E1 Responses to Industrial Group (IG) Information Requests
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Request IR-01:

References: Exhibit E-1, Application, page 8/71, lines 23–24; and Table 15, pages 40–44/71.

Preamble: E1 states that annual investment is constrained to the 2026 approved level of $63.75M per year, with no inflationary increases applied.

(a) Please provide a rate-class-by-rate-class comparison in tabular form of: (i) approved annual spending under the 2023–2025 Plan; (ii) 2026 approved annual spending (the baseline); (iii) proposed annual spending for each year 2027–2031 under the Preferred Plan; and (iv) the dollar and percentage change from 2026 approved spending for each rate class.

(b) If Medium Industrial or Large Industrial spending increases in dollar or percentage terms relative to either the 2023–2025 Plan or 2026 approved spending, what are the drivers of that increase notwithstanding the flat overall budget envelope?

(c) Please reconcile how spending increases for some rate classes are funded within the flat $63.75M/year envelope, identifying which rate classes bear reductions to accommodate those increases.

Response IR-01:

(a) Please refer to Attachment 1 of this IR response.

(b) E1 committed in the 2026 DSM Plan Extension to improve the accuracy of rate class spending estimates in DSM Plans and has relied on several years of historical participation data, as well as program activity expected to occur during each year of DSM Plan implementation, to develop the 2027–2031 rate class estimates. The 2027–2031 DSM Plan rate class estimates were developed in alignment with that commitment and reflect E1's best available forecast of customer participation by rate class.

Spending in the Medium Industrial rate class is projected to increase relative to both the 2023–2025 Plan and the 2026 DSM Extension as Approved for two reasons. First, Medium Industrial customers participated in the Business, Non-Profit and Institutional (BNI) Demand Response program component at higher-than-expected levels during the 2023–2025 Plan period, establishing a higher baseline of engagement. Second, the proposed 2027–2031 Preferred DSM Plan includes planned growth in the BNI Demand Response program component beyond 2026 approved levels, reflecting demonstrated customer appetite and E1's forecasted continuation of that trend.

Spending in the Large Industrial rate class in the proposed 2027–2031 DSM Plan represents an increase from levels in the 2023–2025 DSM Plan, but is consistent with 2026 DSM Extension as Approved spending.

(c) When compared to the 2026 DSM Extension as Approved, the Residential, Large General, and Medium Industrial rate classes have increased spending (on average per year) in the proposed 2027–2031 Preferred Plan – an average increase of $1.5 million per year in the Residential rate class, and average increases of $0.6 million per year in both the Large General and Medium Industrial rate classes. The General and Small General rate classes have decreased spending (on average per year) in the 2027–2031 Preferred Plan – an average decrease of $2.1 million per year in the General rate class, and $0.6 million in the Small General rate class.

Request IR-02:

Reference: Exhibit E-1, Application, page 24/71, lines 4–5; and page 38/71, Section 4 (“Affordability”).

Consistent with the PUA and the NSEB’s regulatory framework, affordability is the primary consideration in the design of the 2027–2031 DSM Plan.

(a) How has E1 defined “affordability” for purposes of its analysis and DSM Plan?

(b) Does E1’s approach to “affordability” reconcile with that used by NSPI? Please explain.

(c) By keeping investment at the 2026 approved level of $63.75 million, has E1 assumed that this is the acceptable/affordable investment level, or has E1 completed its own analysis of whether this amount is in fact an acceptable or affordable level of investment over 2027–2031? Please explain.

Response IR-02:

(a) Please refer to EfficiencyOne’s (E1) response to part (a) of NSEB IR-03.

(b) E1 can only speak to its own approach to affordability in the design of the 2027–2031 DSM Plan and is not in a position to speak on behalf of, NS Power ("NSPI") or its definition of affordability. As described further in E1's response to part (a) of NSEB IR-03, E1's affordability framework is grounded in the principle that DSM investment levels should not create undue rate pressure on customers, and that the approved 2026 budget level of $63.75 million was used as a reference point consistent with that principle.

(c) Please refer to E1's response to part (a) of NSEB IR-03.

Request IR-03:

Reference: Exhibit E-1, Application, Section 3.2.1, pages 26–27/71.

Preamble: E1's Preferred Plan proposes 435.4 GWh in cumulative energy savings over 2027–2031, representing approximately 64% of the 683.1 GWh savings target in NSPI's 2022 Evergreen IRP, which E1 characterizes as a deliberate short-term affordability trade-off.

(a) Recognizing that the IESO-NS is currently undertaking a new IRP, what consultation or engagement has E1 had with the IESO-NS in preparing the current DSM Plan and/or in having DSM Plan assumptions incorporated into the new IRP?

(b) When does E1 anticipate receiving updated avoided cost estimates from the new IRP process?

(c) Depending on the timing of the updated avoided cost estimates and the IRP conclusions, does E1 anticipate a need to seek a mid-course adjustment to DSM targets or program spending if the new IRP results in materially different avoided cost or resource adequacy findings? Please explain.

Response IR-03:

(a) EfficiencyOne (E1) has engaged the IESO-NS through the Demand Side Management Advisory Group (DSMAG) engagement process for the development of the 2027-2031 DSM Plan. E1 is also a stakeholder in the IESO-NS's inaugural Integrated Resource Plan (IRP) development process and has been engaged through that engagement process as facilitated by the IESO-NS. E1 has also met individually with the IESO-NS to discuss DSM Potential Study needs that the IESO-NS has for the inaugural IRP.

(b) E1's current understanding is that updated avoided costs of energy and capacity will be developed using the preferred resource plan following the completion of the IESO-NS's new IRP. Based on the current IESO-NS timeline for the new IRP, E1 does not anticipate updated avoided costs to be finalized for use until sometime in 2027. The avoided costs currently used to inform the 2027-2031 DSM Plan are based on the most recent estimates available from the 2022 Evergreen IRP process.

(c) E1's proposed mid-course adjustment process operates independently of IRP cycles. The mid-course adjustment process is designed to re-allocate savings and investment among programs to achieve Board-approved Performance Targets, rather than to modify those targets or the approved investment envelope. As a result, changes in IRP outcomes - including updated avoided costs or revised resource adequacy findings - do not affect E1's proposed mid-course adjustment process. However, E1 acknowledges that these changes will inform E1's proposed mid-term check in. For additional detail please refer to E1's response to Synapse IR-72.

Request IR-04:

Reference: Exhibit E-1, Application, page 28/71, lines 16–20.

> **Alignment with NS Power's IRP also informed the demand response design. The IRP recognizes demand response as a valuable demand-side resource for managing peak demand and supporting system reliability. Its findings informed the scale and role of demand response within the broader DSM portfolio, ensuring that demand response contributes incremental system value without introducing undue delivery or affordability risk.**

(a) What specific IRP "findings" are being relied upon, which informed the demand response "scale and role"?

(b) Please define the undue delivery and affordability risk identified, and provide the risk assessment framework used in reaching the above conclusion, including any assumptions, scoring, sensitivity testing, mitigation measures considered.

Response IR-04:

(a) The Integrated Resource Plan (IRP) findings relied upon were that demand response is a valuable demand-side resource for managing peak demand and supporting system reliability, that there exists an optimal level of demand response capacity from a system planning perspective, and that demand-side resources—including demand response at base levels—contribute to minimizing long-term system costs. EfficiencyOne (E1) applied these findings by ensuring that the scale of demand response in the 2027–2031 DSM Plan remains within the optimal range identified in the IRP, while designing a measured and phased portfolio that delivers incremental capacity value aligned with peak demand reduction objectives, without exceeding system need or introducing undue delivery or affordability risk.

(b) Undue delivery and affordability risk refers to the increased likelihood that expanding demand response beyond the proposed levels would result in unachievable capacity targets or unreliable performance, and/or impose additional costs without commensurate system benefits, affecting ratepayer affordability. The proposed demand response scale in the 2027–2031 Preferred DSM Plan reflects a balanced application of empirical program experience, modelling and cost-effectiveness analysis, IRP levels, and DSM Advisory Group (DSMAG) feedback and regulatory expectations. This approach ensures that demand response contributes incremental, reliable system value while maintaining deliverability and affordability within the 2027–2031 plan period.

