BEFORE THE NOVA SCOTIA UTILITY AND REVIEW BOARD

In the Matter of an Application by EfficiencyOne (E1) to the Nova Scotia Utility and Review Board for Approval of Supply Agreement for Electricity 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 2023-2025 Demand Side Management (DSM) Resource Plan

(NSUARB M10473)

Evidence of
Alice Napoleon and Kenji Takahashi

On Behalf of
Counsel to Nova Scotia Utility and Review Board

On the Topic of
EfficiencyOne's 2023–2025 DSM Plan

May 20, 2022

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1. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name, title, and employer.

A. Ms. Napoleon: My name is Alice Napoleon. I am a Principal Associate at Synapse Energy Economics ("Synapse"), located at 485 Massachusetts Avenue, Cambridge, MA 02139.

A. Mr. Takahashi: My name is Kenji Takahashi. I am a Senior Associate at Synapse Energy Economics ("Synapse"), located at 485 Massachusetts Avenue, Cambridge, MA 02139.

Q. Please describe Synapse Energy Economics.

A. Synapse Energy Economics is a research and consulting firm specializing in electricity and gas industry regulation, planning, and analysis. Our work covers a range of issues, including economic and technical assessments of demand-side and supply-side energy resources, energy efficiency policies and programs, integrated resource planning, electricity market modeling and assessment, renewable resource technologies and policies, and climate change strategies. Synapse works for a wide range of clients, including state attorneys general, offices of consumer advocates, trade associations, public utility commissions, environmental advocates, the U.S. Environmental Protection Agency, U.S. Department of Energy, U.S. Department of Justice, the Federal Trade Commission, and the National Association of Regulatory Utility Commissioners. Synapse has over 30 professional staff with extensive experience in the electricity industry.

Q. Please summarize your professional and educational experience.

A. Ms. Napoleon: Since joining Synapse in 2005, I have provided economic and policy analysis of electric systems and emissions regulations, with a focus on energy efficiency program design, administration, cost recovery, and benefit-cost analysis (BCA). In my 17 years at Synapse Energy Economics, I co-authored dozens of reports and led major projects for the U.S. Environmental Protection Agency on quantifying the benefits of clean energy resources and for the U.S.

Department of Energy (DOE) on strategic energy management. I have provided testimony and testimony assistance before public utility commissions across the United States and Canada, including in California, Delaware, Illinois, Kentucky, Missouri, New Jersey, New York, Nova Scotia, South Carolina and Virginia. In Colorado, Maryland, and South Carolina, I facilitated and provided expert analysis on program costs and benefits for demand-side resource policy working groups. In Nova Scotia, I have also provided ongoing expert advice on a range of demand-side management (DSM) issues including incentive setting methodologies, BCA, load forecasting, and locational DSM.

Before joining Synapse, I worked at Resource Insight, Inc., where I supported investigations of electric, gas, steam, and water resource issues, primarily in the context of reviews by state utility regulatory commissions.

I hold a Master's in Public Administration from the University of Massachusetts at Amherst and a Bachelor's in Economics from Rutgers University. My resume is attached as Appendix A.

A. Mr. Takahashi: Since joining Synapse in 2004, I have worked on decarbonization planning, programs, and technologies across the energy sector, with a particular focus on the energy, economic, and environmental impacts of building decarbonization measures—including energy efficiency and distributed energy resources.

Over the past 18 years, I have assessed the design, impact, and potential of energy efficiency and distributed energy resource policies and programs in over 40 jurisdictions across North America for a variety of clients, including: environmental groups; municipal, state, and provincial governments; and federal agencies such as U.S. EPA and U.S. DOE. I have assessed numerous energy efficiency and demand response potential studies and conducted a meta-analysis of potential studies on behalf of U.S. EPA. I was also the lead author of the best practice reports on energy efficiency programs on behalf of Ontario Energy Board and Prince Edward Island Regulatory and Appeals Commission. In 2019, I led the analysis of energy efficiency and demand response potential as part of solutions to mitigate the expected rate impacts from the Muskrat Falls Project on behalf of the Newfoundland and Labrador Public Utilities Board. Further, I have provided testimony regarding energy efficiency and distributed energy resources before public utility commissions in several states and provinces including Ontario, Massachusetts, New York, New Jersey, and Pennsylvania.

I hold a master's in Urban Affairs and Public Policy with a concentration in Energy and Environmental Policy from the Biden School of Public Policy and Administration at the University of Delaware, and a bachelor's in Law with a concentration in Public Administration from Kansai University in Osaka, Japan.

Q. Have you previously testified before the Nova Scotia Utility and Review Board?

A. Ms. Napoleon: Yes. I provided evidence in Matter Nos. M06247, M08604, and M09096 regarding the 2015, 2019, and 2020–2022 DSM plans on behalf of counsel to the Nova Scotia Utility and Review Board ("Board"). I also provided evidence in the Advanced Meter Infrastructure cases (Matter Nos. M07767 and M08349) and the Smart Grid proceeding (Matter No. M09519). Further, I supported Tim Woolf in Matter No. M06733 regarding EfficiencyOne's 2016 to 2018 DSM plan and Melissa Whited in the Solar Garden proceeding (Matter No. M10176).

A. Mr. Takahashi: No.

Q. On whose behalf are you providing evidence in this case?

A. We are providing evidence on behalf of Counsel to the Board.

Q. What is the purpose of this evidence?

A. The purpose of this evidence is to describe and assess EfficiencyOne's (E1) 2023–2025 DSM Resource Plan, with a focus on the Settlement Plan. This evidence also provides our recommendations to E1 and to the Board.

