REFERENCE: Page # 28-29

PREAMBLE:

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QUESTION:

Clarify Daymark discusses the ratio of incentives to other costs, and identifies that the incentive ratio is for the electric portfolio are slightly higher than the industry average, and says that “it makes sense for EM to have a somewhat higher incentive allocation to bring greater attention and differentiation to the programs.”

a) Does the ratio of program budgeted incentives relative to other costs provide any indication of the actual incentive amounts relative to customer costs?

b) Could a higher ratio of incentives relative to other costs be caused by under-funding of other budget categories?

c) If the answer to 2 is yes, could under-funding of other budget categories affect deliverability of savings and participation?

RATIONALE:

Clarifying Daymark’s understanding of what can be learned from the ratios it presents.

RESPONSE:

a. No.

b. Yes.

c. Underfunding of other categories could potentially affect deliverability and participation.

REFERENCE: Page # 32

PREAMBLE:

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QUESTION:

Daymark states that “because the early program rollout will not be in the final system developed to track information, EM must be careful to gather and maintain the information necessary to ensure evaluations are complete.” Please describe any deliverability risks that Daymark thinks could result from the delayed availability of the EM CRM system.

RATIONALE:

Evaluation risk is important, but want to see if Daymark also thinks there are program delivery risks.

RESPONSE:

There is some risk to deliverability from a delayed deployment of a fully tested Efficiency Manitoba CRM system. The risk comes from having to deal with incomplete data and possibly duplicate entries associated with program bundles that include program measures that are also marketed as a single program. To the extent that Efficiency Manitoba decides to reallocate budget dollars across individual programs/bundles based on mid-year evaluations that would otherwise benefit from data available from the CRM, this could create ambiguity for delivery partners who need to know what program measures they should promote.

Also, to the extent the CRM also requires use by delivery partners who are expected to help new customers with the installation process, this could hold down participation rates and delay installs into another plan year. Even if the participation rate target is reached in one year, if installation is delayed until the next year, it could create concern among customers having to wait to realize energy savings on their bill and other physical benefits in their homes and businesses.

REFERENCE: Page # 45

PREAMBLE:

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QUESTION:

Daymark indicates that "EM has submitted a plan that meets and exceeds this [5%] goal." Please confirm that, because the goal is based on a ratio of LI/hard to reach budget compared with total spending, the target amount that EM budgets for these customers decreases as the overall budget decreases. In other words, reducing spending overall results in less spending for LI/hard to reach customers too.

RATIONALE:

Sufficiency of LI budgets to meet need.

RESPONSE:

Confirmed, assuming the percentage of budget devoted remains unchanged, as a consequence of 5% being an arithmetic calculation that results from dividing Efficiency Manitoba's proposed budget for the electric programs to serve its LI/hard-to-reach customers by Efficiency Manitoba's total Plan budget. However, this threshold test does not necessarily mean that the amount of the Plan budget allocated to electric programs targeted towards LI/hard-to-reach customers will automatically reduce if Efficiency Manitoba's total Plan budget is reduced, since funds can always be re-allocated in a way that would result in a higher percentage of funds going to programs for LI/hard-to-reach customers.

REFERENCE: Page # 50

PREAMBLE:

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QUESTION:

Daymark states that “EM has projected 18,300 retrofit projects.”

a) Does Daymark’s reference reflect the updated data table provided by EM in IRR to the Coalition (COALITION/EM I-102)?

b) Does Daymark assume that any house that participated in Hydro’s income-eligible programs- even is long as 10-12 years ago- will not have any new energy efficiency opportunities?

RATIONALE:

Understanding Daymark’s analysis of market saturation.

RESPONSE:

a) No.

b) Daymark does not assume that any house that participated in Manitoba Hydro’s income-eligible programs as long as 10-12 years ago will not have new energy efficiency opportunities. This reference to Efficiency Manitoba’s detailed measure-level data related to market size and potential was provided for comparison to Manitoba Hydro’s plan only and does not comment on whether any install under Efficiency Manitoba’s Plan is assumed to be completed at the homes of previous participants in the Manitoba Hydro plan.

REFERENCE: 3 (pdf page 9) 12 (pdf page 18) 15 (pdf page 21) Appendix A, Section A2, page 25 (pdf page 228)

PREAMBLE:

At page 12, the Report states that "As reported by Efficiency Manitoba, the Plan satisfies the mandates of the Act with respect to … 4 (c), mitigating the impact of rate increases and delaying the need for Manitoba Hydro to make capital investments".

At page 15, the Report states that "Even for the cost-effective plan, Efficiency Manitoba acknowledges, per-kWh or per-meter cubed rate increases may be necessary".

At page 3, the Report states: "many of the measures proposed by Efficiency Manitoba have a relatively short measure life".

At pdf page 228, the Efficiency Manitoba submission states: "Efficiency Manitoba understands that the marginal values include projected capital deferral value due to winter capacity savings and value projected in the export market".

QUESTION:

a) Is it Daymark's view that the Plan satisfies the mandate of the Act, Section 4 c) with respect to mitigating the impact of rate increases?

b) If yes, please reconcile this with the statement on page 15 that the Plan will lead to rate increases.

c) Is it Daymark's view that the Plan satisfies the mandate of the Act, Section 4 c) with respect to delaying the need for Manitoba Hydro to make capital investments?

d) If yes, given that many of the measures have a relatively short measure life, what is the basis for concluding that the Plan will delay "the need for Manitoba Hydro to make capital investments"?

RATIONALE:

To clarify Daymark's views.

RESPONSE:

a) Yes. While the Efficiency Manitoba plan will likely increase rates on average in the short-term, the LRI, even with Daymark's proposed modifications, suggests that impacts are significantly less than the rate increases that Manitoba Hydro recently has requested as necessary, given the large construction projects in generation and transmission. Daymark did not perform any studies estimating detailed annual comparisons of rate impacts with and without the Efficiency Manitoba Plan.

b) See a).

c) Yes. Not all measures are short-lived. Daymark did not have a scope of work that included a detailed investigation of marginal values. However, marginal values did include the value of deferring capital investments, and to the extent the timing of the marginal value associated with capacity overlaps the measures in place, one would assume capital projects to some extent are deferred.

d) See c).

REFERENCE: Page # 18 (pdf page 24)

PREAMBLE:

The Report states: "it's worth noting that efficiency improvements in the electric sector in Manitoba likely cause reductions in greenhouse gas emissions in MISO by making more hydro power available to MISO consumers."

QUESTION:

What is the basis for the claim that "efficiency improvements in the electric sector in Manitoba likely cause reductions in greenhouse gas emissions in MISO by making more hydro power available to MISO consumers"?

RATIONALE:

To understand the basis for statements in the Daymark Report

RESPONSE:

Significant reductions in consumption of electricity within Manitoba would very likely result in a combination of less imports of electric power from MISO by Manitoba Hydro or more exports of hydroelectric power to MISO by Manitoba Hydro. Each of these would reduce the amount of fossil generation needed by MISO generation facilities. Because the MISO system has, in most of its hours, either generation utilizing natural gas or coal as its fuel, the result would be to reduce hydrocarbon emissions inside MISO.

REFERENCE: Page # 20 (pdf page 26)

PREAMBLE:

The Report states “Efficiency Manitoba describes its approach to selecting programs in Appendix A, Section A2 of the Plan, using a process that involved both quantitative analysis elements and community engagement (through the Energy Efficiency Advisory Group.)

As stated in the Report, Regulation 11 a) requires that the PUB consider ““[T]he appropriateness of the methodologies used by Efficiency Manitoba to select or reject demand-side management initiatives”.

QUESTION:

a) The Report does not address the “appropriateness of the methodologies used by Efficiency Manitoba”. Does Daymark have a view as to whether the methodologies used by Efficiency Manitoba to select or reject demand-side management initiatives are appropriate”?

b) If yes, please outline what Daymark’s view is and explain why.

RATIONALE:

To obtain and understand Daymark's views.

RESPONSE:

a) Daymark’s report also summarizes on the same page that Efficiency Manitoba considered how best to “leverage” longstanding programs, introduce new programs, and maximize energy and non-energy benefits, while also considering technology lifecycles and developing a “diverse and inclusive portfolio”. Based on these qualitative criteria, it appears that Efficiency Manitoba has selected DSM initiatives appropriate to serve all customer classes and meet the annual savings targets for electric and natural gas. Efficiency Manitoba commented on the qualitative reasons why it may reject an initiative, as described in its response to Coalition/EM 1-10b, including the technology’s energy savings claims not yet being proven, unavailability of local supply of the technology, or inappropriateness for use in Manitoba’s climate. Based on this summary of both quantitative and qualitative reasons, it appears that Efficiency Manitoba’s methods for including or rejecting initiatives were appropriate; however, as noted in our report, they might have been enhanced by more consideration of how measure lives within the portfolios selected might or might not contribute to meeting long-term goals.

b) See response to a) above.

REFERENCE: Page # 22 (pdf page 28)

PREAMBLE:

The Report states: "Efficiency Manitoba's analysis does not include a discussion of the likely impact of the program on actual bill amounts faced by non-participating customers".

QUESTION:

a) Given Daymark's access to Efficiency Manitoba's detailed working papers, did Daymark undertake to determine the likely impact of the program on actual bill amounts faced by non-participating customers?

b) If yes, what were the results?

RATIONALE:

To follow-up on deficiencies Daymark has noted regarding the Efficiency Manitoba submission.

RESPONSE:

a) & b) Daymark did not attempt to determine the bill impacts of the Efficiency Manitoba Plan on non-participating customers. To the best of our understanding, based on our review, the worksheets did not contain the necessary information.

REFERENCE: Page # 71 (pdf page 77)

PREAMBLE:

Daymark's Report states: "Efficiency Manitoba used marginal values of electrical energy and capacity based on on-peak and off-peak seasonal values developed by Manitoba Hydro".

Daymark/EM I-20 a) states:

> "Manitoba Hydro provides Efficiency Manitoba with a forecast of 30 years of generation, transmission and distribution marginal values. The generation marginal values for each year are broken out between marginal energy values and marginal capacity values that are then each differentiated between summer and winter seasons. Transmission marginal values are forecast on the basis of winter capacity for each of the 30 years."

QUESTION:

Daymark's Report states that Manitoba Hydro provided peak and off peak marginal values. However, no reference to peak/off-peak marginal values was made in response to Daymark/EM I-20a). Please reconcile and indicate the basis for Daymark's statement.

RATIONALE:

To clarify Daymark's report.

RESPONSE:

Daymark's statement is based on Efficiency Manitoba's explanation in the Filing (pdf page 130 and pdf page 228). The measure-level workpapers reviewed by Daymark included seasonal on-peak and off-peak marginal values developed by Manitoba Hydro. An extensive review of marginal values developed by Manitoba Hydro was out of the scope for Daymark's engagement; thus, we did not review this information.

REFERENCE: Page # 73-73 (pdf page 79-80)

PREAMBLE:

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QUESTION:

For each of the natural gas and electric portfolios, please provide the weighted average measure life – using savings as the weighting factor.

RATIONALE:

To better understand the period over which the benefits from the Plan will accrue.

RESPONSE:

Please see the table below with the estimated weighted measure life (in years) for both electric and natural gas portfolios.

Portfolio	Weighted average measure life (years)
Electric	8.8
Natural Gas	19.5

The weighted average measure life was estimated using following mathematical formula for each portfolio:

$$\text{Weighted average measure life} = \frac{\sum_{i}^{N}(\text{measure life})_i * (\text{Savings})_i}{\sum_{i}^{N}(\text{Savings})_i}$$

where i is measure and N is the total number of measures in each electric and natural gas portfolio.

REFERENCE: Page # 98 (pdf page 104)

PREAMBLE:

In its Report Daymark present the results of various sensitivity analyses it conducted with respect to the discount rate.

QUESTION:

(a) Did Daymark assess the derivation and appropriateness of the discount rate used by Efficiency Manitoba?

(b) If yes, what were Daymark's conclusions?

RATIONALE:

To test the reasonableness of the discount rate values used in Daymark's sensitivity analyses.

RESPONSE:

a) Daymark did not perform an assessment of the discount rate that is being used within the cost effectiveness testing by EM in their Plan and workpapers. EM uses a 4% real discount rate, which we understand as being consistent with Manitoba Hydro analyses.

b) See (a).

REFERENCE: Page # 77-83 (pdf pages 83-89) 89-93 (pdf pages 95-99)

PREAMBLE:

The Daymark Report discusses alternative cost effectiveness tests including the Total Resource Cost (TRC) Test, the Participant Cost Test (PCT), the Rate Impact Measure (RIM) Test, the Societal Cost Test and the Pure Measure Value Test (PMVT).

QUESTION:

a) In Daymark's view should the results from any of these additional tests be considered by the PUB in making its decision?

b) If yes, specifically which ones and why?

RATIONALE:

To understand the role of the other cost-effectiveness tests discussed by Daymark.

RESPONSE:

a) Yes.

b) The PUB might wish to consider, as additional information, the results of the TRC Test and the Pure Measure Value Test. The results of the Societal Cost Test could also be appropriate to consider when the PUB is reviewing an energy efficiency plan (especially when there are potential associated environmental impacts on health or climate change), or when the PUB is looking at the overall benefits of establishing programs for disadvantaged or hard-to-reach customers, already identified in the ACT as the lower income and the indigenous people populations.

The results of the TRC are a good supplement to the PACT, since a TRC test will identify how consumer costs figure into the overall cost effectiveness picture. In the case of the Efficiency Manitoba Plan, we applied the TRC test, and found that, overall, it did not dramatically change the cost-benefit picture for the proposed programs—however, for a few individual programs, the TRC test highlighted the impact of either required customer expenditures or rebates.

The Pure Measure Value Test highlights those measures that, looking only at measure costs (not at any other associated program costs), do not have a benefit/cost ratio greater than one—for these measures, no matter who pays, cost more than they produce in monetized benefits.

Both of the above tests, we suggest, can be helpful in giving a more complete picture to inform the PUB's deliberations. However, we are not saying that they should be the sole basis for decisions. There may be valid reasons, including non-monetizable benefits and ensuring programming is available to hard to reach customers that provide reasons to continue programs with a benefit/cost ratio of less than one according to either or both of these tests.

REFERENCE: Page # 106-107 (pdf pages 112-113)

PREAMBLE:

The Report provides LRI results calculated over 5 and 10 year time frames as opposed to the 30 years used by Efficiency Manitoba.

Coalition/EM I-33 f) & g) also provides LRI results calculated over 5 and 10 year time frames.

QUESTION:

a) Please further clarify what the values set out in Tables 42 and 43 of the Daymark Report represent. For example, i) does the "5-year" column represent the LRI results of discounting the first five years of benefits and cost for all measures and ii) does the "10-year" column provided represent the LRI result from discounting the first 10 years of benefits for all measures with a life longer than 5 years?

b) Can Daymark provide any insight as to why its 5-year results differ from those provided in response to Coalition/EM I-33 g)?

c) Please provide Daymark's calculation of the LRI results from discounting the first 10 years of benefits and cost for all measures.

d) If the results provided in response to part (c) differs from those provided in response to Coalition/EM I-33 f), can Daymark provide any insight into why?

RATIONALE:

To better understand the LRI sensitivity analysis performed by Daymark.

RESPONSE:

In order to facilitate the understanding of the response, Tables 42 and 43 are provided below.

	Efficiency Manitoba One-Time Equivalent Rate 30-year Increase	Measure life adjusted rate increase Average 1st 5-Years	Average 2nd 5 Years
LRI (¢/kWh)	0.019	0.059	0.031
LRI Percent Increase (using 6¢/kWh)	0.32%	0.99%	0.52%
LRI Percent Increase (using 8¢/kWh)	0.24%	0.74%	0.39%
LRI Percent Increase (using 10¢/kWh)	0.19%	0.59%	0.31%

Table 1: Electric portfolio – rate impact by measure life

	One-Time Equivalent Rate Increase	Measure Life Adjusted Rate Increase Average 1st 5 Years	Average 2nd 5 Years
Lifecycle Revenue Impact (¢/m^3)	0.23	0.41	0.24
LRI Percent Increase (using 19¢/ m^3)	1.22%	2.17%	1.25%
LRI Percent Increase (using 21¢/ m^3)	1.10%	1.97%	1.13%
LRI Percent Increase (using 23¢/ m^3)	1.00%	1.79%	1.03%

Table 43: Natural Gas portfolio – rate impact by measure life[1]

a) Daymark's estimates come from breaking up the LRI into five pieces, corresponding with 5-year (and in one case, 10-year) groupings of measure lives,[2] with each LRI levelizing rate impacts over the number of years corresponding to the group measure life, and adding all of the results together to get the LRI for the first five years. That is, the rate impact of measures lasting five years or lower was levelized over five years; the rate impact of measures lasting from 6-10 years was levelized over ten years; and so on. Since, using this methodology, the rate impact for the measures with lifespans of five years and lower was fully reflected in a levelized five-year calculation, Daymark then eliminated the LRI from this group of measures with 1-5-year measure lives to get the estimated rate impact in the 2nd five years. The rate impact accordingly begins at the highest level, reflecting the levelized costs for all measure groups, and steps down as the levelized cost of each group of measures is fully covered.

b) The response to COALITION/EM 1-33g utilizes cash flows from distinct five-year and ten-year annual periods of benefits and costs, present valued, as the primary input into the LRI impacts. The calculation for five years levelizes all program costs over five years, producing a rate impact number that would cover all program costs within five years. The Daymark methodology, in contrast, estimates the LRI for all of the measure groups over their average lives, utilizing all of the years that the measures are in service. The Daymark calculation thus spreads the rate impacts over the measures' lives. The resulting five-year rate impact reported in Tables 42 and

[1] Levelized over a 30-year period.

[2] 0-5 years; 5-10 years; 10-15 years; 15-20 years; and 20-30 years.

43 therefore is set to fully fund all measures five years or less within five years, but does not fully fund (within five years) measures with longer lives.

This means that there are two basic effects that likely account for Daymark having lower LRI figures: first, more years of savings in dollars accounted for, since Daymark incorporates savings over a longer period than five years, when justified by measure life; and, second, longer periods over which to levelize the LRI. Daymark suggests that our methodology better represents likely annual rate impacts, especially when energy efficiency costs are amortized for ratemaking periods over ten years and not expensed in a single year, as the EM methodology would imply.

c) As found on page 101 (pdf page 107) of the Daymark report, the LRI calculation by EM is shown below:

$$LRI = \frac{[PV(Program\ Costs + Incentives) + PV(Revenue\ Loss) - PV(Marginal\ Benefits)]}{PV(System\ Energy\ kWh)}$$

where:

- program costs and incentives are defined consistently within the Program Administration Cost Test (PACT);
- marginal benefits are defined consistently with the PACT (levelized benefits of the marginal values);
- revenue loss includes the decrease in revenue realized by Manitoba Hydro resulting from lower electricity or natural gas sales as a result of customers' energy savings. The revenue losses were calculated by applying the current Manitoba Hydro Rate structure3 with assumed escalation to the reduced sales resulting from the efficiency programs over the 30-year period; and
- system energy is the Base Electric Load Forecast or Actual Natural Gas extended throughout the 30-year period

The Daymark calculations modified this formula in two ways to estimate the LRI of each 5-year group.

- First, the numerator PVs in the formula are just for measures in the specific measure-life group

[3] Public Utilities Board (PUB) approved rates from June 1, 2019 and November 2018 and adjusted for inflation were used for electric and natural gas respectively.

- Second, in order to capture the average in a five-year period, the denominator used for the PV of System Energy is for the years up to the midpoint of the measure life grouping

This calculation by Daymark provides an estimate of the average impact of each group over the years up to the end of life of the groups. For the average 1st 5-years value we sum up the LRI of all the groups' individual LRI values. The average of the 2nd 5-years value come from summing up the LRI of all group values, eliminating the first group of 1-5-year measure lives. The result is a picture of a potential rate impact, reflecting a hypothetical rate increase that would step down over time as the NPV impact of each five-year group of measures is fully covered during their measure-life window.

d) See the response to part b) above.

REFERENCE: Page # 101 (pdf page 107), footnote 82

PREAMBLE:

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QUESTION:

a) Did Daymark assess the reasonableness of Efficiency Manitoba's use of inflation to adjust the natural gas and electricity rates in the LRI analyses?

b) If yes, what were its conclusions?

RATIONALE:

To understand the scope of Daymark's analysis.

RESPONSE:

a) Daymark did not assess the reasonableness of the inflation assumption.

b) See a).

REFERENCE: Page # 118 (pdf page 124), 44 (pdf page 399

PREAMBLE:

The Report states with respect to the load displacement program: "If the savings result in any projects requiring continued incentives each year, out of the then current year budget, the Efficiency Manitoba Plan assumes that the savings is counted as contributing to each year's annual target for savings achievement. It is the equivalent of a one-year measure life that is implemented again each single year."

QUESTION:

a) There is no reference provided for this statement. Please indicate where in filing Efficiency Manitoba has documented this treatment of load displacement energy savings.

b) To what extent do the Load Displacement Program savings reported in Table A7.14 reflect this treatment?

RATIONALE:

To understand the basis for Daymark's comments and the implications for Efficiency Manitoba's planned savings

RESPONSE:

a) This observation is based on the review of Efficiency Manitoba's measure-level workpapers and the discussion with Efficiency Manitoba in the technical conferences. This treatment refers to Load Displacement – Project One (included in Table 5 of the Daymark Report), which is one of the three load displacement projects proposed in the 2020/23 Plan.

b) Refer to response to CC/Daymark-I-15 (a).

REFERENCE: Daymark evidence

PREAMBLE:

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QUESTION:

a) Please confirm the names of the authors of Daymark's evidence, as well as the authors' respective roles and responsibilities in preparing the evidence.

b) Please provide the curriculum vitae of the authors of Daymark's evidence.

c) Please provide a list of all related prior works completed by Daymark with respect to energy efficiency and demand-side management, as well as a link to where these documents can be found online or a copy of the documents, where not available online.

RATIONALE:

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RESPONSE:

a) The project was a team effort, and the authors had shared and/or overlapping responsibilities, as identified below:

1. John Athas: general oversight over report, compliance, cost-benefit, rate impacts, analytical approach and content, findings
2. Kathleen Kelly: general oversight over report, efficiency programs development and delivery; compliance, findings
3. Melissa Whitten: savings determinations, deliverability review, findings
4. Suman Gautam: savings determinations, detailed data review, cost benefit analysis, EMV analysis, findings

b) Curriculum vitae can be found appended to the end of this response.

c) We are providing 1) a list of related prior works completed by Daymark with respect to energy efficiency and demand-side management, with links; and 2) a table summarizing relevant project experience of Daymark staff (sometime previous to their joining Daymark).

1. Related prior works completed by Daymark with respect to energy efficiency and demand side management, with links:

- Direct Testimony of John Athas on Behalf of the Small Business Advocate before the Nova Scotia Utility and Review Board, July 14, 2014. (See Attachment, "Athas Testimony Nova Scotia 2014")

- Direct Testimony of John G. Athas on Behalf of the Small Business Advocate before the Nova Scotia Utility and Review Board, May 28, 2019. (See Attachment, "Athas Testimony Nova Scotia 2019")
- State of Charge: MA Energy Storage Initiative Study.
- Benefits and Costs of Utility Scale and Behind the Meter Solar Resources in Maryland, November 2, 2018.

2) As demonstrated in the project examples below, our team has worked with regulators and other parties interested and invested in how energy efficiency providers and program offerings are regulated. Our team has also been involved in the review or development of utility scale programs for utilities and completed technical potential studies to inform those program designs and plans.