E1's reference to "undue delivery and affordability risk" reflects an assessment of risks associated with increasing the scale of demand response beyond the level proposed in the 2027–2031 Preferred DSM Plan. This assessment was not based on a single quantitative scoring model, but rather on a structured, evidence-informed evaluation drawing on multiple inputs, including program performance data, modelling results, DSMAG feedback, and system planning objectives.

E1 Responses to Industrial Group (IG) Information Requests
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Request IR-05:

Reference: Exhibit E-1, Application, page 35/71, lines 5–8.

Modified-PAC results for all strategic electrification scenarios modelled during the 2027–2031 DSM Plan development process demonstrated that these measures did not reduce electricity costs for customers when evaluated under the Energy Board-approved modified-PAC test that includes increased utility revenues.

(a) Please provide all strategic electrification scenarios modelled during plan development, including for each:

- **i) The technologies or measures considered;**
- **ii) The modified-PAC inputs and outputs (both with and without the effect of increased utility revenues);**
- **iii) The threshold at which each scenario was found to fail the test; and**
- **iv) The sensitivity of the PAC result to changes in electricity rates, avoided costs, and fuel prices.**

(b) Please confirm the total amount allocated to Enabling Strategies in the 2027–2031 plan for strategic electrification research and development activities, by year, and provide a workplan describing the specific research activities E1 proposes to undertake.

(c) Please confirm whether Medium Industrial and Large Industrial customers are allocated any portion of the Enabling Strategies budget for electrification research. If so, please provide the dollar amounts allocated to each class over the plan period.

(d) If, during the 2027–2031 plan period, circumstances change such that strategic electrification becomes cost-effective under the modified-PAC test, what process would E1 follow to introduce electrification measures, and how would the associated costs be allocated across rate classes?

(e) Please address specifically whether customers would be consulted and Board approval sought respecting cost allocation of new electrification measures.

Response IR-05:

(a) Please refer to EfficiencyOne's (E1) response to SBA IR-05 part (a).

i) Please refer to part (a) of E1's response to this IR.

ii) Please refer to part (a) of E1's response to this IR.

iii) Please refer to part (a) of E1's response to this IR.

iv) Please refer to part (a) of E1's response to this IR.

(b) Please refer to EfficiencyOne's (E1) response to NSEB IR-15 part (a) (ii).

(c) Allocators are applied at the Enabling Strategies category level and not to the individual areas of focus or the key activities that roll up into them. However, to respond to this IR, costs by this activity have been estimated by applying the appropriate category-level allocators for the Medium Industrial and Large Industrial rate classes to the direct expenditures for strategic electrification (from Table 1 of Appendix A – Attachment 5 (Innovation Framework, Process and Plan for 2027-2031). The results are in Table 1, below.

Table 1: Estimated direct expenditures for strategic electrification portion of Innovation area of focus, by rate class

Estimated direct expenditures for strategic electrification portion of Innovation area of focus	Rate class	
	Medium Industrial	Large Industrial
2027 Total	$1,098	$3,848
2028 Total	$1,090	$3,656
2029 Total	$479	$1,580
2030 Total	$398	$1,330
2031 Total	$393	$1,292
2027–2031 Total	$3,459	$11,707

(d) Please refer to EfficiencyOne's (E1) response to SBA IR-05 part (f).

(e) Please refer to EfficiencyOne's (E1) response to SBA IR-05 part (f).

Request IR-06:

Reference: Exhibit E-1, Application, page 36/71; and Exhibit E-1, Appendix B, Section 9, "Enabling Strategies".

Preamble: E1 has asserted that eliminating or materially reducing Enabling Strategies investment would weaken E1's ability to deliver DSM programs effectively and responsibly and provided three qualitative explanations in support of that conclusion.

(a) Has E1 completed any quantitative analysis regarding what amount of investment would be "material" and result in these noted negative impacts? If so, please provide it.

i) If not, how has E1 defined what constitutes "materially reducing" these investments? Please explain.

(b) Please update Table 4 (Enabling Strategies investment) to include comparable values dating back to 2012.

(c) In Table 10, E1 notes it has introduced "Market Transformation" as a <u>new</u> category of Enabling Strategies, but later in Appendix B at pages 90 and 97-98, describes <u>continuing</u> Market Transformation activities. Please reconcile.

(d) Please specify and describe all new Enabling Strategies being introduced during 2027-2031, and the associated cost for each of these activities which did not appear in prior Plans.

(e) With respect to "Other Enabling Strategies",

i) **please provide a table, for each year from 2012 to present, showing budgeted costs and actual spend for each category of expense listed in Appendix B, Table 57, along with the variance (actual minus budget, and percentage).**

ii) **please also provide a year-over-year comparison of actual costs by category, identifying and explaining any material variances.**

Response IR-06:

(a) No, EfficiencyOne (E1) has not conducted any quantitative analysis regarding what amount of investment would be “material” and result in the noted negative impacts.

i) E1 was using the standard definition of "materially", meaning "to a significant extent or degree". The annual average investment in Enabling Strategies in 2027–2031 is aligned with actual costs in 2024 and 2025, which E1 believes will allow the organization to maintain the core activities of Enabling Strategies and some new initiatives. Reducing the spending "materially" from the current actual costs would have a significant impact on E1’s ability to deliver its programs, plan for the future, and meet its regulatory requirements. E1 anticipates the extent of these negative impacts would likely be proportionate to the amount of any reduction from current Enabling Strategies investment levels.

(b) Please refer to Attachment 1 of this IR response.

(c) Market transformation is a new category of Enabling Strategies in the Preferred Plan. In the current 2023–2026 DSM Plan, market transformation is an area of focus under the Development and Research category of Enabling Strategies. As an area of focus in the current Plan period, the heat pump water heater market transformation pilot was launched in 2024. This pilot will continue under the new Market Transformation category in 2027-

2031. For clarification purposes, Table 4 on page 36 of E1's Evidence breaks out the 2026 market transformation costs ($0.7 million) from the total 2026 Development and Research category costs ($2.4 million) in order to provide a comparison with 2027–2031.

(d) As detailed in part (c) of this IR response, Market Transformation is a new category of Enabling Strategies in the 2027–2031 Preferred Plan with a total investment over the five years of $3.8 million.

While support for Mi'kmaw communities has always been part of Education and Outreach activities in previous DSM Plans, support for Mi'kmaw communities has been designated as a specific and new area of focus under the Education and Outreach category in the Preferred Plan with a total investment of $2.8 million to provide tailored support and energy management services to Mi'kmaw communities.

Similarly, while other regulatory matters have always been part of Other Enabling Strategies activities, in the 2027–2031 Preferred Plan, Other Regulatory Matters has been identified as a specific focus area to encompass activities that will be required to support Nova Scotia's Independent Energy System Operator, which was established in 2025. Other Regulatory Matters has a five-year investment of $1.3 million.

Program harmonization is a new activity under the Information & Analytics area of focus of the Development and Research category, with a total investment of $427,500.

(e)

i) The 2027–2031 DSM Plan Application is the first time cost breakdowns were provided by areas of focus under each Enabling Strategies category. From 2012–2022, Other Enabling Strategy costs were categorized in a number of different ways, making it difficult to provide accurate comparisons to the current areas of focus. Actual costs by the same areas of focus are available for 2023–2025 and are provided in Table 1.

