
BEFORE THE NOVA SCOTIA ENERGY BOARD

**IN THE MATTER OF THE *PUBLIC UTILITIES ACT*, RSNS 1989, c 380, as
amended**

- and -

IN THE MATTER OF An Application by EfficiencyOne for Approval of the 2027–
2031 Demand-Side Management (DSM) Purchase Agreement between EfficiencyOne
and Nova Scotia Power Inc., the establishment of a final agreement between the parties,
and approval of a 2027–2031 Demand Side Management (DSM) Resource Plan.

(NSEB M12780)

**Evidence of
Alice Napoleon**

**On Behalf of
Counsel to Nova Scotia Energy Board**

**On the Topic of
2027–2031 Demand Side Management (DSM) Resource Plan**

June 23, 2026

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1 **1. INTRODUCTION AND QUALIFICATIONS**

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

3 A. My name is Alice Napoleon. I am a Senior Principal at Synapse Energy
4 Economics, Inc. (“Synapse”), located at 485 Massachusetts Avenue, Suite 3,
5 Cambridge, MA 02139, USA.

6 **Q. Please describe Synapse Energy Economics.**

7 A. Synapse is a research and consulting firm specializing in electricity and gas
8 industry regulation, planning, and analysis. Synapse’s staff includes over 35
9 professionals with extensive experience in economic and technical assessments of
10 demand-side and supply-side energy resources; energy efficiency and demand
11 response policies and programs; benefit-cost analysis (BCA), avoided cost
12 analyses, integrated resource planning; electricity dispatch and economic
13 modeling and assessment; renewable energy and energy storage technologies and
14 policies; transportation and building sector electrification; and climate change
15 strategies. Synapse works for a wide range of clients, including attorney generals,
16 offices of consumer advocates, public utility commissions, environmental
17 advocates, the U.S. Environmental Protection Agency, U.S. Department of
18 Energy, U.S. Department of Justice, the Federal Trade Commission, and the
19 National Association of Regulatory Utility Commissioners.

20 **Q. Please summarize your professional and educational experience.**

21 A. Since joining Synapse Energy Economics in 2005, I have provided economic and
22 policy analysis of electric systems and emissions regulations, with a focus on
23 energy efficiency programs, system decarbonization, and equity. In my 21 years
24 at Synapse, I co-authored dozens of reports and led major projects for the U.S.
25 Environmental Protection Agency on quantifying the benefits of clean energy
26 resources and for the U.S. Department of Energy on strategic energy
27 management. I have provided testimony and testimony assistance before public
28 utility commissions across the United States and Canada, including in California,
29 Delaware, Illinois, Kentucky, Missouri, New Jersey, New York, Nova Scotia,

1 South Carolina, and Virginia. In Nova Scotia, I have also provided ongoing expert
2 advice on a range of demand-side management (DSM) issues including incentive
3 setting methodologies, BCA, load forecasting, and locational DSM.

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

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

10 **Q. Have you previously testified before the Nova Scotia Energy Board?**

11 A. Yes. I testified before the Nova Scotia Utility and Review Board ("NSUARB"),¹
12 before it became the Nova Scotia Energy Board ("NSEB"). I provided evidence in
13 Matter Nos. M06247, M08604, M09096, and M10473 regarding the 2015, 2019,
14 2020–2022, and 2023–2025 DSM plans on behalf of counsel to NSUARB. I also
15 provided evidence in the Advanced Meter Infrastructure cases (Matter Nos.
16 M07767, M08349, and M11003) and the Smart Grid proceeding (Matter No.
17 M09519). Further, I supported Tim Woolf in Matter No. M06733 regarding
18 EfficiencyOne's 2016 to 2018 DSM plan and Melissa Whited in the Solar Garden
19 proceeding (Matter No. M10176).

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

21 A. I am providing evidence on behalf of Counsel to the NSEB.

22 **Q. What is the purpose of this evidence?**

23 A. The purpose of my evidence is to assess EfficiencyOne's ("E1") proposed 2027-
24 2031 Demand Side Management Resource Plan ("DSM Plan" or "Proposed
25 Plan") and provide my conclusions and recommendations.

¹ References to NSEB include NSEB and NSUARB.

1 **2. SUMMARY OF CONCLUSIONS AND RECOMMENDATIONS**

2 **Q. Please describe your conclusions and recommendations regarding the**
3 **Proposed Plan.**

4 A. My conclusions are as follows:

- 5 • E1’s proposed energy and capacity savings from energy efficiency fall far
6 short of the 2022 Evergreen Integrated Resource Plan (IRP) assumptions
7 about savings.
- 8 • In the 2027-2031 DSM Plan, E1 is proposing a level of investment that is
9 decreasing year over year in nominal terms (when accounting for inflation).
- 10 • E1’s proposed plan is cost-effective over every year of the plan term, with a
11 benefit-cost ratio (BCR) at or above 2.0.
- 12 • E1 eliminated strategic electrification based on its interpretation of the Board
13 Decision in Matter No. 12282, E1 Application for approval of a New Benefit-
14 Cost Analysis Test for Evaluating DSM Plans.
- 15 • E1’s proposed residential demand response program offerings are not cost-
16 effective, and their delivery costs appear to be substantially higher as a share
17 of total program costs compared to similar programs in other jurisdictions. E1
18 plans to phase out the residential electric vehicle (EV) and battery demand
19 response programs without any plans for a process evaluation or
20 reconsideration of new program designs mid-plan.
- 21 • E1 does not uniformly account for performance across the full duration of
22 demand response events even though performance may vary during the event
23 period.
- 24 • E1 does not differentiate Business, Non-profit, and Institutional (“BNI”) Back
25 Up Generator incentives between battery and fossil fuel generator participants.
- 26 • E1’s proposal for a mid-cycle adjustment process is unclear and leaves the
27 decision of whether to file a mid-cycle adjustment entirely up to E1.

28 I recommend the following:

- 1 • NSEB should direct E1 to pursue an amount of electrification in its Proposed
2 Plan that does not increase electricity costs at the portfolio level. This could
3 take the form of the strategic electrification resources that E1 included in its
4 Round 2 modeling. As an alternative to including the strategic electrification
5 from the Round 2 modeling, E1 could develop strategic electrification
6 offerings for low- and moderate-income customers who heat with oil.
- 7 • Regarding residential demand response, E1 should seek opportunities to
8 reduce overall costs per kW of capacity by enrolling new participants in
9 pathways with low marginal costs of customer enablement. E1 should also
10 conduct a process evaluation of the delivery of the residential demand
11 response program to identify opportunities for gaining efficiencies and
12 achieving cost reductions. Additionally, E1 should review its competitive
13 procurement process for residential demand response delivery services.
- 14 • E1 should proceed with phasing out the residential EV and battery demand
15 response pathways as planned. However, E1 should evaluate the program in
16 the near term to identify areas for improvement and also reassess cost-
17 effectiveness midway through the plan as the market develops and as program
18 designs in other jurisdictions evolve.
- 19 • E1 should shift to assessing and weighting performance of demand response
20 over the entire duration of the event.
- 21 • E1 should develop differentiated incentives for its BNI demand response
22 program, with higher incentives for battery-based BNI standby resources than
23 for fossil-fueled generators.
- 24 • The NSEB should establish a threshold that requires E1 to propose and file a
25 mid-cycle adjustment if the budget is anticipated to increase or decrease by
26 more than a specified percent of plan and require E1 to provide a mid-cycle
27 adjustment for any program additions. Within this process, E1 should be able
28 to propose program additions or request program budget increases through the
29 mid-cycle adjustment process.

1 **3. BACKGROUND**

2 **Q. Please provide background on the 2027-2031 DSM Plan filing.**

3 A. The last multi-year DSM Plan covered 2023 to 2025. In late 2025, the NSEB
4 approved an extension to the 2023-2025 DSM Plan to include 2026 (the 2026
5 Extension filing) and bridge the gap between that three-year plan and the five-
6 year plan starting in 2027. Consistent with E1’s convention, I will refer to the
7 combined 2023-2025 DSM Plan and the 2026 Extension filing as the 2023-2026
8 DSM Plan.

9 In October 2025, E1 provided the DSM DSMAG with the results of its Round 1
10 modeling for the 2027-2031 DSM Plan. E1 provided Round 2 model input
11 assumptions and results in February of 2026.

12 On March 31, 2026, E1 filed its proposed 2027-2031 DSM Plan with the Board.

13 **Q. Please summarize the key changes in 2027-2031 DSM Plan.**

14 A. The 2027-2031 DSM Plan is the first five-year DSM Plan in Nova Scotia.

15 E1 provides a comprehensive list of key enhancements to the 2027-2031 DSM
16 Plan as compared to the 2023-2026 DSM Plan in Table 10: 2027–2031
17 Enhancements on pages 59 and 60 of E1’s evidence. I include an abbreviated list
18 focused on the most significant updates below.

- 19 • E1 introduced three new program components including: (1) Residential
20 Mi’kmaw New Home Construction, (2) Residential Solar-PV, coordinated
21 with Residential Mi’kmaw New Home Construction, and (3) Enabling
22 Strategies: Market Transformation.
- 23 • E1 retired three program components including: (1) Residential Efficient
24 Product Rebates: Appliance Retirement, (2) Existing Residential: Green
25 Heat, and (3) Existing Residential: Residential Behaviour.
- 26 • E1 expanded the measure categories offered in Residential Instant Savings
27 Expansion to include space heating equipment delivered mid-stream to
28 customers.

- E1 expanded the measure categories offered in BNI Instant Rebates to include commercial kitchen/laundry equipment and smart thermostats.
- E1 updated BNI Custom Incentives to better support E1's BNI Demand Response program component by encouraging customers to install demand response event compatible equipment and participate in events.

E1 also:

- interpreted the NSEB's Order on E1's Application for Approval of a New Benefit-Cost Analysis Test for Evaluating Demand Side Management Plans² and section 79A(iv) of the Public Utilities Act³ and applied its interpretation of these regulations to its screening of cost-effectiveness and of strategic electrification;⁴
- updated the Standardized Filing Framework, in response to the NSEB's direction in the 2026 Extension Order;⁵
- updated the avoided cost assumptions to reflect the December 2025 results from the 2022 Evergreen IRP Update;⁶

² "While the Board leaves it open to E1 to propose another approach for addressing strategic electrification, in the absence of an acceptable approach, E1 is directed to follow the recommendation of the Industrial Group's consultant, Mr. Patrick Bowman, for assessing strategic electrification using the PAC test and including the increased utility revenues from these activities. Strategic electrification must reduce both greenhouse gas emissions and electricity costs for customers." (see: M12282, NSEB Order, E1 New Benefit Cost Analysis Test for Evaluating Demand Side Management (DSM) Plans, December 10, 2025. Available at: <https://www.nserbt.ca/nseb/matters-evidence>. Accessed 6/1/26.)

³ "(iv) strategic electrification of energy end uses currently powered by fossil fuels in a manner that reduces overall greenhouse gas emissions and electricity costs." (see: CanLII.org. Public Utilities Act, RSNS 1989, c 380. Available at: <https://www.canlii.org/en/ns/laws/stat/rsns-1989-c-380/latest/rsns-1989-c-380.html>. Accessed 6/1/26.)

⁴ E1's response to Synapse IR-07.

⁵ "To continue its engagement with the DSMAG on the Standardized Filing Framework, a review of E1's "balanced plan", the relevant factors and weighing of factors for consideration in E1's next DSM Plan, and the impact of the Board's decision in Matter M12282." (See: M12249, NSEB Decision, 2026 DSM Extension, December 22, 2025. Available at: <https://www.nserbt.ca/nseb/matters-evidence>. Accessed 6/1/26.)

⁶ E1's response to NSEB IR-07 (b) (iii).

- discontinued Residential lamp and fixture incentives in 2025 and will discontinue BNI lamp and fixture incentives in 2029;⁷
- updated measure costs and incorporated evaluation results, which changed some savings values;⁸
- proposed a mid-term check-in and a mid-course adjustment process in response to the NSEB's direction in the 2026 Extension Order; and⁹
- developed an Innovation Framework, Process, and Plan for 2027–2031.

4. ANALYSIS

Q. How is this section of your evidence organized?

A. Below, I provide my findings and, where relevant, recommendations regarding E1's proposed savings and PV generation, budget, cost-effectiveness, electrification, demand response, and mid-term check-ins.

Savings and Generation

Q. Please summarize the annual energy savings and generation proposed by E1 in its 2027-2031 DSM Plan.

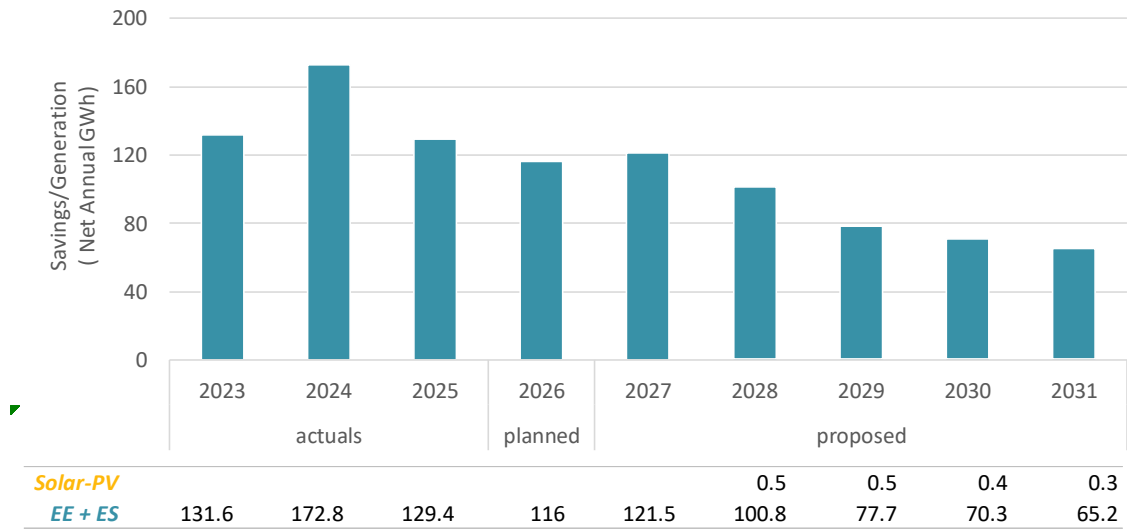
A. E1 proposes energy efficiency savings and solar-PV generation as shown in Figure 1 below. By 2031, E1 projects that annual energy savings for its Preferred Plan decline to 54 percent of the savings proposed for 2027. The projected contribution of generation by solar-PV is too small to see in this figure.

