Hornby, David White, John Rosenkranz, Ron Denhardt, Elizabeth Stanton, Jason Gifford, Bob Grace, Max Chang, Patrick Luckow, Thomas Vitolo, Patrick Knight, Ben Griffiths, and Bruce Biewald). 2011. Northborough, Mass.: Avoided-Energy-Supply-Component Study Group, c/o National Grid Company.

“Affordability of Pollution Control on the Apache Coal Units: Review of Arizona Electric Power Cooperative’s Comments on Behalf of the Sierra Club” (with Ben Griffiths). 2012. Filed as part of comments in Docket EPA-R09-OAR-2012-0021 by National Parks Conservation Association, Sierra Club, et al.

“Audubon Arkansas Comments on Entergy’s 2012 IRP.” 2012. Prepared for and filed by Audubon Arkansas in Arkansas PUC Docket No. 07-016-U.

“Economic Benefits from Early Retirement of Reid Gardner” (with Jonathan Wallach). 2012. Prepared for and filed by the Sierra Club in PUC of Nevada Docket No. 11-08019.

“Analysis of Via Verde Need and Economics.” 2012. Appendix V-4 of public comments of the Sierra Club et al. in response to November 30 2011 draft of U.S. Army Corps of Engineers environmental assessment in Department of the Army Environmental Assessment and Statement of Finding for Permit Application SAJ-2010-02881.

“Avoided Energy Supply Costs in New England: 2011 Report” (with Rick Hornby, Carl Swanson, David White, Ian Goodman, Bob Grace, Bruce Biewald, Ben Warfield, Jason Gifford, and Max Chang). 2009. Northborough, Mass.: Avoided-Energy-Supply-Component Study Group, c/o National Grid Company.

“Avoided Energy Supply Costs in New England: 2011 Report” (with Rick Hornby, Carl Swanson, David White, Jason Gifford, Max Chang, Nicole Hughes, Matthew Wittenstein, Rachel Wilson, and Bruce Biewald). 2011. Northborough, Mass.: Avoided-Energy-Supply-Component Study Group, c/o National Grid Company.

“State of Ohio Energy-Efficiency Technical-Reference Manual Including Predetermined Savings Values and Protocols for Determining Energy and Demand Savings” (with others). 2010. Burlington, Vt.: Vermont Energy Investment Corporation.

“Green Resource Portfolios: Development, Integration, and Evaluation” (with Jonathan Wallach and Richard Mazzini). 2008. Report to the Green Energy Coalition presented as evidence in Ontario EB 2007-0707.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

EXPERT TESTIMONY

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

    Profit margin calculations, including methodology, interest rates.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Profit margin calculations, including methodology and implementation.

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

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

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

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

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

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

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

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

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

Construction schedule and cost of completing Millstone Unit 3.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Demand-side management cost recovery and incentive mechanisms.

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

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

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

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

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

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

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

Economic analysis of proposed coal-fired cogeneration facility.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Allocation of costs and benefits to rate classes.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Performance incentives proposed for the Boston Edison company.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Review of proposed performance standards and valuation of performance.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Application of rate cap. Legislative intent.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Rate decoupling and energy-efficiency goals.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

226. **Connecticut DPUC** Docket 07-04-24, Review of capacity contracts under Energy Independence Act; Connecticut Office of Consumer Counsel, Joint Direct Testimony June 2007.

Assessment of proposed capacity contracts for new combined-cycle, peakers and DSM. Evaluation of contracts for differences, modeling of energy, capacity and forward-reserve markets. Corrections of errors in computation of costs, valuation of energy-price effects of peakers, market-driven expansion plans and retirements, market response to contracted resource additions, DSM proposal evaluation.

227. **NY PSC** Case 07-E-0524, Consolidated Edison electric rates; City of New York. Direct, September 2007.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

239. **Nova Scotia Review Board** Matter No. 01439 (P-884(2)), Nova Scotia Power DSM and cost recovery, Nova Scotia Consumer Advocate. May 2009.

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

240. **Nova Scotia Review Board** Matter No. 0496 (P-172), proposed biomass project, Nova Scotia Consumer Advocate. June 2009.

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

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

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

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

Revenue-decoupling mechanism. Automatic rate adjustments.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

251. **N.S. UARB** Matter No. 02961(P128.10), Port Hawkesbury Biomass Project; Nova Scotia Consumer Advocate. Direct, June 2010.

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

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

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

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

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

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

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

255. **N.S. UARB** Matter No. 03454(NG-HG-R-10), Heritage Gas rates; N.S. Consumer Advocate. Direct, October 2010.

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

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

Revenue-allocation and rate design. DSM program.

257. **N.S. UARB** Matter No. 03665(NSPI-P-891), Nova Scotia Power depreciation rates; N.S. Consumer Advocate. Direct, February 2011.

Depreciation and rates.

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

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

259. **N.S. UARB** Docket Matter No. 03632 (BRD-E-R-10), Renewable-Energy Community-Based Feed-in Tariffs; N.S. Consumer Advocate. Direct, March 2011.

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

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

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

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

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

262. **N.S. UARB** Matter No. 04104 (NSPI P-892); Nova Scotia Power general rate application; N.S. Consumer Advocate. August 2011.

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

263. **N.S. UARB** Matter No. 04175 (NSPI P-202); Load-retention tariff; N.S. Consumer Advocate. August 2011.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Cost allocation. Estimation of marginal customer costs.

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

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

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

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

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

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

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

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

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

Estimation of marginal costs. Fuel switching.

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

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

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

Economic and financial modeling of investment. Treatment of AFUDC.

278. **N.S. UARB** Matter No. M05416; South Canoe wind project of of Nova Scotia Power; N.S. Consumer Advocate. January 2013.

Revenue requirements. Allocation of tax benefits. Ratemaking.

279. **N.S. UARB** Docket No. NSPI-P-892; Depreciation Rates of Nova Scotia Power; N.S. Consumer Advocate. April 2013.

Steam-plant lives and removal costs.

280. **N.S. UARB** Matter No. 05419; Maritime Link cost-recovery regulations; N.S. Consumer Advocate. April 2013.

Load Forecast. Cost effectiveness of proposed project.

281. **N.S. UARB** Matter No. M05092; Tidal energy feed-in-tariff rate; N.S. 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.

Energy Supply Cost Function

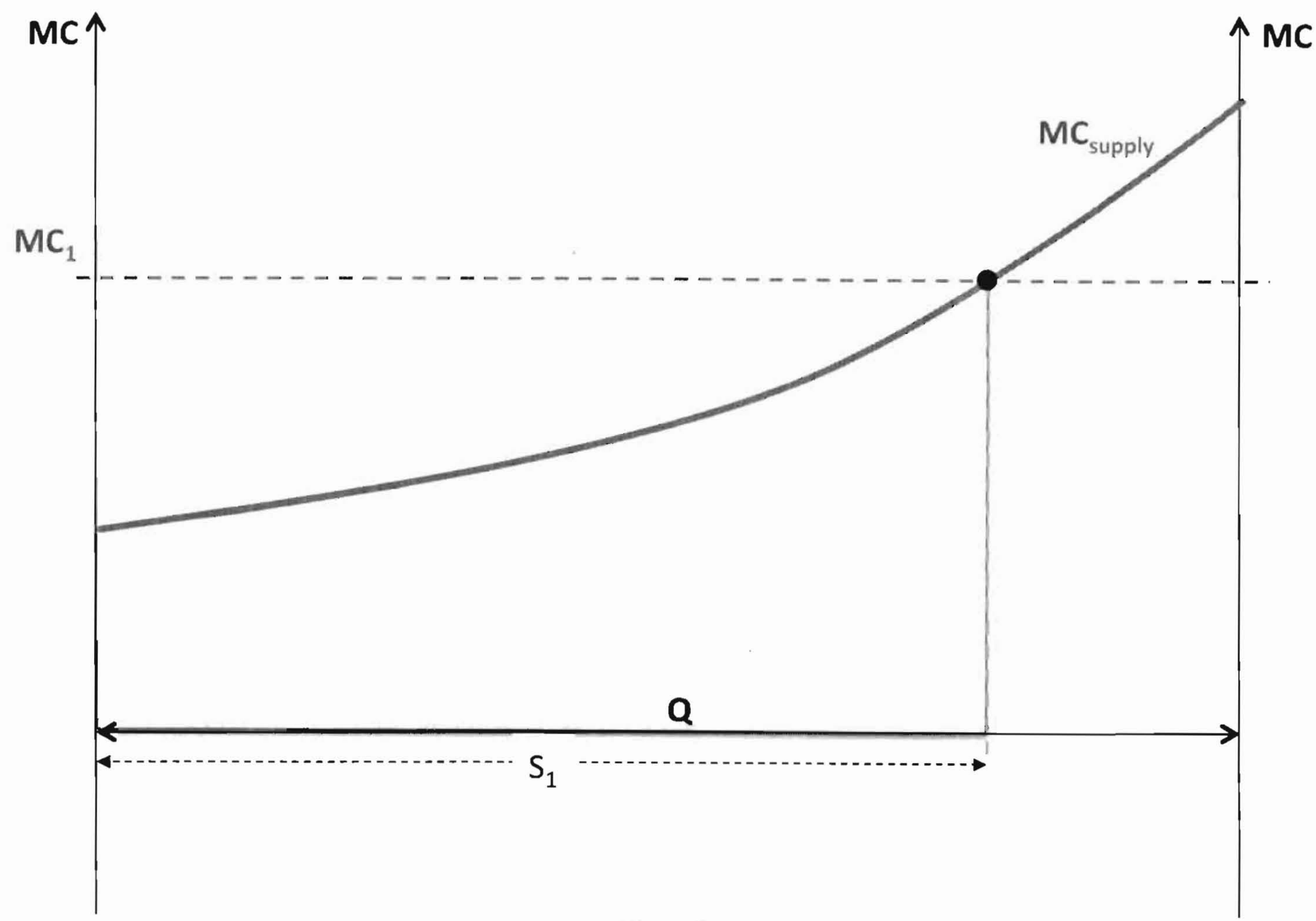

Figure 1

Energy Efficiency Cost Function (right origin)