Table 1: 2023–2025 Other Enabling Strategies costs (Plan and Actual)

Other Enabling Strategies ($ million)	2023			2024			2025		
	Plan	Actual	Variance (Actual to Plan)	Plan	Actual	Variance (Actual to Plan)	Plan	Actual	Variance (Actual to Plan)
DSM Planning	0.0	0.5	0.5	0.9	2.7	1.8	1.1	2.1	1.0
Regular DSM Matters	0.8	0.4	-0.5	0.6	0.4	-0.2	0.5	0.4	-0.1
Other Regulatory Matters	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	**0.9**	**0.9**	**0.0**	**1.6**	**3.1**	**1.6**	**1.6**	**2.5**	**0.9**

Other Enabling Strategies actual expenditures in 2024 and 2025 were higher than set out in the Plan, driven primarily by costs associated with the development, stakeholder engagement, and regulatory process surrounding the initial 2026–2030 DSM Plan development (which ceased once the Nova Scotia government passed legislation to extend E1's current approved 2023–2025 DSM Plan by one year); the development, stakeholder engagement, and regulatory process for the 2026 DSM Extension; and E1's application for approval of a New Benefit Cost Analysis (BCA) Test for Evaluating Demand Side Management Plans, which was developed in 2024 and early 2025, before being filed in Q2 2025 and the subsequent regulatory proceeding over the rest of the year. Additionally, the 2027–2031 DSM Plan's development continued throughout 2025.

ii) Please refer to part (e) i) of this IR response.

Request IR-07:

Reference: Exhibit E-1, Application, page 40/71, lines 19–21.

> **Over the same time period in which the investment of $318.75 million is made, the Preferred Plan will achieve $682.5 million in avoided utility costs.**

Is the stated $682.5 million in "avoided utility costs" the same as the "lifetime customer benefits" reported elsewhere in the Application? If not, please provide a qualitative and quantitative explanation of what is included in the $682.5 million (including major components and any exclusions). If so, please confirm whether carbon costs are included in these avoided utility costs and, if included, identify the carbon price assumptions used.

Response IR-07:

Yes, avoided utility costs and lifetime customer benefits are the same benefit.

E1 uses the following avoided costs:

- Avoided cost of capacity
- Avoided cost of energy
- Avoided cost of transmission
- Avoided cost of distribution

These avoided costs are produced by NS Power, with responsibility transitioning to Nova Scotia's Independent Energy System Operator (NSIESO).

E1 understands that any utility costs associated with carbon pricing or other environmental legislation are included within Integrated Resource Plan (IRP) modelling assumptions and would be reflected within the avoided cost of energy. No carbon costs outside of direct utility costs are included within avoided costs. The carbon costs included in the model would reflect the Nova Scotia Output Based Pricing System (NS OBPS)[1] requirements, which establishes a price per tonne of carbon dioxide equivalent (CO_2e) that is paid for all emissions above the emissions intensity limit depending on the fuel type (natural gas, solid fuel, etc). The price is currently $110/tonne CO_2e for 2026 and increases by $15/tonne CO_2e annually until the price reaches $130/tonne C02e in 2030.

[1] Output-Based Pricing System Reporting and Compliance Regulations - Environment Act (Nova Scotia)

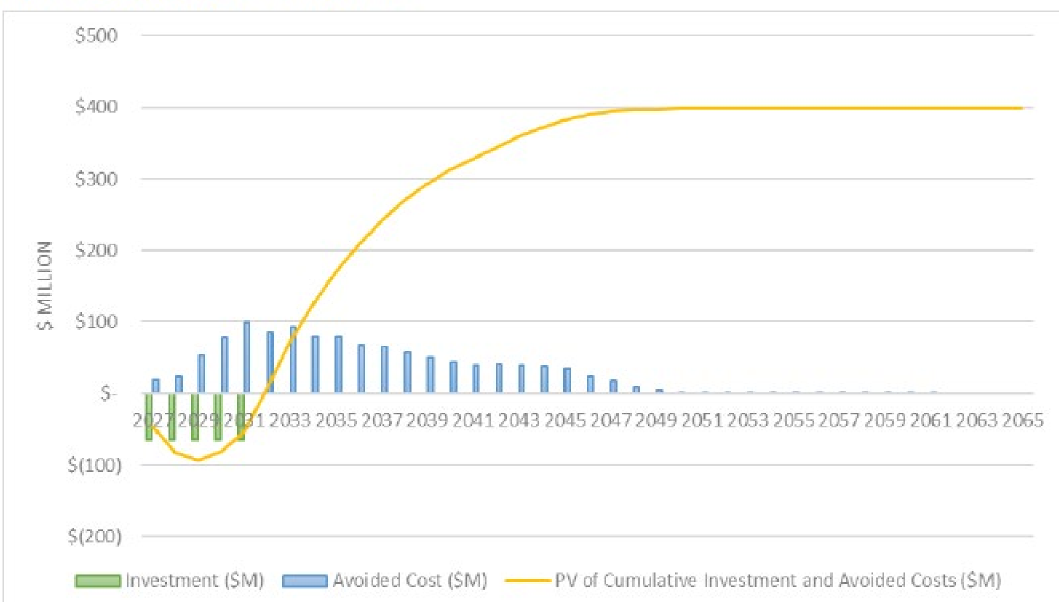
Request IR-08:

Reference: Exhibit E-1, Application, page 41/71; Exhibit E-1(ii), Excel File, Tab "Simple Payback Review".

Preamble: E1 as part of its DSM Resource Plan Filing content includes measure level payback information and justifications for measures with ≤ 3-year payback. This is as directed by NSUAB following the M10473 E1 2023 – 2025 DSM Resource Plan.

E1 provides a summary of its Payback Analysis for the Preferred Plan, where DSM is fully paid back no later than 2032, as shown in Figure 4:

Figure 4: Payback Analysis – Preferred Plan



(a) Does this reflect current approved rates in the 2027-2028 GRA? If not, please explain.

(b) Please provide a version of Exhibit E-1(ii) for the Alternate Scenario (in excel format).

(c) Please provide the measure level payback analysis as per Exhibit E-1-(ii) "Simple Payback Review" tab and an updated Figure 4 (reproduced above) for the Alternate Scenario.

(d) Please confirm that the "Simple Payback Review" tab includes no residential programs.

i) If confirmed, is this because all participant costs for residential programs are fully covered by incentives?

ii) If not confirmed, please explain.

(e) Please provide the methodology for how the Simple Payback is calculated for each year by measure. Please explain why the Simple Payback is calculated "without incentive" (as titled in tab "Simple Payback Review").

(f) Please confirm that the Preferred Plan does not result in any DSM measures in any year not providing full payback within three years. If not confirmed, please provide supporting analysis.

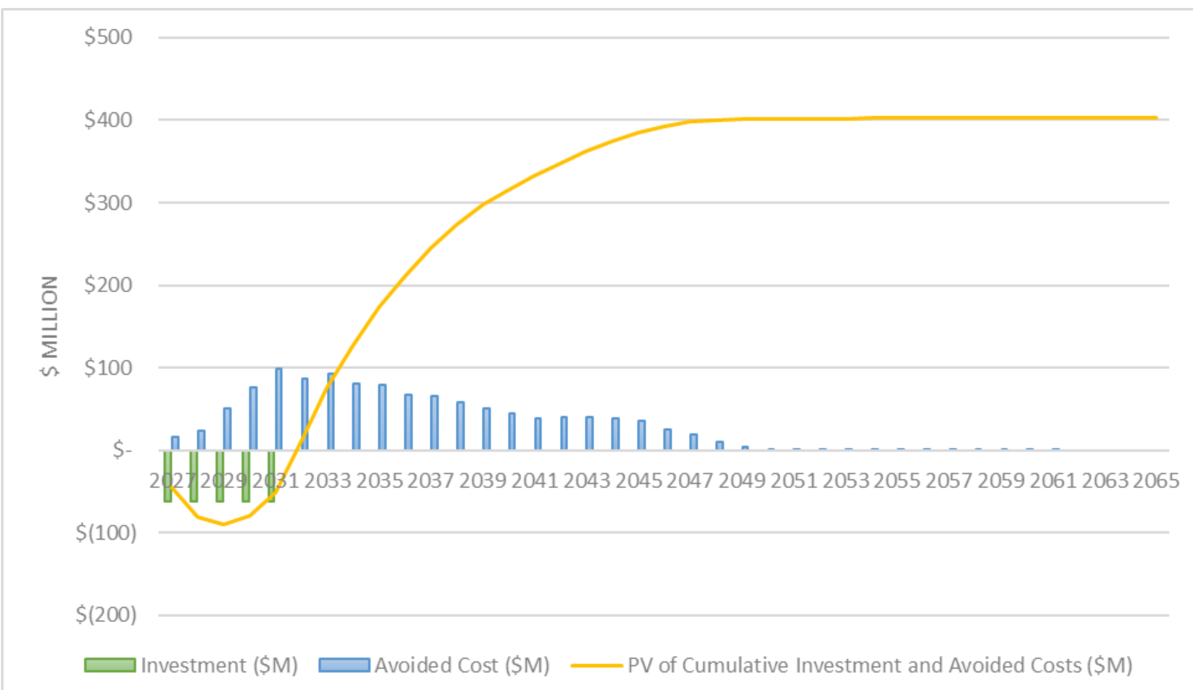
Response IR-08:

(a) Figure 4: The Payback Analysis – Preferred Plan of EfficiencyOne's (E1) Evidence used rates from the NS Power 2025 Tariffs guide, adjusting for the fuel adjustment mechanism (FAM), demand side management cost recovery rider (DCRR), and storm cost recovery rider (SCR) where applicable, as NS Power's 2026–2027 General Rate Application (GRA) was an open matter at the time of modelling. Accordingly, the Payback Analysis does not reflect the rates approved in the 2026–2027 GRA.