⁷ E1's Evidence, page 19.

⁸ E1's response to Synapse IR-21.

⁹ "To discuss with the DSMAG and include a revised process for making mid-course adjustments in its upcoming DSM Plan application." (See: M12249, NSEB Decision, 2026 DSM Extension, December 22, 2025. Available at: <https://www.nserbt.ca/nseb/matters-evidence>. Accessed 6/1/26.)

Figure 1. Proposed 2027-2031 DSM Plan Annual Energy Savings and Generation, by Year and Resource



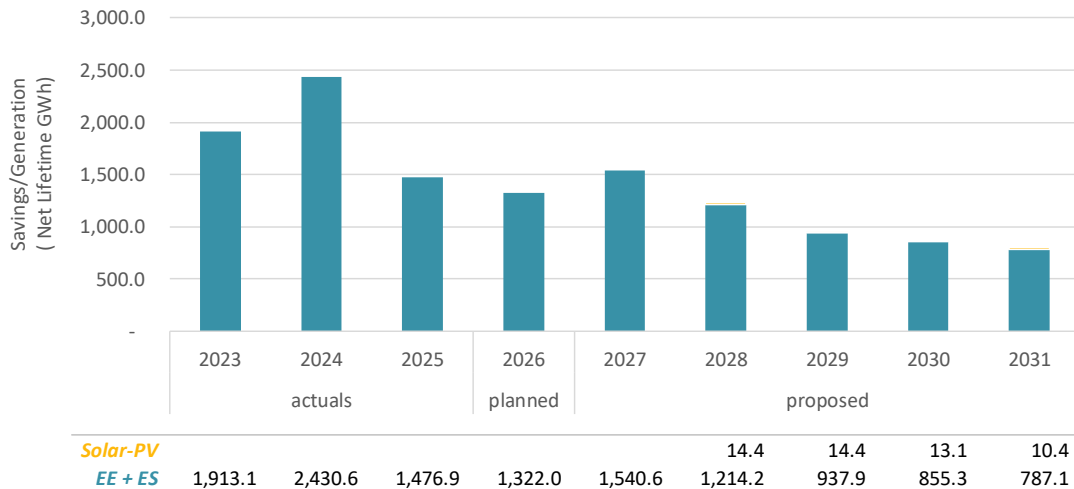
Sources:

- 2023 Actuals: 2023 DSM Annual Progress Report, Table 1: 2023 Results to 2023 Plan as Approved, 2023 Mid-Course Adjustments, and 2023 Year-End Forecast, pg. 6.
- 2024 Actuals: 2024 DSM Annual Progress Report, Table 1: 2024 Results to 2024 Plan as Approved, 2024 Mid-Course Adjustments, and 2024 Year-End Forecast, pg. 6.
- 2025 Actuals: 2025 DSM Annual Progress Report, Table 1: 2025 Results to 2025 Plan as Approved and 2025 Year-End Forecast, pg. 6.
- 2026 Planned: Table 5: 2026 Program Savings and Investment from Appendix A of 2026 DSM Extension for Demand-Side Management Activities.
- 2027-2031 Proposed: E1 2027-2031 DSM Plan, Appendix A: Preferred Plan, Tables 9-13.

Q. Please summarize the lifetime energy savings and solar-PV generation proposed by E1 in its 2027-2031 DSM Plan.

A. As shown in Figure 2 below, E1 estimates that its Preferred Plan would provide steep declines in lifetime energy savings from energy efficiency. By 2031, lifetime energy savings would decline to 52 percent of the savings proposed for 2027. The contribution of generation by solar-PV is too small to see in this figure.

Figure 2. Proposed 2027-2031 DSM Plan Lifetime Energy Savings and Generation, by Year and Resource



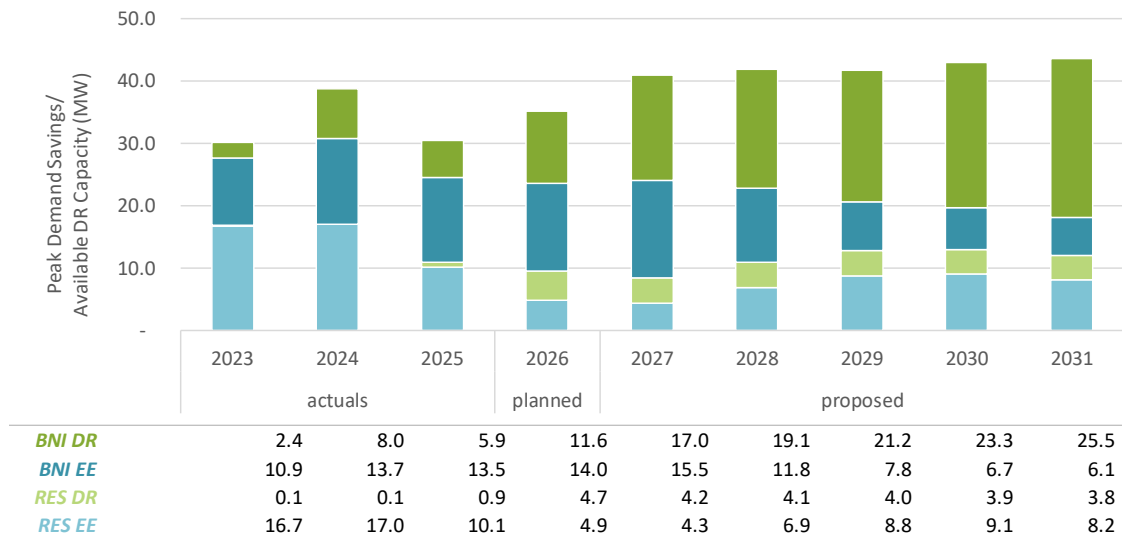
Sources:

- 2023 Actuals: 2023 DSM Annual Progress Report, Table 1: 2023 Results to 2023 Plan as Approved, 2023 Mid-Course Adjustments, and 2023 Year-End Forecast, pg. 6.
- 2024 Actuals: 2024 DSM Annual Progress Report, Table 1: 2024 Results to 2024 Plan as Approved, 2024 Mid-Course Adjustments, and 2024 Year-End Forecast, pg. 6.
- 2025 Actuals: 2025 DSM Annual Progress Report, Table 1: 2025 Results to 2025 Plan as Approved and 2025 Year-End Forecast, pg. 6.
- 2026 Planned: Table 5: 2026 Program Savings and Investment from Appendix A of 2026 DSM Extension for Demand-Side Management Activities.
- 2027-2031 Proposed: E1 2027-2031 DSM Plan, Appendix A: Preferred Plan, Tables 9-13.

Q. Please summarize the peak demand savings and available capacity proposed by E1 in its 2027-2031 DSM Plan.

A. E1's expectations for peak demand savings from energy efficiency and available capacity from the demand response in its Preferred Plan are shown in Figure 3 below. E1 projects that by 2031, capacity from energy efficiency and demand response will total 43.6 MW. From 2027 to 2031, this plan would see capacity contributions from energy efficiency decline and capacity contributions from demand response (DR) grow. Over this time period, E1 expects capacity contributions from demand response to be entirely from existing and new BNI participants. E1 does not plan to add new Residential demand response participants from 2027 to 2031.

Figure 3. Proposed 2027-2031 DSM Plan Peak Demand Savings and Available DR Capacity, by Year and Resource and Sector



Sources:

- 2023 Actuals: 2023 DSM Annual Progress Report, Table 1: 2023 Results to 2023 Plan as Approved, 2023 Mid-Course Adjustments, and 2023 Year-End Forecast, pg. 6.
- 2024 Actuals: 2024 DSM Annual Progress Report, Table 1: 2024 Results to 2024 Plan as Approved, 2024 Mid-Course Adjustments, and 2024 Year-End Forecast, pg. 6.
- 2025 Actuals: 2025 DSM Annual Progress Report, Table 1: 2025 Results to 2025 Plan as Approved and 2025 Year-End Forecast, pg. 6.
- 2026 Planned: Table 5: 2026 Program Savings and Investment from Appendix A of 2026 DSM Extension for Demand-Side Management Activities.
- 2027-2031 Proposed: E1 2027-2031 DSM Plan, Appendix A: Preferred Plan, Tables 9-13.

Q. How do E1's expected energy and capacity savings for its Preferred Plan compare to what is assumed in the latest IRP?

A. Table 1 below provides a comparison of the energy and capacity from E1's DSM reports and plans to Nova Scotia Power's (NS Power) latest IRP from 2022. This table includes both the prior plan period (2023-2026) and the current plan period (2027-2031) for E1's Preferred Plan. I would expect the Preferred Plan to differ from the latest IRP in the following ways by 2031:

- Energy savings from the Preferred Plan's energy efficiency will be approximately 215 GWh less than the assumed energy savings from energy efficiency in the IRP.

- 1 • Peak demand savings from the Preferred Plan’s energy efficiency will be
2 approximately 9 MW less than the assumed peak demand savings from energy
3 efficiency in the IRP.
- 4 • E1’s available capacity from demand response will reach 29.3 MW by 2031.
5 NS Power also has time-varying rate programs that are mutually exclusive of
6 E1’s programs and estimated to contribute 21.0 MW. Together, these
7 programs will exceed the assumed available capacity in the IRP by 6.0 MW.
- 8 • E1’s solar-PV installed capacity is 2.0 MW. NS Power’s planned solar
9 installations are roughly 207.0 MW. Together, these efforts will exceed the
10 assumed installed capacity of 203.0 MW assumed in the IRP by 6.1 MW.
- 11 There is a significant gap between E1’s proposed energy efficiency efforts and NS
12 Power’s assumptions about energy efficiency efforts in the 2022 IRP.

1 **Table 1. Comparison of Energy and Capacity from E1 DSM Efforts to NS Power’s IRP**

Year	E1 DSM Reports/Plans				NS Power DER Reports/Plans		NS Power 2022 Evergreen IRP				E1 + NS Power - IRP			
	EE Energy Savings (GWh)	EE Peak Demand Savings (MW)	DR Available Capacity (MW)	Solar-PV Installed Capacity (MW)	TVP Rate (TOU and CPP combined, MW)	Solar-PV Installed Capacity (MW)	EE Energy Savings (GWh)	EE Peak Demand Savings (MW)	DR Available Capacity (MW)	Solar-PV Installed Capacity (MW)	EE Energy Savings (GWh)	EE Peak Demand Savings (MW)	DR Available Capacity (MW)	Solar-PV Installed Capacity (MW)
2023 A	131.6	27.6	2.5				130.8	25.3	28.0		0.8	2.3	-25.5	
2024 A	172.8	30.7	8.1				124.2	24.7	41.9		48.6	6.0	-33.8	
2025 A	129.4	23.6	6.8				125.6	23.7	46.1		3.8	-0.1	-39.3	
2026 PL	116.0	18.9	16.3		0	25.3	136.3	25.0	45.7		-20.3	-6.1	-29.4	
2027 PR	121.5	19.8	21.2		3.0	53.8	137.1	25.2	45.4		-15.6	-5.4	-21.2	
2028 PR	100.8	18.7	23.2	0.55	5.0	85.6	147.0	26.6	45.2		-46.2	-7.9	-17.0	
2029 PR	77.7	16.6	25.2	0.55	9.0	120.7	135.1	24.5	44.8		-57.4	-7.9	-10.6	
2030 PR	70.3	15.8	27.2	0.50	15.0	159.8	133.3	24.2	44.5		-63.0	-8.4	-2.3	
2031 PR	65.2	14.3	29.3	0.40	21.0	207.1	130.6	23.4	44.3		-65.4	-9.1	6.0	
2023-2031 Total	985.3	14.3	29.3	2.0	21.0	207.1	1,200.0	23.4	44.3	203	-214.7	-9.1	6.0	6.1

2 Notes:

- 3 • A = actual, PL = planned, PR = proposed
- 4 • NS Power Solar-PV Installed Capacity derived by dividing the GWh from the report by 8,760 * 14% (assumed capacity factor) and multiplying by 1,000.

5 Sources:

6 E1 DSM Reports/Plans

- 7 • 2023 Actuals: 2023 DSM Annual Progress Report, Table 1: 2023 Results to 2023 Plan as Approved, 2023 Mid-Course Adjustments, and 2023 Year-End Forecast, pg. 6.
- 8 • 2024 Actuals: 2024 DSM Annual Progress Report, Table 1: 2024 Results to 2024 Plan as Approved, 2024 Mid-Course Adjustments, and 2024 Year-End Forecast, pg. 6.
- 9 • 2025 Actuals: 2025 DSM Annual Progress Report, Table 1: 2025 Results to 2025 Plan as Approved and 2025 Year-End Forecast, pg. 6.
- 10 • 2026 Planned: Table 5: 2026 Program Savings and Investment from Appendix A of 2026 DSM Extension

1 *for Demand-Side Management Activities.*

2 • 2027-2031 Proposed: E1 2027-2031 DSM Plan, Appendix A: Preferred Plan, Tables 9-13.