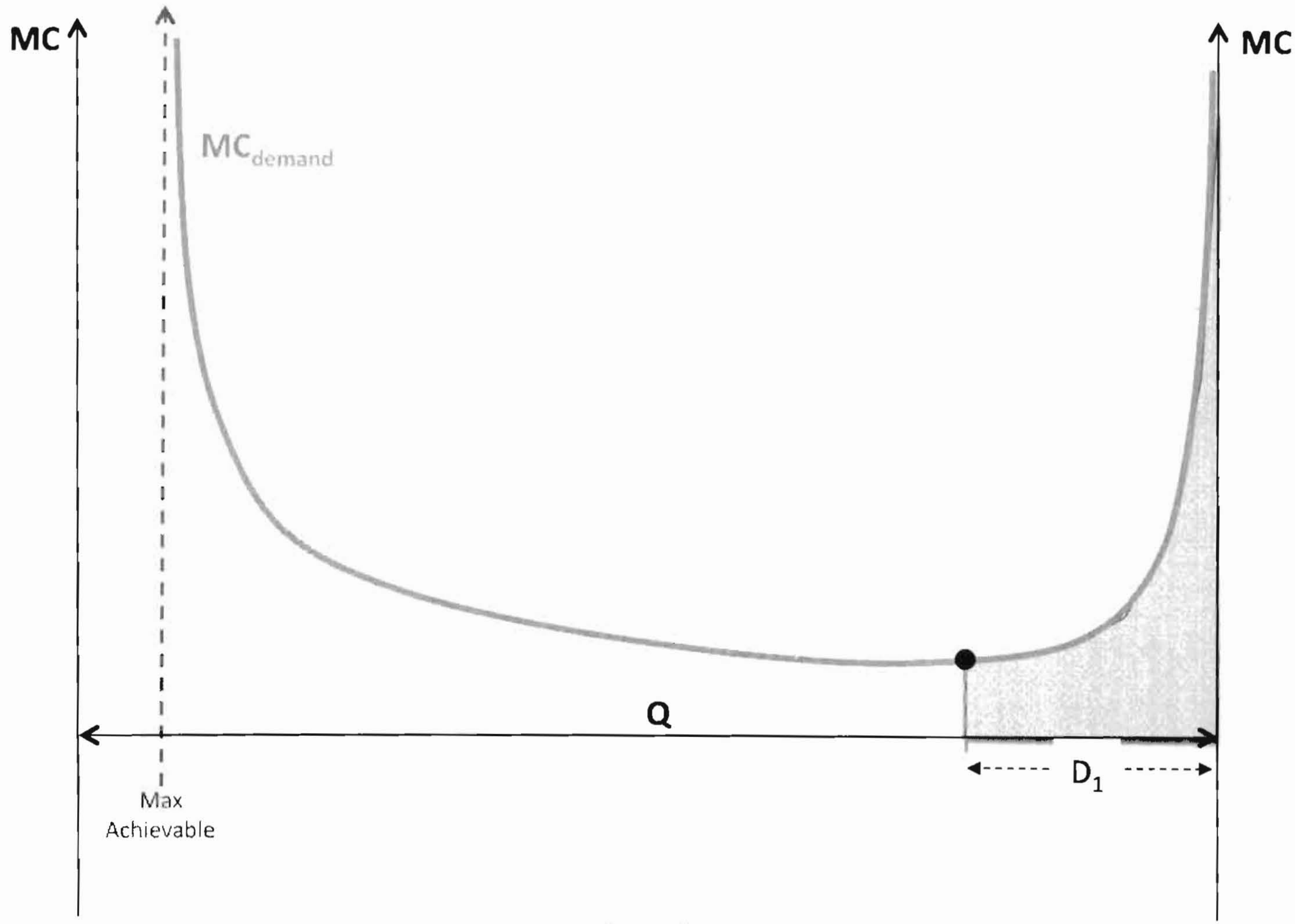

Figure 2

Energy Supply and Efficiency
Initial Resource Allocation

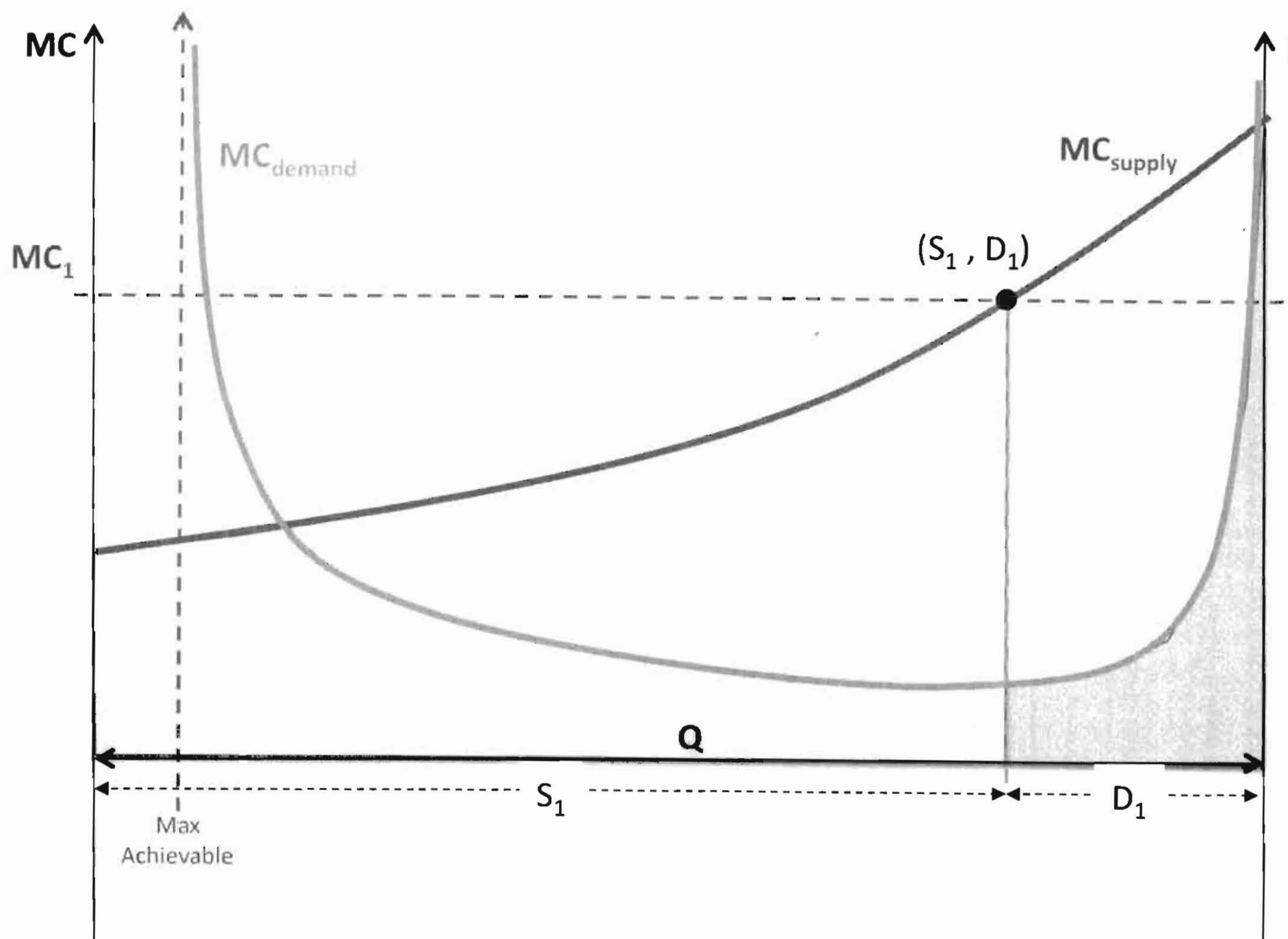

Figure 3

Energy Supply and Energy Efficiency
Least-Cost Resource Reallocation

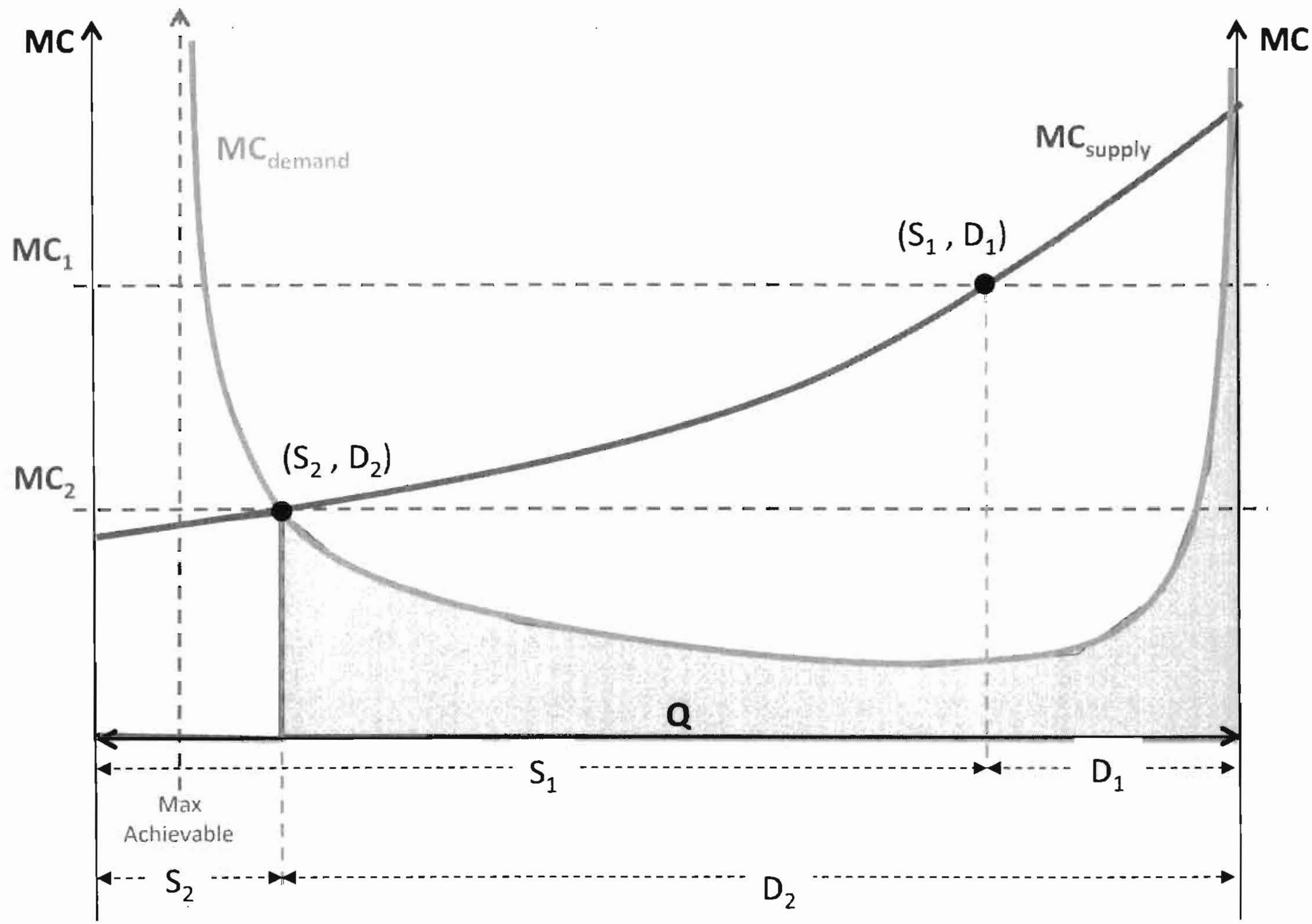

Figure 4

Net Economic Benefits of Substituting All Cost-Effective Efficiency for Supply

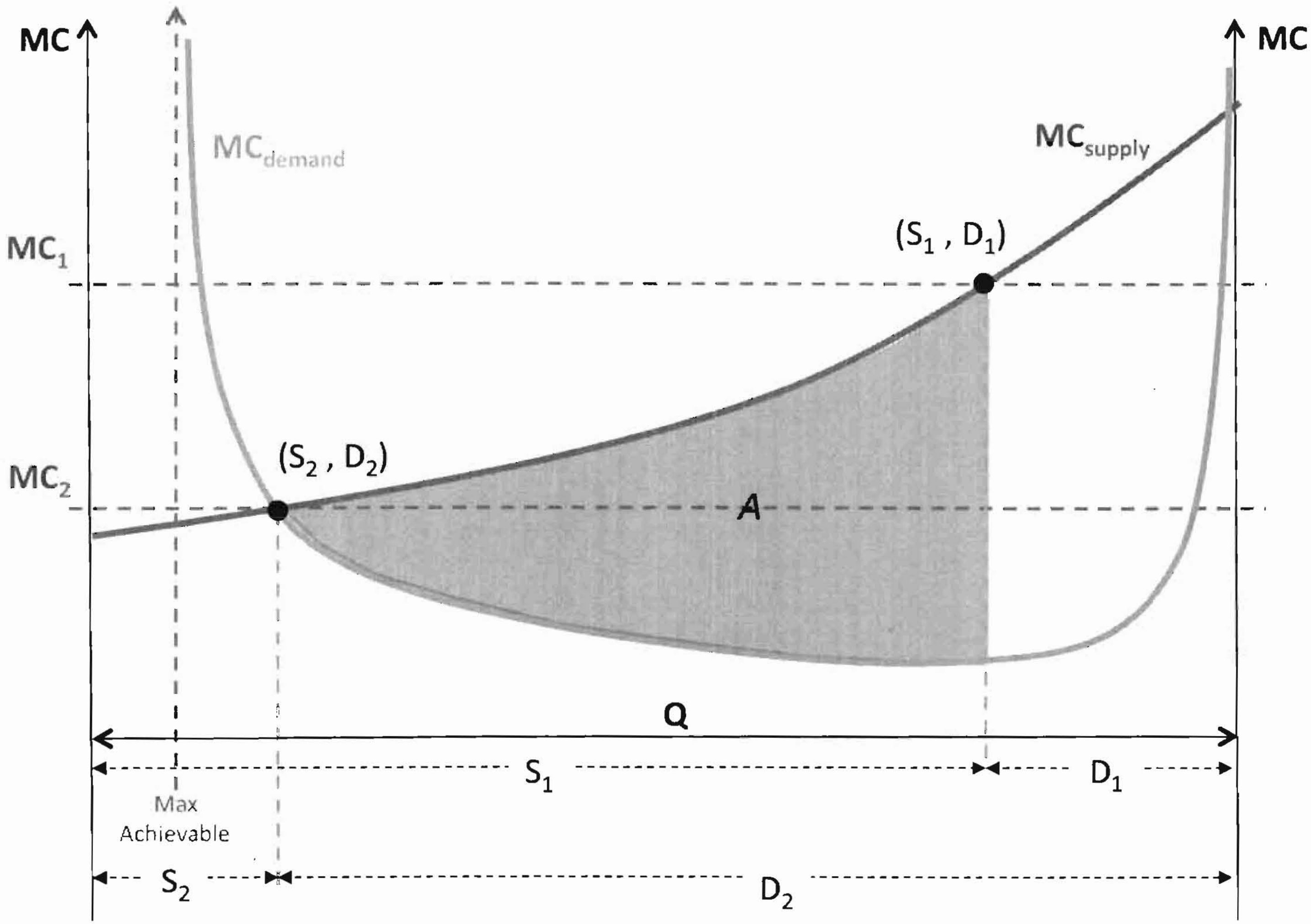

Figure 5

ENERGY EFFICIENCY RETROFIT PROGRAM **CONSULTATIVE WORKSHOP**

November 5th & 6th, 2013

FRANÇOIS BOULANGER & PHILIPPE DUNSKY
DUNSKY ENERGY CONSULTING

FORTIS BC BChydro

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Today's Objectives

- BC Hydro and FortisBC are considering different program options for next program iteration