(b) As noted in Appendix C – Alternate Scenario, page 9, line 11, the Appendix A, Attachment 3: 2027–2031 Energy Efficiency and Solar PV Technical Tables[1] are the same for the Alternate Scenario as the Preferred Plan as there are no changes between the Preferred Plan and Alternate Scenario.

(c) Please refer to part (b) of this IR response regarding the Alternate Scenario Technical Tables, which are identical to those of the Preferred Plan. Please find an updated Figure 4 for the Alternate Scenario reproduced below.

Figure 1: Payback Analysis – Alternate Scenario



(d)

[1] M12780, Exhibit E-1-(ii), EfficiencyOne 2027-2031 DSM Plan Application, March 31, 2026.

i) The Simple Payback Review tab is not limited to non-residential programs. It includes measures in the Instant Savings program component, which is a residential program component. The Simple Payback Review tab presents only those measures - whether residential or non-residential - with simple payback periods of three years or less, for which E1 was directed to provide additional information about the other factors that were considered. The Customer Simple Payback with Incentives and without Incentives are provided for all measures in columns O and P respectively, on each of the annual tabs for 2027–2031 of Appendix A – Attachment 3 – 2027–2031 Energy Efficiency & Solar-PV Technical Tables.

ii) Please refer to the response to IG IR-08, part d(i).

(e) Simple payback measures how many years it will take for the participant’s bill savings to equal or exceed the incremental measure costs paid by that participant in their first year of participation. It is calculated using first-year measure values: first-year participant costs, first-year incentive (when calculating simple payback with incentives), and first-year bill savings. Evaluating simple payback without incentives assesses the economics of the measure from the customer’s perspective absent program intervention.

(f) Not confirmed. Please refer to part (d) (i) of this IR response.

Request IR-09:

Reference: Exhibit E-1, Application, page 41/71, lines 19–20.

> **Consequently, ratepayers have certainty during each term with respect to the cost they will bear in relation to DSM.**

Reference: Exhibit E-1, Appendix A, Table 2, 2023-2026 Approved Rate Class Expenditures and Results, page 11/112.

(a) In determining the level of "certainty" referenced, how has E1 taken into consideration the operation of the Demand Cost Recovery Rider (DCRR) including the recovery of overspends and refunding of underspends that occurred within the 2023-2026 Plan period, anticipated to be trued up over the 2027-2030 period?

(b) In Appendix A, Table 2, E1 provides a value for "% 2023-2025 Results to 2023-2026 Approved". Please explain what this column is intended to represent and why it indicates a -18.1% result for the Large Industrial class, as compared to the +18.4% variance from the approved spending over the 2023-2026 spend.

(c) Please provide a table that disaggregates the anticipated DCRR by year into its component impacts, by customer class, including: (i) the percentage increase to the DSM base rate based on the proposed new spend, (ii) the true-up percentage required to address prior under-recovery spread out over the 2027-2030 period (acknowledging that 2026 will be a forecast and assuming no load variances), and (iii) the combined DSM rate impact inclusive of all applicable components.

(d) For the 2027–2031 Plan, what specific policy changes and limits will E1 implement to promote the stated "certainty" in costs for ratepayers and to prevent a significant DSM rate rider increase at the end of the term? Please explain the specific polices or limits in spending that will be implemented in real time, beyond that included in relation to E1's approach to "midcourse adjustments",

Response IR-09:

(a) EfficiencyOne (E1) was referring to the certainty that E1's spending for the proposed 2027–2031 DSM Preferred Plan is limited to the investment approved by the Nova Scotia Energy Board (NSEB). To provide more certainty at the rate class level, E1 has introduced expanded accountability for rate class spending through the proposed Mid-Course Adjustment (MCA) process by introducing a 15 percent threshold for variance reporting and providing enhanced rate class reporting inclusive of forecast information. E1's intent with these actions is to better integrate rate class assessment and consideration into internal processes, as well as to provide greater visibility into trends, and forecast expectations for stakeholders. Specifically, E1 has integrated rate class assessment into its annual and quarterly forecasting, annual budgeting and mid-course adjustment processes. These assessments may lead to additional specific activities related to marketing, business development and program delivery. E1 is not proposing specific hard caps or limits to rate class spending as part of the proposed 2027–2031 DSM Plan.

E1 acknowledges that any surplus from the 2023–2026 DSM Plan will inform the Balance Adjustment (BA) in NS Power's Demand Side Management Cost Recovery Rider during the 2027–2031 DSM Plan implementation.

(b) The % 2023-2025 Results to 2023-2026 Approved column represents total 2023–2025 expenditures compared to the total 2023–2026 Plan as Approved expenditures. The % 2023–2025 + 2026 to 2023–2026 Approved column represents the total of 2023–2025 expenditures and the approved 2026 DSM Extension, compared to the total 2023–2026 Plan as Approved expenditures. For example, Large Industrial actual expenditures from 2023–2025 were $8.9 million, which is 18.1 percent less than the 2023–2026 Plan as Approved expenditure of $10.8 million. When the 2023–2025 actual expenditure results ($8.9 million) and the approved 2026 DSM Extension ($3.9 million) expenditures are added together they equal $12.8 million, which is 18.4 percent higher than the 2023–2026 Plan as Approved expenditure of $10.8 million.

(c) Please refer to Attachment 1 of this IR response. E1 notes that this attachment is being provided for <u>informational purposes only</u>. Numbers may be subject to change in NS Power's actual Demand Side Management Cost Recovery Rider application. The BA information includes only overspend and underspend by rate class. There has been no interest applied at this time that would reduce the final BA at the end of the DSM Plan implementation.

(d) Please refer to part (a) of this IR response.

Request IR-10:

References: Exhibit E-1, Application, page 47/71; and Exhibit E-1, Appendix A, pages 38–39/112.

Preamble: E1 attributes changes in unit costs between 2026 and 2027–2031 to factors including the end of the Greener Homes top-up incentive, the transition away from low-cost lighting measures, inflation, and reduced evaluated heat pump savings, which E1 states is “largely beyond E1’s control”. The 2027–2031 plan first-year unit cost is stated to be $0.66/kWh compared to $0.49/kWh in 2026. E1 “submits”, however, that the lifetime unit cost of $0.05/kWh reflects a more appropriate efficiency measure.

(a) Please provide a table explaining the increase in first-year unit cost from $0.49/kWh (2026) to $0.66/kWh (2027–2031), broken down by the following drivers:

- **i) Change in measure mix (e.g., shift away from lighting);**
- **ii) Changes in evaluated savings algorithms or parameters (including the ~50% reduction in residential heat pump savings from the 2024 evaluation);**
- **iii) Changes in incentive levels (gross dollars per measure);**
- **iv) Changes in program administration and delivery costs;**
- **v) Changes in participation volumes or market assumptions; and/or**
- **vi) Any other drivers that E1 views as relevant to the analysis which have not yet been identified.**

(b) Please provide the methodology and all assumptions underlying the lifetime unit cost calculation, including assumed savings lifetimes, discount rate, and realization rates by measure.