2. SUMMARY OF CONCLUSIONS AND RECOMMENDATIONS

Q. Please describe your conclusions.

A. Our conclusions are as follows:

- First year energy efficiency savings associated with the Settlement Plan are modestly less than projected for the Round 3 Modeling Preferred Plan but more than the savings for the previous DSM Plan (2020–2022) and for the 2020 IRP Reference Case.
- Energy efficiency peak demand savings for the Settlement Plan are modestly less than projected for the Round 3 Modeling Preferred Plan (4 percent lower) and substantially lower for the previous DSM plan (20 percent lower) but more than the savings and for the 2020 IRP Reference Case.
- The proposed budget for the Settlement Plan is less than the budget for the Round 3 Modeling Preferred Plan but far larger (57 percent greater) than the budget of the previous DSM Plan (2020–2022). Compared to the 2020 IRP Reference Case, the budget for the Settlement Plan is moderately higher (9 percent larger).
- The cost of saved energy for the Settlement Plan is in line with the costs experienced in other jurisdictions. It is also similar to onshore wind in the 2023–2025 period and currently well below the levelized cost of utility-scale solar, offshore wind, and gas combined cycle. We conclude that DSM is highly cost-competitive with other resources, including resources that can help Nova Scotia to comply with the more stringent emissions reductions required by the Environmental Goals and Climate Change Reduction Act.
- At the portfolio level, E1's Settlement Plan is highly cost-effective. Individually, the energy efficiency programs in E1's Settlement Plan are also highly cost-effective using both the Program Administrator Cost (PAC) and total resource cost (TRC) tests. This suggests that there is headroom for increasing DSM investment beyond current levels while maintaining a cost-effective portfolio. On the other hand, the Demand Response program is only

marginally cost-effective based on the TRC (1.1) and not cost-effective under the PAC (0.7).

- E1's inclusion of avoided water and other fuel costs in the benefit-cost analysis (BCA) appears to contradict the Board's finding in Matter M08888 that non-energy impacts should not be considered. The impact of removing these avoided costs would not be material and the portfolio would still be cost-effective using the PAC and TRC tests. These avoided costs should not be included in the PAC in any case. For the TRC, removing non-energy impacts results in an unbalanced test.
- Demand response offers a variety of benefits to the electric system, to the consumers in the province and to the environment. The 2023–2025 DSM Plan provides a suitable framework for demand response. However, there is great uncertainty regarding the ability of the Behavioural DR program to produce winter peak load reductions. Also, E1's DR-related filings do not provide sufficient information for the underlying assumptions for the EV Charging Control program. The proposed peak load impacts from the EV Charging program appear to be overly conservative based on our review of other data sources.
- The focus on investment may do little to ensure that low-income populations experience the benefits of energy efficiency.
- E1 does not have a plan for specific initiatives for development and research, or estimates for associated energy, demand, or carbon savings. While some amount of development and research funding could be appropriate even without a specific plan or estimates of associated benefits, E1 provides no indication of how decisions will be made for this funding.

Q. What are your recommendations?

A. We recommend the following:

- The Settlement Plan should be approved, with modifications as described below.

- The Board should either put more emphasis on the PAC, which should not account for participant costs or participant benefits, and hence is more balanced; or it should launch a process to develop a jurisdiction-specific cost-effectiveness test that reflects the province's policy priorities.
- The Board should approve the proposed demand response program with modifications.
  - We recommend that E1 implement a smaller-scale pilot of the Behavioural DR program to test if and how much winter peak reductions the program can achieve. In addition, we recommend E1 also test and evaluate the impacts of other programmatic approaches such as peak time rebates.
  - E1 should use NSPI's EV load forecast to estimate program participation counts for its EV charging control program.
- We recommend that the Board consider developing and adopting a performance metric related to savings for the low-income segment to ensure that funds are effectively spent and that this population experiences benefits of energy efficiency.
- The Board should require E1 to develop a framework for considering and approving development and research initiatives, projects, and pilots as a condition of approving the proposed budget. The framework should lay out the process, including delineation of roles and responsibilities, for considering and approving development and research activities. It should also specify elements of the study design.

BACKGROUND AND OVERVIEW

Q. Please provide an overview of the process leading up to E1's filing of its proposed 2023–2025 DSM Plan.

A. Leading up to the current DSM Plan, E1 conducted an extensive stakeholder engagement process. This process included multiple stakeholder meetings and three rounds of portfolio modeling. The third round of modeling, which E1 shared with stakeholders in February 2022, produced a Preferred Plan and an Alternate Plan.

On March 11, E1 filed its 2023–2025 DSM proposal with the Board. The letter with the proposal indicated that E1 reached agreement with NS Power on the plan (Settlement Plan), which calls for investment of $173 million, first-year energy savings of 412.7 GWh, and 96.7 MW of system-peak demand savings over the plan period.

From our perspective, the upfront communications resulted in a moderate plan, and we appreciate E1's efforts to engage stakeholders in advance of the plan filing.

3. E1'S DSM PLAN

Energy Savings

Q. What level of energy savings does E1 propose in the Settlement Plan?

A. Table 1 shows first-year energy savings, lifetime energy savings, peak demand savings for energy efficiency, and available demand response capacity, for the Settlement Plan for each of the three plan years. Both annual and lifetime energy savings and available demand response capacity are projected to increase year over year, while peak energy efficiency demand savings would remain relatively flat through the 2023 to 2025 period.

Table 1. Total program savings: annual, lifetime, and peak savings for energy efficiency and available demand response capacity

Year	First-Year Energy Savings (GWh)	Lifetime Energy Savings (GWh)	Peak Energy Efficiency Demand Savings (MW)	Available Demand Response Capacity (MW)
2023	120.7	1,502	26.9	3.0
2024	142.6	1,540	25.6	10.0
2025	149.5	1,639	26.3	17.9
2023–2025 Total	412.7	4,681	78.8	17.9

Q. How do the Settlement Plan savings compare with the savings of the Preferred Plan from the Round 3 Modeling?

A. We show the first-year energy, lifetime energy, and peak demand savings for energy efficiency for the Settlement Plan and the Round 3 Modeling Preferred Plan in Table 2, below.

Table 2. Settlement Plan compared to Round 3 Modeling Preferred Plan savings

2023–2025 Summary			
	First-Year Energy Savings (GWh)	Lifetime Energy Savings (GWh)	Peak Energy Efficiency Demand Savings (MW)
Settlement Plan (March 2022)	412.7	4,681	78.8
Round 3 Modeling Results Preferred Plan (Feb 2022)	427.0	4,845	84
% Change	-3%	-4%	-4%

Source: p.p. 13–20 of 2023–2025 Demand Side Management Resource Plan REVISED DSM Portfolio Scenarios Plan– Preferred Plan & Alternate Scenario (Feb 15, 2022); pp 10-11 of the EfficiencyOne 2023–2025 DSM Resource Plan Filing (March 11, 2022).