3 • Solar-PV installed capacity from E1's response to Synapse IR-10 (c)

4 *NS Power DER Reports/Plans:*

5 • DR: NSPI 2026 Load Forecast Report REDACTED. May 15, 2026. Figure 69: Demand Response Year Direct pg. 93 of 105.

6 • Solar-PV: NSPI 2026 Load Forecast Report REDACTED. May 15, 2026. Attachment 4 Pg. 9 of 80.

7 *NS Power 2022 Evergreen IRP is from E1's response to Synapse IR-10 (b) and (c)*

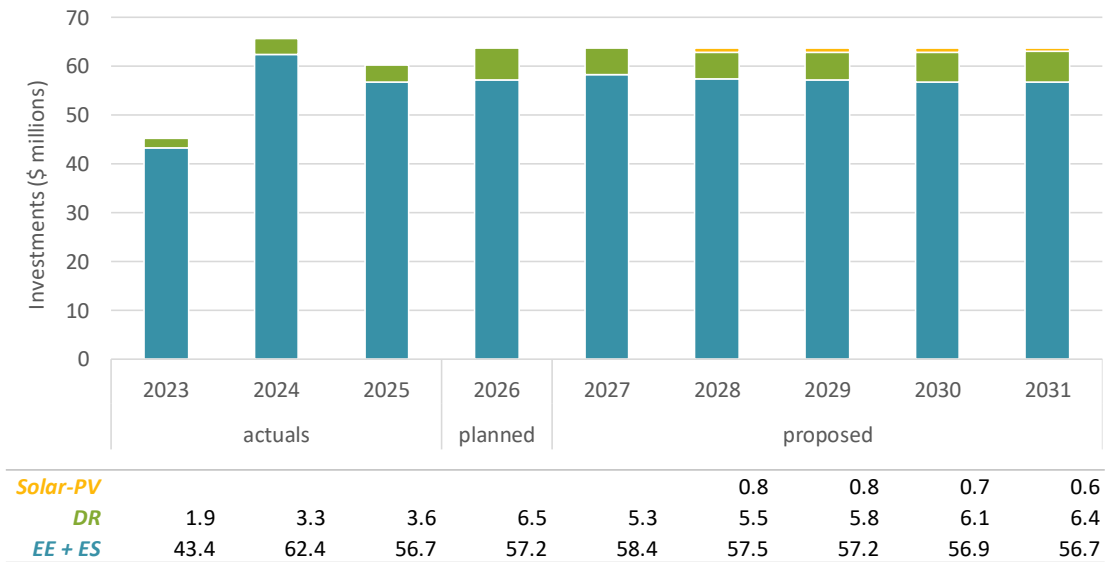
8 *E1 + NS Power – IRP adds NS Power DER Reports/Plans to E1 DSM Reports/Plans and then subtracts NS Power 2022 Evergreen IRP from the total*

Budget

Q. Please summarize the budgets proposed by E1 in the 2027-2031 DSM Plan.

A. E1 proposes an annual budget of \$63.75 million for 2027 to 2031, which is the same as the budget approved by NSEB in the 2026 Extension. Over the course of the five-year period, E1 proposes to allocate approximately 90 percent of its budget to energy efficiency and enabling strategies, 9 percent to demand response, and 1 percent to solar PV as shown in Figure 4 below.

Figure 4. Proposed 2027-2031 DSM Plan Budget, by Year and Resource



Sources:

- 2023 Actuals: 2023 DSM Annual Progress Report, Table 1: 2023 Results to 2023 Plan as Approved, 2023 Mid-Course Adjustments, and 2023 Year-End Forecast, pg. 6.
- 2024 Actuals: 2024 DSM Annual Progress Report, Table 1: 2024 Results to 2024 Plan as Approved, 2024 Mid-Course Adjustments, and 2024 Year-End Forecast, pg. 6.
- 2025 Actuals: 2025 DSM Annual Progress Report, Table 1: 2025 Results to 2025 Plan as Approved and 2025 Year-End Forecast, pg. 6.
- 2026 Planned: Table 5: 2026 Program Savings and Investment from Appendix A of 2026 DSM Extension for Demand-Side Management Activities.
- 2027-2031 Proposed: E1 2027-2031 DSM Plan, Appendix A: Preferred Plan, Tables 9-13.

Q. Why does E1 propose a budget at this level?

A. E1 indicates that it chose this plan to improve affordability. In its Evidence, E1 states: “Consistent with the PUA and the NSEB's regulatory framework,

1 affordability is the primary consideration in the design of the 2027–2031 DSM
2 Plan.”¹⁰ Specifically, E1 focused on short-term affordability. The Evidence states:

3 In the current economic environment, where Nova Scotians face significant
4 cost-of-living pressures, rising interest rates, and electricity rate increases, E1
5 has prioritized near-term affordability while maintaining long-term value in
6 recognition of the unique current economic circumstances and in direct response
7 to DSMAG feedback. To that end, E1 has constrained the annual DSM
8 investment to the EfficiencyOne 2027–2031 DSM Resource Plan Application
9 Evidence 2026 approved level of \$63.75 million, with no annual inflationary
10 increases to the investment, for each year of the 2027–2031 Plan period,
11 resulting in a total investment of \$318.75 million.¹¹

12 **Q. Does the 2027-2031 DSM Plan decrease spending on DSM over time?**

13 A. In effect, yes. The 2027-2031 DSM Plan holds spending flat in real terms. This
14 means that the spending is decreasing year-over-year in nominal terms (when
15 accounting for inflation).¹²

16 **Q. What are the implications of this decrease in spending on DSM between 2027**
17 **and 2031?**

18 A. Over time, lower spending on DSM will increase electricity costs for ratepayers—
19 i.e., make electricity less affordable—because the cost of supply is higher than the
20 cost of DSM.¹³

¹⁰ E1’s Evidence, pg. 24.

¹¹ E1’s Evidence, pg. 24-25.

¹² E1’s responses to Synapse IR-10 (e) and Synapse IR-24 (a).

¹³ Page 40 of E1’s Evidence states, “Based on the cost of fuel as reported in NS Power’s 2025 Management’s Discussion & Analysis (MD&A) of \$0.09/kWh, the cost of DSM at \$0.05/kWh is less than the average cost of fuel by \$0.04/kWh. Since 2015, the cost of fuel in \$/kWh has fluctuated each year as compared to the cost of DSM with the lowest being 166 percent in 2024 and increasing to as high as 343 percent in 2022. In no one year has \$/kWh for DSM been higher than the cost of fuel (Table 5). The ability to avoid fuel costs through the use of a more cost effective DSM alternative is always in the ratepayers’ best interests, even in the short-term. These benefits are then amplified in the long-term. In lowering overall fuel costs for the utility, DSM applies a downward pressure on the fuel adjustment mechanism (FAM), which, in turn, benefits all ratepayers.”

Cost-Effectiveness

Q. Please summarize the cost-effectiveness of the 2027-2031 DSM Plan as compared to the 2023-2026 DSM Plan.

A.

A. Table 2 below provides this comparison. The Program Administrator Cost (PAC) BCR of the portfolio is at or above 2.0 over the entire time period. Further, each resource included in E1's Preferred Plan is cost-effective in each year. Energy efficiency is the most cost-effective resource in the 2027-2031 DSM Plan. Demand response cost-effectiveness is projected to improve significantly in the 2027-2031 DSM Plan period as compared to 2023-2026, driven by improvements in the cost-effectiveness of BNI and a shift in investments to BNI customers. And, solar-PV is marginally cost-effective with a PAC just above 1.0.

Table 2. PAC Cost-Effectiveness by Sector and Resource from 2023 to 2031

	Planned			Planned	Proposed				
	2023	2024	2025	2026	2027	2028	2029	2030	2031
Residential Energy Efficiency	1.8	1.7	1.7	1.4	1.3	1.8	2.0	2.0	1.9
BNI Energy Efficiency	3.3	3.4	3.5	4.0	4.5	4.1	3.7	3.6	3.4
Energy Efficiency Total	2.3	2.3	2.3	2.4	2.8	2.7	2.4	2.3	2.2
Residential Demand Response	0.6	0.6	0.6	0.3	0.9	0.5	0.8	0.7	0.6
BNI Demand Response	0.8	0.8	0.8	0.9	2.9	1.6	2.7	2.3	2.4
Demand Response Total	0.7	0.7	0.7	0.5	2.0	1.2	2.0	1.7	1.8
Solar-PV Total (Residential Only)	n/a	n/a	n/a	n/a	n/a	1.1	1.2	1.2	1.1
Portfolio Total	2.0	2.0	2.1	2.2	2.7	2.5	2.3	2.3	2.1

Sources:

- 2023-2025 Planned: Appendix A, Tables 10-12, Settlement Plan Investment and Savings, by Program Component.
- 2026 Planned: Table 5: 2026 Program Savings and Investment from Appendix A of 2026 DSM Extension for Demand-Side Management Activities.
- 2027-2031 Proposed: E1 2027-2031 DSM Plan, Appendix A: Preferred Plan, Tables 9-13.

Q. How did E1 assess cost-effectiveness in the 2027-2031 DSM Plan?

A. E1 assessed cost-effectiveness at the portfolio level using the PAC test as the primary cost-effectiveness test, with NS Power's weighted average cost of capital of 6.65 percent as the discount rate.

1 E1 also assessed the cost-effectiveness of strategic electrification at the resource
2 level, using the modified PAC test. The modified PAC test is similar to the PAC
3 test, with the only difference being the inclusion of increased utility revenues as a
4 benefit.¹⁴

5 ***Electrification***

6 **Q. Did E1 consider strategic electrification in its modeling leading up to the**
7 **current filing?**

8 A. Yes. E1 included strategic electrification in its Round 2 modeling. In this
9 modeling, strategic electrification focused on building electrification measures
10 delivered via E1's existing program delivery modes and partnerships.¹⁵ E1 did not
11 provide a Rate and Bill Impact Analysis for the 2027-2031 Round 2 results.¹⁶
12 However, the modified PAC for the strategic electrification resource in the Round
13 2 modelling was 0.7.¹⁷

14 **Q. Why might electrification produce a low cost-effectiveness result?**

15 A. Strategic electrification increases electricity sales. Whether this increases
16 electricity *costs* per unit of electricity for the utility system as a whole depends in
17 part on when the sales occur. If these sales occur on the system peak,
18 electrification can result in an increase in electric generation capacity and
19 transmission and distribution costs per kWh. If the increase in sales occurs during
20 non-peak times, the increased sales might result in better system utilization and
21 spread fixed costs across the higher level of sales. In the case of space heating,
22 electrification would likely increase the system peak, thus increasing system costs
23 per kWh.

¹⁴ E1's response to Synapse IR-03.

¹⁵ 2027-2031 Demand Side Management Resource Plan: Round 2 Model Input Assumptions and Results.
Pg. 4.

¹⁶ In previous modeling, E1 found that strategic electrification in the Base Scenario would have average
non-participant rate impacts of between 0.01% and 0.08% depending on the rate class. (2026-2030
Demand Side Management Resource Plan: Round 2 Model Input Assumptions and Results. Appendix
K, Rd 2 – Base tab.)

¹⁷ Table 10: 1SE-Base – Round 2 Modelling Results in E1's response to Synapse IR-02, Attachment 2,
Page 15 of 26.

1 **Q. Did E1 recommend removing strategic electrification from consideration in**
2 **its Round 2 modeling based on the BCA ratio below 1.0?**

3 A. No. While the strategic electrification resource in the Round 2 modelling scored
4 less than 1.0 per the modified PAC, NSEB allows for measures, programs, and
5 resources that are not cost-effective in DSM Plans under two conditions: E1 must
6 provide a valid explanation as to why the resources should be included and the
7 portfolio as a whole must be cost-effective. This guidance from the NSEB stems
8 from the Public Utilities Act, which calls for assessment at the portfolio level.¹⁸
9 Given this guidance, and that E1 did not eliminate strategic electrification during
10 Round 2, it does not appear that E1 eliminated strategic electrification from the
11 2027-2031 DSM Plan based on the results of the modified PAC test alone.¹⁹

12 **Q. Please summarize E1's approach to electrification in its 2027-2031 DSM**
13 **Plan.**

14 A. E1 is not proposing to offer incentives for implementation of any electrification
15 measures in its 2027-2031 DSM Plan. E1 included \$165,975 over the five-year
16 2027–2031 DSM Plan application for innovation activities focused specifically on
17 strategic electrification. The investment is expected to support expert consultation
18 and research into market barriers, technological barriers, and electrification
19 technologies/applications to advance the readiness of future DSM strategic
20 electrification programming.²⁰

21 **Q. Why isn't E1 proposing to offer incentives for implementation of strategic**
22 **electrification?**

23 A. E1 cites the Board Decision in Matter No. 12282 (regarding E1's May 16, 2025,
24 E1 Application for approval of a New Benefit-Cost Analysis Test for Evaluating

¹⁸ 79H(2).

¹⁹ "E1 used a modified PAC (as proposed by the Industrial Group's consultant in the BCA proceeding) to assess strategic electrification in Round 2 results. E1 notes that strategic electrification must both reduce GHG emissions and electricity costs for customers. As of Round 2 results, electrification does not meet that second requirement of reducing electricity costs for customers." (See: Table 17: Update on Board Directives Relating to the 2027-2031 Plan in E1's response to Synapse IR-02, Attachment 2, Page 16 of 26.

²⁰ E1's response to Synapse IR-19 (a).