TOPIC	CLIENT(S)	PROJECT DESCRIPTION
Regulations	Nova Scotia Small Business Advocate	**Expert witness regarding review of Efficiency Nova Scotia (EOne)'s three-year DSM plans.** Our team reviewed EOne's three-year plans in 2015 and in 2019, as well as an interim one-year plan in 2018. We also reviewed annual plans prior to the implementation of the *Electricity Efficiency and Conservation Restructuring (2014) Act* that, among other things, established the three-year plan regulations. **Stakeholder participation in the DSM Advisory Group.** Reviewing matters pertaining to energy conservation as a part of a working group and advising the Small Business Advocate. The issues in the advisory group include, but are not limited to, annual DSM evaluation reports, annual DSM plans, rate and bill impact analysis, incentive setting methodology, non-energy benefits estimation, and cost-effectiveness of DSM programs.
	Guam Public Utilities Commission	**Development of energy efficiency programs.** Directed a team of internal and external consultants, serving as technical advisor to the Guam Public Utilities Commission. Managed negotiations to ensure proper communication of case needs, management of information requests, development of summary memos, and development of final reports for use in commission orders. Participated in a cross-participant team representing the Commission in two important efforts for the island (1) the collaborative development of cost-effective DSM programs with the on-island utility and its consultant and (2) an independent review, on behalf of the Commission, of the electric utility's request for approval of its plans, supporting cost-effectiveness analysis, and recommended system expansion technologies and programs.
	Confidential	**Regulatory and commercial due diligence investigation.** Investigated an international energy company's potential and successful acquisition of a leading provider of aggregated demand response, energy procurement and energy management services to large customers. The assessment

TOPIC	CLIENT(S)	PROJECT DESCRIPTION
		was of short duration requiring immediate immersion through a management presentation, development of key topics for investigation, and tight deadlines for communication. Our analysis investigated the revenue projections and growth strategies in North American markets, assumptions about regulatory change and participation, wholesale market requirements, and potential for market openings over the ten-year forecast projection.
Program strategy and design	Newfoundland and Labrador Hydro	**Energy efficiency program design and regulation.** Investigated and recommended the adoption of energy efficiency programs by Newfoundland and Labrador Hydro's wholesale power customer, Newfoundland Power. Analyzed incentive and funding mechanisms, including through changes in the wholesale pricing structure and the potential for creating a regulatory asset for energy efficiency investments. In other engagements, directed and participated in efforts with Newfoundland Labrador Hydro to develop a revised cost of service and to redesign its retail and wholesale rates for several rate cases.
	Northern Indiana Public Service Company	**Electric and gas demand side management portfolio design.** Directed the development of a portfolio of DSM programs including electric energy efficiency and demand response strategies for NIPSCO's inclusion in its 2007 Integrated Resource Plan filed with the Indiana Utility Regulatory Commission (IURC). Sponsored and provided testimony before the IURC in support of the plan relative to NIPSCO's DSM cost recovery and incentive proposal (Cause No. 43618, December 2008). Also provided a report and supported regulators and stakeholders in NIPSCO's development of gas efficiency programs during 2006.
	Eversource	**Energy efficiency management within a utility.** Kathy Kelly served as Manager of DSM Planning and Manager of DSM Evaluation during her tenure at Eversource (formerly Boston Edison Company). As part of her responsibilities she developed, managed, and evaluated energy efficiency programs for customers within Massachusetts and she testified before the Massachusetts Department of Public Utilities in support of DSM Budgets, DSM Cost Recovery and Incentive Plan, DSM Monitoring and Evaluation Plan (D.P.U. 90-335, 1990-1992). Prior to that she provided periodic testimony relative to DSM implementation plans, evaluation results, and cost recovery projections and reconciliations. Since that time she has advised a variety of clients on program design, cost recovery and evaluation.
	State of Michigan: Department of Technology and Budget Operations	**Energy efficiency and renewable potential study.** Daymark Energy Advisors and its partner were retained to assess the technical, economic, and achievable potential for reducing electric and natural gas use and peak electric demand in the State of Michigan through energy efficiency measures and customer-sited renewable resources. Our team

TOPIC	CLIENT(S)	PROJECT DESCRIPTION
		worked with the Michigan Public Service Commission, the DTMB, plus DTE, Consumers Energy, and other relevant stakeholders to readily incorporate existing and ongoing studies and pertinent customer information into the analysis. As a part of this effort we conducted stakeholder research and reported on findings related to customer attitudes, beliefs, and behaviors that affect their energy use and we assessed customer interest in relevant products and services offered by their electric and natural gas service providers.
Program evaluation	Blackstone Gas Company	**Program evaluation.** Participated in multiple demand side management program evaluations for this Massachusetts gas utility between 2011 and 2016.
	Massachusetts Program Administrators research team Massachusetts Energy Efficiency Advisory Council Puget Sound Energy	**Evaluation of demand side management programs.** Qualitatively and quantitatively analyzed the impact of energy efficiency programs to evaluate the implementation process, assess participant satisfaction, and estimate energy savings. The process evaluation method consisted of in-depth-interviews of program managers, implementers, and participants. Energy efficiency savings were estimated through rigorous statistical and econometric models. The efforts included creating a dataset by combining information on electricity usage, efficiency programs, and weather, accounting for weather-dependent consumption, and then estimating efficiency related savings with the help of difference-in-difference models.
	Green Mountain Power	**Evaluation of emergency demand response programs.** Analyzed the impact of Green Mountain Power's emergency Demand Response (DR) programs on residential customers' electricity consumption during a two-year pilot program in 2012-2013. The analysis examined potential peak load reductions, monthly electricity consumption, and persistence of response with the help of difference-in-difference approaches. The final dataset included 30 million observations comprising of hourly electricity load, critical peak event information, and weather variables.
	Massachusetts utilities on behalf of the Massachusetts Energy Efficiency Advisory Council AEP Ohio	**Customer database building and profile reports.** Developed and managed very large and complex utility data sets for both Commercial and Residential customers of Massachusetts with the help of SAS and SQL using the Extract, Transform, and Load (ETL) process. Responsible for creating a process for effectively loading, cleaning, performing quality checks, and integrating hundreds of raw data files into a single, standardized database. The profile reports included results from exploratory data analysis.

b) Please see the curriculum vitae on the following pages:

John G. Athas

Vice President and Principal Consultant

AREAS OF EXPERTISE

Integrated Resource Planning

Energy Efficiency

Regulatory Advisory Service

Utility Ratemaking

Strategy, Business, and Energy Planning

Financial Evaluation of Energy Assets

Market Advisory

Wholesale Market Analytics

Expert Witness

BACKGROUND

Daymark Energy Advisors
2006-Present

Direct Energy North America
2005

Cambridge Energy Research Associates
2001-2005

Northeast Utilities
1981-2000

United Technologies Corporation
1977-1981

EDUCATION

M.B.A.
University of Connecticut

M.S., Mechanical Engineering
Rensselaer Polytechnic Institute

B.E., Mechanical Engineering
Cooper Union

John draws on nearly 40 years of diverse electric industry experience to provide clients with valuable insights and strategic perspective. His principal practice areas are resource planning, utility ratemaking and regulation, and contracts and transactions, and he leads business development. John has testified before state and provincial regulatory agencies on issues including resource planning, energy efficiency, utility restructuring utility ratemaking and competitive markets.

SELECTED ENERGY EFFICIENCY EXPERIENCE

- Provided detailed review and expert evidence regarding EOne's three-year DSM plan. EOne is the operating affiliate of Efficiency Nova Scotia and its DSM plan covered cost effectiveness testing, affordability, conformance with IRP strategies, and program design.
- Participated in EOne's DSM Advisory Group, advising the Small Business Advocate on how the proposed plan affects the customers they represent. The advisory group focuses on issues including, but are not limited to, annual DSM evaluation reports, plans, rate impact analysis, incentive setting methodology, and non-energy benefits estimation of DSM programs.
- Developed special incentive packages of utility rate discounts and comprehensive energy efficiency investments for large customers in business retention and economic development circumstances.
- Facilitated information exchange and consensus building between utilities and stakeholders in Connecticut's first statewide IRP. Stakeholders included generation owners and developers, energy efficiency planners, regulatory oversight groups, public advocate organizations, environmental organizations, transmission owners and regional transmission ISOs, and consumers.
- Reviewed and critiqued Connecticut's 2012 Comprehensive Energy Strategy on behalf of the Connecticut Energy Advisory Board (CEAB). This was Connecticut's first combined plan for electric, natural gas, and oil.
- Lead IRP planning and the development of related regulatory filings for Green Mountain Power, including the testing of scenarios or DSM program funding levels by Efficiency Vermont.
- Critiqued energy efficiency analysis and programs as part of IRP reviews in Oklahoma, Arkansas, Virginia, North Carolina, Michigan, and Indiana.

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AREAS OF EXPERTISE

Energy Efficiency

Integrated Resource Planning

Management Consulting

Organizational Effectiveness

Regulatory Advisory Services

Strategy, Business, and Energy Planning

Clean Energy Strategy and Policy

DER Planning and Value

Grid Modernization

Utility Ratemaking

Procurement and Portfolio Management

Expert Witness

BACKGROUND

Daymark Energy Advisors
2016-Present

Lummus Consultants International
1997-2015

Boston Edison Company
1977-1997

EDUCATION

M.B.A., Finance
Northeastern University

B.S., Mathematics
University of Massachusetts

A.B. Economics
University of Massachusetts

Kathleen A. Kelly

Vice President and Principal Consultant

Kathleen A. Kelly provides strategic planning, business management, and solution based advisory services to diverse clients in the energy industry. Her principal practice areas are organizational and business process effectiveness, regulatory policy and case strategy, economic and integrated resource planning, and management audits. She has advised utilities, regulators, and major customers on issues including disruptive technologies, regulatory policy shifts, and balanced resource economics and planning.

SELECTED ENERGY EFFICIENCY EXPERIENCE

- Directed and participated in efforts with Newfoundland Labrador Hydro to investigate and recommend the adoption of energy efficiency programs by its wholesale power customer, Newfoundland Power, through changes in the wholesale pricing structure.
- Directed the development of a portfolio of DSM programs including electric energy efficiency and demand response strategies for Northern Indiana Public Service Company (NIPSCO) for inclusion in its 2007 Integrated Resource Plan (IRP) filed with the Indiana Utility Regulatory Commission (IURC). Sponsored and provided testimony in support of the plan. Provided a report and support to regulators and stakeholders regarding NIPSCO's gas efficiency programs during 2006.
- For the Iowa Association of Electric Cooperatives, provided technical facilitation and policy development services to a cross-section of 20 representatives from more than 40 members – resulting in the creation of positions with respect to climate change requirements. The positions and strategies included development of a wide range of approaches to legislative and regulatory policy development on global warming solutions including, in particular, energy efficiency levels and standards, demand response, renewable portfolio standards, and net metering for community resources.
- Directed a team of internal and external consultants, serving as technical advisor to the Guam Public Utilities Commission. These engagements delivered recommendations on diverse technical regulatory filings including opting energy efficiency and renewables, integrated resource plans, net metering programs, review of resource acquisition approaches, and whitepapers on additional topics. Managed client relationships with both the Commission and the regulated power and water utilities to ensure proper communication of case needs, management of information requests, development of summary memos, and development of final reports for use in commission orders. Recent efforts involved developing DSM programs with the on-island utility and reviewing plans for system expansion.

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Melissa Whitten

Managing Consultant

Melissa is an expert in the natural gas industry. She provides clients with economic and regulatory analysis and strategic insights on a broad array of matters including the design and performance of long-term supply strategies, capital investments, and infrastructure replacement planning. In addition to her natural gas industry expertise, she is a leader in electric demand side management planning and evaluation. Melissa has provided expert testimony in seven North American jurisdictions on behalf of utilities, regulatory staffs, and intervening parties.

SELECTED ENERGY EFFICIENCY EXPERIENCE

- Participated in DSM program evaluation for a Massachusetts utility and reviewed the incentive setting mechanism, rate impact and cost effectiveness of DSM plans in Nova Scotia, focusing on small business.
- Managed short- and long- term supply, transportation and storage contracts and innovative peak sharing services for $100 million portfolio, selecting and negotiating with vendors for supply from four major natural gas supply basins across the US and Canada.
- Evaluated utility precedent agreements for recently proposed expansion projects on four interstate natural gas pipelines, analyzing the cost-effectiveness, flexibility and reliability of the contract terms.
- Reviewing impact of revisions to open access tariffs for two Northwestern utilities to appropriately account for stranded costs when large customers choose to wheel power or disconnect.
- Reviewed and evaluated natural gas utility accelerated infrastructure replacement programs and supporting long-term capital plans, leak rates, risk ranking systems, and rate recovery mechanisms filed by gas utilities in two states
- Conducted annual RFPs for natural gas supply and carried out one-on-one negotiations for supply, transportation and storage assets, including utility and industrial customers; awarded contracts and monitored accounting and financial performance through contract close.
- Optimized portfolio performance, renegotiating existing and structuring new supply contracts, as well as storage and pipeline capacity release transactions to offset firm contract costs and recover incremental value for ratepayers.

AREAS OF EXPERTISE

Regulatory Advisory Services

Energy Efficiency

Integrated Resource Planning

Strategic Planning

Utility Ratemaking

Procurement and Portfolio Management

Wholesale Market Analytics

Natural Gas Supply Chain

Economic Advisory Services

BACKGROUND

Daymark Energy Advisors
2009-Present

EMDEC Energy Management Decisions
2000-2001

Cascade Natural Gas Corporation
1993-1999

J. Makowski Associates, Inc.
1990-1993

Boston Edison Company
1987-1988

Applied Expert Systems
1986-1987

Data Resources Inc.
1980-1986

EDUCATION

M.B.A., Finance and Information Systems
University of Rochester

B.A., Economics
University of Massachusetts

Certified Business Economist (CBE)
National Association for Business Economics

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AREAS OF EXPERTISE

Energy Efficiency

Regulatory Advisory Services

Clean Energy Strategy and Policy

Wholesale Market Analytics

Financial Evaluation of Energy Assets

BACKGROUND

Daymark Energy Advisors
2016-Present

DNV GL
2014-2016

EDUCATION

Ph.D., Energy Economics
The Pennsylvania State University

M.S., Energy Economics
The Pennsylvania State University

B.A., Physics and Economics
Illinois Wesleyan University

Suman Gautam, Ph.D.

Economist and Senior Consultant

Suman works with clients on commercial, regulatory, and policy-focused projects in both wholesale and retail energy markets. He applies microeconomic and econometric analysis to market design, pricing, supply and demand forecasting, and policy evaluation. He has examined the economic impacts of energy policy, investments, and energy cost and price changes.

SELECTED ENERGY EFFICIENCY EXPERIENCE

- Led an effort to enhance utilities' market analysis capability by building and understanding energy efficiency program participation and performance metrics.
- Reviewed evaluation reports, DSM plans, and any other matters pertaining to energy conservation as a part of working group. Advised the Nova Scotia Small Business Advocate on how proposed plans would affect the customers they represent. The issues reviewed include, but were not limited to, annual evaluation reports, annual DSM plans, rate and bill impact analysis, incentive setting methodology, non-energy benefits estimation, cost-effectiveness of DSM programs.
- Reviewed the integrated resource planning process and results submitted by Duke Energy Carolinas and Duke Energy Progress to the North Carolina Utilities Commission, including specifically how energy efficiency, demand side management, and renewable energy alternatives were incorporated in the planning and modeling processes.
- Analyzed the impact of energy efficiency programs qualitatively and quantitatively to evaluate the implementation process, assess participation satisfaction, and estimate energy savings. The process evaluation method consisted of in-depth-interviews of program managers, implementers, and participants. Energy efficiency savings were estimated through rigorous statistical and econometric models. The efforts included creating a dataset by combining information on electricity usage, efficiency programs, and weather, accounting for weather-dependent consumption, and then estimating efficiency related savings with the help of difference-in-difference models.
- Analyzed the impact of renewable portfolio standards (RPS) – a state level policy that requires utility companies to include a minimum percentage of renewable or "alternative" electricity – on reducing carbon emissions and how this impact varied with certain RPS characteristics.

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BEFORE THE NOVA SCOTIA UTILITY REVIEW BOARD

DIRECT TESTIMONY OF JOHN ATHAS

ON BEHALF OF

THE SMALL BUSINESS ADVOCATE

July 14, 2014

TABLE OF CONTENTS

I. INTRODUCTION

Q. What is your name and business address?

A. My name is John Athas, and I work for La Capra Associates, One Washington Mall, Boston, MA 02108.

Q. On whose behalf are you testifying in this proceeding?

A. I am testifying on behalf of the Nova Scotia Small Business Advocate ("SBA").

Q. Please describe your background and experience.

A. I am a Principal Consultant and Treasurer at La Capra Associates. I have been with this energy planning and regulatory economics firm for 8 years and involved with electric utility planning, marketing and pricing for 30 years. Prior to my time at La Capra Associates I was with Cambridge Energy Research Associates for 4 years and Northeast Utilities ("NU") for 19 years. During my time at NU, I spent over two years as Director of Market Pricing and Policy, where I managed the Rates, Cost of Service and Special Contracting functions. I have filed testimony on generation planning, integrated resource planning, electric industry restructuring, electric utility flexible rates and special contracts, including load retention and competitive retail electric power marketing within Connecticut, Massachusetts, Arkansas, Nova Scotia, and Oklahoma. My full resume is attached.

Q. What are the particular areas of your experience that have relevance to the petition to approve ENSC's Electricity Demand Management Plan (DSM) for 2015?

A. While at NU as early as 1984 I have been involved in Integrated Resource Planning, a role that included the internal review of proposed DSM programs, from cost benefit to implementation. During my time at La Capra Associates I have been involved in the review of integrated resource plans in 2008, 2009 and 2010 of the Connecticut investor owned utilities which included plans to develop all cost effective DSM. In addition I have performed detail reviews of energy efficiency plans for Oklahoma Gas & Electric, Public Service Oklahoma, Entergy Arkansas, and Manitoba Hydro. I also authored the section of a La Capra Associates' report in North Carolina which reviewed and evaluated energy efficiency potential studies for North Carolina, benchmarking them to other states.

Q. Please describe your educational background.

A. I have a Bachelors degree in Mechanical Engineering from The Cooper Union for the Advancement of Art and Science, a Masters degree in Mechanical Engineering from Rensselaer Polytechnic Institute, and a Masters in Business Administration from the University of Connecticut. I am a licensed Professional Engineer in the State of Connecticut.

Q. What is the purpose of your testimony?

A. I have been retained by the Small Business Advocate to review Efficiency Nova Scotia Corporation's ("ENSC") energy efficiency plan for 2015. This review was limited to the Final Issues List published in this matter by the UARB.

Q. Please summarize your testimony.

A. There are considerable concerns that the SBA has based upon the evidence ENSC has filed in this application as well as other ENSC material, such as responses to information requests. Given the transition that is occurring in the implementation and administration of energy efficiency as a result of the *Electricity Efficiency and Conservation Restructuring (2014) Act.* ENSC has referred to this plan as a 'continuation plan' meaning it is based on prior cost-benefit analyses and provides important continuation of the energy efficiency programs in order to keep achieving energy and peak demand reductions, savings for participants and consistent business signals to the energy efficiency program implementation vendors.

In my testimony I discuss the following positions of the SBA and some of the background that resulted in these thoughts:

1. The Continuation Plan is a reasonable expectation given the transition to operation under new legislation. This conclusion reached by SBA does not mean that ENSC should continue all its program designs, fiscal management and program implementation management in a business as usual manner for 2015.

2. The cost allocation proposed does represent a methodology that the SBA has agreed upon for this one time rate smoothing use only.

3. Contractor procurement concerns expressed by other interveners are an important issue for the SBA and needs investigation outside this proceeding. There is an obligation that comes with the franchise awarded ENSC and now ENS as the energy efficiency utility to procure in a least cost manner that benefits Nova Scotia's businesses.

4. SBA believes the budget level for programs should be $31 million so that with the $4 million under collection from prior years that will be spent in 2015 on efficiency and conservation services it will total $35 million as per the legislation. This is not the $35+4 = $39 million proposed by ENSC. The SBA believes this is consistent with the continuity concept proposed by ENSC. The SBA believes a minimizing program funding to levels that provide continuity, rather than maximizing program expenditures will afford more time for ENSC's program management and allow the new role of NSPI to be assimilated per the legislation.

5. SBA believes the one major issue likely to have a major effect on the energy efficiency programs and funding levels over the course of the 10 years for the ENS franchise is the need for the UARB to establish a clear set of responsibilities under the new legislations. It is critical that the UARB establish the process and responsibilities of ENS and NSPI on DSM program planning, funding levels, program oversight and contractual rights. It is also critical that the review process with the UARB for the 2016 plan and beyond be established based on these responsibilities. This process should define minimum expectations for the content of filings by ENS and NSPI. This process should define the role of the DSM Advisory Group and where the UARB has set opportunities for stakeholders such as the SBA to formally intervene.

6. SBA has concerns about program selection and program management and oversight provided by ENSC, especially the BNI program. E&V reports by Econoler and Peach point to higher savings realization which if true means less program expenditures will likely produce desired savings. If not true then there is broad uncertainty about the load impact of the programs.

The Econoler report cites several poor practices in program implementation that need to be corrected

II. REVIEW OF ENSC's APPLICATION

Q. Can you summarize the information ENSC in their application?

A. ENSC's application starts with discussion of the background of the short history since its establishment in 2010 through the transition it is making as a result of the *Electricity Efficiency and Conservation (2014) Act.*

Next ENSC provides 2013 DSM program results. This includes discussion of the programs in effect for residential, business, non-profit and institutional sectors.

ENSC then describes its adoption of 2015 as a transition year, which actually is that last year of its 2013-2015 DSM Plan and the first year operating under the new legislation.

The 2015 Plan is briefly described within the filing with details provided in Appendix A - The DSM Plan and Appendix B - 2015 DSM Resource Plan Development Approach and Details. The 2015 DSM Program Plan as proposed would have a budget of $35 million, which would be recovered from ratepayers over 8 years beginning in 2016 along with approximately $4 million as a result of under collection from prior years.

Lastly ENSC provides detailed Preliminary Cost allocation Tables in Appendix C.

Q. What is ENSC requesting from the Board in this application?

A. ENSC seeks and Order approving this DSM Resource Plan for the period January 1, 2015 to December 31, 2015.

III. CONTRACTOR PROCUREMENT

Q. Did you find information in this application regarding concerns about contractor Procurement?

A. Yes. There was a letter of complaint submitted by National Foam Supply dated June 13, 2014 that the NSUARB brought into the record. In its response to a NSUARB information request[1], ENSC provided a substantial rebuttal to the complaint. ENSC describes that there had been a prior complaint made in February, 2013 by Pine Glen Investments which was dismissed by the NSUARB on the grounds that a single complainant should not trigger an investigation. ENSC cites that the National Foam Supply is also a single party complaint.[2] In addition to suggesting that the NSUARB could similarly dismiss this complaint on these grounds, the ENSC provided significant discussion on its managerial process for procurement to assure that there are quality vendors in their programs.

Q. Are you satisfied with the information provided by ENSC?

[1] ENSC Response to NSUARB Information Request IR-16
[2] Ibid., Page 3.

A. I do believe that ENSC has provided a very high level view of its process. Contractor Procurement that follows these procedures described by ENSC in its response would constitute a well-run and prudent process. However, the fact that complaints come in one at a time concerns me. In order to coordinate complainants for the aggregate of five the potential contractors that have bid to serve ENSC might come close to in appropriate discussion of bidding. The high level response does not provide specific enough information to make a judgment that the procurement processes are being conducted as described.

Q. What can be done?

A. The ENSC can provide subsequent to this proceeding a detailed and confidential report to the NSUARB that provides specific information comparing selected contractors and those that have not been chosen.

IV. IMPLEMENTATION OF THE *Electricity Efficiency and Conservation Restructuring (2014) Act*[3]

Q. Have you reviewed in detail the *Electricity Efficiency and Conservation (2014) Act*?

A. Yes.

Q. How is the *Act* important to small businesses in Nova Scotia?

[3] Bill NO. 41 Electricity Efficiency and Conservation Restructuring (2014) Act, Chapter 5 of the acts of 2014, May 1, 2014.

A. The *Act* establishes a franchise that will be in existence through at least December 31, 2024. This franchise will deliver electric energy efficiency programs to small businesses throughout Nova Scotia, in addition to residential, non-profit, institutional and large industrial customers. This act authorizes the UARB to approve the annual expenditures beginning on January 1, 2016 of the holder of the Efficiency Nova Scotia ("ENS") franchise, to be paid by NSPI and incorporated into NSPI costs for subsequent ratemaking. These expenditures will likely exceed $40 million per year. Prior annual energy efficiency expenditures have been allocated to small business such that 25% of all expenditures made plus the expenditures made on customers of each specific small business rate class are included in rates. The result is that millions of dollars that represent a meaningful percentage of the rates small businesses pay will come out of the regulation of the ENS franchise programs and costs. Many small businesses will have a life of less than the next ten years of the ENS franchise life established by the *Act.* It is imperative that the programs that result from the ENS expenditures are effective at meeting small business customer needs in their implementation design as well as their incentive structure in order to realize savings for these customers well beyond the increase in their rates to support the ENS franchise.

Q. Are there elements of the *Act* that you feel need to be discussed in this proceeding?

A. Yes. There are three major elements of the *Act* that represent changes in the manner in which programs are developed, approved, implemented and measured.

1. The supply of electric efficiency and conservation activities will be administered by the ENS franchise on a contractual basis with NSPI, with the contract being approved by

the UARB. The act allows for negotiations between NSPI and ENS to arrive at a three year contract for those service under section 79(I0 of the *Act*.

2. The UARB is authorized to approve actual annual expenditures by ENS and provide cost recovery to NSPI for the payments made to ENS to support these expenditures. The *Act* is silent regarding the treatment of any franchise holder expenditure variations below approved levels as to whether these over payments by NSPI that would result are returned to ratepayers.