Total Settlement Plan annual energy savings over the 2023–2025 period are 3 percent lower than for the Round 3 Modeling Preferred Plan. Likewise, lifetime savings are 4 percent lower for the Settlement Plan than for the Round 3 Modeling Preferred Plan. Settlement Plan peak demand savings are 4 percent lower than for the Round 3 Modeling Preferred Plan.

Q. How do the Settlement Plan savings compare with the savings of the prior three-year plan?

A. We show the first-year energy and peak demand savings for energy efficiency for the Settlement Plan and 2020–2022 Plan in Table 3, below.

Table 3. Settlement Plan vs. 2020–2022 Plan savings

	First-Year Energy Savings (GWh)	Peak Energy Efficiency Demand Savings (MW)
Settlement Plan (2023–2025)	412.7	78.8
Prior Three-Year Plan (2020–2022)	367.8	98.3
% Change	12%	-20%

Q. How do the Settlement Plan savings compare with the energy efficiency savings from the 2020 IRP?

A. We show the first-year energy and peak demand savings for energy efficiency for the Settlement Plan and 2020 IRP in Table 4, below.

Table 4. Settlement Plan vs. 2024 IRP savings

	First-Year Energy Savings (GWh)	Peak Energy Efficiency Demand Savings (MW)
Settlement Plan (2023–2025)	412.7	78.8
Energy Efficiency Savings from 2020 IRP Reference Plan (2023–2025)	381	74
% Change	8%	6%

Budget and Cost of Saved Energy

Q. Please describe E1's proposed budget for the Settlement Plan.

A. As shown in Table 5, E1's proposed budget for the Preferred Plan is $173 million over the three years of the plan. Of that budget, half is dedicated to Business, Non-Profit, and Institutional (BNI) programs, and half is dedicated to residential programs (E1 Evidence, p. 13).

Table 5. Proposed budget for the Settlement Plan

Year	Budget ($ million)
2023	53.1
2024	57.5
2025	62.5
Total	173.0

Q. How does this budget compare to the cost of the Preferred Plan from the Round 3 Modeling?

A. We show the budget for the Settlement Plan and the Round 3 Modeling Preferred Plan in Table 6, below.

Table 6. Settlement Plan compared to Round 3 Modeling Preferred Plan cost

2023–2025 Summary	
	Budget ($ million)
Settlement Plan (March 2022)	173.0
Round 3 Modeling Results Preferred Plan (Feb 2022)	180.3
% Change	-4%

Q. How does this budget compare to the savings of the prior three-year plan?

A. We show the budget for the Settlement Plan and the 2020–2022 Plan in Table 7, below.

Table 7. Settlement Plan vs. 2020–2022 Plan budget

	Budget ($ million)
Settlement Plan (2023-2025)	173.0
Prior Three-Year Plan (2020-2022)	110
% Change	57%

Q. How does this budget compare to investment for energy efficiency assumed in the 2020 IRP?

A. We show the budget for the Settlement Plan and the investment in energy efficiency in the 2020 IRP in Table 8, below.

Table 8. Settlement Plan vs. 2024 IRP energy efficiency investment

	Budget ($ million)
Settlement Plan (2023–2025)	173.0
EE Investment from 2020 IRP (2023–2025)	158.6
% Change	9.1

Q. Please describe the lifetime and first-year cost of saved energy (COSE) for the Settlement Plan.

A. The lifetime COSE of the Settlement Plan is $0.035 per kWh, and the first-year COSE is $0.39 per kWh (E1 Evidence, p. 10).

Q. How does this COSE compare with other utilities?

A. In a study of U.S. energy efficiency program costs, Synapse found that costs range from $0.020 to $0.033 per kwh saved, with a weighted average cost of $0.024 per kWh saved (2019 U.S. $) based on data reported to the U.S. Energy Information Administration from 2010–2019.[1] In 2022 Canadian dollars, that is equivalent to $0.033 per kWh saved.[2]

Q. How does the Settlement Plan compare with the Preferred Plan from the Round 3 Modeling in terms of COSE?

A. We show the proposed first year COSE and lifetime COSE for the Settlement Plan and the Round 3 Modeling Preferred Plan in Table 9, below.

[1] Patrick Knight, Bruce Biewald, and Kenji Takahashi. The cost of energy efficiency programs: Estimates from utility reported datasets (In press).

[2] Based on 2 percent inflation and an exchange rate of $1 U.S. equals $1.28 CAD.

Table 9. Settlement Plan and Round 3 Modeling Preferred Plan COSE

2023–2025 Summary		
	First year COSE (2023 $/kWh)	Lifetime COSE (2023 $/kWh)
Settlement Plan (March 2022)	$ 0.390	$ 0.035
Round 3 Modeling Results Preferred Plan (Feb 2022)	$ 0.400	$ 0.035
% Change	-3%	0%

Source: p.p. 13-20 of 2023-2025 Demand Side Management Resource Plan REVISED DSM Portfolio Scenarios Plan– Preferred Plan & Alternate Scenario (Feb 15, 2022); pp 10-11 of the EfficiencyOne 2023-2025 DSM Resource Plan Filing (March 11, 2022).

Q. How does the COSE compare to the cost of other energy resources?

A. We show the levelized cost of saved energy for the Settlement Plan and the levelized cost of other energy resources in the 2020 IRP in Table 10, below.

Table 10. Settlement Plan vs. 2020 IRP cost per MWh, DSM and other energy resources

	$/MWh		
	2023	2024	2025
Settlement Plan	$ 51	$ 53	$ 55
Onshore Wind	$ 55	$ 54	$ 53
Solar PV	$ 86	$ 85	$ 83
Offshore Wind	$ 108	$ 105	$ 103
Gas CC Average	$ 77	$ 77	$ 77

Notes:

- *All values are levelized, except the cost of gas.*
- *Consistent with the IRP, all values are in CAD 2019$. We adjusted values using a 2% inflation rate and an exchange rate of $1.31 CAD per $1.00 USD (consistent with the IRP).*
- *The wind and solar costs were extrapolated based on values for 2020 and 2030 from NSPI's final report on the 2020 IRP.*
- *The IRP provided capital and variable operations and maintenance (O&M) costs for a Gas CC but not fixed O&M or fuel costs. We use U.S. Annual Energy Outlook projections for the price of gas for the New England region and the U.S. National Renewable Energy Laboratory Annual Technology Baseline for fixed O&M.*
- *The levelized cost of energy from a Gas CC is dependent on the cost of fuel. The levelized cost of energy for the Gas CC plant is provided in levelized $/kw-year in the IRP. In our analysis, we convert this to levelized $/MWh. We made several assumptions, with inputs from the IRP, the 2021*

National Renewable Energy Laboratory Annual Technology Baseline, and the 2021 U.S. EIA Annual Energy Outlook, in order to complete this calculation.