1 DSM Plans) as its reason for not including electrification in the proposed 2027-
2 2031 DSM Plan. Specifically, E1 cites these Board directives:

- 3 (a) To use the Program Administrator Cost (“PAC”) test as the primary test for
4 screening cost effectiveness of proposed DSM plans, using Nova Scotia
5 Power’s weighted average cost of capital (“WACC”) as the discount rate,
6 with cost-effectiveness assessed at the portfolio level;
- 7 (b) Unless an alternative acceptable methodology is proposed, to assess
8 strategic electrification programs using the PAC test including increased
9 utility revenues, and that strategic electrification programs must
10 demonstrate a reduction in both greenhouse gas (GHG) emissions and
11 electricity costs before inclusion in a DSM Plan.²¹

12 Further, on page 35 of the Evidence, E1 states:

13 E1 was unable to include Strategic Electrification as a resource in its 2027–2031
14 DSM Plan. E1's exclusion of strategic electrification from the 2027–2031 DSM
15 Plan as a resource is mandated by the statutory requirements of the PUA.
16 Section 79A(b)(iv) defines strategic electrification as activities relating to
17 "strategic electrification of energy end uses currently powered by fossil fuels in
18 a manner that reduces overall greenhouse-gas emissions **and** electricity costs"
19 (emphasis added). This conjunctive requirement that strategic electrification
20 must reduce both GHG emissions and electricity costs was confirmed by the
21 NSEB in its 2025 BCA Decision, which stated that "both requirements for
22 strategic electrification must be met." Because all modeled strategic
23 electrification scenarios failed to reduce electricity costs for customers when
24 evaluated under the Board-approved modified-PAC test, their inclusion as a
25 DSM resource would violate the statutory definition.²²

26 **Q. Did E1 screen strategic electrification for the 2027-2031 DSM Plan?**

27 A. Yes. E1 assessed whether strategic electrification reduced both GHG emissions
28 and electricity costs.²³ Regarding GHG reductions, E1 stated that,

29 E1 assessed GHG emission reductions using emissions information from NS
30 Power's 2022 Evergreen IRP, as long-run marginal emissions rates were not
31 available for this analysis.

32 Also, E1 stated the following regarding electricity costs:

33 E1 focused on building electrification measures to leverage existing
34 partnerships, program infrastructure and expertise. As committed in the BCA
35 matter, E1 did consider hybrid heating measures and worked collaboratively

²¹ E1 2027-2031 Plan, pg. 15

²² E1 2027-2031 Plan, pg. 35.

²³ E1 Evidence, page 69.

1 throughout the modelling process with both Eastward Energy and NS Power. E1
2 reviewed multiple strategic electrification scenarios during plan development,
3 including heat pump water heaters, cold climate heat pumps for space heating,
4 hybrid heating measures and custom measures. Modified-PAC results for all
5 strategic electrification scenarios modelled through the 2027–2031 DSM Plan
6 development process demonstrated that these measures did not reduce electricity
7 costs for customers when evaluated under the Energy Board-approved modified-
8 PAC test that includes increased utility revenues. Even under optimal
9 assumptions where there are no peak impacts arising from the strategic
10 electrification measures, they remained not cost-effective.²⁴

11 **Q. Did E1 find that strategic electrification reduces GHG emissions?**

12 A. Yes. E1’s Round 2 modelling showed that strategic electrification would reduce
13 GHG emissions by 7.5 kilotonnes each year and 131.2 kilotonnes over the
14 lifetime of the measures.²⁵ E1 did not eliminate strategic electrification from the
15 2027-2031 DSM Plan based on this assessment.

16 **Q. How did E1 model the impact of strategic electrification on electricity costs?**

17 A. E1’s documentation of this analysis is unclear,²⁶ and E1 did not provide the
18 model.²⁷ As a result, questions remain regarding which methodology and
19 assumptions E1 used, what the results were, and how E1 interpreted them. It

²⁴ E1 Evidence, page 35.

²⁵ E1’s response to Synapse IR-02, Attachment 2, Table 10: 1SE-Base – Round 2 Modelling Results, page 15 of 26.

²⁶ Whether E1 assessed strategic electrification by itself or only within a larger portfolio that contains strategic electrification is not clear. For example, in its response to SBA IR-05, E1 refers to a strategic electrification scenario: "As part of the development of the 2027–2031 DSM Plan, EfficiencyOne (E1) explored strategic electrification (SE) for inclusion. Specifically, in Round 1 and Round 2 modelling E1 modelled one SE scenario which included both residential and Business, Non-profit and Institutional (BNI) programs. E1 focused on building electrification measures to leverage existing partnerships, program infrastructure and expertise and as such did not model electric vehicles (EVs). As committed in the Benefit Cost Analysis Test (BCA) matter (M12282), E1 did consider hybrid heating measures. E1 reviewed multiple strategic electrification scenarios during plan development, including heat pump water heaters, cold climate heat pumps for space heating, hybrid heating measures and custom measures."

In the same response E1 also discusses strategic electrification measures, seemingly by themselves:

"SE measures were assessed across Rounds 1 and 2 of modelling for the 2027–2031 DSM Plan.

During Round 1, E1 used the Rate Impact Measure test (functionally the same as the modified-PAC) to assess SE as the Nova Scotia Energy Board’s (NSEB) Decision on E1’s BCA matter was not available until December 2025. During Round 2 modelling, E1 used the modified-PAC to assess SE, aligned with the NSEB’s Decision on the BCA matter. In both Rounds SE was found to not be cost-effective.

Notably, even under optimal assumptions where there are no peak impacts arising from the SE measures, they remained not cost effective under the modified-PAC test. SE was not carried forward into the final modelling round of the 2027–2031 Preferred DSM Plan."

²⁷ E1 response to Synapse IR-02 includes results but not the model used.

1 appears that E1 either assessed the BCA of strategic electrification by itself, or E1
2 looked at the change in the portfolio-level BCA (including energy efficiency,
3 demand response, PV) when strategic electrification is added.²⁸

4 However this assessment was conducted, E1 interpreted the results as failing to
5 meet the directives of NSEB’s Decision in Matter M12282.

6 **Q. What does the Board Decision in M12282 say?**

7 A. The Board Decision states:

8 While the Board leaves it open to E1 to propose another approach for addressing
9 strategic electrification, in the absence of an acceptable approach, E1 should
10 follow Mr. Bowman’s recommendation for assessing strategic electrification
11 using the PAC test and including the increased revenues from these activities.
12 The Board notes, however, that both requirements for strategic electrification
13 must be met. It must reduce GHG emissions and electricity costs for
14 customers.²⁹

15 This draws on the Public Utilities Act, which defines strategic electrification as
16 “energy end uses currently powered by fossil fuels in a manner that reduces
17 overall greenhouse gas emissions and electricity costs.”³⁰

18 **Q. Did E1 offer propose another approach for addressing strategic**
19 **electrification?**

20 A. No.

21 **Q. Are there other ways to interpret the NSEB Decision?**

22 A. Yes. The Board Decision, like the statutory language it is based upon, is silent
23 about how to assess “electricity costs.” Critical details that neither the statute nor
24 the Board specified include the level of assessment (customer, measure, program,
25 resource, or portfolio), the time period over which to assess these impacts, and

²⁸ E1’s response to NSEB IR-34 appears to support the later interpretation. E1 states, “E1 assessed scenarios as a whole against the conjunctive requirements of section 79A of the PUA - that is, any strategic electrification resource scenario must reduce both GHG emissions and electricity costs for customers.”

²⁹ Board Decision, M12282, pg. 80-81.

³⁰ 79A.

1 whether the impacts should take the perspective of rates or bills (rather than a
2 BCA perspective).

3 **Q. Do you have any concerns about E1’s interpretation of the NSEB Decision?**

4 A. Given that DSM Plan cost-effectiveness is evaluated at the portfolio level as
5 required by statute,³¹and not at the resource level, measuring cost impacts at the
6 resource level is inconsistent with assessing cost-effectiveness at the portfolio
7 level.³² On the other hand, it seems reasonable to include electrification within the
8 larger portfolio of all resources, so long as the portfolio PAC test score does not
9 go below 1.0.

10 **Q. Is the BCR for the portfolio close to 1?**

11 A. No. Per the 2027-2031 Plan, E1 projects the proposed portfolio to have a Program
12 Administrator Cost (PAC) test result of 2.4. This suggests that there is ample
13 room for including some electrification resources in the portfolio.

14 **Q. What do you conclude?**

15 A. I conclude that it would be reasonable for E1 to pursue an amount of
16 electrification in its 2027-2031 Plan that does not increase electricity costs *at the*
17 *portfolio level*. Table 3 below provides the PAC and Modified-PAC Tests
18 including the strategic electrification from the Round 2 modeling. This table
19 illustrates that E1 could include all the strategic electrification it included in its

³¹ 79H(2).

³² E1 acknowledges that DSM, including strategic electrification, should be measured at the portfolio level: “Pursuant to section 79H(1), its responsibilities include determining ‘the cost-effective demand-side management that must be undertaken for the purpose of this Act’, which in 79H(2) is to be evaluated at the portfolio level. In its decision on the BCA test, the Energy Board confirmed that DSM Plan applications must be evaluated at the portfolio level ‘that would be the aggregate amount of demand-side management programs,’ which also includes strategic electrification. The Energy Board noted at paragraph 168 that the requirement to evaluate the proposed cost-effective demand-side management at the portfolio level implies that, provided the overall portfolio passes the cost-effectiveness test, it is not a contravention of the statute if measures or programs themselves fail. Justification for including such measures and programs could be provided a number of ways, including based on the factors the Energy Board is required to consider under s. 6(2) of the Energy and Regulatory Boards 1 Act. E1’s 2027–2031 DSM Plan passes the Program Administrator Cost (“PAC”) test at the portfolio level with a benefit-cost ratio of 2.4, satisfying this requirement. For the limited number of individual programs and measures that do not independently pass the cost-effectiveness test, E1 has responded to this specifically under Board Directives section 2.2.2.1.” (E1’s Evidence, pg. 5)

1 Round 2 modeling without causing electricity costs to increase at the portfolio
2 level as the modified PAC remains substantially higher than 1.0. This is because
3 the Round 2 investments in strategic electrification are small relative to the rest of
4 the portfolio. The proposed investment in strategic electrification of \$12.2 million
5 between 2027 and 2031 does not materially impact the portfolio cost-
6 effectiveness.³³

³³ 2027-2031 Demand Side Management Resource Plan: Round 2 Model Input Assumptions and Results, pg. 12.

1 **Table 3. Cost-Effectiveness of 2027-2031 DSM Plan Plus SE (Round 2)**

DSM Category	PAC Costs (\$)	Modified-PAC Costs (\$)	PAC Lifetime Benefits (\$)	Modified-PAC Lifetime Benefits (\$)	PAC Test	Modified-PAC Test
EE	\$257.9	\$257.9	\$709.1	\$709.1	2.7	2.7
EE Residential	\$145.0	\$145.0	\$264.4	\$264.4	1.8	1.8
EE BNI	\$112.9	\$112.9	\$444.7	\$444.7	3.9	3.9
DR	\$29.1	\$29.1	\$54.4	\$54.4	1.9	1.9
DR Residential	\$10.3	\$10.3	\$8.0	\$8.0	0.8	0.8
DR BNI	\$18.8	\$18.8	\$46.4	\$46.4	2.5	2.5
PV (Residential only)	\$2.8	\$2.8	\$3.2	\$3.2	1.1	1.1
Total (EE + ES + DR + PV)	\$289.9	\$289.9	\$766.7	\$766.7	2.6	2.6
Total Residential	\$158.1	\$158.1	\$275.6	\$275.6	1.7	1.7
Total BNI	\$131.7	\$131.7	\$491.1	\$491.1	3.7	3.7
Strategic Electrification (Round 2)	\$12.2	\$54.7	\$0.0	\$37.8	0.0	0.7
SE Residential	\$3.6	\$8.1	\$0.0	\$4.9	0.0	0.6
SE BNI	\$8.6	\$46.6	\$0.0	\$32.9	0.0	0.7
Total (EE + ES + DR + PV + SE)	\$302.0	\$344.5	\$766.7	\$804.5	2.5	2.3
Total Residential	\$161.7	\$166.2	\$275.6	\$280.5	1.7	1.7
Total BNI	\$140.3	\$178.3	\$491.1	\$524.0	3.5	2.9

2 Sources:

- 3
- 4
- 5
- EE, DR, PV and Total (EE + ES + DR + PV): E1 2027-2031 DSM Plan, Appendix A: Preferred Plan, Tables 9-13.
 - SE (Round 2): E1's response to Synapse IR-02, Attachment 2, Table 10: 1SE-Base – Round 2 Modelling Results, pg. 15 of 26.
 - Total (EE + ES + DR + PV + SE): Sum of Total (EE + ES + DR + PV) and SE (Round 2).

1 As an alternative to including the strategic electrification from the Round 2
2 modeling, E1 could develop strategic electrification offerings for low- and
3 moderate-income customers who heat with oil. E1 states that the federally funded
4 Oil to Heat Pump Affordability (OHPA) program³⁴ drove “significant interest in
5 the Affordable Single-family Homes program component in recent years by
6 offering free whole home heat pump systems. These projects are geared toward
7 customers with non-electric heating but also benefit many customers who use
8 electric supplementary heating.”³⁵ OHPA will end in 2027.

9 **Q. What is the rationale for focusing electrification investments on low-income**
10 **customers who heat with oil?**

11 A. There are five reasons for focusing electrification investments on this subset of
12 customers.

13 First, affordability concerns should not limit DSM investments that benefit those
14 who struggle most with affordability. Low-income customers are most at risk
15 from an affordability perspective.

16 Second, the war in Iran may create a home heating affordability crisis for
17 customers heating with oil this coming winter. According to a 2024 report
18 commissioned by the Nova Scotia Energy Poverty Task Force, oil-heated
19 households spend 80 percent more on home energy than electrically heated
20 households.³⁶ Any solutions that focus on reducing the reliance of customers on
21 oil for home heating will help with affordability.