3. The process for the filing by NSPI and/or ENS with the UARB for approval of the contract is undefined. The role of the DSM Advisory Group to participate in the program development and in establishing an annual budget to be incorporated into the contract between NSPI and the franchise holder is undefined. The process is silent on how interveners, such as SBA, will have a formal opportunity to intervene in the UARB approval process?

Q. Can you elaborate on your first concern above?

A. Yes. Section 79M (2) clearly states that failure of the franchise holder to achieve performance requirements established by the Board is not the responsibility of NSPI. Then Section 79J (2) states that NSPI's contract with ENS must describe the electricity efficiency and conservation activities that the franchise holder will provide to NSPI as well as the amount that NSPI will pay the franchise holder. Section 79J (3) recognizes that NSPI and the franchise holder may indeed fail to reach agreement on the contract. The undefined and large issue in the legislation, which we assume is left to the UARB to decide, is who determines, between the franchise holder and NSPI, what the budget level should be in the contract, which programs should be added, changed or eliminated, how much should be spent on each program and what the cost effectiveness testing methodology should be used to justify program measures. It is unclear if there any obligations on either NSPI or the franchise holder to propose program plans including total annual expenditure levels that are consistent with the results of NSPI's Integrated Resource Plan which is approved by the UARB.

This is my major concern. We need to understand which party is responsible in order for SBA to understand who we need to work with during the planning process in terms of designing effective programs for small businesses.

Q. What is your second concern regarding the treatment of over collection or under spending by the franchise holder?

A. The SBA does not see within the legislation a requirement that would have the franchise holder return or credit any amounts it spends less than the payments agreed upon in the contract with NSPI? If the franchise holder keeps the payments made in excess of its costs then the franchise holder should not be given the responsibility to solely decide on the amount of expenditures on each program, the target or expected energy savings and the total annual franchise holder expenditures that are approved by the UARB. This presents a problem in possibly the franchise holder filing for approval of the UARB performance targets that may be easy to obtain at the proposed payments levels they will receive.

The SBA believes this moves too far away from setting up the franchise for cost recovery of programs. The SBA concerns could be alleviated if NSPI is responsible for negotiating the performance targets and the budgets for the franchise holder. The SBA would like to see established an NSPI process, working in concert with the franchise holder that develops programs that are cost effective and meet the needs of small businesses, rather than just an ENS process. The SBA would like to see the performance targets be set on a program level or even a measure level that make the franchise holder accountable. The process should be set up to hold NSPI accountable for the level of efficiency and conservation services to be used and useful.

Q. Can you elaborate on your third concern regarding the approval process?

A. Yes. The approval process for the NSPI contract and performance management of the franchise holder is very important. The SBA recognizes the transition year established by the *Act*. Beginning in 2016 the contract for electricity efficiency and conservation services between NSPI and the franchise holder will be set at three years. The DSM planning, the contract negotiations between NSPI and the franchise holder, and the contract approval filing will need to commence this year in order for a January 1, 2016 start date. The SBA would like a specific timetable and milestones set for this process. Also, does this mean that hearings regarding the contract will only take place every three years? Does this then mean that interveners and stakeholder will only get an opportunity to work with NSPI or the franchise holder every three years with respect to program expenditures and program designs? Will this review process for the first three year contract (2016-2018) occur early enough in 2015 to allow material changes in the NSPI-franchise holder contract if ordered by the Board? It is the UARB approval of the contract that approves the services which will be offered by the franchise holder under the contract, the performance metrics for the franchise holder and how much the payments will to the franchise holder under the contract.

V. PROPOSED 2015 DSM RESOURCE PLAN – APPENDICES A & B

Q. Do you have any concerns based upon the information you reviewed in Appendix A of the application?

A. Yes. Appendix A is the description of what ENSC is proposing for programs in 2015. Based upon their own information I see room for reducing some program emphasis, even within my acceptance of the Continuation Plan strategy. These concerns and the others that follow are reasons why the SBA would like to see the DSM Plan for 2015 be approved at an expenditure level of $31 million.

Q. Has ENSC substantiated why they believe it is necessary to have a budget of $35 million rather than $31 million.

A. In my opinion no. In ENSC's expressed concern[4] that there are program benefits and they would produce more savings at a budget of $35 million. They also say it is necessary to "minimize the reduction or loss of energy efficiency services to Nova Scotians", citing several policy level reports. ENSC fails to incorporate its needs to improve delivery with recommendations outlined in the ECONLER Reports of 2012,

[4] ENSC Response to NSUARB IR-3.

2013 and now 2014. In response to an information request[5] ENSC provides how programs would change if their program expenditures were scaled back by $4 million. In this illustration ENSC chose to focus on all the programs that involve service providers or vendors. ENSC did not make an adjustment to the rebate programs. ENSC has provided information[6] that shows this program is proving to be more costly per unit savings than planned when the original 2013-2105 ENSC plan was filed and approves. This also show that the proposed $5.7 million in rebate program expenditures is 14% higher than was approved in the 2013-2015 ENSC plan. I would suggest that taking some or all of the $4 million reduction from the high cost rebate program would minimize the reduction of expenditures on contractors and vendors providing efficiency and conservation services implementation. Even without a change in the rebate program and if the $4 million budget reduction is taken from the programs ENSC has illustrated, I fail to see when a 13% scale back would paralyze the participant and vendor desire for energy efficiency services in the future.

Q. Would you please explain your concerns.

A. The SBA represents customers whose transactions with the ENSC fall under the category in the DSM Plan called Business, Non-Profit and Institutional ("BNI") Programs and Services". The three program sectors in the DSM Plan for BNI include Efficient Product Rebates, Custom Incentives and Direct Installation.

[5] ENSC response to NSUARB IR-4.
[6] ENSC response to Industrial Group IR-6 part a p. 2.

The share of the DSM Plan budget for 2015 allocated to these three program sectors is shown in Figure 1.1.1 – 2015 DSM Resource Plan Savings and Investment[7]. However, while this table shows unit cost for the total plan, it does not show unit cost for the BNI category, which would be helpful for comparison to Residential programs and to illustrate additional comments below.

It is important to note that the unit cost results presented in Figure 1.1.1 are from 2014, which have not yet been reviewed by Econoler. Further, the need to allocate a large share of the budget to the Efficient Product Rebates is called into question by DSM Plan's own comment that the market for basic and low-cost retrofits of lighting measures has become saturated. (Appendix B, page 12 of 20 at 24-25.) Nonetheless, the DSM Plan lists as the objectives of the Efficient Product Rebates program to raise customer awareness, increase market penetration, and transform the market by raising efficiency standards. (Appendix A, page 11 of 22 at 20-25.) If the market has indeed become saturated, then the program would seem to have already met its objectives and perhaps should not receive as large a share of the budget.

The Custom Incentives program works with individual customers directly to help them achieve energy efficiency savings in new and existing facilities. Of particular concern to the SBA is the DSM Plan acknowledgement that these customers "may choose to aggregate multiple sites into a single retrofit or new construction project for which cost-effectiveness is improved and incentives from other programs do not apply." (Appendix A, page 12 of 20 at 19-20.) While the SBA appreciates that this flexibility would allow a customer to achieve an aggregate savings threshold to qualify for certain incentives, it

[7] ENSC Evidence Appendix A page 3 of 22.

should not also become an incentive for ENSC to promote low cost-effectiveness measures that the customer otherwise would not consider investing in or be a reason for the ENSC to avoid developing or revising measures to have improved cost-effectiveness by lowering the cost for the customer. ENSC makes a statement[8] in the application that makes me concerned that in fact they are expanding the implementation of measures that are not cost effective by bundling them with the other cost effective measures. "Participants may choose to aggregate multiple sites into a single retrofit or new construction project for which cost-effectiveness is improved and incentives from other programs do not apply".

Q. Do you have any specific suggestions on changes that ENSC has been slow to implement?

A. Yes. In the application[9] ENSC identified that Innovative Financing would help break down participation barriers for the ENSC programs that exist for small business. The SBA would like to see this be given a higher priority by ENSC

Q. Do you have any concerns based upon the information you reviewed in Appendix B of the application?

A. Yes. Appendix B is the description of ENSC's Development Approach and Details of the 2015 DSM Resource Plan.

Q. Would you please explain your concerns?

[8] ENSC Application Appendix A page 12 lines 18 to 22.
[9] Ibid., page 20 lines 11 to 20.

A. Appendix B states that BNI program targets and budgets are the same as those expected to be achieved in 2014, however, as mentioned above, 2014 results have yet to be evaluated and as indicated below, ENSC has only just published its report for 2014 Q1. The description of BNI programs in this appendix is short but includes several observations that form the basis for the SBA's reluctance to recommend approval of the full funding level the DSM Plan as proposed by ENSC these observations are presented on page 5 of 20 of Appendix B.

- Efficient Product Rebates budgets and targets are expected to be identical to 2014 achieved levels, however, ENSC had to make a mid-course adjustment to the Custom Retrofit component of the Custom Incentives budget and targets to transition lighting projects to this category.
- The New Construction component of the Custom Incentive program is described as having "no energy savings target, as implementation incentives will be provided … through the Efficient Products Rebate programs."

Further, to the SBA's observation above about the need to improve the cost-effectiveness of measures in this program category, the ENSC states that "(I)n comparison to the costs of construction, incentives were relatively low and builders often made compromises on energy efficiency in order to address cost overruns in other areas. As a result, ENSC increased the per-kWh incentives offered to these customers in 2013, resulting in increased unit costs for the program[10]."

[10] ENSC Evidence Appendix B page 14 of 20 lines 8 to 12.

The DSM Plan information does not raise the SBA's level of confidence in the ENSC's expectation that it will achieve the same results as for 2014 when it summarizes the Direct Installation component of the Custom Incentive Program as having:

1. Downward trend in participation levels, and

2. Apparent lower cost-effectiveness "due to the reduction in savings and the ongoing expansion of the suite of supported measures[11]."

In particular response to the ENSC observation above that it had to increase incentives to builders in the new construction category, which adds to the cost of the program, the SBA respectfully suggests that it should instead focus on improving the cost-effectiveness of measures while finding ways to lower the cost to participants. The fact that the Province will adopt updated Model National Energy Codes for Buildings in 2015 should aid the ENSC in this effort. ENSC notes that this code adoption will require budget reallocation within this program sector[12].

As a result, based on its own description of the BNI program sector, it is not clear from ENSC's DSM plan how either the Efficient Product Rebates, Custom Incentive or the Direct Installation budget and targets can be identical to 2014 without a more detailed understanding of what measures were transitioned, how the costs are developed and to which business customer classes they are targeted.

[11] Ibid., page 5 of 20 lines 25 to 26.
[12] Ibid., page 15 lines 7 to 12.

VI. EVALUATION AND VERIFICATION REPORTS FOR 2013 DSM PROGRAMS

Q. Which third party reports of their review of the ENSC 2013 programs have you reviewed?

A. There are two reports that I would like to draw comments from. The first is the "Evaluation of 2013 DSM Programs Efficiency Nova Scotia Corporation" by Econoler[13] dated April 20, 2014. This report as indicated from the title was commissioned by ENSC. The second report "Verification Review of Program Year 2013 Evaluation Results" by H. Gil Peach & Associates / Scan America dated June 5, 2014. This report was for the Nova Scotia Utilities and Review Board.

Q. Have you reviewed the entire Econoler, Evaluation Report?

A. Yes, along with other consultants at La Capra Associates

Q. Which particular areas of the Econoler Evaluation Report do you wish to discuss?

A. The Econoler report is an evaluation of ENSC's 2013 DSM programs and thus provides significant insight into the expected performance of the 2014 plan year just completed and, since ENSC based its 2015 budget and targets on 2014 results, the proposed DSM Plan as well. The Econoler report confirmed higher Actual Energy savings (GWh) than

[13] The report lists CRA Charles River Associates and Equilibrium Engineering as report contributors as well.

in ENSC's original and Mid-Course Adjustment plans[14]. It is important to note, however, that Econoler also made significant changes to sub-categories of the plan that have implications for the BNI program category.

First, a review of "Table 5: Free Ridership Levels"[15], confirms the market saturation of the Efficient Product Rebates measures discussed above. The Econoler report includes the Efficient Product Rebate category under Business Energy Rebates ("BER"). Econoler shows that the free ridership percentage level increased in 2013 compared to 2012.

As a result, Econoler increased the Energy (GWh) savings shown in "Table 9: 2013 Savings Targets and Evaluated Results"[16] under "Evaluated Results" compared to ENSC's values shown in the "Mid-Course Targets" column.

However, Econoler significantly reduced the Evaluated savings for the Direct Install sub-category of the BNI Program, by as much as one-third. The magnitude of this reduction by itself has significant implications for questioning the confidence the ENSC has in its plan for the customer classes that the SBA represents. In addition, the reasons given for the reduction, which appear in Section 3, Overall Recommendations, create concern not only for how the DSM Plan budget and targets are developed but also for how the plan is implemented. The most critical of these concerns are raised in the following recommendations:

[14] ENSC Evidence, Figure 2.1.1 – 2012 DSM Plan Actual Expenditures and Evaluated Energy Savings, page 5 of 27.
[15] Ibid., Page 15.
[16] Ibid., Page 20.

Custom-R1: The ENSC used inappropriate diversity factors, which does not reflect actual demand savings achieved during the peak period. Econoler recommends that ENSC modify its standard calculation tools to correct this problem[17].

Custom-R11: The peak coincidence factor was not included for each project, a recommendation made in the 2012 report but not implemented, raising concern that other recommendations may not be implemented in a timely fashion under a shortened planning phase for the 2015 DSM Plan[18].

BES-R1: Develop a validation process for savings calculations to ensure consistency of the energy savings recorded for each measure[19].

BES-R7: Ensure all lamps are installed by the Das and not left on site to be installed afterwards. On-site visits conducted after the installation of products revealed that only 86 percent of the CFLs were installed. This practice raises the question that costs are higher than they should be because the participant receives the rebate incentive without completing installation and customers pay for the cost of these incomplete stalls in the budget, and finally the savings recorded are not achieved because the installation is incomplete.

This selection of recommendations relating specifically to the BNI program supports and underscores the SBA's concern with the proposed DSM Plan at this time

Q. Have you reviewed the entire Peach, Verification Report?

[17] Econoler Evaluation Report 2013 Program Review page 63, emphasis added.

[18] Ibid., page 65

[19] Ibid., page 70

A. Yes,

Q. What observation do you draw from the Peach, Verification Report?

A. The Peach Verification Report agrees with the ECONOLER Evaluation Report and recommend actions by ENSC to implement ECONOLER recommendations.

Q. Does it appear that ENSC has implemented the recommendations for the ECONOLER Evaluation Reports?

A. I do not see any information within the ENSC Q1 2014 DSM report that would make me believe the recommendations had been implemented.

VII. ENSC MANAGEMENT AND FINANCIAL CONTROLS

Q. Has any evidence in the Application raised your concern regarding ENSC management of the DSM programs to date?

A. Yes

Q. Would you recommend the 2015 DSM Plan as proposed be rejected as a result of these concerns?

A. Yes. These concerns do contribute to my viewpoint that the program expenditure budget be set at the lowest possible level while assuring continuity of the programs in order to maintain vendor participation in program implementation. I believe this should be $31 million or less.

Q. Is ENSC implementing management control changes?

A. Yes. The SBA notes that the DSM Plan includes a description of the ENSC's efforts during 2013 to develop and implement an enterprise risk-management (ERM) framework within the organization. ENSC management has received training on ERM principles and standards for risk management, with the "comprehensive framework" of the ERM is to be developed this year. (Evidence, Section 5.2.2, page 25 of 27 at 12-22.) Since the installed version of the ERM has yet to be completed and tested, and the SBA has not seen examples of its reporting capabilities or discussed with ENSC how it will be utilized in daily decision-making, the SBA reserves its right to comment on this topic as more information becomes available, as well as during the hearing process.

Q. Does this alleviate your concerns?

A. No. The effectiveness of these changes has not been demonstrated.

VIII. RECOMMENDATIONS

Q. What have you concluded from your review?

A. I have several conclusions:

1. The ENSC Continuation Plan development strategy is reasonable given that it is the third year of their 2013-2015 plan coupled with the transitions that will occur under the *Electricity Efficiency and Conservation Services (2014) Act*

2. The Cost Allocation proposed is consistent with the settlement that SBA participated in during 2013.
3. The Contractor Procurement process needs further review.
4. Ratepayers, especially small businesses would be better served with a scaling back of the proposed budget to $31 million.
5. The UARB must clarify responsibilities going forward and set up a process for the next DSM Plan specific timetables for the 2016-2018 DSM program contract review and approval.

Q. What do you recommend?

A. I recommend:

1. The UARB approve the 2015 DSM Plan with the following conditions;
    a. ENSC be instructed to scale back its proposal for programs in 2015 to total $31 million, with a compliance filing of the new program plan to be filed 30 days after the order.
    b. ENSC must file a detail Contractor Procurement Process after consultation with stakeholders within 90 days of the order.
2. The UARB order should include a clarification of responsibilities between ENS and NSPI going forward and a specific timetable for the 2016-2018 DSM program contract review and approval.

Q. Does this conclude your testimony?

A. Yes, it does.

La Capra Associates

John G. Athas

Principal Consultant and Treasurer

John Athas joined La Capra Associates in 2006, bringing nearly 30 years of diverse electric industry experience. He has substantial, hands-on skills having worked for an electric utility, a competitive retail electric services provider, a power technology manufacturer, and an energy industry consulting firm. Through extensive practical application, he has assumed leadership roles in market pricing and policy, resource planning, analysis of competitive wholesale and retail markets, financial and risk analysis, strategic planning, and contracts and transactions. With expertise in utility regulation, energy marketing and product development, energy policy, asset valuation, mergers and acquisitions, and corporate strategy, Mr. Athas has provided clients valuable insight from his unique blend of experience in strategy consulting, technical evaluations and energy market participation.

Mr. Athas holds an M.B.A. from the University of Connecticut, an M.S. in Mechanical Engineering from Rensselaer Polytechnic Institute, and a B.E. from Cooper Union.

PROFESSIONAL EXPERIENCE

Economic Development

- Developed special incentive packages of utility rate discounts and comprehensive energy efficiency investments for large customers in Business Retention and Economic Development circumstances. These packages were coordinated with and integrated into broad incentive packages developed by state and local economic development agencies.
- Provided expert testimony before the Nova Scotia Public Service Board regarding the appropriateness of special load retention tariffs for Nova Scotia Power Incorporated
- Managed NU's economic development and special contracting flexible rate tariffs in Connecticut and Massachusetts.
- Negotiated special contracts with NU's large customers in Massachusetts, Connecticut and New Hampshire.

Rates and Regulation

- Provided expert review and critique for Public Service Organization of Oklahoma's request for proposal for baseload generation in support of the Office of the Attorney General.
- Provided review and comment on the Philadelphia Electric Smart Metering Implementation Plan for the Pennsylvania Office of Consumer Advocate
- Drafted changes to proposed demand-side rules in Oklahoma for the Oklahoma Industrial Energy Consumers.
- Managed rates and cost-of-service functions for Northeast Utilities (NU).

Integrated Resource Planning

- Collaborating to review and critique the Connecticut utilities' 2010 IRP on behalf of the Connecticut Energy Advisory Board (CEAB), including extending analysis and modeling to 2030.

- Managing consultant leading IRP planning and related regulatory filings for various New England electric utilities and cooperatives, including Green Mountain Power, Washington Electric Cooperative (VT), Vermont Electric Cooperative, and Vermont Marble Power.
- Provided a critique of Public Service of Oklahoma's IRP and Oklahoma Gas & Electric Company's IRP, in response to their joint application to build a base load coal fired generating capacity, on behalf of the Oklahoma Attorney General's Office.
- Managed NU's resource planning function from the inception of Integrated Demand/Supply Planning (now IRP) through 1991.

Market Analysis

- Project manager and principal lead on analysis for Vermont Combined Heat and Power and Distributed Generation Potential Study in 2010 on behalf of Vermont's System Planning Committee.
- Provide principal leadership to the team responsible for the La Capra Associates' Electric Market Model, which is used to support the analysis for numerous client projects.
- Conducted scenario planning studies for all North America regional power markets (U.S. and Canada). Provided capacity requirements, resource adequacy assessment, and energy price outlooks.
- Conducted scenario planning studies for all North America regional power markets (U.S. and Canada). Provided capacity requirements, resource adequacy assessment, and energy price outlooks.
- Charged with the role of principal for power research and consulting for the Eastern Energy Service, providing insight into the interactions of electric and gas markets within the Eastern Interconnect.
- Led marketing, structuring and product development for Select Energy's retail energy commodity and energy services business.
- Directed market research regarding customer choice and customer satisfaction.
- Supervised market modeling activities for North America (U.S. and Canada) for Cambridge Energy Research Associates (CERA).
- Analyzed power prices and their impacts on clients in the evolving market structures for ISO New England (ISO-NE), New York Independent System Operator (NYISO) and the PJM Interconnection (PJM).
- Supported the development and marketing, while negotiating a power and energy services package to, major retail aggregations and affinity for Select Energy. This includes the largest Municipal Aggregation the Cape Light Compact for communities on Cape Cod and Martha's Vineyard.

Stakeholder Facilitation and Process

- Facilitated information exchange and consensus building between the utilities and stakeholders —for Connecticut's *first IRP since the 1980s*—including multiple generation owners, operators and developers; energy efficiency planners, regulatory oversight groups and public advocate organizations; environmental agency and environmental advocacy organizations, transmission owners and the regional transmission ISO; and consumers.
- In 2010, facilitated a greatly-expanded process during the subsequent Connecticut IRP to include nuclear power operators, developers, advocates and opposition groups, natural gas utilities and pipeline operators; energy security experts; and CHP developers, policymakers and commercial/industrial business.

Utility Planning

- Project Principal and Witness in the review of acquisition of generation resources in Arkansas (EAI –KGEN Hot Springs, AECC – Suez Hot Spring Plant).
- Managed strategic planning analyses for NU including the areas of competition, integrated resource planning (IRP), and utility strategic and organizational goal development.
- Led the team responsible for analysis and presentation materials for executive planning conferences, including utility diversification into energy services and merchant generation.
- Supervised generation planning for a large utility provided economic and financial analysis of power plant construction and capital additions and determined avoided costs.
- Developed a New England market entry business plan for Direct Energy's retail business.
- Advised the management team at Cape Light Compact on the merits of forming an Electric Cooperative.

Expert Witness

- Presented expert testimony on behalf of the Arkansas Public Service Commission (ASPC) General Staff in *Docket NO.13-033-U In the Matter of the Petition of the Southwestern Electric Power Company for a Declaratory Order Finding That Certain Renewable Wind Energy Purchase Agreements are Prudent, and Wind Energy Purchase Agreements are Energy Only Contracts Eligible for Cost Recovery Through the Energy Cost Recovery Rider*
- Provided expert testimony on behalf of the Small Business Advocate of Nova Scotia in *NSPI-128-13 In the Matter of an Application by Nova Scotia Power Incorporated for Approval of Capital Expenditure for 2013 for South Canoe Wind Project - CI#42127 for $93,091,536*
- Provided expert testimony on behalf of the Small Business Advocate of Nova Scotia *NSPI-128-13 In the Matter of an Application by Nova Scotia Power Incorporated for Approval of its 2013 Annual Capital Expenditure Plan*
- Presented expert testimony on behalf of the Arkansas Public Service Commission (ASPC) General Staff in *Docket NO.12-067-U In the Matter of the Application of Oklahoma Gas and Electric Company for an Oder Approving a Temporary Surcharge to Recover the Costs of a Reneweable Wind Generation Facility*
- Presented expert testimony on behalf of the Arkansas Public Service Commission (ASPC) General Staff in *Docket NO.12-038-U In the Matter of Entergy Arkansas, Inc.'s Request for approval of certain wholesale base load capacity to serve EAI customers and a proposed rider recvoery mechanism for these and other capacity costs.*
- Presented expert testimony on behalf of the Citizen's Action Coalition of Indiana before the State of Indiana Utility Regulatory Commission. *In the Matter of the application of Indiana Michigan Power Company requesting from the Commission, 1) A Finding that the Life Cycle Management program for the Donald C. Cooke Nuclear Plant is Reasonable and Necessary, 2) Approving of Cost and Schedule, 3) Authorizing Recovery through a periodic Rate Adjustment Mechanism, 4) Granting I&M Authority to Defer Costs and 5) GrantI&M future Rate Relief as may be Necessary and Appropriate.*
- Presented expert Public Service Commission regarding IRP and Existing Nuclear Capital Projects. *In the Matter of the application of Indiana Michigan Power Company for a certificate of necessity pursuant to MCL 460.6s and related accounting authorizations*
- Presented expert testimony on behalf of the Arkansas Public Service Commission (ASPC) General Staff in *Docket NO.12-012-U In the Matter of Arkansas Electric Cooperative Corporationfor Approval of the Acquisition of the Hot Spring*

- Provided expert testimony on behalf of the Small Business Advocate of Nova Scotia in *Matter M04862 Application by Pacific West Commercial Corporation and NSPI for a Load Retention Rate*
- Provided expert testimony on behalf of the Small Business Advocate of Nova Scotia in *Matter M04175 Proposed Amendments to Nova Scotia Power Inc.'s Load Retention Tariff*
- Provided expert testimony on behalf of the Small Business Advocate of Nova Scotia in *Matter M04892 Main Computer Centre Upgrade*
- Presented expert testimony on behalf of the Arkansas Public Service Commission (ASPC) General Staff in *Docket NO.11-069-U In the Matter of Entergy Arkansas, Inc.'s Request for Approval of the Acquisition of the Hot Spring Plant to Serve its Retail Customers*
- Presented expert testimony on behalf of the Oklahoma Attorney General before the Oklahoma Corporation Commission regarding IRP and baseload coal RFPs. *(Causes Nos. PUD 200500516, 200600030, 200700012, 2006 through 2007.)*
- Presented expert testimony before the Connecticut Department of Public Utility Control (DPUC) for Select Energy in Connecticut regarding its retail licensing application in 2000.
- Testified on customer impacts, pricing levels and utility planning during various electric industry restructuring proceedings in Connecticut and Massachusetts.
- Presented expert testimony on numerous occasions before the Connecticut DPUC regarding special contract approvals.