(c) Please provide the comparable first-year and lifetime unit cost data for each of the 2023–2025 plan years (actual), the 2026 Extension (plan and actual), and by rate class or sector (residential, BNI, low-income), so that trends can be assessed.

(d) Please confirm whether E1 has benchmarked its projected unit costs against comparable DSM programs in other Canadian or North American jurisdictions, and if so please provide the analysis and data sources. If not, why not?

Response IR-10:

(a) Please refer to Attachment 1 of this IR response for a unit cost analysis by program component that explains the changes of the total costs and total energy savings by program component comparing the 2026 DSM Plan to the 2027–2031 DSM Plan. Please note that program support costs as described in the unit cost analysis include evaluation, marketing and quality assurance costs that have been directly allocated to each program component. Administration and overhead costs include all expense categories such as rent, office supplies, salaries and benefits to name a few, that are shared by program components and are allocated using EfficiencyOne's (E1) approved Cost Allocation Methodology.

i) Changes in measure mix for both costs and energy savings by each program component are provided in Attachment 1.

ii) E1 notes that unitary savings adjustments from the 2025 Evaluation report were not updated in the 2026 DSM Plan due to timing constraints. The impacts of these changes have been incorporated in the 2027–2031 DSM Plan and are provided by each program component in Attachment 1.

iii) Changes in total incentives, not by specific measures, are provided by each program component in Attachment 1. Incentive changes by specific measure are provided in E1's response to IG IR-11 Attachment 2.

iv) This information is provided by each program component in Attachment 1.

v) This information is provided by each program component in Attachment 1.

vi) E1 has provided what is “new” for each program component in Attachment 1.

(b) The lifetime unit cost of $0.05/kWh is calculated as follows:

Total Investment Energy Efficiency + Enabling Strategies ($ million) / Lifetime energy savings (GWh) = Lifetime unit cost ($/kWh)

Total Investment Energy Efficiency + Enabling Strategies = $286.8 million
Lifetime Energy Savings (GWh) = First Year Energy Savings*Weighted Average Measure Life
Lifetime Energy Savings (GWh) = 435.4 GWh*12.3 years = 5,355.1 GWh
$286.8 million/5,355.1 GWh = $0.05/kWh

The measure level measure life, first year energy savings, and lifetime energy savings are provided for each year of the proposed 2027–2031 DSM Plan in Appendix A, Attachment 3 Energy Efficiency and Solar-PV Technical Tables. Specifically, columns D, U and V, respectively.

(c) Table 1 below provides the lifetime unit costs comparable to the $0.05/kWh as reported in the 2027–2031 DSM Plan Application, for each 2023–2031 and Table 2 provides lifetime unit costs at the rate class level.

Table 1: Lifetime Unit Cost ($/kWh) 2023-2031

2023 Actual	2024 Actual	2025 Actual	2026 Plan as Approved	2027 Proposed	2028 Proposed	2029 Proposed	2030 Proposed	2031 Proposed
0.02	0.03	0.04	0.04	0.04	0.05	0.06	0.07	0.07

1 Table 2: Lifetime Unit Cost (4/kWh) 2023-20231 by Rate Class

Rate Class	Year	Lifetime Unit Cost ($/kWh)
Residential/Charitable (2,3,4)*	2023	0.02
	2024	0.03
	2025	0.05
	2026	0.08
	2027	0.09
	2028	0.09
	2029	0.10
	2030	0.11
	2031	0.11
Small General (10)	2023	0.02
	2024	0.02
	2025	0.04
	2026	0.03
	2027	0.03
	2028	0.04
	2029	0.04
	2030	0.05
	2031	0.05
General (11)	2023	0.02
	2024	0.02
	2025	0.03
	2026	0.03
	2027	0.03
	2028	0.03
	2029	0.04
	2030	0.04
	2031	0.05
Large General (12)	2023	0.02
	2024	0.02
	2025	0.03
	2026	0.02
	2027	0.02
	2028	0.02
	2029	0.03
	2030	0.03

Rate Class	Year	Lifetime Unit Cost ($/kWh)
	2031	0.03
Small Industrial (21)	2023	0.02
	2024	0.02
	2025	0.03
	2026	0.02
	2027	0.02
	2028	0.02
	2029	0.03
	2030	0.03
	2031	0.04
Medium Industrial (22)	2023	0.02
	2024	0.04
	2025	0.03
	2026	0.03
	2027	0.02
	2028	0.03
	2029	0.04
	2030	0.04
	2031	0.04
Large Industrial (23, 25)	2023	0.03
	2024	0.02
	2025	0.03
	2026	0.03
	2027	0.02
	2028	0.03
	2029	0.03
	2030	0.04
	2031	0.04
Municipal (24)	2023	0.02
	2024	0.02
	2025	0.03
	2026	0.05
	2027	0.09
	2028	0.08
	2029	0.09
	2030	0.09

Rate Class	Year	Lifetime Unit Cost ($/kWh)
	2031	0.10
Unmetered (999)	2023	n/a
	2024	n/a
	2025	n/a
	2026	0.06
	2027	0.07
	2028	0.07
	2029	0.07
	2030	0.07
	2031	0.08

(d) E1 engaged Apex Analytics to conduct a jurisdictional scan comparing E1's first year unit costs to other similar jurisdictions. A copy of the Apex memo has been included as Attachment 2 to this IR response.

Residential Instant Savings - Cost and Energy Savings Analysis

Costs ($ millions)		
2026 Total Costs	$	2.53
Centrally Ducted Heat Pump -NEW		0.38
Electric Thermal Storage Systems (no energy savings, peak savings only) - NEW		0.14
Mini-Split Heat Pump - NEW		1.26
Impact of Change in Measure Mix		(0.14)
Impact of Program Delivery Cost Escalation		0.14
Administrative / Overhead Cost Reduction		(0.23)
Program Support Cost Increase		0.03
Change in Costs		1.58
2027-2031 Average Cost		4.11
Energy Savings (GWh)		
2026 Energy Savings		4.80
Centrally Ducted Heat Pump - NEW		0.26
Mini-Split Heat Pump - NEW		1.47
Impact of Change in Measure Mix		6.14
Change in Energy Savings		7.87
2027-2031 Average Savings		12.68

Residential Instant Savings
Unit Cost Analysis

2026 Unit Cost	$	0.53
Impact of Change in Costs		0.33
Impact of Change in Energy Saving:		(0.54)
2027-2031 Unit Cost	$	0.32

Home Energy Assessment - Cost and Energy Savings Analysis

Costs ($ millions)		
2026 Total Costs	$	4.96
Impact of Increased Rebates		0.42
Impact of Audit Costs Escalation		0.19
Elimination of Customer Audit Co-Pay		0.50
Impact of Participation on Total Rebates		(0.69)
Impact of Participation on Audit Costs		(0.54)
Program Support Cost Increase		0.20
Administrative / Overhead Cost Reduction		(0.17)
Change in Costs		(0.99)
2027-2031 Average Cost		4.86
Energy Savings (GWh)		
2026 Energy Savings		3.78
Unitary Savings Changes - Wood & Pellet Stoves	-	0.03
Unitary Savings Changes - Heat Pumps	-	1.49
Unitary Savings Changes - Building Envelope		0.54
Impact of Participation Changes	-	0.97
Change in Savings	-	1.95
2027-2031 Average Savings		1.82

Home Energy Assessment
Unit Cost Analysis

2026 Unit Cost	$	1.31
Impact of Change in Costs		(0.03)
Impact of Change in Energy Saving:		1.38
2027-2031 Unit Cost	$	2.67

Efficienct Product Installation - Cost and Energy Savings Analysis

Costs ($ millions)		
2026 Total Costs	$	5.31
Direct Install Costs		2.62
Administrative / Overhead Increase		0.03
Program Support Cost Reduction		(0.06)
Change in Costs		2.59
2027-2031 Average Cost	$	7.90
Energy Savings (kWh)		
2026 Energy Savings		10.47
Direct Installation		(2.55)
Change in Energy Savings		(2.55)
2027-2031 Average Savings		7.91