- Present current context and historical results
- Present different program options
- **Gather valuable feedback on feasibility and potential impacts of these options for further consideration**

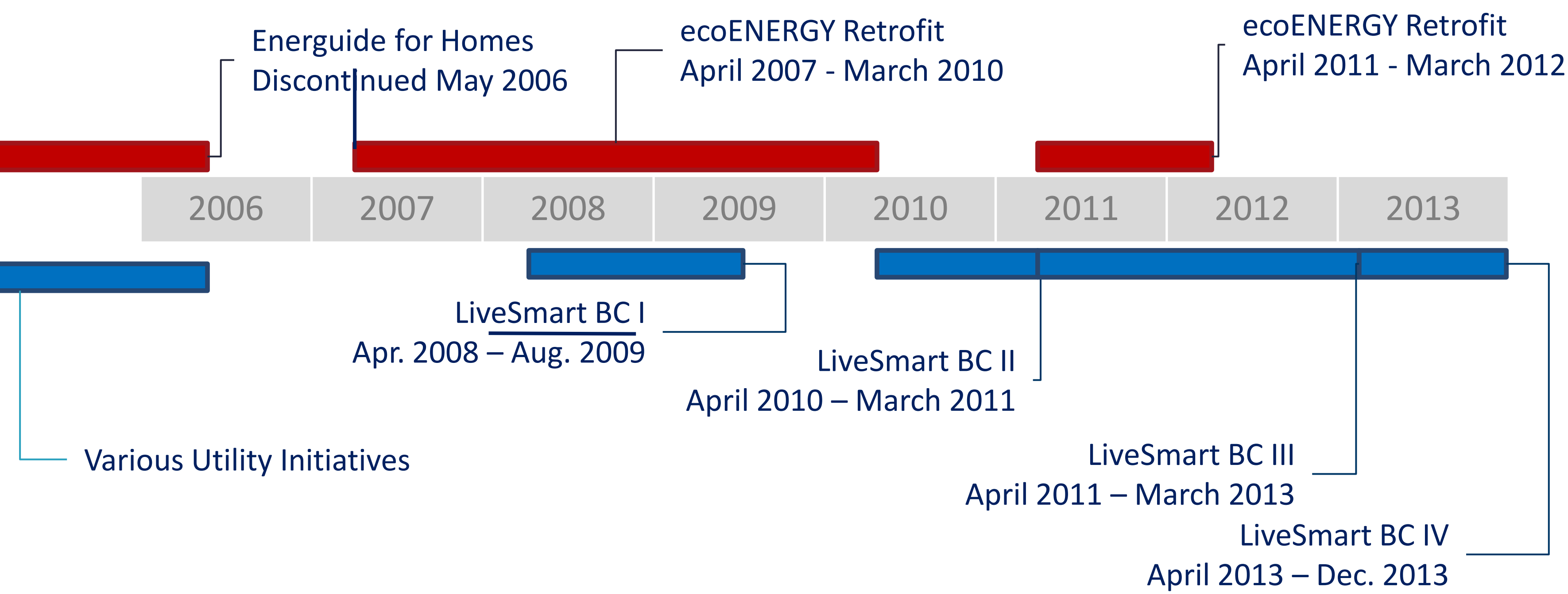
Overarching Objectives

- **Continued support of energy efficiency retrofit projects in BC**
  - Cost-effective Energy Savings, Bill Reduction
- **Increase demand for energy-efficiency retrofits**
  - Push: Energy retrofit contractors, others (on-ramp)
  - Pull: Sustained and growing participation
- **Increase depth of projects**
  - Multiple measures
- **Develop and support the industry**
  - Whole-house energy retrofit
    - *Blower-door assisted weatherization*
    - *Professionalism, Quality*
  - Increased Collaboration