EMPLOYMENT HISTORY

La Capra Associates, Inc. — Boston, MA
Principal Consultant — *2009 - Present*
Managing Consultant — *2006 - 2009*

Direct Energy North America — Stamford, CT
Independent Consultant — *2005*

Assignment – New England Market Entry Business Plan, Channel Management Plan Development

Northeastern US Markets

Developed a business plan outlining the potential market entry for the client into the New England power market.

Cambridge Energy Research Associates — Cambridge, MA
Associate Director, North American Electric Power — *2001 – February 2005*
Eastern North American Energy Service Principal

Developed independent primary research on various aspects of power markets around the Eastern U.S. and Canada, primarily responsible for the Northeast and Midwest markets, including price outlooks for energy and "full requirements" electric power. Analyzed market structure, supply/demand balances, price caps, market clearing prices, capacity markets, and generation technologies.

Northeast Utilities — Berlin, CT
Director, Retail Business Strategy - Select Energy — *1997 – 2000*
Managing Director, Marketing - Select Energy

Directed market strategy, market research, product development, product management, strategic alliance development, retail electric energy supply management and pricing strategy for Northeast

Utilities' unregulated retail energy service company, Select Energy, formed in 1997. Managed the activities of 31 professionals, including six managers. Negotiated a major retail supply agreement with the Massachusetts Municipal Association, which resulted in participation by 120 cities and towns.

Director, Market Pricing & Policy *1995 – 1997*
Directed the work in all areas of pricing for Northeast Utilities and its operating companies: CL&P, WMECo, PSNH and HWPCo, with revenues totaling over $3 billion. Three managerial units comprised the pricing organization, Cost of Service, Rates and Special Contracts. Led the development of proposals in unbundled rates prior to the restructuring of electric utility markets in Connecticut and Massachusetts. Responsible for developing utility discount rate and energy efficiency offerings for large customers in Business Retention and Economic Development circumstances, which were coordinated and packaged into state and local economic development agencies incentive packages.

Manager, Market Analysis *1990 – 1995*
Led market planning and market research functions in developing strategies to prepare NU for the competitive business environment, including sales force program training and development.

Manager, Strategic Analysis & Long Term Resource Planning *1987 – 1990*

Held various positions within the Capacity Planning Department *1981 – 1987*

United Technologies Corporation Hartford, CT
Analytical Engineer – International Fuel Cells/Pratt & Whitney Aircraft *1977 – 1981*

EDUCATION

University of Connecticut Storrs, CT
Masters of Business Administration 1987

Rensselaer Polytechnic Institute – HGC Troy, NY
M.S., Mechanical Engineering 1982

Cooper Union New York, NY
B.E., Mechanical Engineering *1977*
Elected to Pi Tau Sigma **–** *Mechanical Engineering Honorary Fraternity*

PROFESSIONAL ACHIEVEMENTS

- Recipient, **1998 Northeast Utilities Chairman's Award** for innovation in developing offerings and negotiating with large aggregation groups
- Recipient, **1996 Northeast Utilities Chairman's Award** and **1996 Retail Business Group's President's Award** for the role in leading efforts in the Retail Competition Pilot in New Hampshire
- Recipient, **Northeast Utilities 1994 Retail Business Group's President's Award** for developing and successfully implementing special utility contracting efforts
- Licensed **Professional Engineer -** State of Connecticut
- Past appointee to the **Electric Power Research Institute (EPRI**) Industrial Business Unit Council
- Participation in the Energy Committee of the Manufacturer's Alliance of Connecticut, Inc.
- Participation in various **NEPOOL** Committees

- Member of the **Association of Energy Engineers**
- Author of the paper **'Fulfilling on the Promises of Deregulation'**
- Speaking experience includes:
    - 2012, Speaker at EUCI *Resource Planning: A Practitioner's Toolkit for Current Issues*
    - U.S. Chamber Of Commerce Satellite Seminar Series on Deregulation
    - Massachusetts HEFA sponsored conference on *Organizing Energy Buying Groups*
    - INFOCAST Seminars on *Negotiating Power Contracts*
    - Interview on a nationally syndicated news show, *First Business*, on energy deregulation

Summary of Testimony Appearances for John G. Athas

Docket No.	Date	Name
Various	*1983-1991*	*Miscellaneous Dockets before the Connecticut DPUC, Connectciut Siting Council,Massachusetts DPU, and Massachusetts Energy Facility Siting Council on Generation and Integrated Resource Planning topics*
--------	*1993*	*Connecticut DPUC Docket on Retail Wheeling and Transmission Access*
--------	*1994*	*Massachusetts DPU Docket on Electric Industry Restructuring*
91-04-05	*August, 1991*	*Application of Connecticut Natural Gas Corp. for Approval of New and Modified Tariffs*
94-05-13	*July 13, 1994*	*Application of the Connecticut Light and Power Company and Kimberly-Clark Corporation for Approval of a Special Rate Contract56 for Provision of Firm Service to Kimberly-Clark Corporation*
93-12-34	*April 27, 1994*	*Application of the Connecticut Light and Power Company and Hamilton Standard for Approval of Special Electric Rate Contract*
99-08-03	*August, 1999*	*Application of Select Energy, Inc. for an Elecrric Supplier License*
*08-07-01**	*September, 2008*	*DPUC Review of Connecticut 2008 Comprehensive Electric Procurment Plan (integrated Resource Plan)*
*09-05-02**	*July, 2009*	*DPUC Review of Connecticut 2009 Comprehensive Electric Procurment Plan (Integrated Resource Plan)*
*10-02-07**	*June, 2010*	*DPUC Review of Connecticut 2010 Comprehensive Electric Procurment Plan (Integrated Resource Plan)*
NSPI-P-202/ M40175	*August, 2011*	*An Application by NewPage Port Hawkesbury Corp. and Bowater Mersey Paper Company Ltd for Amendments to Nova Scotia Power's Load Retention Tariff and for a Load Retention Rate*
*11-069-U***	*October, 2011*	*In the Matter of Entergy Arkansas, Inc.'s Request for Approval of the Acquisition of the Hot Spring Plant to Serve its Retail Customers*
CAUSE NO. PUD 201100186**	February, 2012	Application of Oklahoma Gas & Electric Company for an Order of the Commission approving a Special Contract with Oklahoma State University and a Wind Energy Purchase Agreement
M04892**	May, 2012	Main Computer Centre Upgrade (Capital Improvements Data Centre)
NSPI-P-203/ M04862	June, 2012	An Application by Pacific West Commercial Corporation and Nova Scotia Power Inc. for a Load Retention Rate
12-012-U**	June, 2012	In the Matter of Arkansas Electric Cooperative Corporationfor Approval of the Acquisition of the Hot Spring Generating Facility Near Malvern, Arkansas
U-17026**	August, 2012	In the Matter of the application of Indiana Michigan Power Company for a certificate of necessity pursuant to MCL 460.6s and related accounting authorizations.
IURC Cause No. 44182	August, 2012	In the Matter of the application of Indiana Michigan Power Company requesting from the Commission, 1) A Finding that the Life Cycle Management program for the Donald C. Cooke Nuclear Plant is Reasonable and Necessary, 2) Approving of Cost and Schedule, 3) Authorizing Recovery through a periodic Rate Adjustment Mechanism, 4) Granting I&M Authority to Defer Costs and 5) GrantI&M future Rate Relief as may be Necessary and Appropriate.
12-038-U	September, 2012	In the Matter of Entergy Arkansas, Inc.'s Request for approval of certain wholesale base load capacity to serve EAI customers and a proposed rider recvoery mechanism for these and other capacity costs.
12-067-U	October, 2012	In the Matter of the Application of Oklahoma Gas and Electric Company for an Oder Approving a Temporary Surcharge to Recover the Costs of a Reneweable Wind Generation Facility
NSPI-P-128.13	January, 2013	In the Matter of an Application by Nova Scotia Power Incorporated for Approval of its 2013 Annual Capital Expenditure Plan
NSPI-P-128.13	January, 2013	In the Matter of an Application by Nova Scotia Power Incorporated for Approval of Capital Expenditure for 2013 for South Canoe Wind Project - CI#42127 for $93,091,536
13-033-U	August , 2013	IN THE MATTER OF THE PETITION OF SOUTHWESTERN ELECTRIC POWER COMPANY FOR A DECLARATORY ORDER FINDING THAT CERTAIN RENEWABLE WIND ENERGY PURCHASE AGREEMENTS ARE PRUDENT, AND WIND ENERGY PURCHASE AGREEMENTS ARE ENERGY ONLY CONTRACTS ELIGIBLE FOR COST RECOVERY THROUGH THE ENERGY COST RECOVERY RIDER
NSPI-P-128.13	February, 2014	In the Matter of an Application by Nova Scotia Power Incorporated for Approval of its 2014 Annual Capital Expenditure Plan
Case No. PUE-2013-00088	February, 2014	Virginia Electric and Power Company’s Integrated Resource Plan filing pursuant to § 56-597 et seq. of the Code of Virginia
PUB NFAT Proceeding***	April, 2014	NEEDS FOR AND ALTERNATIVES TO (NFAT) REVIEW OF MANITOBA HYDRO’S PROPOSAL FOR THE KEEYASK AND CONAWAPA GENERATING STATIONS

** In these Dockets the Filing of the IRP Plans served as the basis for cross examination topics for Mr. Athas*
*** In these Proceedings Mr. Athas filed testimony yet was not asked to appear for cross examination*
**** In this Proceedings the filing of reports by La Capra Associates were the basis for cross examination of Mr. Athas.*

Jointly Considered

CAUSE NO. PUD 200500516	*June 27, 2007*	*APPLICATION OF PUBLIC SERVICE COMPANY OF OKLAHOMA FOR A DETERMINATION THAT ADDITIONAL ELECTRIC GENERATING CAPACITY WILL BE USED AND USEFUL*
CAUSE NO. PUD 200600030	*June 27, 2007*	*APPLICATION OF PUBLIC SERVICE COMPANY OF OKLAHOMA FOR A DETERMINATION THAT ADDITIONAL BASELOAD GENERATING CAPACITY WILL BE USED AND USEFUL*
CAUSE NO. PUD 200700012	*June 27, 2007*	*IN THE MATTER OF THE APPLICATION OF OKLAHOMA GAS AND ELECTRIC FOR AN ORDER OF THE COMMISSION GRANTING PRE-APPROVAL TO CONSTRUCT RED ROCK GENERATING FACILITY AND AUTHORIZING A RECOVERY RIDER*

BEFORE THE NOVA SCOTIA UTILITY AND REVIEW BOARD

IN THE MATTER OF *The Public Utilities Act,* R.S.N.S. 1989, c.380, as amended

- and -

IN THE MATTER OF an Application by EfficiencyOne (E1) for Approval of Supply Agreement for Electric Efficiency and Conservation Activities between E1 and Nova Scotia Power Inc. (NS Power), the establishment of a final agreement between the parties, and approval of a 2020-2022 Demand Side Management Resource Plan (M09096)

DIRECT TESTIMONY OF JOHN G. ATHAS

ON BEHALF OF

THE SMALL BUSINESS ADVOCATE

May 28, 2019

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TABLE OF TABLES

I. INTRODUCTION

Q. What is your name and business address?

A. My name is John G. Athas, and I work as a Principal Consultant for Daymark Energy Advisors, 370 Main St, Worcester, MA 01608. Daymark Energy Advisors, Inc. is a consultancy that has provided policy, planning, and strategic decision support services to the energy industry for over 35 years.

Q. On whose behalf are you testifying in this proceeding?

A. I am testifying on behalf of the Nova Scotia Small Business Advocate ("SBA").

Q. Please describe your education and employment background.

A. I am an electric utility industry planning specialist with nearly 35 years of experience in areas including strategic planning, integrated resource planning, energy efficiency, generation planning, economic and financial analysis, marketing, wholesale power market analysis and forecasting, electric power retail marketing, and rates and pricing.

I am currently a Principal Consultant at Daymark Energy Advisors and have served in that capacity since February 2006. I also serve the firm in a management function as Vice President. Since joining Daymark Energy Advisors, my work has included several aspects of power systems planning and electric industry restructuring, including wholesale and retail market formation, generation asset valuation, resource planning, independent monitor involving wind generating capacity and resource adequacy studies, rates, contracting and retail power marketing.

Immediately prior to joining Daymark Energy Advisors, I worked as an independent consultant with Direct Energy developing retail electric business plans. From 2001 to 2005, I was an Associate Director of North American Electric Power at Cambridge Energy Research Associates ("CERA"). In that capacity I was responsible for market analysis and forecasting of power prices for the regions of the Eastern Interconnect for the US and Canada. Prior to joining CERA, I had various planning positions at Northeast Utilities Service Company ("NU") on behalf of corporate NU and its regulated and competitive companies from 1981 through 2000. From 1987 to 1991, I was the Manager of Strategic Analysis and Long-Term Resource Planning at NU, where my responsibilities included conducting NU's Integrated Resource Planning, the analysis of the NU utility companies' competitive position, and various strategic planning efforts regarding diversification leading to the acquisition of HEC, Inc., an energy service company, and the formation of Charter Oak Energy, a competitive generation affiliate of NU. As part of my planning experience at NU I performed economic analysis of energy efficiency programs, demand management programs and rates as well as on projects such as new generation as well as generation betterment projects, including hydroelectric facilities. . Also, during my time at NU I spent several years working as part of the budget committee working to review and recommend transmission, distribution and customer service related projects. Attachment-1 contains a complete description of my qualifications and expert witness experience.

Q. Have you previously testified before the Nova Scotia Utility and Review Board ("Board or NSUARB")?

A. Yes. I testified before the NSUARB in the proceeding to review An Application by

NewPage Port Hawkesbury Corp. and Bowater Mersey Paper Company Ltd for Amendments to Nova Scotia Power's Load Retention Tariff and for a Load Retention Rate (M40175), Main Computer Centre Upgrade (Capital Improvements Data Centre) (M04892), An Application by Pacific West Commercial Corporation and Nova Scotia Power Inc. for a Load Retention Rate (M04682), In the Matter of an Application by Nova Scotia Power Incorporated for Approval of its 2013 Annual Capital Expenditure Plan (M05339), In the Matter of an Application by Nova Scotia Power Incorporated for Approval of Capital Expenditure for 2013 for South Canoe Wind Project - CI#42127 for $93,091,536, In the Matter of an Application by Nova Scotia Power Incorporated for Approval of its 2018 Annual Capital Expenditure Plan (M08350), In the Matter of an Application by Nova Scotia Power Incorporated for Approval of its 2019 Annual Capital Expenditure Plan (M08984), In the Matter of NS Power Advanced Metering Infrastructure Application (M08349), and In the Matter of an Application by E1 for Approval of a Supply Agreement for Electricity Efficiency and Conservation Activities between the Parties and Approval of the 2016-2018 Demand Side Management ("DSM") Plan-E-ENSC-R-15.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide the results of my review of the proposed DSM Plan for 2020-2022 where EfficencyOne (E1) have proposed a Preferred Plan and an Alternate Plan. As part of that review I also reviewed the evidence and alternative plans and recommendations filed by Nova Scotia Power Incorporated (NS Power). I have been asked to examine the evidence of these parties from the perspective of the small business owner and operators that are serviced under Rate Classes 10, 11 and 21.

A. SMALL BUSINESS PERSPECTIVE

Q. What are the key observations you wish to make based on your review of the Application?

A. The small business community represented by the SBA includes a diverse set of businesses that impact the economy of Nova Scotia; exist often under independent ownership arrangements; and have varied viewpoints on the time value of money, the importance of energy efficiency and environmental priorities.

The small business perspective does have a common base of concerns. These include questions about whether the funding of energy efficiency programs is beneficial to Nova Scotia; the programs are designed strategically and administrated effectively; and the programs for small businesses represent cost effective opportunities, addressing areas of energy consumption important to the members of the small business community. These concerns are the focus of my review.

B. SCOPE OF SBA REVIEW

Q. What information have you relied on to form the basis of your testimony?

A. I have reviewed the E1 evidence and all other E1 reports filed in this Matter. I have also reviewed Board orders from previous DSM Plan applications. I have reviewed the evidence sponsored by NS Power. I have submitted interrogatories on behalf of the SBA. I have reviewed the responses provided by both E1 and NS Power to IRs submitted by all parties, including many work papers and electronically filed spreadsheets. Included in the above are all the information submitted confidentially by NS Power.

C. OVERVIEW OF EVIDENCE

Q. Please provide an overview of how your evidence is organized

A. My evidence is organized in the following manner. The first section, Introduction, provides my background, the description of the evidence and the summary of findings and recommendations. Section II discusses the recommended plans put forth by E1 and NS Power my concerns about the plans. Section III is a more in-depth review of the E1 programs that are applicable for small businesses. Section IV provides my analysis of appropriate savings targets and budget. Section V addresses the additional issues of the Life Time Energy Savings metric, the HST Funds, and NS Power's request to utilize FAM to recover or credit any changes in the E1 approved budget. The final two sections cover my findings and recommendations.

Q. Does your testimony address all the Final Issues List released by the Board?

A. No, it does not. I have focused on the issues of the greatest priority for small businesses and where it was decided that I had the most experience to add to the discussion. Set out below is the list of issues identified by the Board and a brief description of how my evidence addresses them or not.

1. ***Evaluation Report of 2018 DSM programs (Econoler)*** – My evidence does not specifically review or comments on this report but does rely upon information within the report for information as part of Sections II and III
2. ***Verification Report of 2018 DSM programs (Peach)*** – My evidence does not specifically review or comment on this report but does rely upon information within the report for information as part of Sections II and III

3. Status of 2016-2018 verification and evaluation recommendations – This issue is not addressed in my evidence

4. Proposed 2020-2022 DSM Resource Plan – These issues are addressed within Sections II and II unless otherwise noted below.

a) Program development

b) Affordability, including:

- ***Impact of EfficiencyOne Application on affordability for low income residential customers, including but not limited to tenants***

- This issue is not addressed in my evidence.

c) Avoided cost analysis

d) Rate and bill impact analysis

e) Program cost allocation

f) Evaluation and reporting - This issue is not addressed in my evidence

g) Impacts in the use of electricity incentives in the Custom New Construction program where natural gas is a viable alternative fuel source - This issue is not addressed in my evidence

5. Comparison of the Proposed Plan and the Alternate Scenario – This issue is addressed in Section III.C and IV.

6. Relationship of the proposed 2020-2022 DSM Plan to the 2014 Integrated Resource Plan - This issue is addressed in Section II of my evidence.

7. Performance targets, indicators, and thresholds - This issue is addressed in Section V.A of my evidence.

8. Disposition of the HST refund and interest - This issue is addressed in Section V.B of my evidence.

9. Disposition of the surplus funds cumulative underspending related to the 2016-2018 approved DSM investment levels together with associated interest - This issue is addressed in Section V.B of my evidence.

10. NS Power's proposal to consider DSM as a FAM expenditure - This issue is addressed in Section V.C of the evidence.

11. Agreed form of Supply Agreement - This issue is not addressed in my evidence

12. Outstanding items from the Board Order in Matter M08604 – These items are largely addressed and integrated into the body of the evidence in several locations

D. SUMMARY OF RECOMMENDATIONS

Q. Q. What recommendations do you have for consideration by the Board, E1 and NS Power?

A. I have seven recommendations listed below:

1. E1 should be instructed not to promote any measures that have not passed the TRC test analysis with a B/C ratio of less than 1.2
2. The target first year energy savings for E1 should be established at 100 GWh in 2020, 120 GWh in 2021 and 140 GWh in 2022.
3. The E1 budget should be approved at $30 Million (or between $27 and $34.5million) in 2020, and conditionally approved at $34.5 million in 2021 and $41 million in 2022. E1 should be required to file by July 1, 2020 plans for 2021 and 2022, including potential requests for a change in budget.

4. E1 should recalculate the TRC and PAC testing utilizing avoided costs associated with energy and capacity that are reflective of current NS Power system and reset its programs and priorities utilizing the results.

5. The Board should approve the utilization of FAM to credit any reduction in the E1 budget or charge customers to fund any increase.

6. HST funds should be returned to customers through a credit to the FAM

7. The Board should reject the Life Time Energy Savings metric as unnecessary.

Q. Do you have additional recommendations related to the NS Power 2020 IRP that will benefit future DSM Plan applications and review?

A. Currently the role of DSM in the province's energy future, in terms of short-term and long-term resource objectives and potential carbon reduction benefits, is unclear. The upcoming Integrated Resource Plan (IRP), beginning soon, offers an ideal process to engage in debate and establish the value of DSM. Therefore, I offer the following IRP-related recommendations as shown below:

1. The IRP analysis and plan consideration should include energy efficiency options that are from DSM Programs as well as Policy driven appliance and consumption standards.

2. The IRP should include a study on the economics and potential for behind the meter (BTM) generation options, both as customer and utility owned resources.

3. The IRP options should test the cost and feasibility of utilizing programmatic and legislative energy efficiency such as Codes and Standards that:

a. Achieve zero growth in energy consumption through 2040

b. Achieve a decline in consumption equal to 1 percent per year

4. In order to fully evaluate DSM programs, the IRP process should include consideration of CO_2 emissions, pollutants (HG, NOX and SO_2), 10, 20 and 30-year revenue requirement impacts, annual level of average price of electricity and typical customer bills for each of the first five years of IRP implementation.

5. NS Power should be required to produce avoided costs from the approved IRP and update them annually in order to support DSM economic testing, rate design including Renewable to Retail tariffs, the annual capital expenditure (ACE) filing and any renewable energy procurements.

II. E1 2020 -2022 DSM PLAN AND NS POWER ALTERNATIVE

Q. Please provide a short summary of E1's proposed Preferred Plan for 2020-2022 DSM Plan.

A. E1 has proposed a Preferred Plan with an average of $43 million investment for each year of the three-year plan, totaling approximately $129 million. The first-year energy savings are projected to be approximately 141 GWh per year over the three-year plan.1 Table 1 shows annual investment levels and savings target of the proposed Preferred Plan for each year.

E1 mentioned that the Proposed Preferred Plan includes a target of First-year energy savings equal to 1.3% of electricity generation[2]; a cumulative net lifetime CO_2 reduction of 3,180 MT; a lifetime unit cost of $0.022/kWh; a weighted average measure life of 14.2

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[1] M09096, E1 2020-2022 DSM Resource Plan Filing, Evidence, pg. 6

[2] M09096, E1 2020-2022 DSM Resource Plan Filing, Evidence, pg. 7.

years; net system benefits of $493.6 million; and an increase of over 55% in non-lighting energy savings over historical levels.[3] As Table 1 shows, the budget and saving levels proposed for each year of the next three-year DSM plan are very similar.