Efficient Product Installation Unit Cost Analysis		
2026 Unit Cost	$	0.51
Impact of Change in Costs		0.25
Impact of Change in Energy Saving		0.25
2027-2031 Unit Cost	$	1.00

Affordable Single Family Home - Cost and Energy Savings Analysis

Costs ($ millions)		
2026 Total Costs	$	7.68
Heat Pump Cleaning - NEW		0.58
Impact of Increased Upgrade & Heat Pump Costs		0.90
Impact of Audit Cost Escalation		0.14
Impact of Participation on Total Rebates		0.12
Impact of Participation on Audit Costs		(0.39)
Program Support Cost Reduction		(0.20)
Administrative / Overhead Cost Reduction		(0.08)
Change in Costs		1.07
2027-2031 Average Cost	$	8.74
Energy Savings (GWh)		
2026 Energy Savings		2.67
Heat Pump Cleaning - NEW		0.08
Unitary Savings Changes - Whole Home Upgrades	-	0.33
Unitary Savings Changes - Heat Pumps	-	0.81
Impact of Participation Changes		0.05
Change in Savings	-	1.02
2027-2031 Average Savings		1.66

Affordable Single Family Homes
Unit Cost Analysis

2026 Unit Cost	$	2.87
Impact of Change in Costs		0.40
Impact of Change in Energy Saving:		2.01
2027-2031 Unit Cost	$	5.28

Mi'kmaw Home Energy Efficiency Project - Cost and Energy Savings Analysis - Program Wind Up in 2027

Costs ($ millions)		
2026 Total Costs	$	1.15
MHEEP Whole Home - Includes HP - Incentives		(0.43)
Programmable thermostats - Incentives		(0.02)
Audit Costs		(0.16)
Project Management - Supporting Wind Up		0.01
Administrative / Overhead Cost Reduction		(0.26)
Program Support Cost Reduction		(0.18)
Change in Costs		(1.04)
2027-2031 Average Cost	$	0.11
Energy Savings (GWh)		
2026 Energy Savings		0.35
MHEEP Whole Home - Includes Heat Pump - program wind up	-	0.32
Programmable thermostats - program windup	-	0.02
Change in Energy Savings	-	0.34
2027-2031 Averge Savings		0.01

Affordable Multi-Family Home - Cost and Energy Savings Analysis

Costs ($ millions)		
2026 Total Costs	$	1.84
Heat Pump Water Heaters - NEW		0.09
Impact of Increased Comprehensive Stream Incentives		0.26
Impact of Increased Air Source Heat Pump Incentives		0.28
Lighting Projects - Phase out 2029		0.05
Impact of Increased Project Management Costs		0.12
Impact of Participation Changes		(0.55)
Administrative / Overhead Cost Increase		0.18
Program Support Cost Reduction		(0.03)
Change in Costs		0.41
2027-2031 Average Cost	$	2.25
Energy Savings (GWh)		
2026 Energy Savings		0.96
Heat Pump Water Heaters - NEW		0.08
Unitary Savings Changes - Comprehensive Stream		0.11
Unitary Savings Changes - Air Source Heat Pump		0.08
Lighting Projects - Phase Out 2029		0.06
Impact of Participation Changes	-	0.38
Change in Savings	-	0.05
2027-2031 Average Savings		0.92

Affordable Multi-Family Homes Unit Cost Analysis		
2026 Unit Cost	$	1.91
Impact of Change in Costs		0.43
Impact of Change in Energy Saving:		0.12
2027-2031 Unit Cost	$	2.46

Direct Installation (Small Business Energy Solutions) Cost and Energy Savings Analysis

Costs ($ millions)		
2026 Total Costs	$	5.79
Elimination of Customer Direct Install		(0.07)
Wind Up of Lighting		0.41
Measure Mix		(0.36)
Administrative / Overhead Reduction		(0.29)
Program Support Cost Reduction		(0.03)
Change in Costs		(0.33)
2027-2031 Average Cost	$	5.45

Energy Savings (GWh)	
2026 Energy Savings	6.12
Elimination of Customer Direct Install	(0.12)
Wind Up of Lighting	(1.69)
Unitary Savings Change - Mini-Split Heat Pumps	(0.11)
Measure Mix	0.13
Change in Energy Savings	(1.80)
2027-2031 Average Savings	4.32

Small Business Energy Solutions
Unit Cost Analysis

2026 Unit Cost	$	0.95
Impact of Change in Costs		(0.04)
Impact of Change in Energy Savings		0.97
Impact of Elimination of CDI		(0.62)
2027-2031 Unit Cost	$	1.26

Business Energy Rebates Cost and Energy Savings Analysis

Costs ($ millions)		
2026 Total Costs	$	8.10
Wind Up of Lighting		(3.16)
Impact of Non-Lighting Measures		(0.73)
Administrative / Overhead Reduction		(0.44)
Program Support Cost Reduction		(0.15)
Change in Costs		(4.48)
2027-2031 Average Cost	$	3.62
Energy Savings (GWh)		
2026 Energy Savings		31.86
Wind Up of Lighting		(23.10)
Impact of Non-Lighting Measures		1.28
Change in Energy Savings		(21.81)
2027-2031 Average Savings		10.05

Business Energy Rebates
Unit Cost Analysis

2026 Unit Cost		0.25
Impact of Change in Costs		(0.04)
Impact of Lighting Wind Up		0.15
2027-2031 Unit Cost	$	0.36

Custom & Strategic Energy Management Cost and Energy Savings Analysis

Costs ($ millions)		
2026 Total Costs	$	10.84
Impact of Participation Increases		0.10
Retrofits for Equity Deserving Communities - NEW		0.54
Impact of Project Incentive Support		1.75
Administrative / Overhead Increase		0.34
Program Support Cost Reduction		(0.08)
Change in Costs		2.65
2027-2031 Average Cost	$	13.50
Energy Savings (GWh)		
2026 Energy Savings		37.99
Impact of Participation Increases		0.39
Retrofits for Equity Deserving Communities - NEW		2.73
Impact of Project Unitary Savings Changes		6.38
Change in Energy Savings		9.51
2027-2031 Average Savings		47.50

Custom & Strategic Energy Management		
Unit Cost Analysis		
2026 Unit Cost	$	0.29
Impact of Change in Costs		0.07
Impact of Change in Energy Savings		(0.08)
2027-2031 Unit Cost	$	0.28

To: Gina Thompson, Kate McDonald EfficiencyOne
From: Michael Goldman, Matt Nelson, Jodi Hanover, Apex Analytics LLC
Subject: Review of EfficiencyOne First-Year Costs and Unit Cost Reasonableness
Date: May 22, 2026

EfficiencyOne's (E1) first-year energy efficiency (EE) program costs for the 2027–2031 Demand Side Management (DSM) Plan are reasonable, prudent, and consistent with industry norms. To support this conclusion, this memorandum evaluates the reasonableness of E1's first-year unit cost metrics (i.e., dollars per kilowatt-hour saved) through a structured jurisdictional comparison. The Apex team reviewed six comparator jurisdictions - New Brunswick, Prince Edward Island, Newfoundland and Labrador, Manitoba, Vermont, and New Hampshire - that the Apex team deemed similar climatically to Nova Scotia and to the programs run by E1. These jurisdictions mostly overlap with those selected for comparison in the Analysis and Recommendation for 2027-2031 Plan Savings Goals memo, with the additional inclusion of Manitoba at the request of E1.

In addition to reviewing the first-year costs of neighboring jurisdictions, this memo identifies the structural, methodological, and policy factors that drive variation in reported unit costs across jurisdictions. Understanding these factors is essential to interpreting the comparator data accurately. When properly contextualized, these factors reinforce the conclusion that E1's costs are reasonable. The memo also identifies drivers that are contributing to higher costs compared to E1's previous DSM Plan, consistent with trends observed across North America.