BC LIVESMART PROGRAM DATA

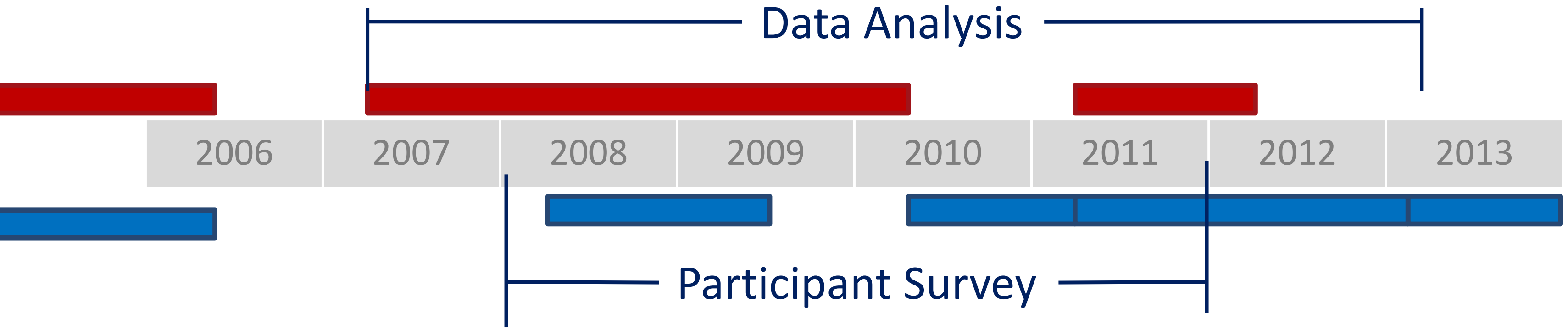
Home Energy Retrofit History

- Long Standing program – in market since 1990's



Home Energy Retrofit History

- Long Standing program – in market since 1990's



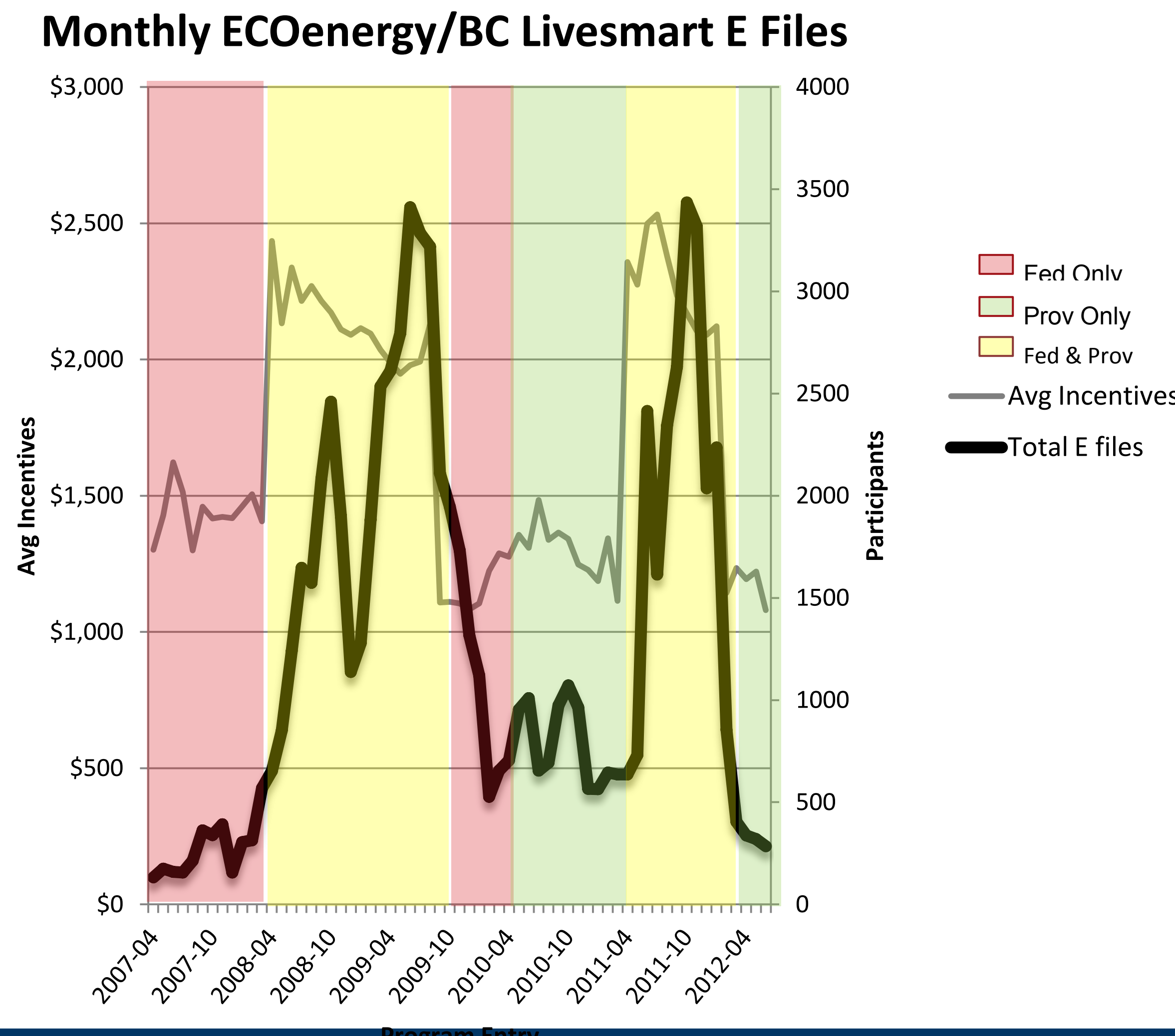
- Historical Results – 2007-2013
- Participant Survey – 2008-2011

LiveSmart BC - Today

- New program incentives launched April 1st 2013
  - Requires whole house energy assessment
    - *Pre-retrofit evaluation prior to Dec 31st, 2013*
    - *Post-retrofit prior to March 31st, 2014*
  - First evaluation subsidized
  - Incentives for specific shell measures only (prescriptive) from BC Hydro and FortisBC only
- Various ongoing pilots

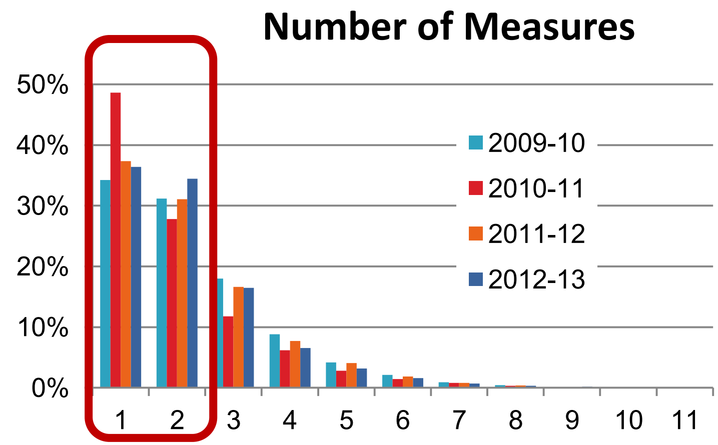
BREADTH (Program Uptake)

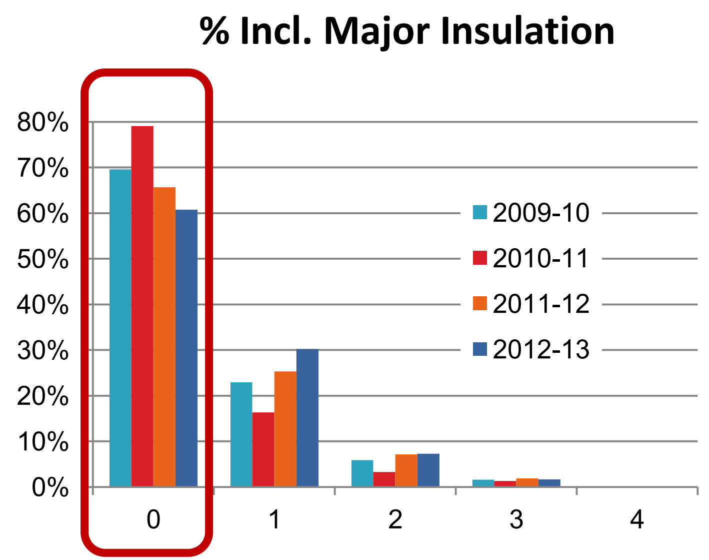
- Historical: high sensitivity to incentives
- Recent: low demand since April 1st, 2013



DEPTH (# of Measures)

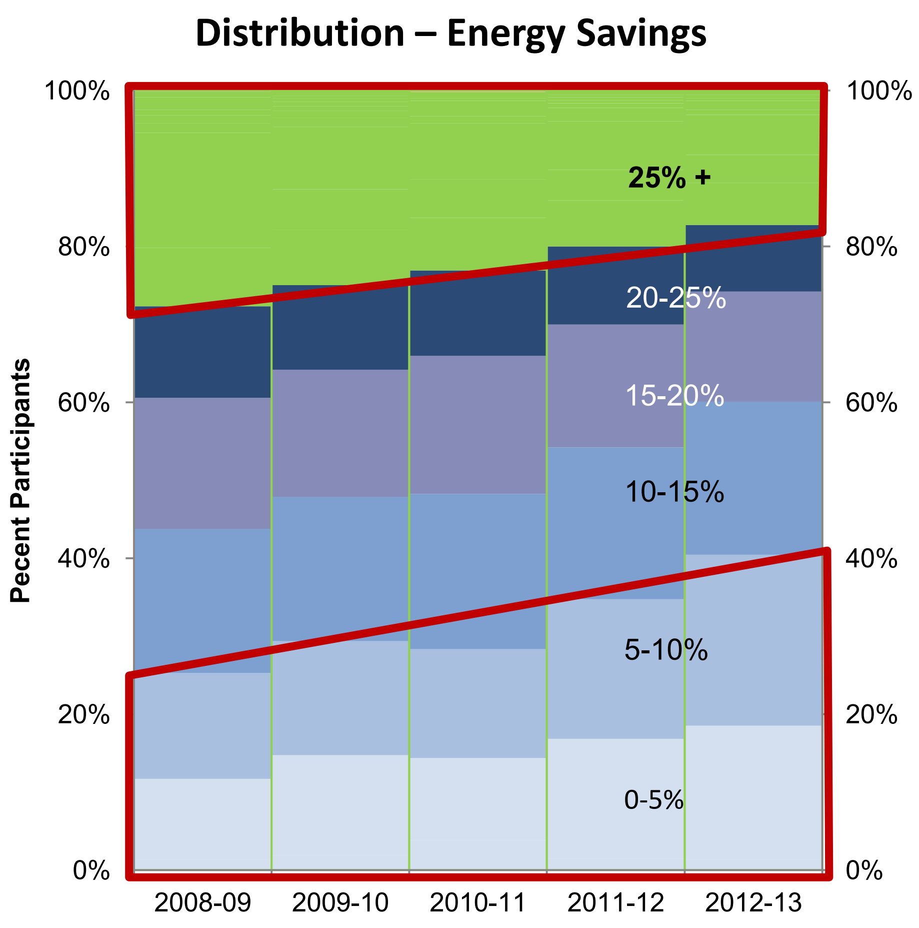
- **2/3 implement two measures or less**
  - ~80-85% when considering insulation and air infiltration as one
- **Large (but diminishing) share doing NO major insulation** (basement, wall, attic)





DEPTH (% Savings)

- **Diminishing depth of savings over time**
  - >25% savings dropped from 28% to 17%
  - <10% savings up from 25% to 40%
- **BOTTOM LINE: depth going in wrong direction**



Expanding Energy Efficiency Resource Acquisition for FortisBC Electric

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Prepared for
The British Columbia Sustainable Energy Association
and the Sierra Club of BC

December 20, 2013

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Expanding Electric Energy Efficiency Resource Acquisition for FortisBC

I. Introduction

This report provides an overview of historic and projected spending and savings data for electric energy efficiency administrators in North America, including over twenty states and two Canadian provinces. The collection was analyzed and an empirical model for estimating the cost of acquiring energy efficiency resources was developed. This model was then used to estimate the cost to FortisBC Electric to acquire energy efficiency savings of 2% of sales starting in 2016 and going through 2023. Unless otherwise stated, values are in United States Dollars.