Table 1: 2020-2022 Preferred DSM Resource Plan Investment and Savings[4]

Year	Investment ($M)	Lifetime Benefits ($M)	First-Year Energy Savings (GWh)	Lifetime Energy Savings (GWh)	Weighted-Average Measure Life (years)	Peak Demand Savings (MW)	Total Resource Cost Test (TRC)	Program Administrator Cost Test (PAC)*
2020	41.9	195.6	140.2	1,967.9	14.0	38.7	1.9	4.7
2021	43.3	208.7	141.3	2,014.5	14.3	40.3	1.9	4.8
2022	43.9	218.4	140.2	2,013.9	14.4	41.1	2.0	5.0
Total	129.1	622.7	421.7	5,996.3	14.2	120.1	1.9	4.8

**PAC Cost is same as E1's proposed budget cost and includes both customer incentives and E1 admin cost.*

Q. Q. What is E1's basis in selecting the proposed budget and savings for the Preferred Plan?

A. According to E1, the three key considerations in developing the Preferred Plan were an emphasis on customer value, need, and affordability[5] which I briefly discuss below:

- E1 states that the appropriate level of customer value, defined as the value of energy savings versus the cost of the plan, was determined based on the 2014 Integrated Resource Plan; industry and historical trends; the DSM Supply Sector capacity; and the 2018 Load Forecast.[6] E1 claims that the Preferred Plan represents a modest increase to DSM energy savings as a percentage of electricity generation, changing from 1.2% to 1.3% of total annual electricity generation, over the three-year period.

[3] M09096, E1 2020-2022 DSM Resource Plan Filing, Evidence, pg. 7
[4] M09096 E1 2020-2022 DSM Resource Plan Filing, Appendix A, pg. 11
[5] M09096 E1 2020-2022 DSM Resource Plan Filing, Appendix A, pg. 11
[6] M09096 E1 2020-2022 DSM Resource Plan Filing, Appendix A, pg. 8

- Customer need, defined by E1 as ensuring a balanced portfolio for all rate classes, was determined by balancing multiple aspects of DSM for the benefit of customers, such as short-term and long-term energy avoidance, program delivery costs, avoided energy and capacity investments, diversity of program delivery, access to programs by all market sectors and rate classes and more, while also addressing barriers to participation and rate impacts.[7]
- Customer affordability, as mentioned by E1, was guided by the determination on the issue of affordability by the 2016 – 2018 DSM Plan decision and was defined as establishing an appropriate investment level by considering many factors, including but not limited to alignment with the IRP; alignment with past expenditures; balanced participation among rate classes; NS Power expenditures; and the balancing of both long and short-term affordability.[8]

Q. What DSM programs have E1 considered in its proposed Preferred Plan?

A. The proposed Preferred Plan includes three different DSM programs each for Residential and Business, Not-for-profit and Institutional (BNI) sector. The programs are similar to those currently being offered by E1 in 2019 DSM Plan.

Table 2 provides a summary of measures, estimated first-year energy and peak demand savings, and benefit-cost information proposed by E1 in its Preferred Plan for 2020.[9] For the Residential sector, E1 is proposing an investment, referred as total PAC cost, of $17.7

[7] M09096 E1 2020-2022 DSM Resource Plan Filing, Appendix A, pg. 18
[8] M09096 E1 2020-2022 DSM Resource Plan Filing, Appendix A, pg. 39
[9] Please note that Table 2 only includes budget associated with DSM program cost. E1 is also proposing in addition of $3.6 million of budget for its "Enabling Strategies" program that includes cost associated with education and outreach, research and development, and regulatory affairs.

million is expected to achieve a first-year energy savings of 56.9 GWh. Similarly, E1 is considering an investment of $20.2 million with an estimated savings of 83.3 GWh in 2020 for the BNI sector DSM programs. The table also present annual budget and savings target for each of the DSM program proposed for 2020 in its Preferred Plan.

Table 2: Summary of Program level savings proposed in Preferred Plan for 2020[10]

DSM Programs	Unique Measure Count	Energy Savings (GWh)	Peak Demand Savings (MW)	Total Avoided Cost Benefits, $ million	TRC cost, $ million	Investment (PAC Cost), $ million
Residential Sector						
Existing Residential	76	35.6	16.2	66.4	35.5	11.2
New Residential	4	5.5	1.6	12.8	8.7	2.8
Residential Efficient Product Rebates	37	15.8	1.7	8.7	6.8	3.7
Residential Sub-total	*117*	*56.9*	*19.5*	*87.8*	*51.0*	*17.7*
Business, Not-for-profit and Institutional Program						
BNI Efficient Product Rebates	116	40.6	8.0	50.9	23.0	7.3
Custom Incentives	3	33.2	8.8	44.4	22.2	9.0
Direct Installation	52	9.5	2.3	12.4	5.9	4.4
BNI sub-total	*171*	*83.3*	*19.2*	*107.7*	*51.1*	*20.6*
Total	**288**	**140.2**	**38.7**	**195.6**	**102.1**	**38.4**

Q. What kind of technologies did E1 proposed in its Preferred Plan?

A. The Preferred Plan considers different technology types for both Residential and BNI sector DSM programs. As shown in Table 3, E1 is considering five different technology types for its Residential DSM programs. And two technology types, Heating and Cooling and lighting, have the majority share of the total budget ($13.3 million out of $17.7

[10] M09096, E1 Application, Appendix A Tech Tables

million) of residential DSM programs and are estimated to achieve 45.2 GWh (out of 56.9) first-year energy savings in 2020.

E1 is considering eight different technology types for its BNI sector DSM program in its Preferred Plan for 2020. And two technology types, lighting and custom measures have a combined budget (investment) of $14.3 (out of $19.2 million) and are estimated to save 66.3 GWh of first-year energy. I discuss custom and light measures included in the BNI sector program in detail later in my Evidence.

Table 3: Summary of Residential and BNI sectors DSM program by technology type in E1's Preferred Plan for 2020[11]

Technology Type	Unique Measure Count	Energy Savings (GWh)	Peak Demand Savings (MW)	Total Avoided Cost Benefits, $ million	TRC cost, $ million	Investment (PAC Cost), $ million	TRC Ratio
Residential Sector							
Res Domestic Hot Water	18	3.0	0.5	2.6	0.6	0.5	4.1
Res Heating, Ventilation and Air-Conditioning	28	27.6	15.7	69.9	40.6	10.6	1.7
Res Lighting	36	17.6	2.4	9.0	4.6	3.2	1.9
Res Other	24	6.2	0.6	4.7	3.9	2.0	1.2
Res Refrigeration	11	2.5	0.3	1.6	1.2	1.5	1.3
Residential Sub-total	*117*	*56.9*	*19.5*	*87.8*	*51.0*	*17.7*	1.7
Business, Not-for-profit and Institutional Program							
BNI Cooking and Laundry	34	0.6	0.1	0.6	0.2	0.1	4.0
BNI Domestic Hot Water	3	0.4	0.1	0.5	0.2	0.2	2.3
BNI Energy Management	2	3.0	0.4	0.8	0.7	0.6	1.1
BNI HVAC	25	2.6	2.0	7.1	1.8	1.1	4.0
BNI Lighting	74	36.1	5.9	41.9	17.6	7.8	2.4
BNI Other (Custom)	1	30.2	8.4	43.6	21.5	8.4	2.0
BNI Process	22	6.1	1.7	9.0	2.6	1.6	3.4
BNI Refrigeration	10	4.3	0.6	4.3	6.5	0.8	0.7
BNI Sub-total	*171*	*83.3*	*19.2*	*107.7*	*51.1*	*20.6*	*2.1*
Total	**288**	**140.2**	**38.7**	**195.6**	**102.1**	**38.4**	**1.9**

[11] M09096, E1 Application, Appendix A Tech Tables

Q. Can you summarize E1 and NS Power's positions in key issues surrounding proposed DSM plans for 2020-2022 period?

A. Yes. Please see

Table 4 where I have summarized the positions of E1 and NS Power on key issues assessed in my Evidence.

Table 4: Summary of Positions of E1 and NS Power on key Board Issues assessed by SBA

Issue	E1	NS Power
Affordability of the Proposed Plan	E1 argues that the Preferred Plan is affordable based on the guidance provided by the Board but provides limited analysis to support it.[12]	NS Power disagrees with E1 and notes that long-term DSM benefits are uncertain[13]; E1 did not perform DSM spending using "comparable" states[14]; E1 did not conduct any customer survey[15]; and E1's Preferred Plan is almost 20% higher than the budget for 2019.[16]
Avoided Cost Analysis	E1 computed avoided costs at the portfolio level by using values computed by NS Power via the 2014 IRP (capacity and energy) process and in 2018 (transmission and distribution). Specifically, E1 used following avoided cost values:[17] Capacity - \$195,990/MW; Transmission[18] - \$10,521/MW; Distribution - \$4,358/MW; and varying energy values by year.	NS Power submitted that the use of annual avoided fuel costs rather than levelized avoided fuel costs would be more appropriate. And NS Power claimed that use of marginal cost over the short to medium term for annual avoided cost is appropriate since "these costs are comparable".[19] NS Power also mentioned that actual marginal cost of last few years which is on the range of \$44 to \$66/MWh and avoided cost estimated based on current market condition is likely lower than E1 use of levelized cost of avoided energy estimated during 2014 IRP process.[20] However, NS Power did not present

[12] M09096 E1 2020-2022 DSM Application, Table 6, pg. 25, & Table 7, pg. 28

[13] M09096 NS Power Reply Evidence, pg. 5, ln. 16-18

[14] M09096 NS Power Reply Evidence, pg. 30, ln. 1-10 & Figure 5. E1 believes DSM plan affordable due to comparison between several "similar" US states: CO, CT, IL, MD, MA & RI. NS Power argues that this is an unfair comparison because the per capita income in NS is significantly lower than the other six.

[15] M09096 NS Power Reply Evidence, pg. 44, ln. 22-23

[16] M09096 NS Power Reply Evidence, pg. 10, ln. 8-12

[17] M09096 E1 RIRs to SBA IR-16 (c)

[18] Transmission and distribution avoided cost components assume an escalation rate of 2% per year.

[19] M09096 NS Power Evidence, pg. 11, lines 17 – 18

[20] M09096 NS Power Evidence, pg. 11, lines 11 – 21

		updated avoided cost numbers.[21] Section III.A of the testimony discussed the necessity of basing cost-benefit analysis on levelized avoided cost calculated based on current market conditions.
Rate and Bill Impact Analysis – Methodology	E1's forward-looking RBIA estimates the high-level, long-term impact to rates and bills of all DSM activities of the Plan. This is done by taking the historical and forecast energy usage combined with the current bill calculations and costs associated with the proposed DSM programs and comparing them to the avoided costs and calculated energy savings due to the DSM programs.[22]	NS Power has prepared their own RBIA by changing allocation of: (1) annual fuel cost reduced by avoided DSM related fuel cost, (2) annual fixed generation and transmission cost reduced by avoided marginal capacity cost, (3) annual fixed demand-related cost by avoided marginal distribution cost, and (4) excluding allocation of customer-related costs.[23]
Comparison of the Proposed Plan and the Alternate Scenario	E1 proposed an Alternate Scenario with a reduction factor of 0.89 to the Preferred Plan and has an annual energy savings of 125 GWh for an average annual investment of approximately $37 million.[24]	NS Power argues that the Alternate Plan proposed by E1 is a subset of the Preferred Plan, meaning that E1 has essentially presented just one plan.
Relationship of the proposed 2020-2022 DSM Plan to the 2014 IRP	E1 notes that DSM levels included in E1's Preferred Plan results in an average proposed energy savings level of approximately 141 GWh per year for each of the three years in the plan period [25] which moves the DSM targets for Nova Scotia toward the Mid-Level DSM levels recommended in the 2014 IRP.[26]	NS Power makes the observations that the 2014 IRP numbers do not take into account the changes to the NS Power system over the last five years such as DER forecast[27], CT forecast output[28], and the actual marginal cost ($44 to $66/MWh) being lower than E1's use of levelized cost of avoided energy of $107/MWh.

Q. Did E1 present Alternative Scenario with its Application?

A. Yes. E1 presented an Alternative Scenario with the same key considerations of customer value, need and affordability.[29] The Alternate Scenario is proposed to deliver

[21] M09096, NSPI (NSUARB) IR-7
[22] M09096 E1 2020-2022 DSM Plan Application, Appendix B, RBIA Spreadsheet
[23] NS Power Reply Evidence, Section 10, pg. 34
[24] M09096 E1 2020-2022 DSM Resource Plan Filing, Evidence, pg. 51
[25] M09096 E1 2020-2022 DSM Resource Plan and Supply Agreement, pg. 7 ln. 24-26
[26] M09096 E1 2020-2022 DSM Resource Plan and Supply Agreement, pg. 10, ln. 5-10
[27] M09096 NS Power Evidence, pg. 11, ln 1-5
[28] M09096 NS Power Evidence, pg. 11, ln 1-5
[29] M09096 E1 2020-2022 DSM Resource Plan Filing Evidence, pg. 51

approximately 125 GWh of incremental energy savings annually during the three-year plan period, for an average investment of approximately $37 million per year.[30] Table 5 sets out the annual budget levels and savings targets for the proposed Alternative Scenario. In Section III of my evidence I provide an assessment of the method used by E1 to create the alternative plan.

Table 5: 2020-2022 Alternative Scenario DSM Resource Plan Investment and Savings[31]

Year	Investment ($M)	Lifetime Benefits ($M)	First-Year Energy Savings (GWh)	Lifetime Energy Savings (GWh)	Weighted-Average Measure Life (years)	Peak Demand Savings (MW)	Total Resource Cost Test (TRC)	Program Administrator Cost Test (PAC)
2020	36.1	171.2	124.4	1,744.4	14.0	33.4	1.9	4.7
2021	37.3	182.1	125.4	1,786.1	14.2	34.5	1.9	4.9
2022	37.6	189.9	124.4	1,785.5	14.4	34.9	2.0	5.0
Total	111.0	543.2	374.2	5,316.0	14.2	102.8	1.9	4.9

Q. Did NS Power recommend alternate DSM Plans that had lower annual costs than proposed by E1 in its Evidence?

A. Yes, in its evidence NS Power recommended the Board direct E1 to develop a lower cost DSM Plan at an annual expenditure level in the range of $27 million to $34 million. E1and NS Power presented four DSM scenarios in its evidence as set out in Table 6 below. Two scenarios are based on an annual budget of $34 million and other two are based on annual budget level of $27 million. Although Navigant prepared these scenarios, they were created at NS Power's request.[32] Table 6 shows annual estimated energy and peak demand savings for each of the recommended scenarios. According to the scenarios run by Navigant, the NS Power recommended annual DSM budget of $27

[30] M09096 E1 2020-2022 DSM Resource Plan Filing Evidence, pg. 51
[31] M09096, E1 2020-2022 DSM Resource Plan Filing
[32] M09096 NS Power Evidence, Appendix A, pg. 64

million to $34 million is estimated to provide first-year energy savings of 102 – 129 GWh and achieve peak demand savings of 34 – 42 MW in 2020. I discuss NS Power's approach of developing these recommended plans in detail in next section of the testimony.

Table 6: Savings Target and Budget Levels of NS Power Recommended Scenarios[33]

Year	Savings and Budget Target	34 M E1 - Navigant A	34 M E1 - Navigant B	27 M E1 - Navigant A	27 M E1 - Navigant B
2020	Energy Savings (GWh)	128.6	134.7	102	106.6
	Peak Demand Savings (MW)	42	39.8	36.5	33.9
	Investment, $ Million	34.1	34.1	27	27
2021	Energy Savings (GWh)	127.7	134	101.7	105.1
	Peak Demand Savings (MW)	41.9	39.7	36.4	33.7
	Investment, $ Million	34.1	34.1	27	27
2022	Energy Savings (GWh)	128.5	134.7	101.8	106.5
	Peak Demand Savings (MW)	41.9	39.7	36.5	33.9
	Investment, $ Million	34.1	34.1	27	27
Total - 2020-2022	Energy Savings (GWh)	384.8	403.4	305.5	318.2
	Peak Demand Savings (MW)	125.8	119.2	109.4	101.5
	Investment, $ Million	102.3	102.3	81	81

Q. Can you summarize the budget levels and estimated energy and peak demand savings of the E1 proposed plans in comparison to the NS Power recommended plans?

A. Table 7 summarizes the proposed budget, estimated first-year energy and peak demand savings, and first-year unit cost of E1 proposed plans along with NS Power recommended plans for 2020 – 2023 period. The budgets proposed by E1 and NS Power for the next three-year DSM plan range from $81 - $129 million with estimated first-year energy savings of between 306 – 422 GWh. Similarly, the first-year unit cost ranges from

33 M09096 NS Power Evidence, Appendix A, pg. 68

$0.25/kWh to $0.306/kWh across different plans. It should be noted that the DSM plan with the lower first-year unit cost does not necessarily make it more cost-effective than DSM plans with a higher first-year unit cost. System needs, and other type of energy resources must be taken into consideration.

Table 7: Comparison of Savings targets and Budget levels different DSM Plans for 2020 – 2022 period

Descriptions (2020 - 2022 DSM Plans)	E1 Proposed Plans		NS Power Recommended Scenarios			
	Preferred Plan	Alternate Scenario	34M E1-Navigant A	34M E1-Navigant B	27M E1-Navigant A	27M E1-Navigant B
Total Budget ($ million)	129.1	111	102.15	102.15	81	81
First-year energy savings (GWh)	421.7	374.2	384.8	403.4	305.5	318.2
Peak Demand Savings	120.1	102.8	125.8	119.2	109.4	101.5
First-year unit cost ($/kWh)	0.306	0.297	0.265	0.253	0.265	0.255

III. CONCERNS REGARDING THE E1 PROGRAMS

A. COST-BENEFIT ANALYSIS

Q. What is the cost-effectiveness screening methodology used by E1 in developing the DSM program?

A. E1 uses the Total Resource Cost (TRC) test as a primary assessment tool for the 2020-2022 DSM Resource Plan. It is based on the standard 2001 California Cost Test Method[34], which has the following formula:

Equation 1: Mathematical Formulation of TRC Test

$$TRC = \frac{Avoided\ Costs\ Benefits}{Utility\ Admin\ Costs\ +Customer\ Costs\ +\ Negative\ Avoided\ Cost\ Benefits}$$

For clarity, the following definitions should be noted:

[34] M09096, E1 (SBA) IR-04

- Avoided Cost Benefits include savings associated with “electric energy, electric demand, water, and natural gas”[35].
- Utility Admin Costs include proposed incentives and E1 administrative costs.[36]
- Customer Costs include the remaining cost of the measure installed in customer’s premise not covered by Utility Admin Costs.
- Negative Avoided Cost Benefits include any cost associated with “increases in consumption due to the installation of an efficiency measure. Notably, this occurs as an increase in natural gas consumption due to electric commercial kitchen equipment switching to gas.”[37]

Q. Please discuss the TRC test results of E1’s proposed Preferred Plan.

A. E1 reported program-level TRC test values of proposed Preferred Plan for 2020 – 2022 period. Table 8 below shows that the average TRC test result under the proposed Preferred Plan is 2.0. [38] This means that E1 estimates that, in net present value terms, the total lifetime benefits of the proposed Preferred DSM Plan is twice the proposed investment amount. Since the TRC values of all proposed programs are greater than 1.0, the cost-effectiveness test passes NSUARB’s mandate that all programs included in the DSM Plan must have TRC of 1.0 or greater.[39]

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[35] M09096, E1 (SBA) IR-04
[36] M09096, E1 2020-2022 DSM Resource Plan Filing, Appendix, Tech Tables
[37] M09096, E1 (SBA) IR-04
[38] M09096 E1 2020-2022 DSM Resource Plan Filing, Appendix A, pg. 9, ln 6 – 17. Moreover, E1 also included the results of Program Administrator Cost (PAC) test for informational purposes.
[39] M09096 E1 2020-2022 DSM Resource Plan Filing, Appendix A, pg. 9, ln. 9 – 10

Table 8: 2020-2022 Preferred DSM Resource Plan Cost Effectiveness Results by Program.[40]

2020-2022 Programs	Total Resource Cost Test (TRC)	Program Admin Cost Test (PAC)
Residential DSM Programs		
Efficient Product Rebates	1.1	2.2
Existing Residential	1.9	6.1
New Residential	1.5	4.6
Business, Not-for-profit and Institutional Programs		
Efficient Product Rebates	2.3	7.4
Custom Incentives	2.1	5.2
Direct Installation	2.2	3.0
Enabling Strategies		
Education and Outreach		
Development and Research		
Other Enabling Strategies		
Total	**2.0**	**4.8**

However, there are some caveats in E1's cost-effectiveness method for the proposed Preferred Plan. The one key is that some of the DSM programs proposed by E1 include measures that have a TRC test result of less than 1.0, which raises the question of what is the correct threshold level for the TRC test.? As well, E1's use of avoided cost based on 2014 IRP evaluation may not reflect current NS Power's system needs and conditions. I discuss each of these concerns and its impact on cost-effectiveness testing in detail below.

Q. Does this mean that E1's proposed Preferred Plan include measures that fail the TRC test?

A. Yes, E1's proposed Preferred Plan includes measures that have a TRC value of less than 1.0 in each year of next three-year DSM Plan. For example, the proposed Preferred Plan

[40] M09096 E1 2020-2022 DSM Resource Plan Filing, Appendix A, pg. 10, Table 1

for year 2020 considered 50 unique measures that have TRC less than 1.0. These reflect approximately 5.2 GWh of first-year energy savings which is about 4% of total first-year savings resulting from proposed Preferred Plan in 2020.

Table 9 provides the summary statistics by different DSM programs by only considering the measures with TRC less than 1.0.[41] Among different programs, BNI efficient product rebates and Residential Efficient Product Rebate programs include majority of the offered measures that have TRC less than 1.0.

E1 further mentioned that even though these measures fail the TRC test, the utility benefits outweigh the utility costs by a factor of 2.2. that is, the average PAC for the measures with TRC less than one is 2.2.[42]

Table 9: Summary of Measures that have TRC less than 1.0 in the proposed Preferred Plan for 2020[43]

Program Name**	Unique Measure Count	First Year Energy Savings (MWh)	Total Avoided Cost Benefits, $	TRC cost, $	PAC Cost*, $	TRC Ratio
BNI Efficient Product Rebates	11	2,232	2,036,440	5,783,630	528,590	0.35
Direct Installation	6	333	383,074	738,950	172,196	0.52
Existing Residential	5	67	82,125	194,219	49,661	0.42
Existing Residential	2	62	20,136	20,503	20,503	0.98
Residential Efficient Product Rebates	18	2,552	1,502,366	2,664,589	848,794	0.56
Total	**42**	**5,247**	**4,024,141**	**9,401,891**	**1,619,745**	**0.43**

**PAC Cost is same as E1's proposed budget cost and includes both customer incentives and E1 administrative cost.*

*** Does not include measures included in Low-income and First Nations programs.*

[41] Please note that measures with TRC less than 1.0 that are offered to low-income and First Nation programs are not included in the summary table.

[42] M09096, E1(SBA) IR-06

[43] M09096, E1 2020-2022 DSM Resource Plan Filing, Appendix A, Tech Tables

Q. Did E1 provide any explanation for including measures that fail the TRC test?

A. Yes, as a part of the response to SBA IR-06, E1 provided various reasons for including measures with a TRC of less than 1.0 in the portfolio of the Preferred Plan. E1 mentioned that it included some of the measures with a TRC less than 1.0 to provide a comprehensive offering to its customers or to support emerging technologies. For example, as a rationale for offering the "*Open to Closed Cooler Conversion*" measure that has a TRC value of 0.35 for the BNI category in 2020, E1 mentioned that it "seeks to offer measures for commercial refrigeration, which has a limited number of applicable measures that lend to prescriptive programs. Removing this measure would cause lost opportunities during refrigeration retrofit projects."[44]Among different rationale provided by E1 for including measures with a TRC value less than 1.0, Daymark categorized them into six major groups. Table 10 includes a summary of a number of unique measures along with the first-year energy savings for six categories. Even though E1 provided individual reasons for including measures that fail the TRC test, I believe these measures should not be included in DSM portfolio at all.

Table 10: Summary of Energy and Demand savings by reasons for including measures with TRC less than 1.0 in Preferred Plan for 2020[45]

Reasons for including Measures with TRC less than 1.0	Unique Measure Count	First Year Energy Savings (MWh)
Aiding other programs	3	2,203
Capture remaining opportunities	3	181
Complete upgrades	7	157
Marginally fails TRC	2	118
New/Emerging measures	27	2,588
Total	**42**	**5,247**

[44] M09096, E1(SBA) IR-06 – Attachment 1
[45] M09096, E1(SBA) IR-06, Attachment 1

Q. Do you agree with E1's application of the concept of 'Lost Opportunities' as you quoted above?

A. No. My understanding of the meaning of lost opportunities is that it applies to measures that pass the TRC test with at least a benefit-cost ratio of 1.0. Lost opportunities apply to a measure implementation that is economic if done at a certain time and would not be economic if delayed. As an example, the cost to increase the amount or type of insulation above the building code in a new residential building is generally going to be substantially less during the construction process than afterwards, due the relatively limited increase in labor. It is likely that the only the difference is in the cost of the materials. When this incremental cost is used as the cost of the efficiency measure, this measure likely has a very good benefit-cost ratio. The increase in costs associated with waiting until after construction is complete to undertake the insulation upgrade could push the benefit-cost ratio under the TRC test well below 1.0 and diminish the likelihood that a homeowner would consider having such a retrofit project done. Thus, additional insulation would be a lost opportunity, since it was economic at the time of construction but not once construction is complete.