³⁴ The Oil to Heat Pump Affordability (OHPA) program provides eligible NS homeowners with a grant of up to \$15,000 and a one-time payment of \$250 to switch from oil heating to an electric heat pump system. This funding goes toward the purchase and installation of the eligible heat pump systems and related expenses such as the safe removal of your oil tank, installation of a back-up electric heating system, and switching over other oil-using household systems, such as a hot water heater. The program is designed to benefit low- to median-income homeowners who are heating their homes with oil. (See: https://natural-resources.canada.ca/sites/admin/files/documents/2025-06/23-05579%20-%20OHPA%20Factsheet_EN-May27-2-2025.pdf and <https://www.efficiencyns.ca/programs-rebates/oil-to-heat-pump-affordability-program>.)

³⁵ E1 response to Synapse IR-46 (a).

³⁶ *A Way Forward: A Made-In-Nova Scotia Home Energy Affordability Program*. Prepared by Roger D. Colton for the Nova Scotia Energy Poverty Task Force. April 2024. Page 4. Available at: https://ecologyaction.ca/sites/default/files/2024-05/AWayForward_FullReport_May2024.pdf. Accessed 5/31/26.

1 Third, many low-income customers in Nova Scotia currently heat with oil.
2 According to 2021 Canada Census data, more than 44,000 Nova Scotian
3 households met the low-income cut-off criteria that is the basis of eligibility for
4 the Affordable Single-family Homes program component.³⁷ According to that
5 same 2024 report commissioned by the Nova Scotia Energy Poverty Task Force,
6 oil is the primary source of heat for about 40 percent of households experiencing
7 energy poverty.³⁸ As a result, I estimate that 17,600 low-income homes heat with
8 oil in Nova Scotia. Efforts to address affordability for customers who heat with oil
9 should not be stalled until the next five-year DSM Plan.

10 Fourth, the lapse of federal funding to electrify low-income customers who heat
11 with oil is well aligned with the timing of this plan. E1 is well positioned to fill a
12 gap that otherwise would not be addressed during the plan period.

13 Fifth, the Nova Scotia Energy Poverty Task Force's home energy affordability
14 program recommendations call for continuing to expand support for targeted
15 energy efficiency and electrification for low- and moderate-income households as
16 a high priority affordability strategy.³⁹

17 **Q. What other comparable jurisdictions are investing in electrification for low-**
18 **income customers?**

19 A. E1 retained Apex Analytics, LLC (Apex) to recommend reasonable savings goals
20 while maintaining affordability for customers in its 2027-2031 DSM Plan. In
21 preparing its recommendation, Apex reviewed savings values for jurisdictions
22 with similar electric loads, climate, programs, and other characteristics. Apex's
23 analysis identified New Brunswick, Prince Edward Island, and the U.S. state of

³⁷ E1's response to Synapse IR-46 (c)

³⁸ *A Way Forward: A Made-In-Nova Scotia Home Energy Affordability Program*. Prepared by Roger D. Colton for the Nova Scotia Energy Poverty Task Force. April 2024. Page 4. Available at: https://ecologyaction.ca/sites/default/files/2024-05/AWayForward_FullReport_May2024.pdf. Accessed 5/31/26.

³⁹ *A Way Forward: A Made-In-Nova Scotia Home Energy Affordability Program*. Prepared by Roger D. Colton for the Nova Scotia Energy Poverty Task Force. April 2024. Page 5. Available at: https://ecologyaction.ca/sites/default/files/2024-05/AWayForward_FullReport_May2024.pdf. Accessed 5/31/26.

1 New Hampshire as the most similar jurisdiction to Nova Scotia.⁴⁰ NB Power
2 integrated electrification of low- and moderate-income customers with oil heated
3 homes into its 2024/2025 to 2026/2027 DSM Plan. This effort draws on \$32.0
4 million in provincial and federal funding, which represents 14 percent of the total
5 three-year proposed spending.⁴¹ Also, Efficiency Manitoba is the first jurisdiction
6 in the country to implement the Canada Greener Homes Affordability Program, a
7 new initiative that will offer free home energy efficiency upgrades for low- to
8 median-income households. The program allows homeowners and renters to
9 access free upgrades like insulation, air sealing, and heat pumps.⁴² While the
10 energy efficiency administrators of New Brunswick and Manitoba are both crown
11 corporations, which are regulated differently than E1, these programs may have
12 lessons that pertain to Nova Scotia.

13 **Q. Did E1 propose increases in ratepayer funding to address other gaps in**
14 **federal or provincial funding that supported energy efficiency?**

15 A. Yes. E1 proposes to increase incentive levels for the Affordable Multi-Family
16 program following the conclusion of the provincial DSM top-up funding.⁴³ So, E1
17 has stepped in to provide stable and continuous incentive funding for programs
18 and measures that are important to Nova Scotians.

19 **Q. Are there other considerations E1 should account for with regards to**
20 **electrification?**

21 A. Yes. NS Power has identified feeders that are currently constrained and NS Power
22 is working on transmitting this information to E1.⁴⁴ For these constrained feeders,

⁴⁰ Table 1. Scoring of Comparable Jurisdictions from E1's response to NSEB IR-08, Attachment 1, Apex Analytics. *Analysis and Recommendation for 2027-2031 Plan Savings Goals*. May 22, 2026.

⁴¹ Synapse Energy Economics. *Review of New Brunswick Power's 2024/25 to 2026/27 DSM Program Initiatives Update In New Brunswick Power's 2024-2025 General Rate Application (Matter No. 552)*. Prepared for the New Brunswick Energy and Utilities Board Staff. March 28, 2024. Available at: <https://www.synapse-energy.com/review-new-brunswick-powers-2024-2027-dsm-plan>. Accessed 6/1/26.

⁴² Efficiency Manitoba. *News Release: Canada Launches Greener Homes Affordability Program in Manitoba*. September 12, 2025. Available at: <https://efficiencymb.ca/articles/canada-greener-homes-affordability-program/>. Accessed 6/1/26.

⁴³ E1 Evidence. Table 10: 2027-2031 Enhancements. Pages 59 and 60.

⁴⁴ E1's response to Synapse IR-54 (f).

1 there is a dollar benefit to reducing electricity use and a cost to increasing
2 electricity use. E1 should use this locational data to target electrification efforts to
3 feeders that are not constrained.⁴⁵

4 Also, E1's low-income programs include incentives for long-term maintenance
5 and repairs for customers that convert to heat pumps from electric resistance
6 heating.⁴⁶ E1 should provide this incentive for low-income households who
7 convert to heat pumps from oil heating as well.

8 In addition, E1 should maintain the current OPRA requirement that home energy
9 assessments be conducted prior to electrification, which means that E1 may need
10 to increase the low-income budget for home energy assessments. If a home
11 energy assessment identifies weatherization as an opportunity, E1 should
12 encourage the customer to weatherize when they electrify to achieve additional
13 electricity cost savings and energy affordability benefits.

14 Lastly, a 2024 report titled *A Way Forward: A Made-In-Nova Scotia Home*
15 *Energy Affordability Program* recommends that E1 target electrification to low-
16 and moderate-income customers who use the most energy and who have the
17 highest arrears.⁴⁷ NS Power has data on customers with high arrears and high
18 energy use (which are often characteristics of lower-income households); NS
19 Power could refer customers that are high priority based on these criteria to E1 for

⁴⁵ E1's response to Synapse IR-54 states, "The disruption to NS Power's customer advanced metering infrastructure (AMI) data feed to E1 has not yet been resolved, and E1 does not have a definitive date as to when access will be restored. NS Power has confirmed that an enhancement is planned for its regular customer billing data transfer to E1 to include Feeder ID in order to tie specific customers to specific locations, enabling locational targeting. E1 expects to receive this data following the restoration of the AMI data transfer."

⁴⁶ Gaede, J., Nippard, A., Turner, K. 2026. *The 2025 Energy Efficiency Programs Report*. Efficiency Canada, Carleton University, Ottawa, ON. Page 54. Available at: <https://www.efficiencycanada.org/2025-programs-report/>. Accessed 5/31/26.

⁴⁷ *A Way Forward: A Made-In-Nova Scotia Home Energy Affordability Program*. Prepared by Roger D. Colton for the Nova Scotia Energy Poverty Task Force. April 2024. Page 89. Available at: https://ecologyaction.ca/sites/default/files/2024-05/AWayForward_FullReport_May2024.pdf. Accessed 5/31/26.

1 further screening and follow-up.⁴⁸ This targeting will advance the resolution of
2 payment troubles, improve affordability, and reduce fossil fuel consumption.

3 *Demand Response*

4 **Q. Please summarize E1's demand response offerings as part of the 2027-2031**
5 **DSM Plan.**

6 A. In the 2027-2031 period, E1 plans to offer several pathways, each focused on a
7 type of demand response measure. These pathways include water-heating and
8 thermostat demand response to existing residential program participants, and
9 curtailment demand response to both existing and new BNI participants. E1 also
10 proposes a new offering "Loadshift to Back Up Generators (BUGs)" for BNI
11 customers, while proposing to phase out its existing battery and EV programs for
12 residential customers.

13 E1 is not planning to enroll new Residential demand response participants in its
14 plan.⁴⁹ As a result, E1 projects that over the plan period residential participation
15 will decline, as shown in Table 4, and total residential curtailment capacity will
16 fall, as shown in Table 6 below. Meanwhile, overall budgets and capacities grow
17 due to the additions of new BNI participants, and the total cost per kW of capacity
18 will fall over the course of the plan period, as shown in Table 5, Table 6, and
19 Table 7 below. On average, total residential program cost-to-curtail is nearly three
20 times (2.9x) that of the BNI program.

⁴⁸ It is my understanding that NS Power does not have data on which customers are low- and moderate-income and that E1 would need to get this data from another source.

⁴⁹ E1's response to Synapse IR-77.

1

Table 4. Preferred Plan Demand Response Program Participants

Participants	2027	2028	2029	2030	2031	Average
Residential	22,940	22,483	22,034	21,593	21,160	22,042
Water Heaters	2,674	2,620	2,568	2,516	2,466	2,569
Thermostats	20,266	19,863	19,466	19,077	18,694	19,473
BNI	169	173	173	175	175	173
Curtailment	158	162	162	164	164	162
Curtailment Loadshift to BUGs	11	11	11	11	11	11
Total	23,109	22,656	22,207	21,768	21,335	22,215

2

Source: EI's response to Synapse IR-90, Attachment 1.

3

Table 5. Preferred Plan Demand Response Program Budgets

Budget (\$000)	2027	2028	2029	2030	2031	Total
Residential	2,168	2,040	2,035	2,030	2,026	10,299
Water Heaters	502	381	387	391	396	2,057
Thermostats	1,667	1,658	1,648	1,639	1,630	8,243
BNI	3,145	3,454	3,765	4,077	4,388	18,828
Curtailment	1,916	2,251	2,583	2,905	3,225	12,880
Curtailment Loadshift to BUGs	1,229	1,203	1,182	1,172	1,163	5,948
Total	5,313	5,493	5,800	6,107	6,414	29,128

4

Source: EI's responses to Synapse IR-90, Attachment 1.

5

Table 6. Preferred Plan Demand Response Program MW Capacity

Available Capacity (MW)	2027	2028	2029	2030	2031	Average
Residential	4.2	4.1	4.0	3.9	3.8	4.0
Water Heaters	1.1	1.1	1.1	1.0	1.0	1.1
Thermostats	3.1	3.0	2.9	2.9	2.8	2.9
BNI	17.0	19.1	21.2	23.3	25.5	21.2
Curtailment	10.3	12.4	14.6	16.6	18.7	14.5
Curtailment Loadshift to BUGs	6.6	6.6	6.7	6.7	6.7	6.7
Total	21.1	23.2	25.2	27.3	29.3	25.2

6

Source: EI's responses to Synapse IR-90, Attachment 1.

7

Table 7. Preferred Plan Demand Response Program Budget/kW Capacity

Budget/kW Capacity (\$)	2027	2028	2029	2030	2031	Average
Residential	521	500	510	519	528	516
Water Heaters	458	355	368	379	392	391
Thermostats	544	552	560	569	577	560
BNI	185	181	178	175	172	178
Curtailment	185	181	177	175	172	178
Curtailment Loadshift to BUGs	185	181	178	175	173	178
Total	251	237	230	224	219	232

8

Source: EI's responses to Synapse IR-90, Attachment 1.

1 **Q. Please describe E1's projections of cost-effectiveness over the Plan period.**

2 A. Over the course of the plan period, the Residential PAC BCR ranges between 0.5
3 and 0.9, while the BNI BCR is substantially higher and always above one, ranging
4 between 1.6 and 2.9, as shown in Table 8 below.

5 **Table 8. Preferred Plan Demand Response Program PAC BCRs**

PAC BCR	2027	2028	2029	2030	2031	Average
Residential	0.9	0.5	0.8	0.7	0.6	0.7
BNI	2.9	1.6	2.7	2.3	2.4	2.4
Total	2.0	1.2	2.0	1.7	1.8	1.7

6 *Source: E1's Response to Synapse IR-62(b), Tables 2 and 3; Table 47 of Appendix A: Preferred*
7 *Plan*

8 **Q. Do you have any concerns about E1's demand response program proposal?**

9 A. Yes. I identify major concerns regarding the following aspects of E1's demand
10 response proposal:

- 11 • E1's proposed residential demand response program offerings have PAC
12 BCRs less than 1.
- 13 • E1's residential demand response delivery costs appear substantially
14 higher as a share of total program costs compared to similar programs in
15 other jurisdictions.
- 16 • E1 plans to phase out the residential EV and battery demand response
17 programs without any plans for a process evaluation or reconsideration of
18 new program designs mid-plan.
- 19 • E1 does not uniformly weight performance across the full duration of
20 demand response events.
- 21 • E1 does not differentiate BNI Back Up Generator incentives between
22 battery and fossil fuel generator participants.