II. Research and Analysis of Efficiency Portfolio Costs and Savings

A. Data from Regulatory Filings

GEEG collected historical cost and savings data on efficiency portfolios reported to regulators for states with the greatest savings as a percentage of sales, including California and Northeastern states; for Midwestern and Western states with significant efficiency portfolios (Iowa, Nevada, and Wisconsin); and for neighboring jurisdictions of Arkansas and Texas. Where possible, GEEG obtained cost and saving data separately for the residential and nonresidential sectors. GEEG also collected efficiency spending and savings data for two Canadian provinces, British Columbia and Nova Scotia. Finally, GEEG assembled the latest information available on future plans for electric end-use efficiency investment in several leading states and provinces.

1. Historical Results

For the states mentioned above, Table 1 presents historical data on annual savings as a percentage of electric energy sales, and spending per annual kWh of savings, by year, ranked in decreasing order in terms of savings as a percentage of sales. Using the same four savings tiers depicting the ACEEE cost data in Figure 2, Table 1 is an attempt to make a direct comparison between energy efficiency programs and the pool of energy sales that these programs directly influence.

Table 1: Statewide Totals by Year, Classified by Performance Tier, Ranked by Savings as a Percentage of Sales

State / Province	Year	Savings as a % of Sales	2013$/ kWh-yr
Tier 1			
VT	2008	2.33%	$0.27
CA	2010	1.97%	$0.27
VT	2010	1.94%	$0.35
VT	2011	1.74%	$0.38
CA	2005	1.61%	$0.19
VT	2007	1.60%	$0.24
Tier 2			
CT	2010	1.49%	$0.32
VT	2009	1.46%	$0.38
MA	2011	1.42%	$0.36
HI	2008	1.38%	$0.11
NV	2009	1.35%	$0.10
HI	2011	1.31%	$0.21
CT	2008	1.28%	$0.31
CA	2011	1.26%	$0.41
RI	2011	1.25%	$0.37
NV	2008	1.24%	$0.08
Pac. NW	2008	1.24%	$0.12
IA	2009	1.20%	$0.21
MA	2010	1.12%	$0.43
CT	2007	1.12%	$0.31
NS	2011	1.12%	$0.24
CT	2006	1.11%	$0.25
Pac. NW	2009	1.10%	$0.18
CT	2001	1.10%	$0.36
Pac. NW	2007	1.09%	$0.12
RI	2009	1.07%	$0.33
CA	2009	1.06%	$0.43
RI	2010	1.05%	$0.34
CT	2005	1.03%	$0.30
CA	2008	1.02%	$0.51
IA	2010	1.01%	$0.22
HI	2009	1.01%	$0.18
BC	2010	0.98%	$0.23
CT	2004	0.97%	$0.29
CA	2004	0.93%	$0.20
RI	2006	0.91%	$0.29
ME	2008	0.87%	$0.13
VT	2005	0.87%	$0.37

State / Province	Year	Savings as a % of Sales	2013$/ kWh-yr
Tier 2 (continued)			
VT	2006	0.86%	$0.36
MA	2007	0.86%	$0.27
NV	2006	0.86%	$0.06
CT	2009	0.85%	$0.33
CT	2002	0.84%	$0.45
IA	2006	0.84%	$0.17
Pac. NW	2002	0.83%	$0.20
IA	2007	0.83%	$0.17
RI	2005	0.82%	$0.29
Pac. NW	2001	0.82%	$0.18
RI	2007	0.81%	$0.29
VT	2003	0.81%	$0.38
BC	2007	0.81%	$0.09
BC	2005	0.81%	$0.11
ME	2010	0.81%	$0.18
VT	2004	0.81%	$0.39
MA	2005	0.80%	$0.33
IA	2008	0.79%	$0.20
MA	2004	0.79%	$0.36
MA	2009	0.78%	$0.49
HI	2010	0.78%	$0.27
CA	2007	0.77%	$0.54
RI	2008	0.77%	$0.27
Pac. NW	2006	0.77%	$0.17
BC	2004	0.77%	$0.13
HI	2007	0.75%	$0.24
MA	2006	0.75%	$0.36
Pac. NW	2003	0.74%	$0.18
BC	2009	0.74%	$0.21
NV	2007	0.72%	$0.07
Pac. NW	2005	0.72%	$0.18
NY	2010	0.71%	$0.23
ME	2009	0.70%	$0.18
ME	2007	0.69%	$0.16
MA	2008	0.69%	$0.36
IA	2005	0.69%	$0.19
NS	2010	0.68%	$0.24
Pac. NW	2004	0.68%	$0.18

Table 1 **(Continued)**

State / Province	Year	Savings as a % of Sales	2013$/ kWh/yr Saved
Tier 3			
IA	2004	0.65%	$0.21
VT	2002	0.64%	$0.42
VT	2001	0.62%	$0.35
WI	2009	0.61%	$0.22
NJ	2009	0.61%	$0.24
BC	2008	0.60%	$0.18
MA	2003	0.57%	$0.49
NY	2005	0.56%	$0.18
NY	2006	0.56%	$0.18
ME	2006	0.55%	$0.15
NS	2009	0.53%	$0.13
IA	2003	0.52%	$0.23
BC	2006	0.52%	$0.13
WI	2010	0.52%	$0.26
NY	2007	0.51%	$0.20
NY	2009	0.50%	$0.26
NJ	2005	0.47%	$0.27
MA	2002	0.45%	$0.62
BC	2011	0.45%	$0.47
NJ	2010	0.44%	$0.48
NJ	2004	0.42%	$0.35
NJ	2008	0.42%	$0.26
IA	2002	0.38%	$0.26
IA	2001	0.37%	$0.28
CT	2003	0.37%	$0.45
CA	2006	0.36%	$0.67
AR	2010	0.33%	$0.09
HI	2006	0.33%	$0.34

State / Province	Year	Savings as a % of Sales	2013$/ kWh/yr Saved
Tier 4			
NJ	2007	0.27%	$0.44
NY	2004	0.24%	$0.46
AR	2009	0.24%	$0.09
OK	2010	0.23%	$0.26
NY	2008	0.23%	$0.47
PA	2009	0.19%	$0.17
AR	2008	0.18%	$0.11
NS	2008	0.17%	$0.15
TX	2008	0.17%	$0.18
TX	2009	0.16%	$0.21
NJ	2006	0.16%	$0.73
TX	2010	0.15%	$0.21
TX	2007	0.12%	$0.21
TX	2006	0.10%	$0.21

* New York has rolled out a number of new programs in 2009 under the EEPS initiative. These programs have not yet been accounted for in this table. Additionally, savings values for NYSERDA from 2008 onward only include appliance savings from the New York Energy $martSM Products Program.

Figure 1 shows the annual state and province data for 2006 through 2011 from Table 1, with the cost per kWh saved per year in 2013$ mapped against the savings as a percent of sales.

Figure 1: Historical Costs and Savings for States and Provinces by Year

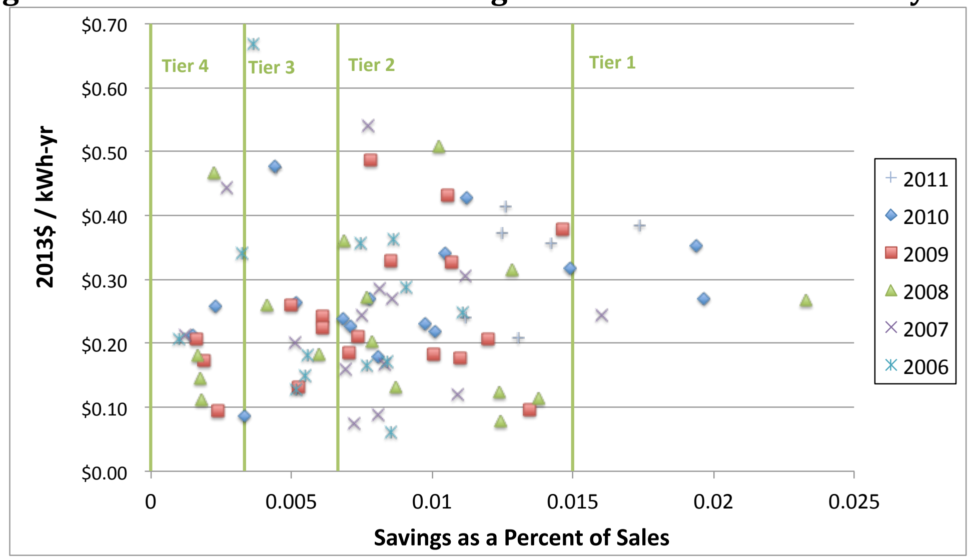


Table 1 shows that annual energy savings as a percentage of sales varies for leading efficiency portfolios and varies widely, both geographically and over time. Data is presented from highest to lowest savings as a percentage of sales, again divided into the four savings tiers.

Examination of the program-year data reveals that several states with DSM portfolios in the top two performance tiers over time have progressed through lower tiers. Also evident from program year performance data is that moving up from one tier to the next is common, especially to and from the second tier. For example, Connecticut increased annual savings from 0.37 percent to 1.49 percent of sales between 2003 and 2010, moving from Tier 3 to just below Tier 1. Nova Scotia recently went from 0.17 percent of sales in 2008, Tier 4 results, to 0.68 percent of sales in 2010, Tier 2 results. These observations support the feasibility of ramping up utility investment over time.

Another significant observation, not readily evident from the data, is that the top three tiers are all represented by both utility- and non-utility portfolio administrators. California, Connecticut, Rhode Island and Massachusetts portfolios are all administered by distribution utilities; Maine, Vermont, Hawaii, and Wisconsin all have relied on non-utility (either government or non-government) administration for at least the last five years. New Jersey has changed from utility to non-utility program administration several years ago; New York has evolved in the opposite direction, supplementing government agency administration of statewide programs with utility-administered programs starting in 2009.

This finding supports the feasibility of scaling up FortisBC's efficiency resource acquisition: the existing capabilities of Fortis BC need not be a binding constraint.