By contrast, E1 is applying the tag of 'lost opportunity' to a measure that is uneconomic under the Board approved TRC test. It may be a lost opportunity to add to the savings achievements of E1 but is not a lost economic opportunity. It is my position that this is a misapplication of the concept of lost opportunity and should not be part of E1's programs.

Q. Why do you believe that some or all measures that fail the TRC test should be excluded from the DSM Plan?

A. I believe that the measures with a TRC test result of less than 1.0 should not be considered in the DSM portfolio at all. The measures that have a TRC value less than 1.0 means that the lifetime benefits associated with the measure are less than the total cost – direct installation cost and any administrative cost – of the measure. As a result, including measures with TRC less than 1.0 in a DSM Plan will result in having to use the benefits incurred from other measures to pay for the cost of installing measures with the lower TRC value. Moreover, including such measures will result in less overall program-level net benefits than would have been achieved without including such measures.

E1 also agrees that measures with a TRC less than 1.0 put downward pressure on the overall TRC of the portfolio[46] meaning that including these measures reduces the total estimated benefits. This is ignoring the threshold in their own economic testing.

Q. What do you believe is the appropriate minimum level of TRC value to use for selecting measures in the DSM Plan?

A. In my opinion, the TRC threshold of 1.0 does not account for various things such as payback period relative to the measure life, policy objectives that are different than least-cost option, and risks associated with future technology adoption rates, technology obsolesce, and free-ridership.

A TRC of 1.0 for a measure basically means that, at the net-present value, the cost and benefits over a measure's entire estimated life are equal. This is also called break-even

[46] M09096, E1(SBA) IR-06

point from investment standpoint. If we believe that energy efficiency measures should generate a level of return, we may need to consider a different pay-back period than the measure life. Other measure specific characteristics such as future adoption rates and technology obsolesce also impact the payback period. For example, if we believe that there is a risk for a technology to be replaced before it reaches its measure life, then a shorter period than the measure life should be considered in the benefit-cost analysis. Based on the above considerations, I believe the TRC value threshold level for DSM measures should be set higher than 1.0. A ratio of 1.2 would mean that instead of breaking even over a measure life, measures should have economic breakeven points at approximately 80% of the estimated measure life. This would at least partially address the concerns about technology obsolesce, free-ridership, errors in measure life or other factors that make the lifetime savings at risk.

Q. Do you have other concerns with E1's cost-effectiveness methodology that could impact the reported TRC results?

A. Yes. I have concerns about the avoided cost values used by E1 in developing the TRC test. As discussed in Section II of my testimony, E1 used levelized capacity and energy avoided cost values developed by NS Power in the 2014 IRP process. I believe that the avoided cost estimated based on current NS Power system would be different, most likely lower, than the one used by E1 in its cost-benefit analysis because the system load and outlook have changed since 2014 IRP process and there is abundance of market-priced non-emitting import energy.[47]

[47] M09096 E-9 20190412 NS Power to UARB 2020-2022 DSM Plan Evidence, pg. 11, lines 19 – 21

Q. Did NSP present updated levelized avoided cost calculation to what it estimated during 2014 IRP process?

A. No. Even though, NS Power pointed out the avoided cost calculated for 2014 IRP may not align with current market conditions, NS Power mentioned that they "do not have an updated long-term resource plan from which to calculate avoided energy and capacity costs for DSM; therefore, the 2014 IRP avoided costs are still the most recent calculation."[48]

Moreover, NS Power argued that the levelized avoided cost values cost the current system, citing that the actual marginal cost ($44 to $66/MWh) during last few years being lower than E1's use of levelized cost of avoided energy of $107/MWh.[49] But, marginal cost and avoided costs are not same concept. As NS Power pointed out in an IR response, marginal cost represents the cost of producing the next unit of generation and this cost can vary hourly based on real-time market and system conditions. Whereas, avoided costs "represent the incremental cost of generating or purchasing electricity that would not be incurred if an alternative source is added to the system."[50] NSP should have provided updated avoided cost that is reflective of current system needs and market conditions to facilitate E1's cost-benefits analysis.

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[48] M09096, NSPI (NSUARB) IR-7
[49] M09096 NS Power Evidence, pg. 11, lines 11 – 21
[50] M09096 NS Power (NSUARB) IR-7

Q. How does a potentially lower than currently used levelized avoided cost impact reported TRC results of the Preferred Plan?

A. The avoided cost values impact the numerator of the TRC test (see **Equation 1**). Lower avoided cost values reduce the benefits associated with DSM savings which in turn lowers the TRC value. So, if the actual avoided cost components (generation, capacity, and T&D avoided costs) are less than the values used by E1 in its benefit-cost analysis, the actual TRC values will be less than reported values of the measures included in the proposed Preferred Plan (see Appendix A of E1's filing). This in turn would affect the selection of measures of the proposed Preferred Plan.

B. PROGRAM DESIGN CONCERNS

Q. Did you review any DSM programs in detail from E1's proposed Plan?

A. Yes. I reviewed the programs that are applicable to small business in Nova Scotia. The Direct Installation and Custom programs were developed for the BNI Sector in E1's proposed Preferred Plan. The Direct Installation program, marketed as Small Business Energy Solutions, "provides small business customers access to technical assistance and financial incentives for the installation of energy efficient and system-peak demand reduction equipment."[51] Similarly, the Custom part of the program is designed for non-profit, institutional, commercial and industrial customers, as it will "work directly with customers to identify and implement energy efficiency and system-peak demand reduction projects that are not supported by other ENS programs."[52]

[51] M09096 E1 2020-2022 DSM Resource Plan Filing, Appendix A, pg. 68
[52] M09096 E1 2020-2022 DSM Resource Plan Filing, Appendix A, pg. 60

Q. Do you have any concerns regarding the Direct Installation and Custom Programs included in E1's proposed Preferred Plan?

A. Yes, I do. My concerns with the Direct Installation program are that the incentive levels set for this program are significantly higher than other programs and this program is heavily focused on lighting. Similarly, regarding the Custom program, I have concerns with E1's proposed budget level as E1 has consistently failed to meet similar targets for the same program during the 2016 – 2018 period.

Q. Please describe your concern about the incentive levels for the Direct Installation program being higher than other DSM programs.

A. The proposed incentive levels[53] for measures included in the Direct Installation program are significantly higher than average incentive levels in the overall DSM Plan. The overall DSM portfolio of the Preferred Plan has an incentive level of 38%[54] of total program cost, whereas the incentive level, expressed as PAC cost as percentage of total cost, for the Direct Installation program is at 75% of the total program cost as presented in Table 11.

The table also includes technology-level incentive levels along with first-year savings and benefits and cost information of the Direct Installation program proposed in Preferred Plan for 2020. The incentive levels for lighting measures included in the Direct Installation program are at 80% of the total cost. This level of incentive for lighting measures is notably high, considering E1's acknowledgement of rapid market

[53] Incentive levels = PAC cost / TRC Cost. For simplicity, the program admin cost (PAC) that consists both direct incentive levels and admin cost is used as incentive levels.

[54] M09096 E1 2020-2022 DSM Resource Plan Filing, Appendix A, Tech Tables. The overall PAC cost is $38.4 million, whereas total TRC cost is $102.1 million.

transformation in the lighting industry in its Application.[55] Providing more than necessary incentive levels for customers to install efficiency measures is not cost-effective. The unnecessary and expensive incentives provided for lighting measures could be better utilized to provide support to small business customers to install targeted measures that they would otherwise not install themselves. Please note that E1 is considering the total budget of $3.6 million (out of total budget of $4.4 million) for lighting measures for the Direct Installation program in 2020.

Table 11: Performance Targets, Investment Levels, and Benefits for Direct Installation Program of proposed Preferred Plan for 2020

Technology Type	Energy Savings (MWh)	Peak Demand Savings (kW)	Total Avoided Cost Benefits, $	TRC cost, $	PAC Cost*, $	TRC ratio	PAC Cost as % of Total Cost (Incentive Level)
BNI Cooking and Laundry	92	13	129,509	25,207	50,225	5.1	199%
BNI Domestic Hot Water (DHW)	221	54	223,877	128,192	120,819	1.7	94%
BNI HVAC	497	864	2,513,088	738,975	533,827	3.4	72%
BNI Lighting	8,509	1,376	9,342,831	4,511,501	3,592,666	2.1	80%
BNI Process	38	11	53,805	32,203	20,585	1.7	64%
BNI Refrigeration	155	18	143,781	432,205	83,931	0.3	19%
Total	**9,512**	**2,336**	**12,406,891**	**5,868,283**	**4,402,054**	2.1	75%

**PAC Cost is same as E1's proposed budget cost and includes both customer incentives and E1 admin cost.*

[55] M09096 E1 2020-2022 DSM Resource Plan Filing, Evidence, pg. 19

Q. Please describe your concerns about the Direct Installation program being heavily focused on lighting measures.

A. The Direct installation program proposed by E1 for the next three years is still heavily focused on lighting. Despite a great deal of emphasis and discussion in E1's Application regarding diversifying its portfolio beyond lighting measures,[56] they continue to account for a majority of first-year energy savings for the Direct Installation program. As shown in Table 5 above, the proposed lighting measures of the Direct installation program included in the proposed Preferred Plan are expected to contribute almost 90% of the total first-year savings for the (8.5 GWh of total 9.5 GWh of savings. The trend of market transformation being observed in the lighting industry suggests the free-ridership numbers are higher than currently assumed by E1 in its benefit-cost analysis, implying that the TRC test value would be lower than current estimate of 2.1 as reported by E1 for Direct Installation program for its Preferred Plan (see Table 11 above).

Q. Did you perform any analysis of how a higher than anticipated free-ridership number for lighting programs impacts the TRC test?

A. Yes, I performed a simple analysis to assess how the TRC test results would change with varying levels of free-ridership.

There are two assumptions within the E1 estimates for energy savings from a program. The first assumption is an estimate of how many individuals will install a measure as a result of advertising, the increase in measure availability to purchase, or familiarity with the measure since they have seen or heard about the measures potential without receiving

[56] M09096 E1 2020-2022 DSM Resource Plan Filing, Evidence, pg. 19. Also discussed in Direct Testimony of David Hill, pg. 9

a program's incentive. This is referred to as internal spillover. This effect is estimated to result in a 10% increase over those measures installed as a result of the incentives.

The second assumption deals with cases where some of the measures would have been installed even without program incentives, yet the customers qualified and received incentive payments. This is referred to as free-ridership. E1 assumes 20% of those receiving incentives would be free-riders.

These two factors are combined into a ratio used to convert gross savings to net program savings. This net-to-gross ratio (NTGR) is used in the benefit-cost analysis. The formula for this is $\mathrm{NTGR} = (1 - \%\ \text{free ridership} + \%\ \text{internal spillover})$[57]. If the assumption of spillover is closer to zero, rather than 10%, and the free-ridership rate is higher than assumed by E1, then the NTGR ratio would decline. E1 assumptions result in an 88% NTGR in its cost-benefit analysis of the proposed Preferred Plan and a reported TRC benefit-cost ratio of 2.1. As shown on Table 12, if the spillover effect is eliminated then the NTGR would be 80%, reducing the TRC benefit-cost ratio of lighting measures to 1.9.

I believe that, given that lighting has been a significant part of the energy efficiency program landscape over the past several years and even decades, it is reasonable to expect that the amount of efficient lighting that would be installed regardless of incentive is likely to be greater than the 20% assumed by E1. If the estimated amount of free ridership with efficient lighting goes up to 40% (producing a NTGR of 60%), then the Lighting measures included in the Direct Installation barely pass the TRC test. Thus, it is

[57] M09096, E1(SBA) IR-27

imperative that free-ridership estimation, which in turn impacts NTGR, should be properly estimated for the lighting measures within the Direct Installation program.

Table 12: Analysis of impact on TRC levels by varying NTGR for Lighting Measures of Direct Installation Program of proposed Preferred Plan

Different NTGR scenario for Lighting Measures	NTGR	Energy Savings (MWh)	Total Avoided Cost Benefits, $	TRC cost, $	TRC Ratio
Proposed Preferred Plan	88%	8,509	9,342,831	4,511,501	2.1
A - Spillover=0, Free-ridership 80%	80%	7,736	8,493,482	4,511,501	1.9
B - Spillover=0, Free-ridership 70%	70%	6,153	6,756,179	4,511,501	1.5
C - Spillover=0, Free-ridership 60%	60%	4,195	4,606,486	4,511,501	1.0
D - Spillover=0, Free-ridership 50%	50%	2,384	2,617,321	4,511,501	0.6

Q. Please provide a short description of the Custom program offered in the Proposed Preferred Plan for the BNI Sector?

A. The Custom Incentive program of the proposed Preferred Plan includes three program components – Custom Energy Efficiency; Energy Management Information Systems (EMIS); and Strategic Energy Management (SEM). Table 13 shows estimated first-year energy savings and peak demand savings along with total cost (TRC cost) and proposed E1 budget (PAC cost) of all three program components. The total estimated first-year energy savings is 33.2 GWh with the investment level of about $9.0 million.

The Custom Energy Efficiency program component, which was developed to serve individual non-profit, institutional, commercial and industrial customers, covers "retrofits, new construction, building optimization, demand reduction, and small new construction service"[58]. It has the largest budget, $8.4 million, and is estimated to achieve 30.2 GWh of first-year energy savings in 2020.

Table 13: Summary of measure-level information included in proposed Preferred Plan of Customer program for 2020

Measures	Energy Savings (MWh)	Peak Demand Savings (kW)	TRC cost, $	PAC Cost, $	TRC ratio
Custom Energy Efficiency	30,189	8,363	21,477,331	8,396,159	2.6
Energy Management Information Systems	1,509	254	359,052	259,836	1.4
Strategic Energy Management	1,509	179	358,282	323,618	1.1
Grand Total	**33,208**	**8,796**	**22,194,666**	**8,979,613**	**2.5**

Q. Has E1 provided any further information on the type of measures included in the Custom Incentive program?

A. No. E1 did not provide any information on the proposed type of measures for the Custom Incentive program in its Application. In response to an IR requesting additional information, E1 responded that "because the Custom program component is flexible and performance-based, it does not have a fixed set of measures. It is modelled as a single general measure comprising all five of these categories. This approach is consistent with the 2016-2018 Plan modeling approach."[59] E1 further explained that while the custom programs offered in 2020-2022 DSM plan are similar to previous years' DSM programs, the Demand Reduction and Small New Construction Service, are new for the 2020-2022 Plan.[60]

[58] M09096, E1(SBA) IR-43
[59] M09096, E1(SBA) IR-43
[60] M09096, E1(SBA) IR-43 (c)

Q. What are your concerns regarding Custom programs included in the proposed Preferred Plan for the BNI Sector?

A. My concern is that E1 may not meet the proposed targets for the Custom program during 2020–2022 plan period.

Q. Why do you think E1 may not meet the Custom energy targets during the plan period?

A. This is based on the historic trend of E1 not meeting targets set for the Custom program. Table 14 sets out the status of first-year energy savings and budget levels of planned and mid-course adjusted targets and actual achieved levels. As shown in the table, for 2018, E1 only achieved 14.7 GWh of net incremental energy savings for its Custom Incentive program as compared to the mid-course adjusted first year savings target of 25.8 and Planned first-year savings target of 34.4 GWh.[61] The achieved first-year savings for Custom program in 2018 is 57% of mid-course adjusted target and 43% of planned targets.

Table 14: Status of Planned, Mid-Course Adjusted, and Actual first-year energy savings and Budget of Custom Program during 2016 – 2018 DSM Plan.

DSM Plan Year/Target	First-year Energy Savings (GWh)			Budget ($ Million)		
	Planned	Mid-Course adjusted	Actual	Planned	Mid-Course adjusted	Actual
2016*	34	33.3	25.9	6.8	6.4	4
2017**	34.1	30.5	22.4	6.5	6	4.2
2018***	34.4	25.8	14.7	6.5	5.1	4.2
Average Annual	**34.2**	**29.9**	**21.0**	**6.6**	**5.8**	**4.1**

Sources:
**M07964, 2017 DSM Annual Progress Report, Page 2.*
***M08604, 2017 DSM Annual Progress Report, Page 2.*
****M09096, 2018 DSM Annual Progress Report, Page 2.*

[61] E1 2018 DSM Annual Progress Report Table 1, pg. 2

It is my concern that E1 may not be able to meet the targets set for the Custom program in 2020-2022 DSM Plan given the 2018 results where E1 only achieved 57% of the mid-course adjusted targets for first-year savings[62] and the lack of significant proposed process improvements for the Custom programs in 2020-2022 DSM Plan.[63]. I recommend that E1 provide a detailed plan with respect to its Custom programs in order to achieve the Custom program-specific targets bring set for the next three-year plan.

Q. What has been the trend in the past years for meeting the overall DSM first-year energy savings target, despite it not meeting the Custom program specific savings targets?

A. E1 has met its <u>overall</u> target of first-year energy savings in aggregate in the past years. However, this has been due to increasing savings target for rebate-based programs and reducing targets set for Custom programs during the mid-course adjustment. For example, in the 2018 mid-course adjustment process for the BNI category, E1 increased the first-year energy savings target for "Efficient Product Rebates" program by 55.2% and increased the budget by 38% over what had been originally filed. [64] Whereas, mid-course adjusted energy savings target of "Customer Incentive" program was reduced by more than 25% and the budget decreased by 22% from the original filing.[65] It has to be noted that despite the reduction, E1 did not meet the revised target for the Custom program. At the same time, the "Efficient Product Rebates" in the BNI sector ended up

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[62] E1 2018 DSM Annual Progress Report Table 1, pg. 2

[63] E1 mentioned that it is planning various process improvements for the 2020-2022 DSM Plan such as hiring an additional Business Development Manager, enhancing internal expertise, and improving project management. (Source: M09096, E1(SBA) IR-44).

[64] E1 2018 DSM Annual Progress Report Table 1, pg. 2

[65] E1 2018 DSM Annual Progress Report Table 1, pg. 2

achieving 49% more first-year energy savings than the mid-course adjusted target by spending 15% more than the mid-course adjusted budget for the same program.[66]

Q. What are the implications for not meeting targets set for Custom programs?

A. Although it may be reasonable to shift resources from Custom program to rebate-based programs in order to meet the overall savings target, it could have larger implications for the long-run success of the program. Specifically, I have the following concerns for this shifting of resources from Custom programs to rebate-based programs:

- Measures offered in the Custom program and instant rebate programs are different. As Custom programs serves customers individually based on their need, they tend to offer deeper savings than rebate-based programs.
- Custom programs may provide more opportunity for E1 to engage with customers, build relationships and provide information about other energy efficiency measures.
- There is the risk that instant rebate-based savings programs have higher free-ridership than custom programs and realized (evaluated) savings from instant programs could be lower than the targeted (claimed) savings.
- Custom programs include categories such as new construction customers, providing E1 with opportunity to install efficient measures during the construction phase. If E1 is not able to serve as many new construction customers, there could be a “lost opportunity” of not installing efficient measures during the construction phase as retrofits usually costs more.

[66] E1 2018 DSM Annual Progress Report Table 1, pg. 2

IV. SBA ANALYSIS OF SAVINGS TARGET AND BUDGET

A. ALTERNATIVE PLAN FUNDING

Q. How did E1 develop the proposed Alternative Plan?

A. As discussed earlier, E1 proposed an Alternative Scenario in addition to the Preferred Plan. However, the measures and programs modeled in both the Preferred Plan and the Alternate Plan are the same. [67] The difference is that the Alternative scenario considers a reduced participation level when compared to the Preferred Plan. Specifically, most of the programs were scaled down by factor of 0.89 from the Preferred Plan to create the Alternative Scenario.[68]

Q. Did you perform any incremental benefit-cost analysis between the Preferred and Alternative Plans (i.e. only considering additional programs considered in the Preferred Plan as compared with the Alternative Plan)?

A. Yes.

Q. Can you summarize the results of the incremental analysis?

A. The benefit-cost analysis of incremental measures included in the Preferred Plan is the same as the Alternative Scenario and Preferred Plan. Since the measures and programs included in the Preferred Plan and Alternative scenario are similar, there are no differences in measure-level cost effectiveness between the Alternative Scenario,

[67] M09096, E1(SBA) IR-21(a)

[68] M09096, E1(SBA) IR-15. And measures related with Affordable Multi-family Housing and Non-profit Organizations program component, First Nations Home Energy Efficiency program component, and demand reduction in the Home Energy Assessment, Green Heat, Small Business Energy Solution, and Business Energy Rebates program components were scaled down between 50 % to 67%.

incremental measures, and the Preferred Plan.[69] This means that there are no real alternate plans, rather there is just a smaller version on the Preferred Plan.

Q. What is your opinion on Alternative Scenario developed by E1?

A. In my opinion, the Alternative scenario proposed by E1 is not entirely independent from the Preferred Plan. Although the Alternative Scenario requires a different DSM funding level, it was created using a scaling factor of 0.89 for most of the programs and measures included in the Preferred Plan.

When asked about E1's interpretation of the Board's Order in M06733 E1 stated that "EfficiencyOne did not interpret the Nova Scotia Utility and Review Board's order to require E1 to include the full range of investment suggestions as alternate scenarios in its subsequent Applications. E1 understood that any alternate scenarios included in an Application were intended to represent a viable and deliverable DSM Plan, incorporating all of the requisite considerations that would inform the E1 Preferred Plan and be developed using the same rigor as the Preferred Plan, albeit at a lower investment level than the Preferred Plan."[70]

Q. Did E1 engage NS Power when developing the Alternative Scenario?

A. E1 stated that it engaged NS Power and the DSMAG in developing the Alternative Scenario. In response to SBA IR-26 , E1 replied that it shared both the Preferred Plan and Alternative Scenario beginning in the fall of 2018 with NS Power to "encourage input

[69] M09096, E1(SBA) IR-21(d)
[70] M09096, E1(SBA) IR-31

into the development of both of these options."[71] Furthermore, E1 mentioned that it had various one-to-one meetings with NS Power and it coordinated an exchange with Navigant to facilitate the modelling of various DSM investment scenarios put forward by NS Power. [72]

Q. Did NS Power agree with the proposed levels of DSM investment put forth by E1 for its Preferred Plan and/or the Alternative Scenario?

A. No.

Q. Did NS Power put forward different options of DSM investment levels in their evidence?

A. Yes. NS Power recommended to that the Board that it direct E1 to develop a lower cost DSM Plan at an expenditure level in the range of $27 - $34 million per year for the 2020-2022 time period.[73]

Q. Has NS Power performed its own analysis to determine that the appropriate level of DSM investment is in the range of $27-$34 million?

A. To my knowledge, NS Power did not perform its own analysis to show that the range of $27-$34 million budget is appropriate for E1's annual budget.[74] In response to SBA IR-5, NS Power stated that it "has not conducted a resource planning analysis to determine how

[71] M09096, E1(SBA) IR-26
[72] M09096, E1(SBA) IR-26
[73] M09096, NS Power Evidence, pg. 37
[74] NS Power worked with E1 and Navigant to have four scenarios created through the ProCESS model which E1 used to create its Preferred Plan and Alternate scenario (Source: M09096, NS Power (SBA) IR-8). However, to my knowledge, the level of investment for these scenarios were provided by NS Power.

much DSM it wants or needs to procure for the 2020-2022 period." [75] Further, without providing any supporting analysis, NS Power stated that "it has been monitoring its system load and peak to draw the conclusion … that funding at or below 2019 levels should enable E1 to design a program that maintains current system conditions at a more affordable cost to customers than E1's preferred plan."[76] While I see the logic in NS Power's statement, since I have not seen any supporting analysis, it should hold little weight.

Q. What is the basis of NS Power for recommending the DSM budget in the range of $27-$34 million?

A. NS Power does not provide its rationale for proposing this range but instead critiques the DSM levels proposed by E1 for the Preferred Plan to justify the lower investment level for its recommended Plan. NS Power states that E1's Preferred Plan, seeking a first-year budget increase of approximately 23 percent, is inconsistent with the annual DSM spending growth rates in other jurisdictions.[77] In addition, NS Power points out that the proposed level of investment for E1's preferred plan "does not account for short-term rate impacts or the economic realities in Nova Scotia."[78]

[75] M09096, NS Power (SBA) IR-5.
[76] M09096, NS Power (SBA) IR-5
[77] M09096, NS Power Evidence, pg. 36
[78] M09096, NS Power (SBA) IR-2

B. SBA ADJUSTMENTS

Q. Does your analysis suggest a different level of savings target and budget levels than proposed by E1 in its Preferred Plan?

A. The analysis shows that based on the numbers E1 should reduce its proposed Preferred Plan budget by $8.4 million to $33.6 million for 2020. This level of budget reduction would reduce E1's proposed Preferred Plan's estimated first-year energy savings by 25.7 GWh to 114.5 GWh.