As shown throughout the memo, differences in program maturity, savings attribution, measure mix, and policy objectives drive variation in reported $/kWh values. When these factors are considered, and when E1's costs are assessed against applicable cost-effectiveness criteria, Apex concludes that E1's submitted first-year costs reflect prudent program design and appropriate cost levels consistent with the objectives and requirements of the 2027-2031 DSM Plan.

Challenges with Cross-Utility Comparisons

Per-unit cost metrics are frequently used as high-level indicators of economic efficiency in EE programs. However, such comparisons are rarely "apples to apples." Portfolio costs and savings outcomes are heavily shaped by jurisdiction-specific conditions and regulatory frameworks. The following factors - among others - are particularly important when interpreting cross-jurisdictional $/kWh comparisons:

- **Program maturity and historical investment levels.** Jurisdictions with long-standing programs often face higher marginal acquisition costs as lower-cost opportunities are exhausted, whereas newer portfolios may still have lower-cost savings available.
- **Climate and end-use load shapes.** Regional differences in heating and cooling demand significantly affect achievable savings, particularly for HVAC-focused portfolios.
- **Energy prices and avoided costs.** Higher avoided costs can justify greater spending per kWh saved, while lower-price jurisdictions may appear less expensive on a unit basis even with similar program impacts.
- **Regulatory requirements and policy mandates.** Explicit requirements related to equity, electrification, or market transformation can increase unit costs.
- **Eligibility to claim Codes and Standards (C&S) savings.** Jurisdictions permitted to count C&S savings will typically report lower average unit costs given the scale and low marginal cost of those savings.
- **Portfolio composition across customer classes.** Portfolios with higher shares of low-income, residential retrofit, or deep EE measures will generally show higher $/kWh values than portfolios dominated by commercial lighting or industrial process improvements.

As an example, utilities operating in warmer climates often experience lower costs per kWh saved, particularly when low-cost HVAC efficiency savings are available. Conversely, portfolios emphasizing equity objectives, electrification, or deeper retrofits would reasonably expect higher acquisition costs.

Results of Jurisdictional Scan

Tables 1 through 3 summarize first-year unit costs in Canadian dollars (CAD) on a portfolio; residential; and business, non-profit, and institutional (BNI) basis across a set of comparator jurisdictions, drawn from publicly available annual reports, regulatory filings, and plan documents (see Appendix A for detailed sources). Key observations include:

- On a portfolio-level basis, E1 falls on the lower-cost end of the comparator group once outlier jurisdictions are appropriately put in context.
- Manitoba and New Brunswick materially influence rankings due to unique accounting treatments, industrial program structures, and ability to claim very low-cost savings.
- When Manitoba and New Brunswick's accounting and industrial savings treatments are excluded or normalized, E1 emerges as one of the least expensive portfolios among the jurisdictions.

Table 1. First-Year Unit Costs Ranked from Most to Least Expensive on a Portfolio Basis

Jurisdiction	Portfolio
	CAD
Newfoundland and Labrador	$1.38
New Brunswick (w/o Industrial Program, Business Rebate)*	$1.12
New Hampshire	$0.96
Vermont	$0.89
Prince Edward Island	$0.86
EfficiencyOne	$0.66
New Brunswick**	$0.35
Manitoba***	$0.25

* This estimated cost for New Brunswick removes cost and savings associated with the Industrial Program, as well as costs associated with programs with no associated savings.

** New Brunswick's Initiatives Update had a $0.06/kWh cost for its Industrial Program, which appears to be an outlier compared to other jurisdictions. This extremely low cost for Industrial savings substantially brings down the overall portfolio cost.

*** Manitoba costs were taken directly from their 24-25 Annual Report Supplement. However, for the reasons discussed in more detail below, Apex does not consider Manitoba to be a reliable comparator for E1's portfolio given significant differences in portfolio composition, savings attribution methods, and measure mix. Manitoba is included in this analysis for completeness and transparency, but should be given limited weight in assessing E1's cost reasonableness.

Table 2. First-Year Unit Costs Ranked from Most to Least Expensive on a Residential Basis

Jurisdiction	Res
	CAD
New Hampshire	$2.26
Vermont	$1.30
New Brunswick (w/o Industrial Program, Business Rebate)	$1.17
New Brunswick	$1.17
EfficiencyOne	$1.15
Prince Edward Island	$0.86

Table 3. First-Year Unit Costs Ranked from Most to Least Expensive on a BNI basis

Jurisdiction	BNI
	CAD
New Brunswick (w/o Industrial Program, Business Rebate)	$0.77
Vermont	$0.70
New Hampshire	$0.50
Prince Edward Island	$0.46
EfficiencyOne	$0.33
New Brunswick	$0.11

In researching and developing the tables above, Apex attempted to find either the most recently filed actual savings from an Annual Report (or equivalent) or planned savings that most closely aligned with the upcoming 2027–2031 Plan time period. Unit costs used to populate Tables 1–3 can be found in Appendix A. For those values that were originally denoted in U.S. dollars (USD) (Vermont and New Hampshire), Apex applied an exchange rate of $1.00 USD = $1.37 CAD. Apex was only able to ascertain portfolio level costs for Manitoba and Newfoundland and, as such, we did not include broken-out values for Residential and BNI. Similarly, sector-level breakdowns were not available for all comparator jurisdictions in every table; where a jurisdiction is absent from a sector-level table, this reflects data unavailability rather than selective exclusion.

Structural Drivers of Unit Costs in Comparator Jurisdictions

A comparison between Nova Scotia and Manitoba highlights how accounting and portfolio design decisions influence reported $/kWh first year costs. Drivers of unit costs are described below. Additional details related to Efficiency Manitoba's EE portfolio can be found in Appendix B.

Behavioral and Lighting Measures. Manitoba's portfolio includes substantial behavioral and lighting savings, which are among the lowest-cost efficiency resources available. Behavioral savings represent roughly half of residential savings in forecasts, while lighting dominates large portions of commercial savings. Inclusion of these measures significantly lowers average unit costs compared to jurisdictions where lighting and behavioral programs have been reduced or eliminated.

Codes & Standards Savings. Approximately 25 percent of Manitoba's total reported savings come from codes and standards, which frequently deliver savings at only a few cents per kWh. Portfolios that include large volumes of C&S savings will usually report lower average costs than portfolios relying primarily on customer-site retrofits or new construction projects.

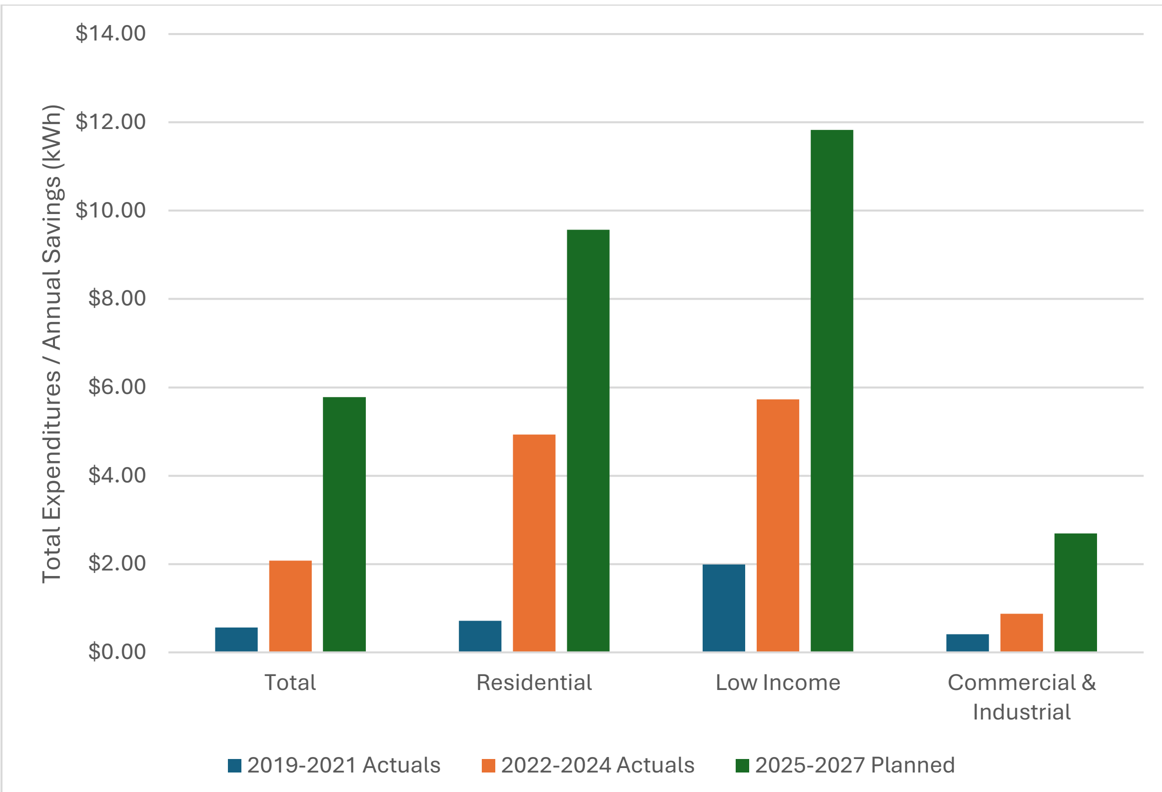
Legacy Load Displacement Projects. Manitoba also continues to count savings from a small number of large, multi-year load displacement projects dating back several years. These projects behave more like generation resources than traditional DSM measures and may not be eligible for incentive treatment in many jurisdictions such as Nova Scotia.