2. Future Plans

GEEG obtained efficiency investment expenditures and planned savings for several jurisdictions with portfolios that ranked in the top two tiers in Table 1. Table 2 presents planned annual incremental savings as a percentage of electric energy sales for along with planned spending (in 2013 dollars) per kWh-yr saved.

Table 2: Planned Electric Energy Efficiency Portfolio Savings and Costs in the US and Canada

State / Province	Year	Savings as a % of Sales	2013$/kWh-yr
Tier 1			
RI	2014	2.45%	$0.45
MA	2015	2.26%	$0.40
MA	2014	2.19%	$0.40
VT	2017	2.16%	$0.44
VT	2019	2.16%	$0.44
MA	2013	2.13%	$0.41
VT	2018	2.13%	$0.44
VT	2016	2.09%	$0.44
VT	2014	2.07%	$0.41
RI	2013	2.06%	$0.48
VT	2013	2.06%	$0.40
VT	2012	2.04%	$0.38
MA	2012	1.99%	$0.51
VT	2015	1.96%	$0.45
VT	2020	1.95%	$0.49
VT	2021	1.95%	$0.48
Pacific Northwest	2020	1.67%	$0.24
Pacific Northwest	2019	1.67%	$0.24
RI	2012	1.67%	$0.51
Pacific Northwest	2021	1.65%	$0.24
Pacific Northwest	2018	1.64%	$0.23
Pacific Northwest	2017	1.61%	$0.23
Pacific Northwest	2016	1.54%	$0.23

State / Province	Year	Savings as a % of Sales	2013$/kWh-yr
Tier 2			
Pacific Northwest	2015	1.41%	$0.22
Pacific Northwest	2014	1.38%	$0.24
Pacific Northwest	2013	1.30%	$0.24
CA	2012	1.21%	$0.42
Pacific Northwest	2012	1.21%	$0.24
Nova Scotia	2017	1.20%	$0.32
CT	2011	1.19%	$0.31
HI	2012	1.18%	$0.30
Nova Scotia	2016	1.16%	$0.32
Nova Scotia	2015	1.13%	$0.30
Pacific Northwest	2011	1.13%	$0.24
Nova Scotia	2014	1.11%	$0.29
Nova Scotia	2013	1.08%	$0.28
PA	2011	1.03%	$0.17
PA	2012	1.00%	$0.18
NV	2011	0.89%	$0.16
AR	2013	0.74%	$0.32
Tier 3			
NV	2013	0.57%	$0.23
NV	2012	0.51%	$0.28
AR	2012	0.50%	$0.35
AR	2014	0.31%	$0.17
Tier 4			
AR	2011	0.26%	$0.36

Also included in Table 2 are plans from Arkansas, showing a southern state's planned rise from Tier 4 to Tier 2. Oklahoma Gas and Electric's (OG&E) service territory includes part of western Arkansas, and approximately 10% of OG&E's 2009 sales were in Arkansas.[1] In proceedings before the Arkansas Public Service Commission, OG&E estimated that "it could ramp up to savings of 'slightly less than 1% per year'"[2]. In effect, OG&E is stating that it is capable of elevating its OK portfolio savings from Tier 4 performance in 2011 to Tier 3 performance in 2012, and then to Tier 2 performance in 2013.

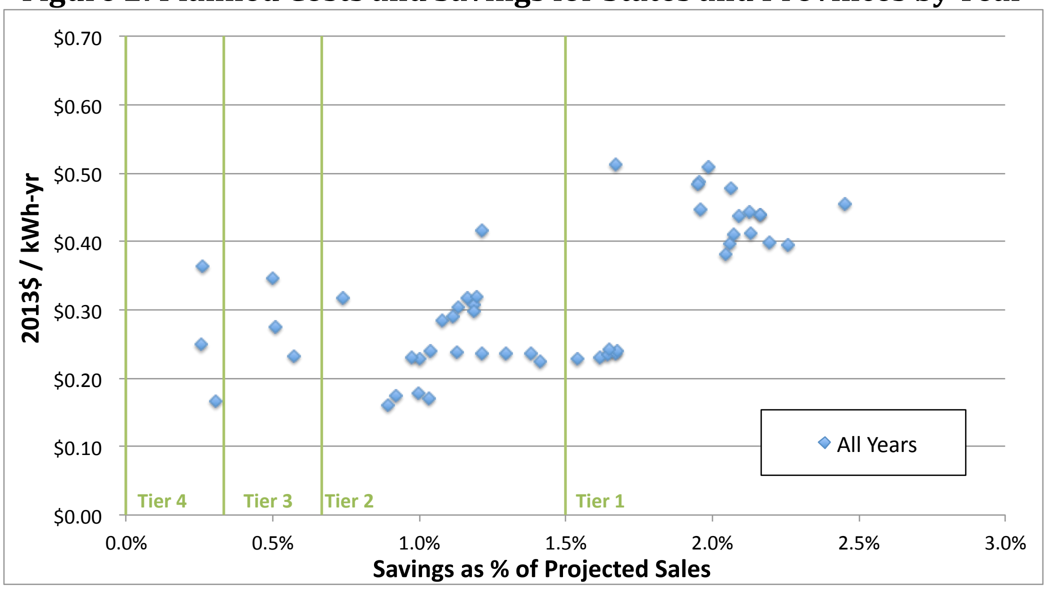
[1] From US Energy Information Administration's Form 861

[2] Arkansas Public Service Commission: Docket No. 08-137-U, Order No. 1 (December 10, 2010). Page 12.

Costs of saved energy are expected to increase in Tier 1 states to over $0.40/kWh-year saved, as well as in the second tier jurisdictions of Connecticut and Massachusetts. Lower costs of savings projected for Nova Scotia are consistent with the fact that the province has only recently begun to ramp up efficiency investment in the last several years.

Figure 2 shows cost per kWh saved per year in 2013$, from Table 2, plotted against the savings as a percent of sales from a state or province's planned energy efficiency efforts.

Figure 2: Planned Costs and Savings for States and Provinces by Year



Prospectively, the positive correlation between the savings costs and savings depth is more pronounced in Figure 2 than it is in historical data depicted in Figure 1.

B. Econometric Analysis of Efficiency Resource Acquisition Costs

Using data collected on past and planned cost and savings, GEEG developed a multivariate regression model that predicts energy efficiency resource acquisition costs per kWh of annual savings as a function of four types of variables:

- Savings depth (% of annual sales)
- Time: Portfolio maturity (years); post-2011 plan vs. historical results; year that portfolio investment commenced
- Customer sector (nonresidential)
- Location (if the portfolio is in New England or California)

The model is estimated using ordinary least-squares regression from a pooled (time series, cross section) sample of 481 observations of annual efficiency spending and savings data for portfolio administrators in 19 American states and two Canadian provinces. In 226 cases (443 of the data points), spending and savings data are reported separately for residential and non-residential efficiency investment; in 38 other cases, data was available only at the portfolio level. In aggregate, the dataset represents approximately $27.5 billion of historical and planned investment (in 2013$), generating cumulative annual energy savings of over 100,000 GWh/yr.

All the model's estimated coefficients are highly statistically significant (with confidence levels beyond 99.9%). The model accounts for over 85 percent of the sample variance of the dependent variable, acquisition cost per kWh-yr (Adjusted R-square = 0.8732). Table 3 and Table 4 below show general information regarding the model.

Table 3: Linear Regression Model for Cost of Energy Savings

Variables		Coefficients	Std. Error	t value	Pr(>|t|)	Signf
Dol_kWh_Yr_201:	Y					
Intercept		0				
Per_Sav	X_1	-29.74	3.22	-9.238	<2.00E-16	***
Per_Sav_Pow	$1/X_1$	0.00007	0.00002	4.344	1.710E-05	***
Per_Sav_Sq	X_1^2	634.4	94.9	6.685	6.550E-11	***
Yr_1	X_2	0.00018	0.00001	17.068	<2.00E-16	***
Maturity	X_3	0.0086	0.0013	6.576	1.290E-10	***
Nonres	X_4	-0.0721	0.0115	-6.296	7.010E-10	***
Planned	X_5	0.0634	0.0155	4.098	4.910E-05	***
CA	X_6	0.2582	0.0220	11.730	<2.00E-16	***
NE	X_7	0.2032	0.0141	14.374	<2.00E-16	***

*Signif. codes: 0 '***' 0.001 '**' 0.01 '*' 0.05 '+' 0.1 ' ' 1*

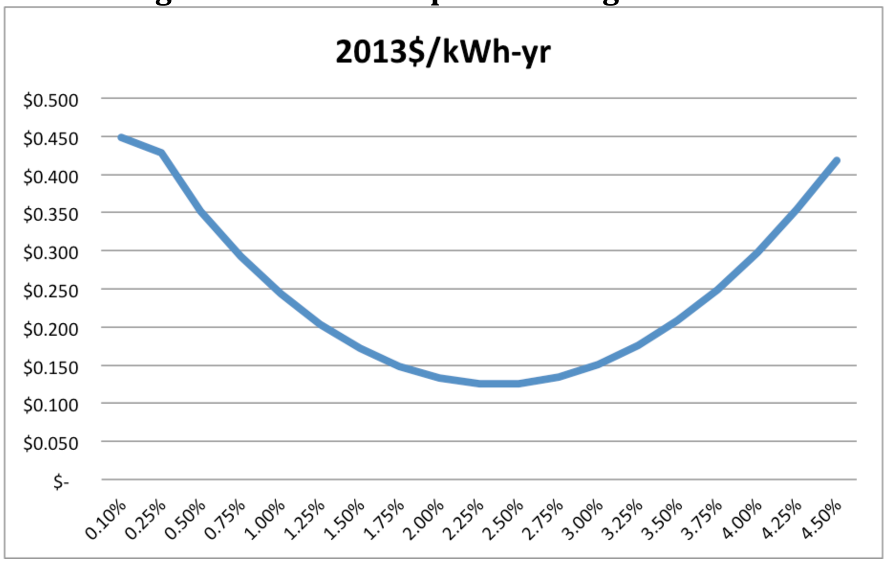
Table 4: Linear Regression Model Summary Statistics

Regression Statistics		Residuals	
Residual standard error	0.1234 on 470 degrees of freedom	Min	-0.278
Multiple R-squared	0.8755	1Q	-0.072
Adjusted R-squared	0.8732	Median	-0.010
F-statistic	367.4 on 9 and 470 DF	3Q	0.062
p-value	< 2.2e-16	Max	0.532

The model predicts that acquisition costs increase with portfolio maturity and with each calendar year. Nonresidential efficiency acquisition costs are $0.0721/kWh-yr cheaper than residential or total portfolio costs. Acquisition costs are lower outside California and New England, with the former adding $0.2582/kWh-yr and the later adding $0.2032/kWh-yr to costs.