Q. What does this data show?

A. Our analysis finds that on a levelized basis the cost of DSM is similar to onshore wind in the 2023–2025 period. Of the resources considered, onshore wind and DSM remain the lowest cost resources in the immediate future. The levelized cost of DSM is currently well below the levelized cost of utility-scale solar, offshore wind, and gas combined cycle. We conclude that DSM is highly cost-competitive with other resources, including resources that can help Nova Scotia comply with the more stringent emissions reductions required by the Environmental Goals and Climate Change Reduction Act.

Cost-Effectiveness

Q. Has E1 provided cost-effectiveness results for the Settlement Plan?

A. Yes. E1's cost-effectiveness results, in terms of the PAC test and the TRC test, are shown in Table 11.

Table 11. Cost-effectiveness of the Settlement Plan

2023-2025 Settlement Plan	TRC Test	PAC Test
Residential Energy Efficiency (EE) Programs		
Efficient Product Rebates	1.1	2.2
Existing Residential	1.5	2.4
New Residential	2.6	4.8
Residential Low-Income	1.0	1.2
Residential Sector Total	**1.5**	**2.4**
Business, Non-Profit & Institutional (BNI) Energy Efficiency (EE) Programs		
Efficient Product Rebates	3.7	7.5
Custom Incentives	2.5	4.3
Direct Installation	2.2	3.0
BNI Low-Income	2.8	7.6
BNI Sector Total	**2.9**	**5.0**
Energy Efficiency Portfolio Total (includes Enabling Strategies and energy efficiency programs)	**2.0**	**3.3**
Demand Response (DR) Program		
DR Program Total	**1.1**	**0.7**
Overall portfolio (includes Enabling Strategies, energy efficiency, and demand response)	**2.0**	**2.9**

Sources: E1 2023-2025 DSM Resource Plan Application, Table 1 and Table 2.

Q. How do you interpret the cost-effectiveness results?

A. At the portfolio level, E1's Settlement plan is highly cost-effective. The PAC result for the portfolio means that for every dollar of investment in DSM, the system realizes \$2.90 in benefits. The TRC result for the portfolio means that for every dollar of investment in DSM, the system and participants realize \$2.00 in benefits. Individually, the energy efficiency programs in E1's Settlement Plan are also highly cost-effective using both the PAC and TRC tests. The high cost-effectiveness of the programs and the portfolio further suggests that there is headroom for increasing DSM investment beyond current levels while maintaining a cost-effective portfolio.

On the other hand, the Demand Response program is only marginally cost-effective based on the TRC (1.1) and not cost-effective under the PAC (0.7). We discuss the Demand Response program in the following section.

Q. Do you have any concerns with E1's analysis of the cost-effectiveness of the Settlement Plan?

A. Yes. E1 has included non-electric fuel costs and reduced water costs in the TRC and PAC calculations (E1 RIR to NSUARB IR-09). However, the April 15, 2020 Decision in M08888 found that Board did not have jurisdiction to take non-energy impacts into account in cost-effectiveness testing.[3] The decision in M0888 regarding non-energy impacts was issued after the Board's Decision of August 2, 2019 in the 2020–2022 DSM Plan matter (M09096); hence, the current 2023–2025 DSM Plan matter is the first time that the finding of the M08888 Decision is required to be applied.

Q. Are non-electric fuel costs and reduced water costs types of non-energy impacts?

A. The Decision in M08888 does not set forth a definition for non-energy impacts but suggests that they are anything that does not directly impact the use of electricity, which would include avoided water and other fuels.[4]

Q. How do other jurisdictions treat avoided non-electric fuel and reduced water costs?

A. Some jurisdictions consider other fuel and water savings "readily measurable" impacts. These readily measurable impacts are included in the TRC as they stand in contrast to the more difficult-to-quantify non-energy impacts that the Decision mentions as being too far afield from the definition of electricity efficiency and conservation activities in the Public Utilities Act:

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[3] Nova Scotia Utility and Review Board, Decision in M08888, April 15, 2020.
[4] Id., p. 17.

"The Board refers back to certain of the non-energy benefits referenced in the Vermont Energy evidence, such as noise reduction, property value, reduction in labour costs, health benefits and an array of environmental benefits. Such a broad array of considerations cannot be squared with the definition of electricity efficiency and conservation activities in the Public Utilities Act."[5]

These avoided costs do not have an impact on electric system costs, and thus they are not included in the PAC.

Q. Does E1 explain why it included the non-electric fuel and reduced water costs in the TRC and PAC calculations?

A. E1 indicates that these avoided costs have historically been included in the TRC and PAC test calculations for the DSM Plan applications (E1 RIR to NSUARB IR-09). E1 also states that:

Both non-electric fuel costs and reduced water costs represent quantifiable resource impacts, with non-electric fuel costs representing an energy impact, as opposed to a non-energy impact or benefit. E1 submits that the focus of the Vermont Energy Investment Corporation's (VEIC) work in Nova Scotia represented customer-facing non-energy impacts based on the work of Massachusetts and other American jurisdictions, as opposed to resource impacts (E1 RIR to NSUARB IR-09).

Q. What impact would excluding non-electric fuel and reduced water costs have on the BCA?

A. The impact would not be material and the portfolio would still be cost-effective using the PAC and TRC tests. E1 indicates that additional non-electric fuel costs decrease the cost-effectiveness of the measures that contain those impacts and represent 0.4 percent of total avoided costs on an absolute Net Present Value

[5] Id, p. 17.

(NPV) basis. Impacts from water savings are also very small: water savings represent 0.002 percent of total avoided costs on an absolute net present value basis (E1 RIR to NSUARB IR-09).

Q. What do you conclude regarding E1's inclusion of non-electric fuel costs and reduced water costs in the BCA?

A. Since these avoided costs do not have an impact on electric system costs, they should not be included in the PAC in any case. While including these avoided costs in a TRC is consistent with how the TRC is generally defined, these avoided costs should not be included in the BCA for the TRC test in keeping with the Board Decision in M08888. However, removing these costs from the TRC will result in a test that is skewed. A TRC that includes participant costs but does not include participant benefits is inherently unbalanced.