23 I will explain these issues in detail below.

1 **PAC benefit-cost ratios and avoided costs**

2 **Q. Please explain your concerns about the cost-effectiveness of the residential**
3 **demand response programs based on the PAC test.**

4 A. In the 2026 Extension of E1's DSM program, my colleague Jennifer Kallay stated
5 in her testimony that the purpose of demand response is to provide utility system
6 benefits, and she recommended that E1 develop a plan to achieve a cost effective
7 demand response program, i.e. with a PAC that is greater than 1.0. Thus, I am
8 concerned about the cost-effectiveness of the Residential demand response
9 program, which E1 projects will have an average PAC over the DSM Plan period
10 of 0.7. As shown in Table 8 above, E1's modeling does not indicate that this
11 component of the program will be cost-effective in any year of the plan period.
12 However, E1's statements about the projected cost-effectiveness of the residential
13 demand response component over the course of the plan period are not internally
14 consistent. E1 states that "through direct discussions with the IESO Demand Side
15 Management team, the [residential demand response] program is expected to
16 reach cost-effectiveness under the Program Administrator Cost (PAC) test within
17 the next year."⁵⁰ Later in the evidence, E1 contradicts itself, claiming instead that
18 the residential demand response program "is expected to achieve cost-
19 effectiveness within the next two to three program seasons."⁵¹ Neither of these
20 conclusions that the program is expected to become cost-effective is supported by
21 E1's response to Synapse IR-62(b), which shows the residential PAC BCR
22 ranging between 0.5 and 0.9 during the plan period, as detailed in Table 8 above.

23 **Q. How does the planned 2027 residential response program PAC BCR**
24 **compare to that of the 2026 extension?**

25 A. Looking at only the residential demand response pathways that E1 plans to
26 continue (water heater and thermostat), E1 projects that the planned PAC BCR
27 will increase from 0.28 in 2026 to 0.89 in 2027 and to 0.7 on average over the
28 course of the plan period, as demonstrated in Table 9 below.

⁵⁰ Evidence, pg. 31.

⁵¹ Evidence, pg. 32.

Table 9. Residential Demand Response PAC Benefit-Cost Ratios, 2026-2027

	2026	2027	2027-2031
Water Heater	0.31	1.06	0.80
Thermostat	0.27	0.85	0.66
Total	0.28	0.89	0.7

Source: Synapse Analysis of: E1, 2026 Extension filing, Appendix A, Attachment 4, pg. 19c; E1, 2027-2031 Plan, Appendix A, Attachment 4, pages 19 a and c, E1's Response to Synapse IR-62, Table 2.

Q. How does E1 plan to achieve this growth in the PAC BCR between 2026 and 2027?

A. E1 states that its “expectation regarding the continued improvement in Residential Eco Shift cost-effectiveness is informed by: observed year-over-year improvements in program participation and performance; experience and lessons learned from more mature jurisdictions such as Ontario; the expected benefits associated with increased participant scale; and E1’s ongoing program optimization efforts.”⁵² My analysis shows that E1 plans to achieve the projected increase in BCR (from 0.28 in 2026 to 0.90 in 2027) by both decreasing costs and increasing benefits per kW of capacity, as shown in Table 10 below.

Table 10. Residential Thermostat and Water Heater Planned Benefits and Costs per kW Capacity, 2026-2027

\$ / kW Capacity	2026	2027	% Change
Benefits per kW	363	507	39%
Costs per kW	1,283	563	-56%
BCR	2026	2027	
PAC	0.28	0.90	

Source: Synapse Analysis of: 2026 Extension filing, Appendix A, Attachment 4, pg. 4, 19c; E1, 2027-2031 Plan, Appendix A, Attachment 4, pg. 4a, 19c.

Q. In which budget categories does E1 plan to realize cost savings per kW of capacity?

A. E1 plans to cut residential thermostat and water heater demand response budgets per kW of capacity across all budget categories. As shown in Table 11 below, the planned reduction in technology enablement costs accounts for the majority (68

⁵² E1’s Response to Consumer Advocate IR-06(a)

1 percent) of the overall decrease in costs per kW, while combined administrative
2 and delivery follows with 14 percent of the overall reduction.

3 **Table 11. Residential Thermostat and Water Heater Budget**
4 **Categories per kW Capacity, 2026-2027**

Total Cost / kW Capacity	2026	2027	% of Cost Reduction
Incentives	102	66	12%
Marketing	26	7	6%
Technology Enablement	235	30	68%
Admin + Delivery	460	418	14%
Total	823	521	

5 *Source: E1's responses to Synapse IR-90, Attachment 1*

6 **Q. Does E1 plan to make operational changes to the residential demand**
7 **response program in response to the PAC BCR being below one?**

8 A. Yes. E1 states that it “does not intend to enroll new Residential Demand Response
9 customers during the 2027–2031 period because the program's current cost-
10 effectiveness metrics do not support the incremental cost of new customer
11 acquisition and device installation at this time.”⁵³

12 **Q. What do you recommend regarding enrolling new participants in the**
13 **residential demand response program over the plan period?**

14 A. E1 should seek opportunities to reduce overall costs per kW of capacity by
15 enrolling new participants in pathways with low marginal costs of customer
16 enablement.

17 **Q. Do you have any other recommendations regarding the residential demand**
18 **response PAC BCR?**

19 A. Yes. Beyond seeking out opportunities to decrease average costs per kW of
20 capacity, E1 should also evaluate program design changes that could drive higher
21 average benefits per kW capacity. Such modifications could include revisions to
22 pre-heating durations and setpoints, event setbacks, and event durations. E1 could
23 also target the most constrained circuits to increase the benefits associated with
24 avoided transmission and distribution costs.

⁵³ E1's Response to Synapse IR-52

1 **Residential demand response delivery costs**

2 **Q. What are program delivery costs?**

3 A. E1 states that “Program Delivery Costs are costs paid to third parties (e.g.,
4 Demand Response Management System providers, Commercial and Industrial
5 Curtailment delivery agent).”⁵⁴ Currently, “E1 remains contracted with its
6 existing Residential DR implementation vendors, including the vendor supporting
7 the thermostat pathways and the vendor supporting the domestic hot water
8 controller pathway.”⁵⁵

9 **Q. What is E1’s proposed budget for residential demand response, and what**
10 **share does E1 plan to use for program delivery?**

11 A. E1 proposes a total budget of \$10.3 million for the residential demand response
12 programs over the plan period, consisting of \$1.3 million for incentives and \$6.7
13 million for program delivery. Incentives therefore account for only 13 percent of
14 the total residential demand response budget, while program delivery costs
15 account for 63 percent of planned spending. On a per-participant basis, these
16 budgets represent approximately \$12 in incentives per participant and \$61 in
17 delivery costs per participant.⁵⁶

18 **Q. How do E1’s Residential program delivery costs compare to other**
19 **jurisdictions?**

20 A. E1’s proposed residential demand response delivery costs as a share of total
21 budgets appear substantially higher than similar programs in other jurisdictions.
22 The independent evaluator’s comparison shows that total non-incentive spending—
23 inclusive of program delivery, program administration, marketing, and other
24 costs—accounted for only 27 and 29 percent of residential demand response
25 budgets for Rhode Island Energy and National Grid (Massachusetts), respectively.
26 Meanwhile, E1 has proposed a budget consisting of 77 percent for total non-

⁵⁴ E1’s response to Synapse IR-90(b).

⁵⁵ E1’s response to Synapse IR-90 (d).

⁵⁶ Synapse Analysis of E1’s response to Synapse IR-90, Attachment 1.

1 incentive spending, and 63 percent for program delivery alone.⁵⁷ This finding
2 raises concerns about whether E1’s residential demand response programs are
3 being administered cost-effectively and whether the proposed delivery budget is
4 reasonable.

5 **Q. What is E1’s approach to managing program delivery costs?**

6 **A.** On the overall DSM plan, E1 states that it has

7 “heard some concerns from stakeholders that program delivery costs have
8 increased unreasonably since the last plan. However, E1 submits that the
9 observed changes in unit costs are attributable to identifiable structural (e.g.,
10 reduced government funding, evaluation results) and market factors (e.g., further
11 evolution of the lighting market, particularly in the BNI sector, increased costs
12 of equipment, technology and labour) that are largely beyond E1’s control, and
13 that E1 has taken active steps to demonstrate the management and containment
14 of costs within this environment. Notably, customer incentives account for 71
15 percent of total costs in the Preferred Plan, an increase from 66 percent in the
16 2026 DSM Plan.”⁵⁸

17 Therefore, the overall plan’s spending share on incentives (71 percent) is over
18 five times that of the residential demand response program (13 percent). To
19 manage costs, E1 commits to benchmarking costs “with those of other similar
20 industries, organizations, and DSM administrators, where appropriate, through
21 market research and market comparisons prepared by independent third parties;”
22 following “rigorous procurement practices to achieve best value by acquiring
23 goods and services through competitive processes;” “conducting third-party
24 independent audits and reviews;” and “implementing industry-leading
25 methodologies to maximize cost-effectiveness across all aspects of program
26 delivery.”⁵⁹

⁵⁷ Table 18, page 31, Econoler, *Residential Demand Response Final Report*, at PDF page 677 of E1’s 2025
DSM Programs Evaluation Final Report, March 24, 2026.

⁵⁸ Pg. 46, E1 Evidence.

⁵⁹ Pg. 48, E1 Evidence.

1 **Q. Does E1 address the high program delivery costs for the residential demand**
2 **response program specifically?**

3 A. No. E1 does not address the high delivery costs of the residential demand
4 response program specifically. According to the Round 1 Model Input
5 Assumptions and Results, E1 “reviewed DR incentives, program delivery costs,
6 program administration costs and sector allocation, identifying potential
7 opportunities to reduce the overall investment.”⁶⁰ However, while E1
8 disaggregated the drivers of energy-efficiency unit-cost savings and retained
9 Apex Analytics to review first-year energy-efficiency costs and unit cost
10 reasonableness in May 2026, neither of these two assessments evaluated delivery
11 costs for the demand response programs.⁶¹

12 E1’s share of total proposed plan spending on incentives is very low relative to
13 comparable programs, such as Rhode Island Energy and National Grid
14 Massachusetts, which spend over 70 percent of their residential demand response
15 budgets on incentives.⁶² In contrast, E1 plans to spend only 13 percent of the 2027
16 residential budget on incentives, and 63 percent on program delivery.⁶³

17 **Q. What do you recommend regarding E1’s residential program delivery**
18 **vendors?**

19 A. E1 should conduct a process evaluation of the delivery of the residential demand
20 response program to identify opportunities for gaining efficiencies and achieving
21 cost reductions. Process evaluations can also find opportunities to improve
22 effectiveness, including lessons from how other utilities deliver these programs.
23 Additionally, E1 should review its competitive procurement process for
24 residential demand response delivery services to ensure it enables E1 to choose
25 from a pool of competitive bidders the most cost-effective delivery solution.

⁶⁰ Pg. 2, 2027-2031 Demand Side Management Resource Plan - Round 1 Model Input Assumptions and Results.

⁶¹ E1 Response to IG IR-10, Attachments 1 and 2.

⁶² Table 18, page 31, Econoler, Residential Demand Response Final Report, at PDF page 677 of E1’s 2025 DSM Programs Evaluation Final Report, March 24, 2026.

⁶³ Synapse Analysis of E1’s Response to Synapse IR-90, Attachment 1.

1 **EV and battery demand response programs**

2 **Q. E1 proposes to phase out its EV and battery demand response programs.**
3 **What is E1's rationale?**

4 A. E1 plans to phase out the EV and battery pathways before the start of the 2027
5 demand response season. E1 states that it excluded these pathways from the
6 proposed 2027-2031 DSM Plan due to "cost-effectiveness, low enrollment,
7 operational complexity, DERMS/product-compatibility issues, and, for EVs,
8 unreliable event availability due to customer charging habits."⁶⁴

9 **Q. How cost-effective are the EV and battery pathways?**

10 A. E1 does not provide BCRs in the 2027-2031 plan. However, based on the 2026
11 extension, the PAC BCRs for these two programs are concerningly low: only 0.05
12 for the EV pathway and 0.18 for the battery pathway.⁶⁵

13 **Q. You stated earlier that E1's modeled benefits per kW reduction for the**
14 **thermostats and water-heater pathways are higher under the 2027 plan vs**
15 **the 2026 plan. If the EV and battery programs were to see similar**
16 **improvements in their modeled benefits per kW reduction, would they come**
17 **close to cost-effectiveness?**

18 A. No. Even if the EV and battery pathways experienced E1's assumed 39 percent
19 growth in benefits per kW reduction for the thermostat and water-heater
20 pathways, the EV and battery pathways would still be far from cost-effective.

21 **Q. Do you agree with phasing out these pathways at this time?**

22 A. Yes. E1's proposed residential thermostat and water heater programs on their own
23 are not expected to be cost-effective over the course of the plan, making it
24 challenging for the residential demand response portfolio to support pathways
25 such as EVs and batteries with very low modeled BCRs.

⁶⁴ E1's response to Synapse IR-16 (b).

⁶⁵ E1, 2026 Extension filing, Appendix A, Attachment 4, page 19c.