Q. What is the basis for your recommended levels of savings target and budget levels?

A. My basis for recommending those levels of first-year savings and investment is based on the following overall reduction and program-level reductions in E1's proposed Preferred Plan:

- Remove measures that have TRC that are less than 1.2.
- Reduce targets of Custom Incentive programs to the achieved level by E1 during 2016 – 2018 period.
- Reduce lighting-specific incentives for the direct installation program.

Table 15 presents budget and savings reductions recommended for each of the issues listed above. I also provide detailed descriptions for the recommended reductions for each of these issues in the latter part of this section. The amount of first-year savings and budgets are based on the measure-level information provided by E1 for its proposed Preferred Plan of 2020. Please note that I excluded DSM programs offered to special customer groups – low income and First Nation programs – from my assessment.

Table 15: List of Budget and Savings reductions recommended in E1's proposed Preferred Plan

Description	Budget (PAC Cost), $	First-year energy savings (MWh)
Proposed target for DSM Program	38,384,489	140,194
Special Customer Group DSM Programs	2,641,427	2,765
Proposed target for DSM Program without Special Customer focused programs	35,743,062	137,429
Enabling Strategies	3,600,000	0
Total budget and savings target in the Preferred Plan	41,984,489	140,194
Proposed Reductions		
1. Measures that have TRC and PAC lower than 1.2	3,618,981	13,981
2. Reduction in Custom Incentive Program	3,240,917	11,653
3. Reduction in Incentive level for Lighting measures in Direct Installation Program	1,497,191	0
Total Recommended Reduction	*8,357,089*	*25,634*
Recommend Budget and Savings Target for 2020	**33,627,401**	**114,560**

Q. Are there any further adjustments that you think are warranted?

A. Yes. The $33.6 million above have yet to be adjusted to account for utilizing the lower avoided costs that NS Power is recommending. I have not performed a detailed analysis, but a lower avoided cost would create a drop in the TRC test benefit-cost ratios. This would push some measures below our proposed 1.2 benefit-cost ratio threshold. I would estimate that a further reduction of about 10% in savings and budget would result in an estimated 100 GWh target savings and a budget of around $30 million.

Q. Do you think that this level should be set for all three years of the plan?

A. No. In fact I believe that E1 would be able to adjust to these changes both in efficient administration and more fine-tuned incentives such that it would likely be able to justify savings targets increasing to 120 GWh in 2021 and 140 GWh in 2022, requiring a restoration of a budget target to the $34.5 million in 2021 and then step up to a level proposed by E1 in 2022 of around $41 million.

Q. Why step up the targets for savings and budgets so aggressively in the second and third year of the DSM Plan?

A. I recognize that E1 is accurate at pointing out that the 2014 IRP analysis demonstrated at that time DSM programs can create significant savings in the neighborhood of 170 GWh or more. I would expect that the upcoming IRP would also determine a large role for energy efficiency, although perhaps not as strong as the 170 GWh level. This is why I think it is appropriate that if E1 can demonstrate 120 GWh of cost effective energy efficiency program first year savings for 2021 and 140 GWh in 2022 while the IRP is being conducted and finalized it would be a good strategy for the Board to authorize such budget levels.

C. SBA ANALYSIS

Q. Please provide your assessment of measures that have TRC value of less than 1.2.

A. I recommend that the Board direct E1 to remove any measures that have a TRC ratio of less than 1.2. My reasoning to raise the TRC threshold to 1.2 for a cost-effectiveness test is discussed above in an earlier section of my Evidence (refer to Section III.C).

Moreover, I also recommend the Board to exclude any measures that have a TRC ratio less than 1.2.

I recommend the Board to exclude the budget level of $3.6 million with estimated first-year energy savings of 14.0 GWh that have measure-level TRC ratio of less than 1.2 and are currently proposed by E1 in its Preferred Plan for 2020. Please refer to Table 16

Table 16 for detailed information on program-level summaries of measures that have TRC and PAC ratios of less than 1.2.

Table 16: DSM program-level summary by including measures that have TRC and PAC ratios less than 1.2

DSM Program	Unique Measure Count	Energy Savings (MWh)	Total Avoided Cost Benefits, $	TRC cost, $	PAC Cost, $
BNI Efficient Product Rebates	19	4,150	4,982,079	8,422,862	1,009,449
Custom Incentives	2	3,019	802,295	717,335	583,454
Direct Installation	9	718	967,308	1,234,545	357,653
Existing Residential	12	538	510,850	612,550	230,141
Residential Efficient Product Rebates	22	5,556	3,075,570	4,144,419	1,438,284
Total	**64**	**13,981**	**10,338,103**	**15,131,710**	**3,618,981**

Q. Do you recommend any reductions to the Custom Incentive program?

A. Yes. I recommend reducing the budget and savings level of the Custom Incentive program to 61% of the currently proposed level in the Preferred Plan. This results in a $3.2 million reduction to the annual budget and a reduction of 11.7 GWh of first-year energy savings. The 61% reduction-level is based on the achieved savings target during 2016 – 2018 period. As shown in Table 17, E1 only achieved first year energy savings of 21.0 GWh from planned savings target of 34.2 GWh.

Table 17: Proposed Reduction in Custom Incentive Program from E1's Preferred Plan.

Description	Budget, $	First-year energy savings (GWh)
Proposed budget and savings target	8,396,159	30,189
Recommended reduction %	61.40%	
Recommended budget and savings target	5,155,242	18,536
Recommended reduction	**3,240,917**	**11,653**

Q. Do you recommend any reductions from the Direct Installation program?

A. Yes, I recommend reducing high incentive levels currently proposed for lighting measures included in the Direct Installation program. As I discussed in the earlier portion of my evidence, E1 is proposing almost 90% of the incentive (total PAC Cost as percentage of total TRC Cost) for lighting measures, whereas average lighting incentive for the overall portfolio is at 49%. I recommend that E1 set the incentive levels for lighting measures in the Direct Installation program at the same 49% level as shown in Table 18. With the discussion and acknowledgement of the transformation of the lighting market, I do not foresee any issues of E1 not achieving the estimated first-year energy savings target of 7.9 GWh with the reduced incentive levels. Thus, I recommend the budget level of lighting measures to be reduced by $1.5 million and set at $1.8 million for 2020.

Table 18: Recommended Reduction in the Incentive levels of lighting measures in Direct Installation Program

Description	Budget (PAC Cost), $	Total Cost (TRC Cost), $	First-year energy savings (GWh)
Proposed budget and savings target	3,319,301	3,714,352	7,945
Current incentive level for lighting		89%	
Recommended Incentive level for lighting		49%	
Recommended budget and savings target	1,822,111	3,714,352	7,945
Recommended reduction	1,497,191	0	0

V. ADDITIONAL ISSUES

A. BOARD ISSUE #7 – PERFORMANCE TARGET, LIFETIME ENERGY SAVINGS

Q. What is the purpose of a Performance Target for a DSM plan?

A. The purpose of a Performance Target in a DSM Plan is to provide a benchmark, defined by the desired level of savings in kWh, generated by the adoption of measures by customers that yield one or multiple types of savings. E1's DSM plan includes measures that may yield annual kWh savings, annual peak demand savings and lifetime energy savings. These benchmarks form a scorecard against which E1's management can be evaluated by comparing realized savings against actual spend for measures installed.

Q. What Performance Targets does E1 included in its current plan and what is the evaluation threshold for determining compliance?

A. E1 includes the following Established Performance Targets:

i. Cumulative annual energy savings.

ii. Cumulative annual peak demand savings.

E1's performance is evaluated over the period of the Board-approved Supply Agreement rather than annually and is deemed to be in compliance if it achieves at least 90% of the threshold for each target.[79]

[79] M09096 2020-2022 E1 DSM Resource Plan Application, pg. 46, ln 9-13

Q. Why has E1 proposed Lifetime Energy Savings as an additional performance target for its plan?

A. E1 has proposed a third Performance Target called Lifetime Energy Savings for two reasons:

a) E1 believes that a balanced DSM plan resulting in long-term cost savings must be weighed against the short-term rate impact of the plan, with the latter objective represented by the existing Performance Targets.[80]

b) E1 also believes that ratepayers benefit from a plan including measures requiring investment in longer-lived assets that continue to return annual savings to the customer over many years.[81]

Q. What threshold has E1 proposed for the Lifetime Energy Savings Performance Target?

A. E1 has proposed a Lifetime Energy Savings Performance Target Threshold of 75% over the deemed life of a given measure, which is subject to change based on in-situ conditions.[82]

Q. How does the application of a Lifetime Energy Savings Performance Measure benefit ratepayers?

A. Adding a Lifetime Energy Savings performance target may help incentivize investments in longer-lived assets that benefit ratepayers whose income is dependent upon energy

[80] M09096 2020-2022 E1 DSM Resource Plan Application, pg. 47, ln 17-26
[81] M09096 2020-2022 E1 DSM Resource Plan Application, pg. 48, ln 5-9
[82] M09096 2020-2022 E1 DSM Resource Plan Application, pg. 50, ln 3-5

intensive processing requirements that support revenue growth, or even residential customers who are upgrading or buying new homes. When a DSM program offers measures with similar first year energy savings in kWh/year, customers who may be otherwise inclined to look at measures requiring a higher participant investment would benefit from choosing between options by looking at Lifetime Energy Savings.

Q. Do you agree with the benefit of including Lifetime Energy Savings as a Performance Target in E1's DSM plan?

A. Yes, I do, however, I find two caveats should be recognized with employing a lifetime energy savings metric as a performance target:

i. As E1 itself notes, lifetime energy savings is not a perfect proxy for lifetime benefits, which can change over time[83]; and

ii. Inclusion of lifetime savings sets-up a trade-off between achieving programs as planned and could incent E1 to move mid-year toward higher program costs because it favors those measures that help reach the performance threshold faster.

Therefore, I recommend that the threshold for achieving compliance should be the same for all three performance targets, i.e., 90%, and the DSM program composition should be informed by cost-effectiveness at the measure level.

[83] M09096 2020-2022 E1 DSM Resource Plan Application, pg. 50, ln 17-19

B. BOARD ISSUE #8 - DISPOSITION OF THE HST FUND AND INTEREST

Q. Please explain the background of the Harmonized Sales Tax (HST) Fund referred to in E1's filing.

A. On December 23, 2013, when Efficiency Nova Scotia Corporation (ENSC, the predecessor to E1) filed its Reply Evidence to its application for UARB approval of its 2014 DSM Cost Recovery Rider (DCRR), it included recovery of the full amount of HST owed for 2012 due to having taken an Input Tax Credit (ITC) related to HST that was subsequently denied by the Canadian Revenue Agency (CRA). In that filing, ENSC confirmed that the issue of HST recovery was first reviewed and approved for inclusion by the UARB in the 2013 DCRR[84], but also explained that the Department of Energy (NS DOE) requested that the UARB deny recovery of the HST from customers for the 2012 DSM Balance Adjustment (BA).[85] Subsequently, ENSC reached a Settlement Agreement with DSM stakeholders supporting approval of the first two years of ENSC's 2013-2015 plan and agreed to absorb HST costs within already approved DSM investment levels for 2013 and 2014 while awaiting the results of its appeal of the CRA ruling.[86]

In 2015 the ENS Transition Corporation (ENS) took over the ENSC challenge through an appeal of an Excise Tax Act assessment by the Minister of National Revenue for ITCs but appealed for HST recovery for the full period of May 1, 2010 through January 31, 2015.[87]

[84] ENSC 2014 DCRR Application M05985 (E-ENSC-R-14) Reply Evidence, Dec 23, 2013, pg. 3, ln 15-17
[85] ENSC 2014 DCRR Application M05985 (E-ENSC-R-14) Reply Evidence, Dec 23, 2013, pg. 3, ln 6-7
[86] ENSC 2014 DCRR Application M05985 (E-ENSC-R-14) Reply Evidence, Dec 23, 2013, pg. 3, ln 25-28, and ENSC(MEUNSC) IR-2, pg. 1, ln 8-9 and 17-19.
[87] M09096 2020-2022 E1 DSM Resource Plan Application, pg. 53, ln 1-4

Q. Was ENS successful in its appeal?

A. Yes, it was. On September 18, 2018 ENS recovered $14,123,207.10 in HST funds plus accrued interest of $895,164.50 for a total refund amount of $15,018,371.60 ("HST Refund"). The HST Refund has been invested in a short-term interest-bearing account earning an annual interest rate of 2.65%.[88]

Q. Why is the HST Refund an issue in this proceeding?

A. The HST Refund is an issue in this proceeding because the two parties to the 2016-2018 Supply Agreement, E1 and NS Power, have agreed to abide by terms of Schedule B thereto, which provides for any surplus at the end of the Term to be refunded to NS Power unless otherwise directed by the UARB. E1 and NS Power agree that this provision under Schedule B also applies to any surplus realized by E1 delivering Performance Targets at a lower cost than approved in its budget.[89] An example of this type of surplus is discussed in the section dealing with DSM as a FAM Expense below. However, E1 also considers the HST Refund an Asset under the Electricity Efficiency and Conservation Restructuring (2014) Act (the "*Act*").

Q. How does E1 justify the HST Refund being defined as an Asset under the Act?

A. E1 emphasizes that the HST Refund represents monies collected by NS Power through the DCRR mechanism and provided to ENSC for delivery of DSM activities and therefore is

[88] M09096 2020-2022 E1 DSM Resource Plan Application, pg. 53, ln 5-10

[89] M09096 2020-2022 E1 DSM Resource Plan Application, Appendix G, Schedule B, pg. 2, ln 29-31 and M09096 E-9 20190412 NS Power to UARB 2020-2022 DSM Plan Evidence, Section 8. HST/SURPLUS, pg. 28 ln 6-11

an asset of ENSC (succeeded by E1) and supports it claim by referencing the definition of an Asset in subsection 8 of the Act, which states:

> “**Assets acquired on or after Implementation Date**
> 8. Any assets of the Corporation acquired on or after the Implementation Date must be transferred to Nova Scotia Power Incorporated for the benefit of the customers of Nova Scotia Power Incorporated as directed by the [Review] Board. 2014, c.5, s.8.”[90]

Q. How does E1 propose to dispose of the HST Refund?

A. E1 proposes to apply the HST Refund as an adjustment to reduce by an equal amount the annual budget for its proposed 2020-2022 DSM plan, which would reduce the annual amount for its Preferred Plan by approximately $5 million from $43 million to $38 million.

Q. How does E1 support its proposal to use the HST Refund to reduce its requested budget for the 2020-2022 period?

A. E1 argues that the HST Refund should be used to reduce its 2020-2022 annual budget because it:

- aligns the refund with the original use of funds – presumably E1 means here for DSM investment activities;
- enhances affordability of the 2020-2022 DSM Plan;[91]

[90] M09096 2020-2022 E1 DSM Resource Plan Application, pg. 53, ln 12-24
[91] M09096 2020-2022 E1 DSM Resource Plan Application, pg. 54, ln 6-11

- allows for the amounts to be precisely allocated to each rate class, relying on the allocation methodologies as finalized for the 2010-2014 Balance Adjustments.[92]

Q. Did E1 attempt to negotiate with NS Power to find a common view for disposition of the HST Refund as participants in the Supply Agreement?

A. Yes, E1 referred in its Application to holding "a series of discussions on the various approaches" but they were not able to reach agreement with NS Power on a joint recommendation to the UARB.[93]

Q. How does NS Power propose to treat the HST Refund?

A. NS Power states that it "strongly disagrees" with E1's proposal and "requests that the UARB order that the HST Refund be returned to NS Power for the benefit of customers" in accordance with the same above referenced Section 8 of the Act.[94]

Q. Does NS Power's proposal differ from E1's proposal for treatment of the HST Refund?

A. NS Power argues that its proposed treatment is more equitable than E1's because:

a) HST settlement funds were collected from all customers as part of the DSM Rider and should be returned to all customers, not just those participating in DSM programs.

[92] M09096 2020-2022 E1 DSM Resource Plan Application, pg. 55, ln 7-14, and Figure 3, pg. 54, ln 15
[93] M09096 2020-2022 E1 DSM Resource Plan Application, pg. 53, ln 29-31
[94] M09096 E-9 20190412 NS Power to UARB 2020-2022 DSM Plan Evidence, pg. 28 at ln 24-28

b) Applying the HST Refund would benefit customers by reducing short-term rate pressure; and

c) The availability of the HST Refund should not influence the amount of DSM to be approved in E1's application.[95]

Q. Which proposal for disposition of the HST Refund do you support?

A. I find E1's claim to the HST Refund as an asset of E1 is not supported by the timing of the *Act* when the amounts to be refunded were originally collected during the 2010-2012 period. For this same reason, I find NS Power's arguments a) and c) above more compelling because the amounts were collected prior to the change in legislation and they were collected from all customers.

However, NS Power's statement that the HST Refund should be returned to for the benefit of customers and to alleviate short-term rate pressure is not specific enough. NS Power is not making any commitment here to process the HST Refund amount separately after the Board approves the DSM Budget. Further, while it references short-term rate pressure, NS Power does not confirm that it will apply the refund in the first year, leaving open the possibility that it will use the HST Refund to avoid efficiencies in its own operations that would allow it to absorb a higher DSM budget without increasing rates.

Q. What do you recommend for the disposition of the HST Refund?

A. I find that the most accurate and fair way to dispose of the HST Refund is a combination of components of both E1's and NS Power's proposals. I recommend that the HST Refund

[95] M09096 E-9 20190412 NS Power to UARB 2020-2022 DSM Plan Evidence, pg. 29 at ln 9-11

should be returned to customers using E1's calculation reflecting the allocation methodology for collection during the 2010-2012 period, but only after the Board approves the DSM budget so that the amount is received by customers in the next FAM AA/BA filing, as proposed by NS Power for DSM. This will assure that treatment of the HST Refund will not be conflated with cost-effectiveness of E1's proposed budget or NS Power's decision whether to absorb higher DSM costs in lieu of filing for a General Rate Application.

C. BOARD ISSUE #10 - DSM AS FAM EXPENSE

Q. Has NS Power made a proposal to treat DSM costs differently than what is currently prescribed by legislation?

A. Yes, NS Power has proposed that DSM costs be dealt with either as part of the FAM or in a similar manner. As NS Power has $34.05 million in its non-fuel budget apportioned to DSM, NS Power proposes that any variation from that amount (whether a decrease or an increase) approved by the Board for the 2020-2022 DSM Supply Agreement period be apportioned to the FAM account prior to the next General Rate Application (GRA).[96]

Q. How are DSM costs collected now?

A. Pursuant to legislation, NS Power must contract with E1 for an amount of DSM services and recover that amount in its non-fuel rates. Both the amount of DSM and the amount of revenue requirement to be collected through non-fuel rates are fixed during a three-year rate stability period that ends this year. In this proceeding, the UARB may approve a change to the E1 budget above or below the current amount of $34.5 million consistent

[96] M09096 E-9 20190412 NS Power to UARB 2020-2022 DSM Plan Evidence, pg. 30 at ln 3-7

with the goals stated in legislation and based on the evidence presented by the applicants and intervening parties, while NS Power's non-fuel rates would remain fixed.

Q. How does NS Power propose to collect the variation in the approved DSM budget as a surcharge in the FAM?

A. In response to information requests, NS Power proposed that E1's contract cost be included in the Base Cost of Fuel (BCF) rate component and the difference between collection of E1's contract costs and actual costs be reported in a true-up proceeding as the FAM AA (Actual Adjustment) component. Since the FAM BCF and AA rate components are also filed for FAM costs, NS Power proposes tracking and reporting DSM costs separate from FAM costs.

Q. What are the over-arching goals of the legislation that support the requested average annual budget amount?

A. The two over-arching goals of the legislation are to secure long-term benefits for Nova Scotia ratepayers from cost-effective energy efficiency program investments balanced by reasonable short-term rate impacts.

Q. Does E1's proposal exceed the current plan amount?

A. Yes, it does. At the UARB's request, E1 has proposed both its Preferred Plan and an Alternative budget scenario, both of which call for average annual investment amounts that exceed what is collected under the current plan. The Preferred Plan requires a first-year investment level of $43 million, an increase of approximately $8.5 million or 23%, while the Alternative Scenario Plan is based on an average annual investment level of $37 million, an increase of $2.5 million or 7%.[97]

Q. What rationale does NS Power give for treating DSM as a FAM expense?

A. NS Power argues that its proposal to collect the incremental DSM costs enhances non-fuel rate stability in two ways by passing through potential DSM rate increases or decreases sooner than under current legislation.

First, rate stability is enhanced by treating under-recoveries of incremental DSM program costs no differently than those for non-fuel rates. Currently, NS Power holds an under-recovery of FAM costs in a deferral account to be applied at the end of the rate stability period as an offset to current non-fuel costs for the upcoming year. Should the UARB approve one of the higher budgets proposed by E1, this could more than offset any deferral balance, forcing NS Power to absorb the higher E1 budget amount to be recovered in already capped non-fuel rates. NS Power objects to the imposition of higher DSM costs, arguing that having to absorb E1's proposed DSM budget through its non-fuel rates would in turn require it to request a rate increase in a GRA proceeding, which would mitigate against the goal of minimizing short-term rate impacts.

Second, NS Power argues that under their proposal any positive deferral account balances would be applied sooner under the FAM because accumulated DSM payment or credit would flow through the annual FAM AA/BA process, rather than making customers wait until the end of the multi-year rate stability period.[98]

[97] M09096 E-9 20190412 NS Power to UARB 2020-2022 DSM Plan Evidence, pg. 25 at ln 14-19
[98] M09096 NS Power (IG) IR-6 (b) and (c), pg. 2

Q. Does NS Power's proposal to treat DSM as a FAM expense apply only to E1's 2020-2022 planning period?

A. No, NS Power has proposed at the time of the next GRA filing the entire amount of E1's customer funded DSM budget be collected through the FAM by returning to a similar mechanism in use prior to the legislative change.[99] This previous recovery process collected funds allocated to the rate classes through a Demand Side Management Cost Recovery Rider (DCRR) plus a DCRR Balance Adjustment true-up mechanism (BA), with these DSM riders updated in the FAM BCF AA/BA filings.[100]

Q. Does E1 agree NS Power's proposal to treat DSM as a FAM expense?

A. E1 is silent on the issue of treating DSM as a FAM expense. However, E1 implicitly supports DSM as a reduction in the amount of fuel required, thereby lowering fuel costs and putting downward pressure on the FAM.[101]

Q. Why does NS Power believe it cannot absorb E1's proposed increase in the DSM budget without requesting a general rate increase?

A. NS Power argues that to be able to absorb E1's proposed DSM budget without a rate increase, it would have to find an additional $9 million in cost reductions during each year of the 2020-2022 period. NS Power implies that it has the discretion to do so only by making adjustments to its existing OM&G budget of approximately $250 million per year, which it declares is an unreasonable expectation.[102] Instead, NS Power argues that E1

[99] M09096 E-9 20190412 NS Power to UARB 2020-2022 DSM Plan Evidence, pg. 30, ln 7-11
[100] M09096 NS Power (IG) IR-6 (a), pg. 1-2
[101] M09096 2020-2022 E1 DSM Resource Plan Application, pg. 46, ln 23-25
[102] M09096 E-9 20190412 NS Power to UARB 2020-2022 DSM Plan Evidence, pg. 12, ln 1-3

should have sought to restructure its organization and supplier network to reduce future costs rather than request higher budgets.[103] I believe this is a very easy statement for NS Power to make but I have not seen evidence of E1 becoming more productive as the organization matures in terms of reducing administrative costs.

Q. Are there additional implications for ratepayers if the UARB approves E1's request for a higher budget and also agrees to NS Power's request to treat DSM as a FAM expense?

A. Yes, there is a potential for this to cause a different impact by rate class compared to the allocation for non-fuel rates.

Q. Does NS Power provide any evidence that an increase in the E1 contract costs would necessitate NS Power filing a GRA to maintain financial health?

A. No, it does not.

Q. Does NS Power explain why it cannot find further decreases in its OM&G budget to accommodate E1's proposed plans?

A. No, it does not.

[103] M09096 E-9 20190412 NS Power to UARB 2020-2022 DSM Plan Evidence, pg. 12, ln 5-7

Q. Should NS Power be willing to explain why it cannot adjust its OM&G budget to accommodate E1's proposed plans?

A. In lieu of addressing its own budget, NS Power repeats E1's claim that moderately-priced DSM is harder to come by and then makes an analogous claim to having "fewer areas" where it can achieve savings.[104] However, merely claiming the right to reciprocal flexibility is not the same as providing support for NS Power's position, which is missing and should be provided in more detail. For example. NS Power makes three observations to support its argument for a lower E1 budget:

- NS Power states that it will have access to market-based clean energy forecasts to be priced below the incremental DSM costs of $64 MWh in E1's Preferred Plan, an avoided cost metric that NS Power suggests E1 has overlooked.[105]
- NS Power goes further to say that it "is not currently forecasting further capacity additions in the near to mid-term".[106]

In the next breath, NS Power says that distributed energy resources (DER) and non-regulated DSM are curbing load growth organically without the need for electricity incentives NS Power is confusing the funding of efficiency and the funding of eliminating load, The benefits of 'economic' energy efficiency do not go away because some customers install their own behind the meter generation.