Q. What do you recommend regarding cost-effectiveness testing?

A. The Board should put more emphasis on the PAC, which should not account for participant costs or participant benefits, and hence is more balanced; or it should launch a process to develop a jurisdiction-specific cost-effectiveness test that reflects the province's policy priorities. Development of a jurisdiction-specific test is laid out in the *National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources*, including energy efficiency and demand response.[6]

5. ASSESSMENT OF SETTLEMENT PLAN PROPOSAL

Reducing Peak Load Growth in the Province

Q. What is the projected energy load growth in the province?

A. According to NS Power's 2022 Load Forecast Report, energy consumption is projected to remain relatively flat over the next 10 years, as shown in Table 12.

[6] National Energy Screening Project, 2020. National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources. Available at, https://www.nationalenergyscreeningproject.org/national-standard-practice-manual/.

Table 12. Forecast total system energy, 2013–2032

Year	Net System Requirement (GWh)	Growth (%)
2013	11,194	6.9
2014	11,037	-1.4
2015	11,099	0.6
2016	10,809	-2.6
2017	10,873	0.6
2018	11,250	3.5
2019	11,077	-1.5
2020	10,723	-3.2
2021	10,902	1.7
2022	11,144	2.2
2023	11,163	0.2
2024	11,240	0.7
2025	11,265	0.2
2026	11,298	0.3
2027	11,319	0.2
2028	11,366	0.4
2029	11,363	0.0
2030	11,371	0.1
2031	11,414	0.4
2032	11,519	0.9
Compound Annual Growth, 2023-2032		0.3
10-year projected Growth, 2023-2032		3.0
Compound Annual Growth, 2013-2032		0.1
20-year Growth, 2013-2032		2.9

Source: 2022 Load Forecast Report, Figure 3.

Unlike energy, demand is projected to show marked growth over the next ten years. As shown in Table 13, peak demand is expected to grow 25 percent over the 2013–2032 period. Considering 2023–2032 only, peak demand is expected to grow 16 percent.

Table 13. Historical and forecast system peak demand, 2013–2032

Year	System Peak (MW)	Growth (%)
2013	2,033	8.0
2014	2,118	4.2
2015	2,015	-4.9
2016	2,111	4.8
2017	2,018	-4.4
2018	2,073	2.7
2019	2,060	-0.6
2020	2,050	-0.5
2021	1,968	-4.0
2022	2,165	10.0
2023	2,185	0.9
2024	2,215	1.4
2025	2,253	1.7
2026	2,291	1.7
2027	2,326	1.5
2028	2,361	1.5
2029	2,398	1.6
2030	2,434	1.5
2031	2,479	1.9
2032	2,532	2.1
Compound Annual Growth, 2023–2032		1.5
10-year projected Growth, 2023–2032		16.0
Compound Annual Growth, 2013–2032		1.1
20-year Growth, 2013–2032		24.5

Source: 2022 Load Forecast Report, Figure 3.

Q. What do these forecasts suggest for DSM planning?

A. Targeting demand growth with DSM and demand response, as proposed by E1, is appropriate in light of peak load growth trends.

Demand Response

Q. How has E1 incorporated demand response in its 2023–2025 DSM Plan?

A. E1 incorporated a portfolio of six demand response programs in the 2023–2025 DSM Plan with a projected peak demand reduction of 17.9 MW from 2023 through 2025. E1 engaged Guidehouse (formerly Navigant Consulting) to develop the portfolio of demand response programs including demand response modeling and a Demand Response Roadmap (Attachment 5), which were built on the 2019 Potential Study. The total budget for the Demand Response program portfolio is approximately $10 million. E1 also assumed an additional $2.1 million investment by NSPI on the same demand response programs (Appendix A - Attachment 6 - 2023–2025 Demand Response Technical Tables).

Q. Please provide a summary of the six demand response programs.

A. The proposed six demand response programs are:

- Direct Load Control (DLC) program
- Behind-the-Meter (BTM) Battery Control program
- Business, Non-Profit & Institutional (BNI) Curtailment program
- Behavioural DR program
- Critical Peak Pricing program
- EV Charging Control program

Table 14 provides detailed program costs by sector that E1 expects to spend for the 2023–2025 planning timeframe, excluding the costs by NSPI. The largest program in terms of program costs is the DLC program (50 percent of the total cost), with the majority of the program cost allocated to residential customers. The second largest program is the BNI Curtailment program that accounts for 33 percent of the total budget. The rest of the programs have much smaller budgets accounting for about 2 to 9 percent of the total budget.

Table 14. Proposed program costs for 2023-2025 by program and sector (excluding NS Power's costs)

	Residential	Non-Residential	Total
BNI Curtailment		$3,290,918	$3,290,918
DLC	$4,546,953	$484,274	$5,031,227
CPP	$50,070	$106,348	$156,418
BTM Battery Control	$271,785	$676,976	$948,761
EV Charging Control	$352,043		$352,043
Behavioural DR	$233,076		$233,076
Total	**$5,453,926**	**$4,558,517**	**$10,012,443**

Source: Appendix A - Attachment 6 - 2023-2025 Demand Response Technical Tables (Settlement)

Table 15 provides the projected program costs for 2023–2025 including NSPI's program costs. Most of the program costs increase by about 10 percent with NSPI's costs while the costs for the EV Charging Control program and the CPP program increase by about 40 percent and 840 percent respectively. Because the CPP program is a pricing program, E1 assumes the majority of the program cost is borne by NSPI.

Table 15. Proposed program costs for 2023–2025 by program and sector (including NS Power's costs)

	Residential	Non-Residential	Total
BNI Curtailment		$3,696,029	$3,696,029
DLC	$4,824,439	$525,945	$5,350,383
CPP	$605,540	$705,163	$1,310,704
BTM Battery Control	$306,829	$763,641	$1,070,470
EV Charging Control	$495,205		$495,205
Behavioural DR	$262,131		$262,131
Total	$6,494,143	$5,690,779	$12,184,922

Source: Appendix A - Attachment 6 - 2023-2025 Demand Response Technical Tables (Settlement)

Table 16 shows projected cumulative peak reductions for these programs. In terms of peak load reductions, the BNI Curtailment is expected to offer the largest impact with 9 MW by 2025 (about 50 percent of the portfolio impact). The DLC program offers the second largest peak savings with 6 MW by 2025.