1 **Q. Despite their low modeled 2026 BCRs, do EV charging and batteries hold**
2 **promise as demand response assets in Nova Scotia?**

3 A. Yes. Initial results from E1's EV and battery pathways show strong curtailment
4 from responding devices: the independent evaluator reported an average
5 curtailment of 4.02 kW per responding EV charger and 3.51 kW per responding
6 battery in 2025, which is much higher than the 385 W recorded per responding
7 water heater and 69 to 112 W recorded per responding thermostat (depending on
8 the heating load served).⁶⁶

9 **Q. Could the EV charging and battery demand response markets grow over the**
10 **course of the 2027-2031 plan period?**

11 A. Yes. As shown in Table 12 below, 2025 actual MW capacities for the EV and
12 battery pathways were only 2 and 3 percent of their estimated achievable
13 potentials for 2031, respectively. The opportunities and economics of EV and
14 battery demand response may change considerably over the course of the plan
15 period.

16 **Table 12. Residential Demand Response 2025 Actual Capacity (MW)**
17 **as Percent of 2031 Achievable Potential (MW)**

	2025	2031	2025 % of 2031
Water Heaters	0.05	0.88	6%
Thermostats	0.75	2.46	30%
EV Charging	0.03	1.36	2%
Batteries	0.03	1.14	3%

18 *Source: Battery and EV Potential: 2026 Plan Extension, Appendix A, Attachment 4, Sheet 3;*
19 *Water Heater and Thermostat Potential: 2027-2031 Plan, Appendix A, Attachment 4, Sheet 3a;*
20 *2025 Actuals: E1's Response to Synapse IR-90, Attachment 1.*

⁶⁶ Table 19, page 32, Econoler, *Residential Demand Response Final Report*, at PDF page 678 of E1's 2025 DSM Programs Evaluation Final Report, March 24, 2026.

We assume that Econoler's reported 2025 performance data are averages among responding device (not across all enrolled participants) because E1's reporting of 2025 actuals as part of Synapse IR-90, Attachment 1 reflects lower pathway-average performance of only 0.16 kW per EV participant, 2.5 kW per battery participant, 50 W per water-heater participant, and 70 W per thermostat participant.

1 **Q. What do you recommend regarding the EV and battery demand response**
2 **pathways?**

3 A. I recommend that E1 proceed with phasing out these pathways as planned, but
4 reevaluate cost-effectiveness under updated program designs midway through the
5 plan during the mid-term check-in. This reevaluation is warranted because of the
6 huge potential growth in the market over the next few years and the evolving
7 program designs seen from other jurisdictions. E1 should pursue a process
8 evaluation of these programs to both assess weaknesses in their existing designs
9 and research precedent models from other jurisdictions.

10 **Q. Would you recommend E1 consider alternative program designs for EV**
11 **charging demand response?**

12 A. Yes. Because at-home EV charging is driven primarily by schedules and
13 routines,⁶⁷ the event-based curtailment strategy currently used for the EV program
14 may be a poor fit. Average performance across the whole EV pathway in 2025
15 was only 0.16 kW per enrolled device.⁶⁸ Meanwhile, Rhode Island Energy's EV
16 demand response program achieved better performance in 2025: about 0.33 kW
17 per enrolled device.⁶⁹ Instead of this event-based curtailment approach, E1 could
18 evaluate program designs that shift charging off-peak throughout the year, rather
19 than just during select events.

20 **Q. Do you recommend a specific alternative EV program design?**

21 A. Not at this time. A 2025 Rivian study using 2023 home-charging data from more
22 than 5,000 vehicles found that EV owners actively scheduled charging to align
23 with time-of-use tariffs or load management programs in only about 26 percent of

⁶⁷ Jose Tupayachi, Mustafa C. Camur, Kevin Heaslip, and Xueping Li. *Spatio-Temporal Graph Convolutional Networks for EV Charging Demand Forecasting Using Real-World Multi-Modal Data Integration*. University of Tennessee, October 2025, page 13. arXiv:2510.09048. Available at: <https://arxiv.org/pdf/2510.09048>. Accessed 6/9/26.

⁶⁸ Table 19, page 32, Econoler, *Residential Demand Response Final Report*, at PDF page 678 of *E1's 2025 DSM Programs Evaluation Final Report*, March 24, 2026.

⁶⁹ PDF page 11, *ConnectedSolutions 2025 Summer Recap and SRP Three-Year Plan*, Rhode Island Energy Efficiency Council meeting, March 19, 2026. Available at: https://eec.ri.gov/wp-content/uploads/2026/03/ConnectedSolutions-2025-Summer-Recap-and-SRP-Three-Year-Plan_EEC-Meeting_03192026.pdf. Accessed 6/9/26.

1 sessions, indicating that active customer management of charging is uncommon
2 under current typical EV demand-response designs.⁷⁰ However, more nascent
3 “managed charging” programs—through which program administrator or utility
4 sets charging schedules—could lead to better performance. A 2026 Brattle Group
5 analysis of data sourced from EnergyHub’s EV load-flexibility service, found that
6 actively managed charging programs can deliver coincident peak reductions
7 roughly 55 percent greater than passive time-of-use rates.⁷¹ Specifically, early
8 results from National Grid Massachusetts’ managed charging program
9 demonstrated that 80 percent of charging occurred during off-peak hours in
10 2023.⁷² E1 should evaluate at a high level the potential efficacy of each of these
11 three program designs—the current event-based approach, behavioral through
12 time-of-use rates, and program-managed charging—so that if and when the
13 market shows signs of further development, E1 is ready to put in place needed
14 market interventions.

15 **Calculations of peak load reductions**

16 **Q. Please explain how E1 proposes to assess demand response performance**
17 **across the duration of demand response events.**

18 A. E1’s evaluation of available demand response capacity is weighted toward the
19 early hours of an event. E1 states that for its residential program it “evaluates
20 available DR capacity based on demand reduction during winter event hours,
21 primarily the first two hours of eligible events,”⁷³ and “for Business, Non-profit
22 and Institutional (BNI) DR, the same methodology is used.” Yet E1’s event data
23 indicate that the residential and BNI events are consistently four hours long, and

⁷⁰ Rivian Automotive. *The Untapped Potential of Smart Charging: How EV Owners Can Save Money and Reduce Emissions Without Behavioral Change*. 2025. arXiv:2503.03167. Available at: <https://arxiv.org/pdf/2503.03167>. Accessed 6/9/26.

⁷¹ The Brattle Group. *Demonstrating the Full Value of Managed Electric Vehicle Charging*. Prepared for EnergyHub. January 2026. Available at: <https://www.brattle.com/wp-content/uploads/2026/01/Demonstrating-the-Full-Value-of-Managed-Electric-Vehicle-Charging.pdf>. Accessed 6/9/26.

⁷² Slide 9, Massachusetts Department of Public Utilities presentation at the August 7, 2024 Electric Vehicle Infrastructure Coordinating Council (EVICC) meeting. Available at: <https://www.mass.gov/doc/dpu-presentation-at-8724-evicc-meeting/download>. Accessed 6/9/26.

⁷³ E1’s response to Synapse IR-18 (a).

1 that residential capacity degrades by roughly half between the first and fourth
2 hours (BNI hourly data is not available).⁷⁴

3 **Q. Why does this misalignment matter?**

4 A. If E1 dispatches four-hour events and claims savings on a four-hour basis but
5 evaluates performance based primarily on the first two hours, the methodology
6 overstates the performance of pathways for which the curtailment degrades over
7 the event, most notably the thermostat and water-heater pathways. By
8 comparison, the battery and EV pathways, which can sustain output across the full
9 event, are made to look relatively worse than they are. I therefore recommend that
10 E1 weight performance equally across all hours of each event. Equal weighting
11 would produce a more accurate comparison across pathways and would
12 strengthen the relative cost-effectiveness case for the battery and EV pathways. I
13 also recommend further consideration of whether a four-hour event is the most
14 appropriate duration, given NSPI's electric system peak hours.

15 **BNI Program Offerings**

16 **Q. What is the major concern with BNI Demand Response program?**

17 A. E1 projects 11 participants will join its new BNI Back Up Generator "BUG"
18 demand response program for the 2027 season and deliver 6.6 MW of capacity.⁷⁵
19 These BUG resources are predominantly fossil-fueled. While the overall GHG
20 impact of occasional BUG dispatch is relatively small, the local air-quality and
21 fine particulate matter (PM_{2.5}) impacts should not be overlooked. As part of
22 Canada's Review and Assessment of the Canada-U.S. Air Quality Agreement
23 2023, a bilateral committee found that nationwide PM_{2.5} concentrations have
24 plateaued, yet levels in Atlantic Canada remain some of the highest in the
25 country.⁷⁶ Therefore, additional scrutiny should be given to initiatives that will
26 increase PM_{2.5} concentrations in Nova Scotia.

⁷⁴ E1's response to Synapse IR-18 (c)i, (c)ii.

⁷⁵ E1's response to Synapse IR-90, Attachment 1.

⁷⁶ US-Canada Air Quality Committee, Review and assessment of the Canada-United States Air Quality Agreement, 2023. Accessed June 16, 2026. Available At: <https://www.canada.ca/en/environment->

1 **Q. What do you recommend?**

2 A. To address these local air-quality impacts and to fill a gap in E1’s offerings (E1
3 has no BNI pathway dedicated to batteries) I recommend that E1 develop a higher
4 incentive for battery-based BNI standby resources than for fossil-fueled
5 generators. A differentiated incentive would encourage cleaner capacity, extend
6 the battery pathway’s benefits to the BNI sector, and reduce reliance on emitting
7 generation during demand response events.

8 *Mid-Term Check-Ins and Mid-Course Adjustments*

9 **Q. Please summarize E1’s proposal regarding mid-term check-ins during the**
10 **2027-2031 DSM Plan.**

11 A. E1 proposes one mid-term check-in with the DSMAG during the first quarter of
12 2029, which is when E1 plans to begin its engagement with the DSMAG on the
13 next five-year plan. This mid-term check-in will occur regardless of how actual
14 DSM performance compares to the plan.⁷⁷

15 **Q. Please summarize E1’s proposal regarding mid-cycle adjustments during the**
16 **2027-2031 DSM Plan.**

17 A. E1 may adjust the plan mid-cycle if actual DSM performance diverges
18 significantly from the plan. E1 proposes to explain actual spending and savings
19 that varies from planned by more than 20 percent at the program level. E1 also
20 proposes to explain actual spending that varies from planned by more than 15
21 percent at the rate class level. However, E1 proposes to retain full discretion as to
22 whether to file a mid-cycle adjustment (MCA) based on any significant variances
23 between plan and actuals.

24 E1 states that circumstances that could trigger the need for an MCA may include:
25 “significant and unforeseen changes in avoided costs, material shifts in market
26 conditions or technology availability, legislative or regulatory changes affecting

climate-change/services/air-pollution/issues/transboundary/canada-united-states-air-quality-agreement-overview/review-assessment-2023.html

⁷⁷ E1’s response to Synapse IR-72.

1 DSM delivery, or other extraordinary events materially impacting plan feasibility
2 or ratepayer value.”⁷⁸ E1 does not mention the addition of programs or
3 termination of programs as a trigger for an MCA. E1 intends for MCAs to be
4 informational in nature, limited, year-only adjustments to program-level budgets
5 and savings to respond to changes that were not known at the time of Plan
6 development. According to E1, MCAs will not change NSEB-approved
7 Performance Targets.⁷⁹

8 In summary, E1 does not propose any specific performance threshold or trigger
9 that would necessitate the filing of an MCA by E1. If E1 decides to file an MCA
10 in any given year, E1 will propose the MCA in E1’s Q1 Report to be filed on May
11 25th.^{80,81}

12 **Q. Are mid-term check-ins and mid-cycle adjustments important components of**
13 **the 2027-2031 DSM Plan?**

14 A. Yes. Nova Scotia legislated a change from three-year DSM planning periods to
15 five-year DSM planning periods starting with the 2027-2031 DSM Plan.⁸² Five
16 years is a long DSM planning period relative to other provinces.⁸³ Factors that
17 impact the performance of a DSM program, including but not limited to the
18 saturation, efficiency, cost, and commercial availability of technologies, can
19 change over just a few years. E1’s proposed mid-term check-ins provide
20 important opportunities for status updates. Mid-cycle adjustments can provide
21 necessary opportunities to alter programs over the course of those five years.

22 **Q. Do other jurisdictions have mid-term modification processes?**

23 A. Yes. The Massachusetts energy efficiency program administrators have a process
24 for filing “mid-term modifications.” The Department of Public Utilities requires

⁷⁸ E1’s Evidence, page 66.

⁷⁹ E1’s Appendix A – Preferred Plan, page 107.

⁸⁰ E1’s response to Synapse IR-72.

⁸¹ E1’s response to Synapse IR-89.

⁸² CanLII.org. Public Utilities Act (amended), SNS 2022, c 53. Bill No. 228 (as passed). Available at:
<https://www.canlii.org/en/ns/laws/astat/sns-2022-c-53/latest/sns-2022-c-53.html>. Accessed 6/1/26.

⁸³ See Table 1. Current utility DSM plans on page 13 of Gaede, J., Nippard, A., Turner, K. 2026. *The 2025 Energy Efficiency Programs Report*. Efficiency Canada, Carleton University, Ottawa, ON. Page 54. Available at: <https://www.efficiencycanada.org/2025-programs-report/>. Accessed 5/31/26.

1 programs administrators to file a mid-term modification if certain criteria are met,
2 such as if an increase or decrease of more than 10 percent in three-year plan
3 budgets at the sector level is anticipated.⁸⁴

4 **Q. Are E1's mid-term check-in and mid-cycle adjustment proposals adequate?**

5 A. No. There should be one or more thresholds at which E1 is required to provide a
6 mid-cycle adjustment.

7 **Q. What do you recommend?**

8 A. I recommend that the NSEB establish several thresholds that would trigger a
9 requirement for E1 to propose and file a mid-cycle adjustment:

- 10 • If spending is anticipated to decrease or increase by more than a specified
11 percent of plan, such as 10 or 15 percent.
- 12 • If E1 seeks to terminate any program or implement a new program.