It also predicts acquisition costs as a polynomial function of savings depth. Figure 3 isolates the effect of savings depth on a portfolio in 2013, that started in 2009, and is located outside New England and California. It clearly indicates both scale economies for savings up to 2.5% per year of sales, and diminishing returns thereafter.

Figure 3: Effect of Depth of Savings Isolated



III. Application of Empirical Analysis: Scaling Up Energy Efficiency Resource Acqusistion for FortisBC

A. FortisBC's Historic and Planned Savings

FortisBC has recently scaled back its planned electric energy efficiency. Table 5 shows FBC's plans to achieve approximately 0.50% savings as a percent sales for 2014 through 2018.

Table 5: FortisBC Electric Planned Energy Efficiency

Year	Spending (CAD $000s)	Savings (MWh)	Savings as a % of Sales	$/kWh-yr
2014	$3,001	12,800	0.48%	$0.23
2015	$3,087	12,887	0.47%	$0.24
2016	$3,054	12,823	0.47%	$0.24
2017	$3,100	12,823	0.46%	$0.24
2018	$3,153	12,823	0.46%	$0.25

B. Achievable Efficiency Resource Acquisition Targets for FortisBC

This report establishes the feasibility of a more aggressive scenario for acquiring energy efficiency resources than what is currently projected by FBC. By following industry best practices, FBC can ramp up its planned efficiency investment to reduce forecast electricity sales by two percent annually beginning in 2016. To get to this point, FBC should:

- Achieve savings as a percent of sales of 1.0% in 2014
- Achieve savings as a percent of sales of 1.5% in 2015
- Achieve savings as a percent of sales of 2.0% in 2016
- Maintain the 2.0% savings level through 2023

Figure 4 depicts, and Table 6 summarizes, the impact the two percent scenario would have on FBC's future electric energy requirements. This analysis considers "Year 1" to be the first year that DSM projections differ from those provided by FBC, currently 2014. This analysis projects out new savings for 10 years beyond the shift to higher savings, to 2023. To calculate the savings values, FBC's reference load forecast was used as the basis, with the total of the commercial, industrial, lighting, and irrigation sales representing the non-residential sector sales.

Figure 4: FBC Sales Forecast Compared to Supply

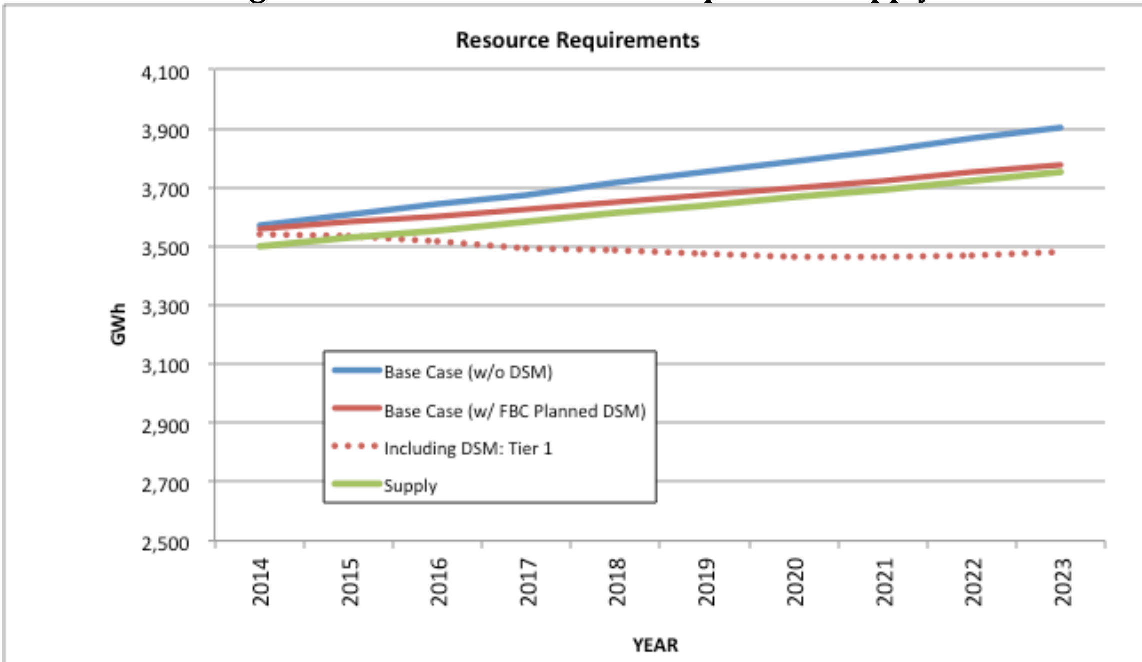


Table 6: FBC Efficiency Savings (Cumulative Annual[3], with Line Losses[4])

Time Period		GWh
Year 1	2014	27
Year 2	2015	65
Year 5	2018	211
Year 10	2023	391

Reducing FBC's electric energy requirements by two percent annually would yield cumulative annual savings by 2023 of 391 GWh. In addition, it would mitigate the need for new supply resources, that still exists when FBC's current DSM plans are taken in to account. Detailed savings and sales projections are in Appendix A.

C. Predicting Costs of FortisBC's Energy Efficiency Savings

The linear regression model developed in the previous section predicts portfolio administrator unit acquisition costs ($/kWh-yr) based on values selected for each

[3]The cumulative savings incorporate measure decay. The decay is based on analysis done by Efficiency Vermont on February 28, 2012 for the Vermont Department of Public Service. By the end of year 5, incremental residential savings will have decayed by 41% and non-residentail savings will have decayed 6%. By the end of year 10, savings will have decayed by 92% and 37% respectively.

[4] Savings shown "with line losses" reflect the higher amount of energy required at generation to provide the net energy used by consumers. Conversely, energy "sales" are shown "without line losses".

explanatory variable. This regression model was used to estimate FBC's projected costs to achieve Tier 1 savings identified above. 2013 USD values were converted to CAD values using an average exchange rate for 2013 of 0.97175.

1. Projected Acqusition Costs for Expanded FortisBC Portfolio

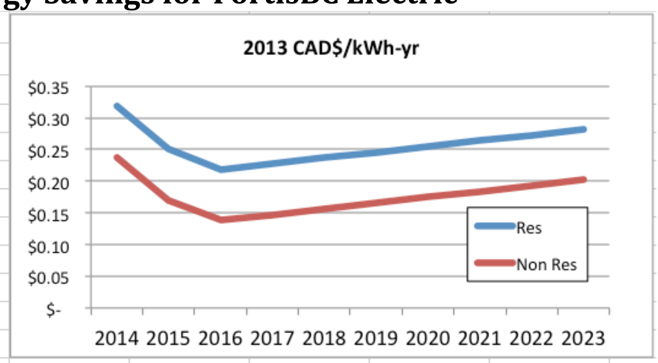
a. Costs per kWh of annual savings

The regression equation was used to project costs for the expanded portfolio, first by ramping annual savings up to 1.0% of sales in 2014, 1.5% in 2015, and then scaling all the way up to 2.0% per year going forward. The regression model also sets the "planned savings" variable to true, and acknowledges that FBC programs go back to the start of the data set in 2004. Additionally, variables for California and New England are set to false. These assumptions are then used to forecast costs for the expanded portfolio's two components: (1) forecast costs for residential energy efficiency resources, and, (2) forecasts for non-residential energy efficiency resources. Table 7 shows the savings acquisition costs predicted by the model.

Table 7: Cost of Energy Savings for FortisBC Electric

Predicted 2013 CAD$/kWh-yr

Year	% Sav	Res	Non Res
2014	1.00%	$ 0.32	$ 0.24
2015	1.50%	$ 0.25	$ 0.17
2016	2.00%	$ 0.22	$ 0.14
2017	2.00%	$ 0.23	$ 0.15
2018	2.00%	$ 0.24	$ 0.16
2019	2.00%	$ 0.25	$ 0.17
2020	2.00%	$ 0.25	$ 0.17
2021	2.00%	$ 0.26	$ 0.18
2022	2.00%	$ 0.27	$ 0.19
2023	2.00%	$ 0.28	$ 0.20



The residential costs start at CAD$0.32/kWh-yr, falling to as low as CAD$0.22/kWh-yr by 2016, and then rising monotonically thereafter to CAD$0.28/kWh-yr by 2023. Non-residential costs start at CAD$0.24/kWh-yr range, falling to CAD$0.14/kWh-yr, and ending up near CAD$0.20/kWh-yr.

b. Annual portfolio expenditures

GEEG estimated annual budgets for each portfolio scenario by multiplying the sector-level acquisition costs in Table 7 by the annual incremental savings acquired (detailed in Appendix A). The table below shows predicted FBC spending by sector by year to meet top-tier portfolio savings targets.