Table 16. Projected cumulative peak reductions for 2023–2025 by program and sector (MW)

	Residential	Non-Residential	Total
BNI Curtailment		9.00	9.00
DLC	5.40	0.50	6.00
CPP	0.02	0.01	0.03
BTM Battery Control	0.50	1.20	1.70
EV Charging Control	0.08		0.08
Behavioural DR	1.10		1.10
Total	7.10	10.70	17.90

Source: Appendix A - Attachment 6 - 2023-2025 Demand Response Technical Tables (Settlement)

Q. Do you support the inclusion of the demand response programs in the 2023–2025 DSM Plan?

A. Yes. Demand response offers a variety of benefits to the electric system, to the consumers in the province, and to the environment. Demand response can avoid costly traditional supply solutions (such as energy procurements and generation capacity and system investments) with lower costs. Demand response measures such as energy storage and thermal storage (e.g., hot water tank) can also absorb excess renewable generation and thereby promote the integration of renewable energy resources on the grid. Further, as electric vehicles and building electrification (e.g., heat pump) will be promoted further in the future, the role of targeted demand response will be vital to manage growing loads on congested distribution systems.

We believe the 2023-2025 DSM Plan is a suitable framework for demand response and that E1 should help promote demand response as much as possible in coordination with NSPI. E1 is uniquely positioned to promote demand response by taking advantage of its program development and delivery capabilities as well as its customer outreach channels.

Q. Do you have any concerns about any aspect of E1's demand response program plan?

A. While the overall demand response program savings and costs appear reasonable, we have concerns about a few aspects of the filing specific to the Behavioral DR program and the EV charging control program.

Q. Please provide a high level summary of the Behavioral DR program.

A. The Behavioral DR program sends targeted notifications and messaging to residential customers in order to encourage them to reduce their load during peak days. The program offers no financial incentives. The design of this program is similar to a typical residential energy efficiency behavior program except that this program targets only a few hours on peak days. E1 has a plan to reduce winter peak loads of about 1 MW by 2025 with the Behavioral DR program at a program investment of about $233,000 by E1 and $29,000 by NSPI (Appendix A - Attachment 6 workbook, “19. Annual Cost_Option" tab).

Q. Please describe your concerns about the Behavioral DR program.

A. Many utilities have implemented behavioral programs over the past decade across North America. However, such programs focus on annual energy savings instead of peak load savings. While some programs report peak load savings, such savings are for the summer season. We are also not aware of any utilities that implement behavioral programs to reduce winter peaks.

Q. How did Guidehouse develop winter peak load reductions from the Behavioral DR program?

A. In response to our IR-21, E1/Guidehouse mentions that it relies on a single meta-analysis study titled “2019 National Grid Behavioural Demand Response Evaluation Findings,” conducted by Guidehouse for National Grid. This study summarized peak savings from four utility jurisdictions: Consumers Energy in Michigan, DTE Energy in Michigan, Efficiency Vermont for Green Mountain Power, and Portland General Electric (PGE) in Oregon. However, it appears that all four jurisdictions except PGE targeted summer peak reduction through their behavior demand response programs. Even for the PGE’s program, the report mentioned that “There were 6 events in each summer; events were also called in the winter but those will not be discussed in this memo." Thus, the applicability and reliability of the results from this study for winter peak reductions in Nova Scotia is questionable.

Q. Did you review PGE's program performance on winter peaks? If so, please describe it.

A. Yes. PGE implemented a Residential Pricing Pilot program (also called Flex 1.0 pilot) which incorporated three program components: (a) opt-in peak time rebate (PTR), (b) opt-in time-of-use rate and PTR, and (c) behavior demand response (BDR) public alert strategy. The last component is similar to the Behavior DR program E1 has proposed. PGE found few winter peak load impacts from customers served by the BDR approach, with negative 0.7 percent in the morning (slightly increased loads) and 1 percent in the afternoon on peak days.[7] On the other hand, PGE found about 2 to 13 percent of winter peak reductions by customers who receive financial incentives under the first two program approaches. Based on this pilot demand response program, PGE developed and offered an opt-in peak time rebate to residential customers in 2019 as the Flex 2.0 pilot.[8]

Q. What is your recommendation for the Behavioural DR program?

A. There is a great uncertainty about winter peak load reductions from this program as mentioned above. Thus, we recommend that E1 implement a smaller-scale pilot program and test if and how much winter peak reductions the proposed Behavioural DR program can achieve. In addition, we recommend E1 also test and evaluate the impacts of other programmatic approaches such as peak time rebates, which were tested and implemented by PGE.

Q. Please provide a high level summary of the EV Charging Control program.

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[7] Cadmus. 2018. *Flex Pricing and Behavioral Demand Response Pilot Program*. Table 2, page 5. Available at: https://edocs.puc.state.or.us/efdocs/HAH/um1708hah16432.pdf.

[8] Cadmus. 2020. Flex 2.0 Demand Response Pilot Program – Evaluation Report. Available at: https://edocs.puc.state.or.us/efdocs/HAQ/um1708haq124912.pdf.

A. The EV Charing Control Program manages EV charging by controlling it either through the EV supply equipment or onboard telematics in the vehicle. This program targets residential EVs and offers $32 incentive per kW of peak reduction per year. E1 has a plan to reduce winter peak loads by about 0.08 MW by 2025 (the DR Roadmap, page 40). The total program investments for the 2023 to 2025 period are about $352,000 by E1 and $143,000 by NSPI (Appendix A - Attachment 6 workbook, "19. Annual Cost_Option" tab).

Q. What is your concern about the EV Charging Control program?

A. E1's demand-response-related filings including Guidehouse's DR Roadmap do not provide sufficient information for the underlying assumptions for the EV Charging Control program such as EV forecasts and kW peak reduction per vehicle. This lack of key data for this EV program is problematic especially because many industry experts project a rapidly growing number of EVs over the coming decade, and because it is vital to fully understand the magnitude of the change and take advantage of the change as the opportunity to manage EV loads as a key demand response resource. Thus, it is very important to use the most up-to-date and best available information to assess the potential of EV's demand response capability and develop a plan based on the potential.