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[104] M09096 E-9 20190412 NS Power to UARB 2020-2022 DSM Plan Evidence, pg. 11, ln 24-26
[105] M09096 E-9 20190412 NS Power to UARB 2020-2022 DSM Plan Evidence, pg. 6, ln 5-9
[106] M09096 E-9 20190412 NS Power to UARB 2020-2022 DSM Plan Evidence, pg. 8, ln 13-15

Q. What do you find regarding NS Power's claim that it cannot accommodate any increase in E1's proposed plan within its own budget capacity?

A. While I recognize that NS Power asked E1 to model lower plans with budgets ranging between $27 million and $34 million[107], this is not the same as NS Power negotiating with E1 for the amount that it is willing to contract because it believes this is the amount that is cost-effective for ratepayers. As a result, I find that NS Power should provide further justification for why it did not engage in further negotiations with E1 in a timely manner to produce the lower budget it seeks.

Q. What do you find with regard to E1's claim that DSM should not be defined by the amount of budget remaining under NS Power's rate cap without a rate increase?

A. I find that E1 has justified its request for a budget increase on 1) changes in market trends that dictate 2) pursuit of more complex investment programs. However, the amount of that increase has yet to be fully supported by a detailed budget for those BNI measures that they claim will add to that cost. I applaud E1's commitment to refund surplus amounts not spent during the 2016-2018 period, which is consistent with their first premise and evaluates their budget on current market needs. But by resting its case for a higher budget almost solely on the claim that Nova Scotia should have the capacity to achieve 1.3% percent of electricity generation because other jurisdictions have done the same (and they hit this target once in the last five years) does not demonstrate how they will do so given past performance. Further, the claim that certain programs are more costly to pursue going-forward contradicts E1's achievement that "Nova Scotians have benefited from a robust

[107] M09096 E-9 20190412 NS Power to UARB 2020-2022 DSM Plan Evidence, pg. 25, ln 21-24 and in response to M09096 NS Power IR-07 and IR-09

development of the DSM supplier sector."[108] Either the DSM supplier sector is robust enough to access the 1.3% target by engaging with its customers now or it is not; E1 cannot have it both ways after six years of program development.

Q. What do you conclude based on your observation of this internal contradiction within E1's application?

A. I find that NS Power's criticism that E1 should review its supply costs has validity and should be reviewed for sufficient progress to reach milestones achieved in similar jurisdictions with active BNI-type programs before approving E1's request for its Preferred Plan or, indeed, any increase to its current budget.

Q. Does NS Power confirm whether there is an over or under recovery of targeted DSM spending included in its non-fuel account?

A. Yes, NS Power claims that over the term of E1's current 2016-2018 planning period it has exceeded the target amount of DSM at a lower spend level than approved by the UARB, equal to a $7.1 million surplus. Per the terms of the 2016-2018 DSM Supply Agreement, E1 must refund this surplus to NS Power unless otherwise directed by the UARB.

[108] M09096 E-9 20190412 NS Power to UARB 2020-2022 DSM Plan Evidence, pg. 16, ln 22-25

Q. Does NS Power confirm that it will refund this surplus to customers through the FAM, similar to its proposal to treat any increase or decrease in E1's approved budget?

A. No, it does not. Instead, NS Power requests simply that the funds be returned to NS Power. Without an explicit statement from NS Power on this subject, we are left to speculate that it will use this $7.1 million surplus to offset increases in OM&G costs to avoid a GRA filing.

Q. Are there any intangible benefits associated with opening up E1 funding cost-recovery for NS Power through the FAM?

A. Yes. I believe that removing the conflict of increasing the amount of DSM resource within an IRP action plan and a prudent level of other O&M expenditures will level the playing field between DSM Program resources and the other resource choices such as capitalized generation, transmission and distribution resources as well as purchase power resources.

Q. What do you recommend regarding NS Power's request to treat DSM as a FAM expense?

A. I find that this request is reasonable on a going forward basis because the benefits of DSM are primarily an effective reduction in FAM expense in that FAM costs would be higher in the absence of DSM program participation. I would condition my recommendation to approve this request on the requirement NS Power pass through any penalties imposed on E1 for under-performance.

Q. What do you recommend regarding the $7.1 million DSM surplus accrued over the term of the 2016-2018 supply agreement?

A. The DSM budget is absorbed by NS Power within the non-fuel account during the rate stability period. Therefore, I recommend that 1) NS Power be required to confirm that it will return this $7.1 million DSM surplus to customers according to the same cost allocation methodology used to recover non-fuel costs. I am concerned, however, that if this $7.1 million is not returned to customers as soon as possible, and the UARB approves the higher budget requested for E1's Preferred Plan, that it will be used by NS Power to avoid a GRA. Therefore, I also recommend that the $7.1 million DSM surplus amount be returned to customers during the next FAM AA/BA proceeding.

VI. FINDINGS

Q. Do you have specific recommendations that you would like the Board to consider?

A. Yes, I have will have recommendations for the Board, E1 and NS Power to consider below after I provide a list of more specific findings.

Q. Why do you say you have recommendations also for E1 and NS Power to consider?

A. I've included E1 and NS Power in the recommendations since they will be providing rebuttal evidence, prior to hearings and Board deliberations.

Q. Please provide your list of findings.

A. I have fifteen findings as shown below:

1. E1 has utilized outdated avoided costs in its benefit-cost testing, based on 2014 IRP analyses, despite communications on more recent avoided costs between E1 and NS Power.

2. The DSM budget planning process suffers from unclear objectives for developing a DSM Plan. The DSM Plan setting process could be improved with specific objectives that have come out of IRP and are approved by the Board as to whether or how soon DSM activities should reach a particular savings so long as the programs are economic.

3. Energy Efficiency planning should center around its impact such as energy savings, peak demand reductions, future load objectives such as a maximum, perhaps zero electric growth target, or carbon reductions, not the amount of the budget.

4. E1 extends its activities beyond the implementation of cost-effective measures by targeting and funding the installation of measures that fail to achieve a total resource cost (TRC) test benefit-cost ratio of 1.0, on the basis of adding other programs to capture remaining opportunities even though the measures are uneconomic.

5. E1 is applying the tag of 'lost opportunity' to a measure that is uneconomic under the Board approved TRC test. It may be a lost opportunity to add to the savings achievements of E1 but it is not a lost economic opportunity. It

would be helpful if the Board clarifies that this is a misapplication of the concept of lost opportunity and should not be part of E1's programs.

6. E1 needs to utilize more information on the adoption rates of lighting measures without programs and incentives in order to more accurately capture the impact of free-ridership on program cost effectiveness and incentive design.

7. A substantial portion of the budget can be reduced with adjustments to overly aggressive incentive levels, raising the threshold benefit-cost ratio from 1.0 to 1.2, eliminating the funding of all measures that do not meet the 1.2 benefit-cost ratio threshold, reducing the large amount of lighting focus in the programs and adjusting to a lower level of avoided costs from the 2014 IRP levels..

8. Despite stating that the plan de-emphasizes lighting savings, in 2020 the Direct Installation program in E1's preferred plan, marketed as Small Business Energy Solutions, allocates 82% of the program's total budget on, and derives 89% of its target savings from, lighting programs.

9. E1 has set targets, both in budget and first-year energy savings, and program design of its Custom program in the proposed Preferred Plan similar to 2016 – 2018 levels where it has consistently failed to meet reduced mid-course targets in these years

10. NS Power has requested a symmetrical treatment of any approval of alternative budget levels for E1 in its proposal for incorporating the change in FAM.

11. NS Power's proposal to utilize FAM for cost recovery may increase the collaboration between NS Power and E1 in future DSM planning.

12. E1 has not included evidence that its organization can successfully achieve implementation of a dramatic increase in program activity represented by the large percentage increases in the proposed budget for the Preferred Plan.

13. The amount of HST funding of E1 that is no longer required to hold in reserves is by rights the property of the NS Power customers.

14. Neither NS Power nor E1 has proposed programs that particularly increase support of the small business community

15. E1 inappropriately applies the terminology “lost opportunity” to non-economic measures.

VII. RECOMMENDATIONS

Q. What recommendations do you have for consideration by the Board, E1 and NS Power?

A. I have several recommendations that pertain to the specific DSM Plan application and some that pertain to the NS Power IRP process such that future DSM planning and budget applications can be more informed as to the overall need for DSM programs as a resource.

Q. Please provide your recommendations specific to the current DSM Proposed Preferred Plan application.

A. I have seven recommendations as shown below.

A. SUMMARY OF RECOMMENDATIONS

Q. Please provide your recommendations specific to the current DSM Proposed Preferred Plan application.

A. I have seven recommendations as shown below.

1. E1 should be instructed not to promote any measures that have not passed the TRC test analysis with a B/C ratio of less than 1.2
2. The target first year energy savings for E1 should be established at 100 GWh in 2020, 120 GWh in 2021 and 140 GWh in 2022.
3. The E1 budget should be approved at $30 Million (or between $27 and $34.5million) in 2020, and conditionally approved at $34.5 million in 2021 and $41 million in 2022. Further, E1 should be required to file by July 1, 2020 plans for 2021 and 2022, including potential requests for a change in budget.
4. E1 should recalculate the TRC and PAC testing utilizing avoided costs associated with energy and capacity that are reflective of current NS Power system and reset its programs and priorities utilizing the results.
5. The Board should approve the utilization of FAM to credit any reduction in the E1 budget or charge customers to fund any increase.
6. HST funds should be returned to customers through a credit to the FAM
7. The Board should reject the Life Time Energy Savings metric as unnecessary.

Q. Do you have additional recommendations related to the NS Power 2020 IRP that will benefit future DSM Plan applications and review?

A. Since DSM's role in the provincial energy future, short-term and long-term resource objectives, and potential carbon reduction benefits are currently unclear. Future IRP analysis and selection as well as updates should be the place to debate and establish the value of DSM. I offer the following IRP-related recommendations as shown below:

1. IRP analyses and plan considerations should include energy efficiency options of DSM Programs and Policy driven appliance and consumption standards as well as the effects of increased electrification.
2. IRP should study the economics and potential for behind the meter (BTM) generation resource options as resources, potentially customer and utility owned.
3. IRP plans to be studied should test the cost and feasibility of utilizing programmatic and legislative energy efficiency such as Codes and Standards that:
   a. Achieve zero growth in energy consumption through 2040
   b. Achieve a decline in consumption equal to 1 percent per year
4. In order to fully evaluate DSM programs, include metrics in IRP such as CO2 emissions, pollutants (HG, NOX and SO_2), 10, 20 and 30-year revenue requirement impacts, annual levels of average prices of electricity and typical customer bills for each of the first five years of IRP implementation.
5. Require NS Power produce avoided costs from the approved IRP and updated annually to support DSM economic testing, rate design including Renewable to

Retail tariffs, the annual capital expenditure (ACE) filing and any renewable energy procurements.

Q. Does this conclude your testimony?

A. Yes.

DAYMARK
ENERGY ADVISORS

John G. Athas

Vice President and Principal Consultant

John draws on 40 years of diverse electric industry experience to provide clients with valuable insights and strategic perspective. His principal practice areas are resource planning, utility ratemaking and regulation, and contracts and transactions, and he leads business development. John has testified before state and provincial regulatory agencies on issues including resource planning, energy efficiency, utility restructuring utility ratemaking and competitive markets.

INDUSTRY EXPERIENCE

Daymark Energy Advisors | www.daymarkea.com | Worcester, MA

Daymark Energy Advisors is a consultancy that provides economic planning and strategic advisory services to the North American electric and natural gas industries.

Vice President and Principal Consultant | 2016–Present

- Manage business development and brand strategy
- Oversee events participation and marketing materials

Treasurer | 2008-2016

- Manage the company's administrative, accounting, finance, payroll, accounts payables and receivables processes

Principal Consultant | 2009–2016
Managing Consultant | 2006–2009

Consulting practice includes:

- Electric resource evaluations including integrated resource planning
- Utility ratemaking and regulation
- Contracts and transactions
- Utility demand side management program review
- Renewable energy economics and policy

Direct Energy | https://www.directenergy.com/ | Stamford, CT

Direct Energy provides retail electricity, natural gas, and home and business energy-related services to nearly four million customers in North America.

Independent Consultant | 2005

- Developed a business plan for Direct Energy's market entry into the Northeastern U.S. power market.

Cambridge Energy Research Associates | Cambridge, MA

Associate Director, North American Electric Power | 2001–2005
Eastern North American Energy Service Principal | 2002-2005

- Developed independent primary research on various aspects of power markets around the eastern U.S. and Canada
- Responsible for price outlooks for energy and full requirements electric power in the northeastern and midwestern U.S. markets
- Analyzed market structures, supply and demand balances, price caps, market clearing prices, capacity markets, and generation technologies

Northeast Utilities (now Eversource) | Berlin, CT

Director, Retail Business Strategy, Select Energy | 1997–2000
Managing Director, Marketing, Select Energy | 1997–2000
Director, Market Pricing and Policy | 1995–1997
Manager, Market Analysis | 1990–1995
Manager, Strategic Analysis and Long-Term Resource Planning | 1987–1990
Multiple positions within the Capacity Planning department | 1981–1987

Electric utility leadership included:

- Created the branding and marketing functions for Select Energy's retail energy sales, which was then the largest retail provider in New England
- Developed a service offering and negotiated a contract for the largest aggregation in New England and for the Cape Light Compact, which was the first successful municipal aggregation
- Led the rates and cost of service departments through utility restructuring
- Led a strategic planning special team in the areas of diversification and marketing
- Managed the integrated resource planning function from its inception in 1986 to 1991
- Negotiated economic development and special flexible rate tariffs contracts with large commercial and industrial customers

Accolades:

- Recipient of the 1998 Northeast Utilities Chairman's Award for innovation in developing offerings and negotiating with large aggregation groups
- Recipient of the 1996 Northeast Utilities Chairman's Award and the 1996 Retail Business Group's President's Award for the role in leading efforts in the Retail Competition Pilot in New Hampshire
- Recipient of Northeast Utilities' 1994 Retail Business Group's President's Award for developing and successfully implementing special utility contracting efforts

United Technologies Corporation | Hartford, CT

Analytical Engineer for International Fuel Cells and Pratt & Whitney Aircraft | 1977–1981

LICENSES, TESTIMONY & PRESENTATIONS

Licenses

Licensed Professional Engineer in the State of Connecticut

Expert Testimony

FORUM	ON BEHALF OF	MATTER
Georgia Public Service Commission	Georgia Public Service Commission Public Interest Advocacy Staff	Georgia Power Company's 2019 Integrated Resource Plan and Application for Certification of Capacity from Scherer Unit 3 and Plant Goat Rock Units 9-12 and Application for Decertification of Plant Hammond Unit 1-4, Plant Macintosh Unit 1, Plant Estatoah Unit 1, Plant Langdale Units 5-6, and Plant Riverview Units 1-2 Docket No. 42310
Arkansas Public Service Commission	Arkansas Public Service Commission General Staff	Application of the Empire District Electric Company for approval Holding Company Interests in Renewable Wind Generation Facilities Docket No. 18-029-U
Nova Scotia Utility and Review Board	Nova Scotia Small Business Advocate	Public Utilities Act, R.S.N.S. 1989, c.380, as amended Application by NS Power for approval of the 2019 Annual Capital Expenditure Plan Matter No. M08984
Rhode Island Public Utilities Commission	Division of Public Utilities and Carriers	The Narragansett Electric Company d/b/a National Grid investigation as to the propriety of proposed tariff changes Docket No. 4770
Arkansas Public Service Commission	Arkansas Public Service Commission General Staff	Application of the Empire District Electric Company for approval of its Customer Savings Plan, which addressed the acquisition of wind generation assets and a coal generating unit retirement Docket No. 17-061-U
Arkansas Public Service Commission	Arkansas Public Service Commission General Staff	Application of Southwestern Electric Power Company for approval to acquire a wind generating facility and to construct a dedicated generation tie line Docket 17-038-U
Nova Scotia Utility and Review Board	Nova Scotia Small Business Advocate	Public Utilities Act, R.S.N.S. 1989, c.380, as amended CI 47124 – NS Power Advanced Metering Infrastructure Project Application Matter No. M08349
Nova Scotia Utility and Review Board	Nova Scotia Small Business Advocate	Public Utilities Act, R.S.N.S. 1989, c.380, as amended CI 29807 - Tusket Falls Main Dam Refurbishment Project Matter No. M08162
Arkansas Public Service Commission	Arkansas Public Service Commission General Staff	Entergy Arkansas, Inc. application for an order finding the deployment of advanced metering infrastructure to be in the public interest and exempt from certain application rules Docket 16-060-U

FORUM	ON BEHALF OF	MATTER
Oklahoma Corporation Commission	Oklahoma Hospital Association	Application of Oklahoma Gas & Electric, for an order from the Commission to modify its rates, charges, and tariffs for retail electric service in Oklahoma Cause No. PUD 201500273
New Brunswick Energy and Utilities Board	New Brunswick Public Intervener	Review of New Brunswick Power Corporation's Class Cost Allocation Study (CCAS) methodology Matter 271
Nova Scotia Utility and Review Board	Nova Scotia Small Business Advocate	Application by Nova Scotia Power Inc. concerning sales of renewable low impact electricity generated within Nova Scotia by a retail seller to a retail customer pursuant to the Electricity Act Matter No. M06214
Newfoundland and Labrador Board of Commissioners of Public Utilities	Newfoundland & Labrador Hydro	2013 AMENDED General Rate Application Prudence Review Docket No. P.U. 28(2013)
Oklahoma Corporation Commission	Oklahoma Hospital Association	Application of Public Service Company of Oklahoma, an Oklahoma corporation, for an adjustment in its rates and charges and the electric service rules, regulations, and conditions for electric service in the state of Oklahoma Cause No. PUD 201500208
Nova Scotia Utility and Review Board	Nova Scotia Small Business Advocate	Application by EfficiencyOne for approval of a supply agreement for electricity efficiency and conservation activities between EfficiencyOne and Nova Scotia Power Inc., the establishment of a final agreement between the parties, and approval of the 2016-2018 Demand Side Management (DSM) Plan-E-ENSC-R-2015 Matter No. M06733
Arkansas Public Service Commission	Arkansas Public Service Commission General Staff	Petition of Entergy Arkansas, Inc. requesting approval of the acquisition of a generating unit at the Union Power Station to serve its retail customers Docket 14-118-U
Arkansas Public Service Commission	Arkansas Public Service Commission General Staff	Petition of Entergy Arkansas, Inc. for a declaratory order regarding a purchase power agreement for a renewable resource Docket 15-014-U
New Brunswick Energy and Utilities Board	New Brunswick Public Intervener	Review of New Brunswick Power Corporation's General Rate Application Matter 272
Michigan Public Service Commission	Michigan Environmental Council National Resources Defense Council	Consumers Energy Company general electric rate case GRC-U-17735. April 2015.
Manitoba Public Utilities Board	Manitoba Public Utilities Board	Needs for and alternatives to (NFAT) review of Manitoba Hydro's proposal for the Keeyask and Conawapa generating stations (2013/14). In this proceeding, the filing of reports by Daymark Energy

FORUM	ON BEHALF OF	MATTER
		Advisors were the basis for cross examination of Mr. Athas.
Commonwealth of Virginia, State Corporation Commission	Southern Environmental Law Center	Virginia Electric and Power Company's integrated resource plan filing pursuant to § 56-597 et seq. of the Code of Virginia Case No. PUE-2013-00088
Nova Scotia Utility and Review Board	Nova Scotia Small Business Advocate	Application by Nova Scotia Power Incorporated for approval of its 2014 Annual Capital Expenditure Plan Matter No. M05994
Arkansas Public Service Commission	Arkansas Public Service Commission General Staff	Petition of the Southwestern Electric Power Company for a declaratory order finding that certain renewable wind energy purchase agreements are prudent, and wind energy purchase agreements are energy only contracts eligible for cost recovery through the Energy Cost Recovery Rider Docket No.13-033-U
Nova Scotia Utility and Review Board	Nova Scotia Small Business Advocate	Application by Nova Scotia Power Incorporated for approval of capital expenditures for 2013 for the South Canoe Wind Project - CI#42127 for $93,091,536 Matter No. M05416
Nova Scotia Utility and Review Board	Nova Scotia Small Business Advocate	Application by Nova Scotia Power Incorporated for approval of its 2013 Annual Capital Expenditure Plan Matter No. M05339
Arkansas Public Service Commission	Arkansas Public Service Commission General Staff	Application of Oklahoma Gas & Electric Company for an order approving a temporary surcharge to recover the costs of a renewable wind generation facility Docket No. 12-067-U
Arkansas Public Service Commission	Arkansas Public Service Commission General Staff	Entergy Arkansas, Inc.'s request for approval of certain wholesale base load capacity to serve Entergy Arkansas customers and a proposed rider recovery mechanism for these and other capacity costs Docket No. 12-038-U
Indiana Utility Regulatory Commission	Citizen's Action Coalition of Indiana	Application of Indiana Michigan Power Company requesting from the Commission, (1) a finding that the Life Cycle Management program for the Donald C. Cooke Nuclear Plant is reasonable and necessary, (2) approving of cost and schedule, (3) authorizing recovery through a periodic Rate Adjustment Mechanism, (4) granting I&M authority to defer costs and (5) granting I&M future rate relief as may be necessary and appropriate Cause No. 44182
Michigan Public Service Commission	Michigan Environmental Council	Indiana Michigan Power Company application for a certificate of necessity pursuant to MCL 460.6s and related accounting authorizations Docket No. U-17026
Arkansas Public Service Commission	Arkansas Public Service Commission General Staff	Arkansas Electric Cooperative Corporation's request for approval of the acquisition of the Hot Spring

FORUM	ON BEHALF OF	MATTER
		Generating Facility near Malvern, Arkansas Docket No. 12-012-U
Nova Scotia Utility and Review Board	Nova Scotia Small Business Advocate	Application by Pacific West Commercial Corporation and NSPI for a load retention rate Matter No. M04862
Nova Scotia Utility and Review Board	Nova Scotia Small Business Advocate	Proposed amendments to Nova Scotia Power Inc.'s load retention tariff Matter No. M04175
Nova Scotia Utility and Review Board	Nova Scotia Small Business Advocate	Nova Scotia Power Incorporated's Main Computer Centre Upgrade, Capital Work Order CI# 40314 Matter No. M04892
Arkansas Public Service Commission	Arkansas Public Service Commission General Staff	Entergy Arkansas, Inc.'s request for approval of the acquisition of the Hot Spring Plant to serve its retail customers Docket No. 11-069-U
Oklahoma Corporation Commission	Oklahoma Attorney General	Integrated resource planning and baseload coal requests for proposals in 2006 through 2007 Causes Nos. PUD 200500516, 200600030, 200700012
Connecticut Department of Public Utility Control (DPUC)	Select Energy	Retail licensing application in 2000
Connecticut Department of Public Utility Control (DPUC) Massachusetts Department of Public Utilities	Northeast Utilities	Several electric industry restructuring proceedings, providing testimony on customer impacts, pricing levels and utility planning
Connecticut Department of Public Utility Control (DPUC)	Northeast Utilities	Several requests for approval of special contracts
Connecticut Department of Public Utility Control (DPUC)	Northeast Utilities	Part of the Connecticut Natural Gas 1991 Rate Application regarding the compatibility of the company's proposal for a natural gas fired chiller promotion program on the basis that it was equivalent to electric utility energy efficiency programs

Invited Speaker, Papers & Conference Presentations

- *Fulfilling on the Promises of Deregulation,* paper published in 1999 on the Select Energy website and presented at the Utility Restructuring Conference in New York City.
- *A Practitioner's Toolkit for Current Issues,* presented at EUCI's Resource Planning Conference in 2012.
- Presented at the U.S. Chamber of Commerce's *Satellite Seminar Series* on deregulation
- Presented at the Massachusetts HEFA-sponsored conference on organizing energy buying groups

- Presented at multiple INFOCAST seminars on negotiating power contracts
- Interviewed on a nationally syndicated news show, *First Business*, on energy deregulation

EDUCATION

M.B.A. | University of Connecticut, Storrs, CT | 1987

M.S. Mechanical Engineering | Rensselaer Polytechnic Institute, Troy, NY | 1982

B.E. Mechanical Engineering | Cooper Union, New York, NY | 1977