Table 8: FBC Spending Projections (Millions of 2013 CAD$)

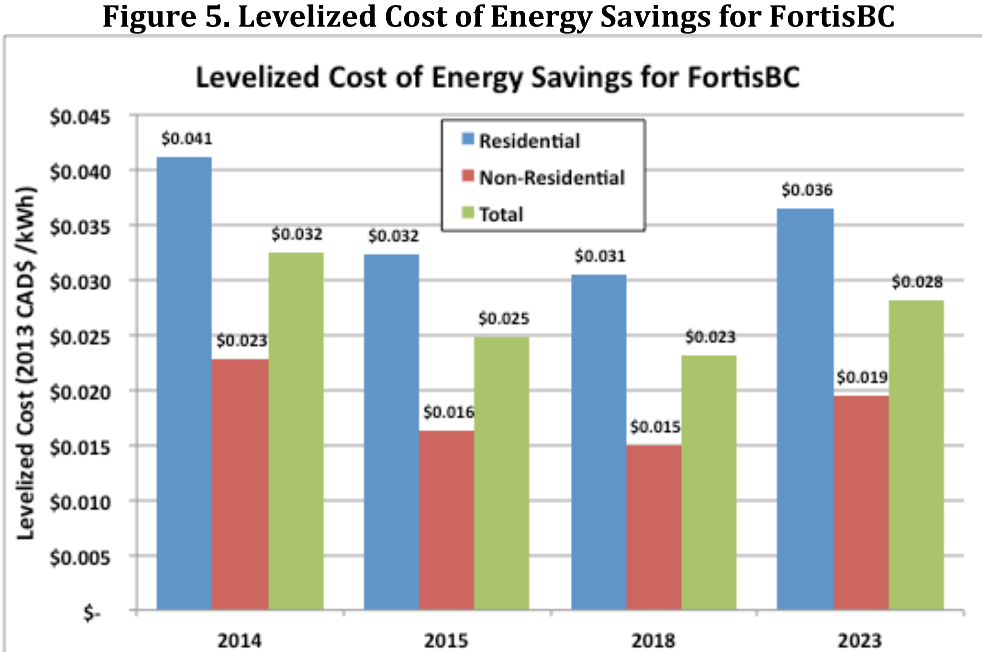
Year	Residential	Non-Residential	Total
2014	$4.51	$3.04	$7.55
2015	$5.36	$3.31	$8.68
2018	$6.92	$4.20	$11.12
2023	$8.59	$5.78	$14.37
NPV (@4.93%)	$52.4	$33.0	$85.3

c. Levelized Costs of Saved Electric Energy

GEEG calculated the levelized cost per kWh of electric efficiency savings using a real discount rate of 4.93 percent, and assuming an average savings lifetime of 10 years for residential programs and 15 years for nonresidential programs. This is consistent with expectations about the greater longevity of high-efficiency lighting, HVAC, and other equipment most likely to constitute the majority of future efficiency investments in each sector. These calculations assume that FBC expands residential and nonresidential efficiency in proportion to their existing portfolio shares. In reality, it would be expected that FBC would disproportionately invest in the nonresidential sector due to the low acquisition costs of efficiency savings.

The results are shown in the figure below. Achieving two percent annual savings is projected to cost between CAD$16 and CAD$41 per MWh saved.

Figure 5. Levelized Cost of Energy Savings for FortisBC



2. Incremental Savings and Spending

Table 9 shows the incremental electricity savings of a Tier 1 program over and above FBC's plan and additional annual portfolio expenditures that industry experience predicts will be needed to acquire them.

Table 9: Comparison of Savings and PV of Budgets

		Cumulative GWh Savings			Present Value Cumulative Budgets (Millions 2013 CAD$)		
Time Period		Tier 1	FBC Planned	Difference	Tier 1	FBC Planned	Difference
Year 1	2014	26.9	12.8	14.1	$7.2	$3.0	$4.2
Year 2	2015	65.3	25.7	39.6	$15.1	$5.9	$9.1
Year 3	2016	116.5	38.5	78.0	$23.6	$8.7	$14.9
Year 4	2017	165.0	51.3	113.6	$32.3	$11.4	$20.9
Year 5	2018	211.3	64.2	147.1	$41.0	$14.0	$27.0

The present worth of portfolio expenditures over the planning horizon for expanding efficiency investment is $27 million.

D. Cost-Effectiveness of Expanding FBC's Efficiency Resource Acquisition

The cost-effectiveness of expanding efficiency resource acquisition is determined by the net benefits of the additional investment compared to the base case spending and savings. Benefits consist of the long-run marginal costs of electric energy and capacity avoided by the energy and peak demand savings from efficiency investment.

Achieving top-tier energy efficiency performance from 2014 through 2023 would generate CAD$251 million in present worth of net benefits (present worth of benefits minus present worth of costs). GEEG calculated the benefits of expanding FBC's efficiency acquisition using avoided cost values provided by Paul Chernick, which start at CAD$0.09189/kWh in 2014 and rise to CAD$0.16949 in 2021.[5]

The scope of costs included this cost-effectiveness analysis is limited to those incurred and avoided on the electricity system by electricity customers through electricity prices. It does not cover resource costs incurred by customers to participate in the efficiency investments. In particular, the analysis does not include costs of efficiency investments paid by participants toward the additional savings of the expanded portfolio. These real costs must be counted under the total resource

[5] See Section IV(E) of accompanying testimony.

and the societal perspectives regulators recognize as the true litmus tests of the economic merits of competing resource alternatives.

GEEG has not estimated the additional customer contribution associated with expanding FBC's planned investment. Industry experience does provide some guidance, however. In general, top-tier portfolios typically involve programs that pay financial incentives that cover all or most of the incremental costs of additional efficiency savings. Moreover, expanding participation and per-participant savings involves real implementation costs, such as additional marketing and technical assistance.

Consequently, it is possible to estimate the amount of missing customer contribution as a percentage of the portfolio expenditures predicted with GEEG's empirical cost model. If A is the share of portfolio expansion expenses devoted to financial incentives, and B is the share of efficiency costs covered by financial incentives, then the missing customer share, C, is a percentage of the portfolio costs:

$C = A * (1/B – 1)$.

So if financial incentives represent four fifths of portfolio expenditures, and financial incentives typically cover three quarters of the total resource costs of additional efficiency investment, then customer (and/or other third-party contributions) would be 27 percent in addition to the estimated program expenditures to achieve top-tier portfolio savings. These assumptions are consistent with industry best practices associated with the most aggressive efficiency portfolios.[6]

For example, if the average portfolio cost of expanded efficiency savings is 4.4 cents levelized per kWh, then under these assumptions, missing customer contributions would be worth another 27%, or 1.2 cents/kWh, for a total resource cost of 5.6 cents/kWh.

Based on GEEG's projection of expanded portfolio expenditures, CAD$34 million is the estimated present worth of customer and third-party costs associated with expanding FBC's efficiency acquisition plan. Incorporating these costs into the calculation of total resource costs, expanding FBC's portfolio to achieve top-tier performance would yield $251 million in net benefits to British Columbia's economy over the life of the efficiency measures installed.[7]

[6] Higher values of A and B lower the amount of omitted customer contribution. The 80% and 75% assumed here for incentive budget and efficiency cost shares are consistent with aggressive financial incentives to induce greater participation and savings per participant.
[7] Calculations are presented in Appendix B

APPENDIX A

Detailed Projections for FortisBC

Appendix A – Detailed Projections for FortisBC

PROJECTION ASSUMPTIONS

Sector	Measure Life
Residential	10
Non-Residential	15
Real Discount Rate	4.93%
Line loss factor	8.8%

Year	Savings as a Percent of Sales	2013 CAD$/kWh-yr	
		Residential	Non-residential
2014	1.0%	$0.32	$0.24
2015	1.5%	$0.25	$0.17
2016	2.0%	$0.22	$0.14
2017	2.0%	$0.23	$0.15
2018	2.0%	$0.24	$0.16
2019	2.0%	$0.25	$0.17
2020	2.0%	$0.25	$0.17
2021	2.0%	$0.26	$0.18
2022	2.0%	$0.27	$0.19
2023	2.0%	$0.28	$0.20

INCREMENTAL SAVINGS

Projected Incremental Annual Energy Efficiency GWh Savings (without losses)

Year	Residential	C&I	Total
2014	14.2	12.8	26.9
2015	21.4	19.4	40.8
2016	28.8	26.2	55.0
2017	29.0	26.5	55.5
2018	29.2	26.9	56.1
2019	29.5	27.2	56.7
2020	29.7	27.6	57.3
2021	29.9	27.9	57.8
2022	30.2	28.3	58.4
2023	30.4	28.6	59.0

Appendix A – Detailed Projections for FortisBC

CUMULATIVE ENERGY SAVINGS

Projected Cumulative Energy Efficiency Savings GWh (without losses)*.

Year	Residential	C&I	Total
2014	14.2	12.8	26.9
2015	33.1	32.2	65.3
2016	58.1	58.4	116.5
2017	80.3	84.7	165.0
2018	100.2	111.1	211.3
2019	118.6	137.2	255.8
2020	134.9	162.8	297.7
2021	147.0	186.7	333.7
2022	154.7	209.7	364.3
2023	159.6	231.7	391.3

* The cumulative savings incorporate measure decay. The decay is based analysis done by Efficiency Vermont on February 28, 2012 for the Vermont Department of Public Service. By the end of year 5, incremental residential savings will have decayed by 41% and non-residential savings will have decayed 6%. By the end of year 10, savings will have decayed by 92% and 37% respectively.

SALES FORECASTS (GWh, without Losses)

Fiscal Year	Without Energy Efficiency	With Energy Efficiency
2014	2,694	2,665
2015	2,722	2,651
2016	2,750	2,623
2017	2,774	2,595
2018	2,806	2,576
2019	2,834	2,556
2020	2,863	2,539
2021	2,892	2,529
2022	2,922	2,525
2023	2,952	2,526

Appendix A – Detailed Projections for FortisBC

SPENDING PROJECTIONS

Year	Budgets (Millions 2013$)		
	Residential	C&I	Total
2014	$4.51	$3.04	$7.55
2015	$5.36	$3.31	$8.68
2016	$6.28	$3.62	$9.90
2017	$6.59	$3.90	$10.49
2018	$6.92	$4.20	$11.12
2019	$7.24	$4.50	$11.75
2020	$7.57	$4.81	$12.39
2021	$7.91	$5.13	$13.04
2022	$8.25	$5.45	$13.70
2023	$8.59	$5.78	$14.37

APPENDIX B

Calculation of
Total Resource Cost Test
for FortisBC

Appendix B – Calculation of Total Resource Cost Test for FortisBC

Description	Value	Formula
Share of incremental expenditures assigned to financial incentives (vs. marketing, administration, delivery)	80%	*a*
Share of additional efficiency measure cost covered by incremental financial incentives	75%	*b*
Total resource cost including customer contribution toward expanded efficiency investment, times portfolio investment	127%	*c = a[(1/b)-1]+1*
Total portfolio spending, $/kWh	$0.031	*d*
Incentives	$0.025	*e = a x d*
Non-incentives	$0.006	*f = d - e*
Total measure resource cost with customer contribution	$0.033	*g = e/b*
Customer contribution	$0.008	*h = g - e*
Total resource cost of savings	**$0.039**	*I = d + h*
Customer contribution as % adder to portfolio expenditures	26.7%	*j = h / d*
Total portfolio spending, PV (Millions of 2013$)	$128	*k*
Customer contribution	$34	*l = k x j*
Total measure resource cost with customer contribution	$162	*m = k + l*
Benefits, PV (Millions of 2013$)	$413	*n*
TRC Net Benefits, PV (Millions of 2013$)	$251	*o = n - m*