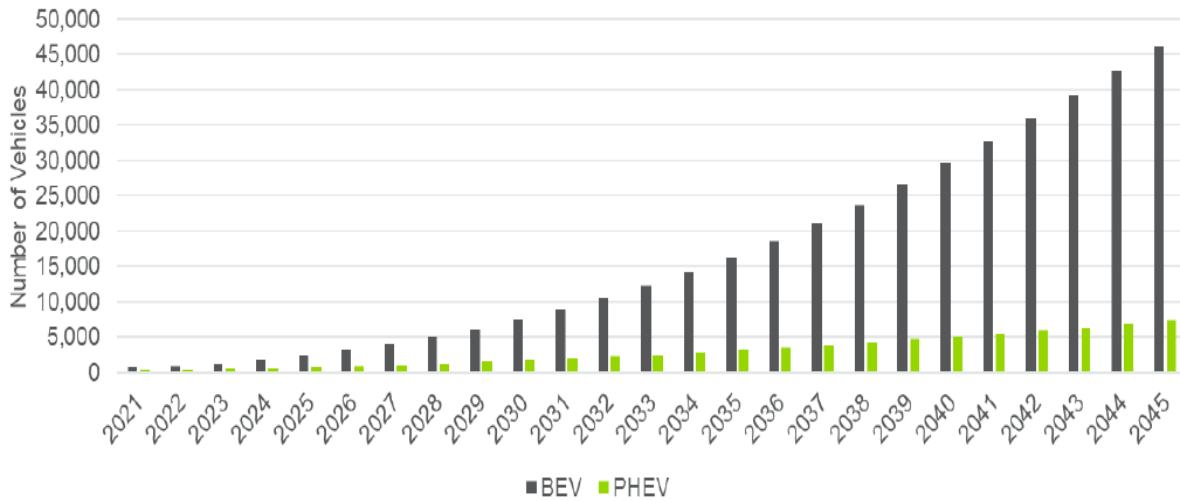
Further, we are also concerned that the proposed peak load impacts from this program are likely to be overly conservative based on our review of other data sources.

Q. Please describe your concern about EV forecasts from EV charger controls.

A. One of the major issues with the proposed EV Charging Control program is that E1 or Guidehouse did not provide their EV forecast in their analysis of EV Charging Control potential provided in the DR Roadmap. While the 2019 Potential Study provided a forecast of EVs, it is not clear if Guidehouse used the same EV load forecast in its DR Roadmap. This EV forecast assumes approximately 2,500 EVs in 2025 as shown in the figure below. The DR Roadmap assumes "20% steady state participation level (as % of eligible vehicles)" and "Ramps up to 60% of steady state participation level by 2025."

This appears to mean that 12 percent of eligible vehicles (20 percent times 60 percent, or 12 percent) will participate in the program by 2025. Applying the 12 percent to 2,500 EVs for 2025, we expect 300 EVs/charging controls in 2025. However, according to the DR Roadmap, Guidehouse assumed 179 charging controls in 2025 as shown in Table 17 below, along with EV peak kW reduction and kW reduction per control.

Figure 1. EV forecast in the 2019 Potential Study



Source: Navigant. 2019. Nova Scotia Energy Efficiency and Demand Response Potential Study for 2021-2045, page 94.

Table 17. EV peak reduction and charging control counts

	EV peak kW reduction	EV charging controls	kW per control
2023	-	-	
2024	0.02	36	0.43
2025	0.08	179	0.43

Source: Appendix A - Attachment 6 - 2023-2025 Demand Response Technical Tables (Settlement).

More importantly, NSPI recently developed its own EV forecast including peak impacts from EVs (Table 18). NSPI used two different assumptions (0.9 kW/vehicle and 1.3 kw/vehicle) to estimate peak load impacts. According to this forecast, NSPI forecasts 15,680 EVs in 2025.[9] Applying the 12 percent factor (mentioned above) to this forecast, the number of EVs and charging controls would be 1,882. This is an order of magnitude higher participation rate in 2025 than E1 assumes.

Table 18. EV forecast and peak load impacts by NSPI

Year	EVs	Peak @ 0.9kW/vehicle (MW)	Peak @ 1.3kW/vehicle (MW)
2022	2,864	2	4
2023	5,978	5	8
2024	10,258	9	14
2025	15,680	14	21
2026	22,232	20	30
2027	29,908	27	40
2028	38,671	35	52
2029	48,465	45	66
2030	59,299	55	81
2031	75,192	69	102
2032	96,612	89	131

Source: NSPI. 2022. 2022 Load Forecast Report. *Figure 28*

In our opinion, E1 should use NSPI's EV load forecast to estimate program participation counts for its EV charging control program.

Q. Please describe your concern about E1's peak reduction estimates for the EV charger control program.

Based on our review of NSPI's EV and associated load forecasts, we conclude that E1's EV and associated peak load impacts from the EV charger control program are overly conservative. In Table 19, we first provide estimates of program participants and peak load reductions based on NSPI's EV forecast, adjusted for the participation rate assumptions used by E1 for the EV charging control program. We assume that participation rates start at 4 percent of EVs in 2023 and increase to 12 percent in 2025. We then provide E1's participant

[9] NSPI. 2022. *2022 Load Forecast Report*. Figure 28.

estimates and peak load reduction estimates for this program in the same table. As mentioned above, NSPI uses two different peak load impact assumptions from EV chargers. The 0.9 kW/vehicle is based on an analysis conducted by E3 for NSPI.[10] The 1.3 kW/vehicle is NSPI's own assumption. The resulting peak load reduction impacts based on NSPI's EV forecast range from 1.7 MW to 2.4 MW in 2025 as shown in Table 19. In contrast, E1's peak reduction estimate is just 0.08 MW, about 3 percent to 5 percent of the peak reduction estimates based on NSPI's EV forecast.

Table 19. EV charger peak reduction estimates, based on NSPI's forecast and E1's EV charger estimates

	EV charger forecast based on NSPI's EV forecast				E1 EV charger forecast	
	NSPI's EV forecast	Projected participants based on E1's assumption	Adjusted peak @ 0.9kW/vehicle (MW)	Adjusted peak @ 1.3kW/vehicle (MW)	E1's participant estimates	E1's peak estimates (MW)
2023	5,978	239	0.2	0.3	0	0.00
2024	10,258	821	0.7	1.1	36	0.02
2025	15,680	1882	1.7	2.4	179	0.08

Q. Are there any other concerns about key assumptions used in E1's EV peak impact analysis?

A. Yes. Based on the participation and total peak reduction estimates by E1/Guidehouse, we estimate that E1/Guidehouse assumes 0.43 kW/vehicle impact. This is less than half of the peak impact NSPI is assuming.