13 **Q. Does this conclude your evidence at this time?**

14 A. Yes, it does.

⁸⁴ Specifically, the Massachusetts Department of Public Utilities adopted its proposed change regarding mid-term modifications that requires “concurrent Department and Council review of the following modifications: (1) the addition of an energy efficiency core initiative, hard-to-measure core initiative, or demonstration project; (2) the transition of a hard-to-measure core initiative to an energy efficiency core initiative; or (3) any modification that results in an increase or decrease to the three-year term sector budget of more than ten percent (Straw Proposal § 3.8.2). The Department also proposed to require Council review of the following modifications: (1) the termination of an existing energy efficiency core initiative or hard-to-measure energy efficiency core initiative; or (2) a modification to the implementation of one or more energy efficiency core initiatives that is projected to result in a decrease in the energy efficiency program benefits over the three-year term that is greater than 20 percent.” (See: Massachusetts Department of Public Utilities. Case 20-150-A. *Investigation by the Department of Public Utilities on its own Motion into Updating its Energy Efficiency Guidelines, Guidelines for the Methods and Procedures for the Evaluation and Approval of Energy Efficiency Plans and Energy Efficiency Reports*. May 3, 2021. Pages 13-14. Available at: <https://www.mass.gov/order/investigation-by-the-dpu-into-updating-its-ee-guidelines>. Accessed 6/17/26.)

1 APPENDIX A: RESUME

Alice Napoleon, Senior Principal

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PROFESSIONAL EXPERIENCE

Synapse Energy Economics, Inc., Cambridge, MA. *Senior Principal*, Apr 2026–Present; *Principal Associate*, Jun 2021–Apr 2026; *Senior Associate*, Jun 2013–Jun 2021; *Associate*, Jul 2008–Jun 2013; *Research Associate*, Apr 2005–Jul 2008

- Provides expert analysis, stakeholder support, research, expert witness services, and consulting services regarding energy efficiency program design and performance, funding and incentive mechanisms, cost-effectiveness screening, potential studies, and strategic planning.
- Develops and sponsors testimony on electric and natural gas energy efficiency plans, energy transition planning and policy, innovative programs, regulatory structures, and advanced metering infrastructure (AMI) proposals in states and provinces across the U.S. and Canada.
- Conducts distributional equity analysis and develops reports on disparate impacts of electric and natural gas infrastructure on economic, social, and health outcomes, as well as options for improving energy equity. Analyzes factors that affect participation in, and the effectiveness of, energy efficiency programs to inform program design and targeting efforts.
- Oversees and conducts interviews and research, including literature reviews and case studies.

Resource Insight, Inc., Arlington, MA. *Research Assistant*, 2003–2005

Responsible for conducting research and analysis of electric, gas, steam, and water resource issues. Conducted discounted cash flow analysis for asset valuation. Developed market-price benchmarks for analysis of power-supply bids including energy, capacity, ancillary services, transmission, ISO services, losses, and adjustment for load shape. Prepared discovery responses, formal objections, comments, and testimony; collaboratively wrote and edited reports; created and formatted exhibits. Participated in drafting an Energy Plan for New York City. Edited solicitation for competitive power supply to serve aggregated municipal load.

University of Massachusetts, Amherst, MA. *Teaching Assistant*, 2001–2002

Developed and taught lessons on applied math to a diverse group of incoming graduates; tutored students in microeconomic theory and cost benefit analysis; graded problem sets and memoranda.

International Council for Local Environmental Initiatives, Berkeley, CA. *Cities for Climate Protection Intern for the City of Northampton, MA*, 2001

Compiled primary and secondary source data on energy consumption and solid waste generation by the municipal government, city residents, and businesses; applied emissions coefficients to calculate total GHG emissions; identified current and planned municipal policies that impact GHG emissions;

researched the predicted local effects of global warming; gathered public feedback to provide acceptable and proactive policy alternatives. Composed a GHG emissions inventory describing research findings; wrote and distributed a policy report and press releases; gave newspaper and radio interviews; addressed public officials and the public during a televised meeting.

University of Massachusetts, Amherst, MA. *Research Assistant*, 2000–2001

Located federal data sources, identified changes, and updated a research database to evaluate the Habitat Conservation Program; proofread articles and white papers; composed a literature review on land use modelling. Collaboratively administered, tested, and proposed interface enhancements for a web-based data warehouse of regional habitat change research; formally presented the system to an independent research group.

Court Square Data Group, Inc., Springfield, MA. *Administration Manager*, 1998–2000; *Project Administrator*, 1996–1998

As Administration Manager, analysed profitability and diversity of income sources; managed cash flow, expense, and income data; created budgets; devised and implemented procedures to increase administrative efficiency; implemented new accounting system with minimal disruption to workflow.

As Project Administrator, coordinated implementation of software features; identified opportunities for future development; monitored problem resolution; wrote and coordinated production of a user's manual and questionnaires; edited technical proposals and a business plan.

EDUCATION

University of Massachusetts, Amherst, MA
Master of Public Administration, 2002

Rutgers University, New Brunswick, NJ
Bachelor of Arts in Economics, 1995

Syracuse University, Syracuse, NY, 1994

PUBLICATIONS

Knight, P., S. Kwok, E. Ashley, A. Glaser Schoff, S. Schadler, S. Sharaf, A. Zeng, A. Napoleon. "Making Energy More Affordable in New York." Presentation prepared for the Natural Resources Defense Council and the Evergreen Collaborative, March 2026.

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Woolf, T., A. Napoleon, D. Goldberg, E. Carlson, C. Mattioda. 2023. *Distributed Equity Analysis for Energy Efficiency and Other Distributed Energy Resources*. Synapse Energy Economics for Lawrence Berkley National Lab and E4TheFuture.

Hopkins, A. S., A. Napoleon, K. Schultz. 2023. *The High Cost of New York Gas Utilities' Leak- Prone Pipe Replacement Programs*. Synapse Energy Economics for Natural Resources Defense Council.

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Hopkins, A. S., S. Kwok, J. Litynski, A. Napoleon, K. Takahashi. 2022. Memo: Evaluation of Draft Consultant Reports in Massachusetts DPU Docket 20-80. Synapse Energy Economics for Conservation Law Foundation.

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Frost, J. S. Kwok, K. Takahashi, A.S. Hopkins, A. Napoleon. 2021. *New York Heat Pump Trajectory Analysis*. Synapse Energy Economics for NRDC.

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Fagan, R., A. Napoleon, A. Rochelle, A. Sommer, W. Steinhurst, D. White. K. Takahashi. 2006. *Mohave Alternatives and Complements Study: Assessment of Carbon Sequestration Feasibility and Markets*. Sargent & Lundy and Synapse Energy Economics, Inc. for Southern California Edison.

TESTIMONY

New York Public Utilities Commission (Case Nos. 25-E-0072 and 25-G-0073): Direct and Rebuttal Testimony of Alice Napoleon in the Matter of Consolidated Edison Company of New York, Inc. regarding proposed gas-side investments, particularly as those investments relate to energy affordability and state decarbonization policy. On behalf of Natural Resources Defense Council. May 30, 2025.

Michigan Public Service Commission (Case No. U-21806): Direct Testimony of Alice Napoleon in the matter of the Application of Consumers Energy Company for authority to increase its rates for the distribution of natural gas and for other relief. Synapse Energy Economics for Michigan Environmental Council and Sierra Club. April 23, 2025.

Michigan Public Service Commission (Case No. U-21291): Direct Testimony of Alice Napoleon in the matter of the Application of DTE Gas Company for authority to increase its rates, amend its rate schedules, and rules governing the distribution and supply of natural gas, and for miscellaneous accounting authority. Synapse Energy Economics for Michigan Environmental Council, Natural Resources Defense Council, and Sierra Club. May 7, 2024.

New York Public Service Commission (Case 23-G-0627): Direct Testimony of Alice Napoleon in the Matter of the Rates, Charges, Rules and Regulations of National Fuel Gas Distribution Corporation. On behalf of Natural Resources Defense Council. March 1, 2024.

New York Public Service Commission (Case 23-G-0225 and Case 23-G-0226): Direct Testimony of Alice Napoleon regarding proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of KeySpan Gas East Corporation d/b/a National Grid for Gas Service and The Brooklyn Union Gas Company d/b/a National Grid NY for Gas Service. On behalf of Natural Resources Defense Council. September 1, 2023.

Nova Scotia Utility and Review Board (NSUARB M11003): Evidence of Alice Napoleon in the Matter of The Public Utilities Act, R.S.N.S 1989, c.380, as amended, and the application of Nova Scotia Power Inc.

for Authorization to Overspend on Capital Work Order CI47124- Advanced Metering Infrastructure. On behalf of Counsel to Nova Scotia Utility and Review Board. June 22, 2023.

New York Public Utilities Commission (Case No. 22-E-0064 and 22-G-0065): Direct and Rebuttal Testimony of Alice Napoleon and Asa Hopkins regarding Con Edison's proposed gas-side investments as greenhouse gas mitigation strategies and gas extension allowance rule changes and the need for long-term planning for the gas system and adequacy of the company's non-pipe alternatives framework. On behalf of Natural Resources Defense Council, May 2022.

Nova Scotia Utility and Review Board (M10473): Evidence of Alice Napoleon and Kenji Takahashi regarding EfficiencyOne's 2023-2025 DSM Resource Plan, with a focus on the Settlement Plan. On behalf of Counsel to Nova Scotia Utility and Review Board, May 2022.

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Nova Scotia Utility and Review Board (Matter No. M09519): Evidence of Alice Napoleon regarding Nova Scotia Power's Smart Grid Nova Scotia Project proposal. On behalf of Counsel to the Nova Scotia Utility and Review Board. February 19, 2020.

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TESTIMONY ASSISTANCE

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State of New Jersey Board of Public Utilities (Docket No. EO14080897): *Direct testimony of Kenji Takahashi regarding the Petition of Public Service Electric & Gas Company to continue its Energy Efficiency Economic Extension Program on a Regulated Basis (EEE Extension II).* On behalf of New Jersey Division of the Ratepayer Advocate. November 7, 2014.

Kentucky Public Service Commission (Case No. 2014-00003): *Direct testimony of Tim Woof regarding Louisville Gas and Electric Company and Kentucky Utilities Company's proposed 2015-2018 demand-side management and energy efficiency program plan.* On behalf of Wallace McMullen and the Sierra Club. April 14, 2014.

State of New Jersey Board of Public Utilities (Docket No. GO12050363): *Direct testimony of Maximilian Chang regarding South Jersey Gas Company's proposal to extend and modify its energy-efficiency programs.* On behalf of New Jersey Division of the Ratepayer Advocate. November 9, 2012.

State of New Jersey Board of Public Utilities (Docket No. GO12070640): *Direct testimony of Robert Fagan regarding New Jersey Natural Gas Company's petition for approval of the extension of the SAVEGREEN energy efficiency programs.* On behalf of the New Jersey Division of the Ratepayer Advocate. October 26, 2012.

State of New Jersey Board of Public Utilities (Docket No. GO11070399): *Direct testimony of Robert Fagan regarding Elizabethtown Gas Company's Proposed Energy Efficiency Program.* On behalf of New Jersey Division of the Ratepayer Advocate. December 16, 2011.

State of New Jersey Board of Public Utilities (Docket No. GR11070425): *Direct testimony of Robert Fagan regarding New Jersey Natural Gas Company's petition for approval of the extension of the SAVEGREEN energy efficiency programs.* On behalf of the New Jersey Division of the Ratepayer Advocate. November 16, 2011.

State of New Jersey Board of Public Utilities (Docket No. GR10030225): *Direct testimony of David Nichols regarding New Jersey Natural Gas Company's Proposed Energy Efficiency Program.* On behalf of New Jersey Division of the Ratepayer Advocate. July 9, 2010.

Virginia State Corporation Commission (Case No. PUE-2009-00097): *Direct testimony of William Steinhurst regarding Appalachian Power Company's Integrated Resource Plan filing pursuant to Va. Code § 56-597 et seq.* On behalf of the Southern Environmental Law Center, Chesapeake Climate Action Network, Appalachian Voices, and the Virginia Chapter of The Sierra Club. March 23, 2010.

Delaware Public Service Commission (Docket No. 07-20): *Jointly authored an expert report, with Robert Fagan, William Steinhurst, David White, and Kenji Takahashi, In the Matter of Integrated Resource Planning for the Provision of Standard Offer Service by Delmarva Power & Light Company Under 26 DEL. C. §1007 (c) & (d).* On behalf of the Staff of Delaware Public Service Commission. April 2, 2009.

State of New Jersey Board of Public Utilities (BPU Docket EM05020106): *Direct and surrebuttal testimony of Bruce Biewald, Robert Fagan, and David Schlissel regarding the Joint Petition Of Public Service Electric and Gas Company And Exelon Corporation For Approval of a Change in Control Of Public*

Service Electric and Gas Company And Related Authorizations. On behalf of New Jersey Division of the Ratepayer Advocate. November 14, 2005, and December 27, 2005.

Illinois Commerce Commission (Dockets 05-0160, 05-0161, 05-0162): *Direct testimony of William Steinhurst regarding Ameren's proposed competitive procurement auction (CPA).* On behalf of Illinois Citizens Utility Board. June 15, 2005, and August 10, 2005.

Illinois Commerce Commission (Docket 05-0159): *Direct testimony of William Steinhurst regarding Commonwealth Edison's Proposal to implement a competitive procurement process.* On behalf of Illinois Citizens Utility Board and Cook County State's Attorney's Office. June 8, 2005, and August 3, 2005.

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