What is the implication of modifying the per unit peak impacts?

A. The levelized cost (based on the TRC test) and benefit-cost ratio of the EV Charging Control program would be significantly improved using NSPI's peak load impact assumptions. Table 20 present our calculation of levelized costs

[10] This estimate reflects EV load shapes, driving and patterns as well as "the diversity of driving behavior, EV types, and 5 charging access across the Nova Scotia driving population." (NSPI. 2022. 2022 Load Forecast Report. page 43)

using NSPI's per unit peak impact assumptions (0.9 kW and 1.3 kW per unit) and compares with E1/Guidehouse's assumption (which was calculated in Table 17 above). The resulting levelized costs are approximately $150/kW-year to $100/kW-year with NSPI's assumptions. Based on the results of levelized costs and benefit-cost ratios for the proposed DR programs (shown in Table 21), we expect that the EV Charging Control program would be more economical than the CPP program at $150/kW-year or than the Behavioural DR program at $100/kW-year. Based on the benefit-cost ratios of these two programs, it is likely that the EV Charging Control program would be cost-effective using NSPI's per unit peak assumptions.

Table 20. Levelized cost estimates with different unit peak savings assumptions

	kW/unit	Levelized Cost ($/kW-yr)
E1/Guidehouse	0.43	315
NSPI assumption 1	0.90	151
NSPI assumption 2	1.30	104

Table 21. TRC levelized cost by DR program

DR program	**TRC Levelized Costs ($/kW-yr.)**	**TRC Benefit-Cost Ratio**
BTM Battery Control	$25	6.35
BNI Curtailment	$81	1.61
Behavioural DR	$125	1.18
CPP	$165	0.94
DLC	$258	0.62
EV Charging Control	$315	0.53

Source: Appendix A - Attachment 5: Demand Response Roadmap. Table 2.

Portfolio Emphasis on Low-Income Customers

Q. What does E1 propose with respect to programs for low-income customers?

A. E1 developed the proposed plan with the objective of dedicating 17–22 percent of investment to low-income customers (E1 Evidence, p. 13). This appears to be responsive to feedback from Synapse, other DSMAG members, and other stakeholders about the importance of addressing the needs of this segment.

Q. How was this goal set?

A. The 17–22 percent investment target is based on the low-income prevalence in the province, per the 2016 Census (Evidence, p. 13).

Q. Do you have any concerns about a focus on investment?

A. Yes, the focus on investment may do little to ensure that low-income populations experience the benefits of energy efficiency. Energy efficiency targeting low-income populations offer these customers a way to manage their bills. Low-income customers generally spend a large portion of household income on energy bills; that is, they have high energy burdens. In general, reducing energy burdens for this population produces proportionally large benefits, both for these customers and for ratepayers as a whole (e.g., through reductions in arrearages and collection expenses).

Q. What do you recommend?

A. We recommend that the Board consider developing and adopting a performance metric related to savings for this segment to ensure that funds are effectively spent and that this population experiences benefits of energy efficiency. First-year savings for low-income households can provide immediate bill relief, while lifetime savings can provide long-term reduction in bills.

Development and Research

Q. What is E1 proposing for development and research?

A. E1 proposes increased investment in development and research specifically targeting innovation in the Settlement Plan (E1 Evidence, p. 13). E1 is budgeting $4.5 million for this: $1.5 million for each of the years 2023, 2024, and 2025 (Appendix A, p. 232). In Appendix A, E1 describes the areas on which it intends to focus:

> *In 2023-2025, E1 will increase its focus on innovation, pilots, and emerging technologies within the development and research category of its Enabling Strategies. These activities enable adoption of measures, offerings, or delivery approaches that demonstrate cost-effectiveness and/or energy savings potential but are not yet fully understood or established in the Nova Scotia market. Focusing on product development and pilot projects generates Nova Scotia-specific findings about cost-effectiveness and market demand before making larger investments in program deployment and delivery. Innovation pilots typically facilitate early-stage analysis and testing on emerging technologies, strategies for program delivery, or initiatives that have been implemented elsewhere but not in the Nova Scotia market. Activities within this area of focus include:*
>
> - *developing programs for current and future DSM Plan portfolios;*
> - *researching and exploring the market potential for emerging technologies and service delivery models;*
> - *redeveloping or improving existing DSM program and product offerings;*
> - *conducting pilots to evaluate new initiatives, program enhancements, measures, or delivery approaches; and*
> - *promoting more favorable market conditions for the increased use of energy-efficient products and services, including strategies to implement demand response activities.*
>
> *Future areas of focus are expected to include electrification, deep retrofits, virtual audits, and market transformation (Appendix A, p. 133).*

Q. Do you have concerns with this proposal?

A. Yes. In E1's response to NSUARB IR-7 indicates that E1 does not have a plan for specific initiatives or estimates for associated energy, demand, or carbon savings. While some amount of development and research funding could be appropriate even without a specific plan or estimates of associated benefits, E1 provides no indication of how decisions will be made for this funding. A framework for considering and approving development and research initiatives, projects and pilots should be fleshed out.

Q. What elements should be included in this framework?

A. The framework should lay out the process, including delineation of roles and responsibilities, for considering and approving development and research activities. Also, consistent with our recommendations in the Smart Grid matter, a framework for research and pilots should specify elements of the study design, including the following:

- What has already been learned from previous research, and how these past and potentially ongoing learnings will relate to the currently proposed research.
- What the gaps are in understanding that the current proposed research proposes to fill.
- What alternative approaches could be used to fill in these knowledge gaps, and why the proposed approach is better than alternatives.
- How the metrics and data collected will enable E1 to decide whether to recommend rolling out to a full-scale program.
- The logic for the pilot study design.
- Whether there are opportunities for learning on other, related issues.

Q. What do you recommend?

A. The Board should require E1 to develop a framework, as described above, as a condition of approving the proposed budget for development and research.

Q. Does this conclude your evidence at this time?

A. Yes, it does.

APPENDIX A: RESUME