Key Drivers of Rising Portfolio-Level $/kWh Costs Over Time

While the first-year costs of E1's 2027–2031 DSM Plan reflect an increase over previous iterations of the Plan, this is to be expected and is in line with observations across North America. The Apex team highlights illustrative examples from Massachusetts below to show how these market forces are manifesting in practice. While Massachusetts is not a direct proxy for Nova Scotia in terms of scale or market structure, it represents one of the most well-documented, mature EE markets in North America and clearly illustrates the structural cost pressures that are beginning to affect jurisdictions like Nova Scotia. Where available, similar trends have been observed in the comparator jurisdictions identified in this report.

Removal of Low-Cost Savings. Many jurisdictions have reduced or eliminated lighting and behavioral programs due to market transformation and updated evaluation practices. As these low-cost savings exit portfolios, average $/kWh values increase. As Massachusetts removed its behavioral and lighting programs since 2019, the cost to acquire has steadily and consistently increased over time (see Figure 1).

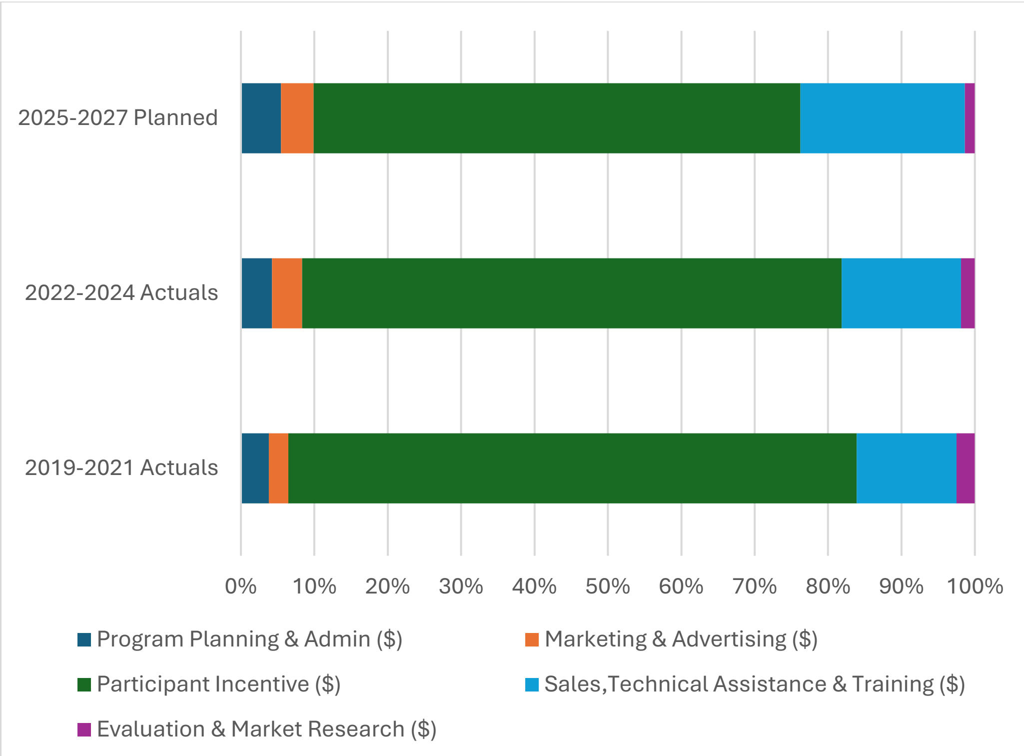
Figure 1. Massachusetts Cost to Acquire 2019-2027



Measurement & Verification Updates and Net Savings Adjustments. As programs mature, evaluations often reduce net-to-gross ratios and reported savings as equipment markets mature and transform. While this is widely regarded as a sign of program maturity rather than declining performance, the impact is lower claimable savings.

Market Transformation Effects. Codes, standards, and consumer preferences increasingly default to efficient measures and products over time, with the result being that remaining opportunities are oftentimes more complex and expensive. As the EE programs matured Massachusetts over time, the allocation of the portfolio budget had to necessarily change as well, as early adopters and other easily captured savings were claimed. Over time, an increasingly larger share of budget had to be allocated to Marketing and Sales, Technical Assistance, and Training (i.e., non-incentive spending categories) in order to capture remaining savings (see Figure 2).

Figure 2. Massachusetts EE Cost Categories 2019-2027



Expanded Low-Income and Equity Programs. Greater emphasis on low-income programs raise average unit costs due to higher incentives, broader scopes of work (including barrier mitigation), and lower per-project savings. These outcomes reflect equity and access goals, not inefficiency.

Electrification Measures. Increasing investment in electrification (e.g., heat pumps) can raise budgets, while yielding limited or no incremental electric kWh savings because many benefits accrue on the fossil-fuel side. This dynamic increases the reported electric $/kWh costs even when total system benefits increase.

Review of E1's 2027–2031 Portfolio

The Apex team reviewed E1's analysis of E1's historical (2025 actuals), near-term DSM Plan projections (2026), and longer-term DSM Plan averages (2027–2031) across residential and BNI EE programs. Overall, the analysis shows an upward trend in unit costs across most programs over time, driven primarily by a combination of (1) declining or more targeted participation, (2) shifts toward higher-cost, more comprehensive measures (particularly heat pumps and whole-home upgrades), and (3) planned wind-down of lower-cost, high-savings measures such as lighting and direct install offerings.

At the portfolio level, the total unit cost for all EE programs increases from approximately $0.44 in 2025 to $0.49 in 2026, and to approximately $0.66 on an average basis for 2027-2031. This increase reflects structural changes in program composition rather than simple cost escalation. As lower-cost measures are phased out or deemphasized, the remaining portfolio increasingly consists of capital-intensive measures with higher per-unit costs and, in some cases, lower incremental energy savings. This is all in line with the trends described in the prior section.

Residential Programs

Within the residential sector, unit costs increase between 2025 and the 2027–2031 period, with variation by program type.

Residential Instant Savings shows an increase in unit cost in 2026 relative to 2025, followed by a decline in the out-years. The 2026 increase is driven largely by a reduction in energy savings associated with lower participation and changes in the measure mix, including the introduction of higher-cost measures. In contrast, the 2027–2031 average reflects a rebound in savings and higher overall program scale, resulting in a lower unit cost than 2026, though still above 2025 levels.

Home Energy Assessments experience the largest sustained increase in unit cost across the study period. Unit costs rise in 2026 and increase further in the 2027–2031 average. This trend is attributable to reduced participation, declining downstream savings from associated measures, changes in customer co-payments, and increased rebate levels. While total program costs remain relatively stable, the reduction in realized energy savings increases the cost per unit of savings.

Efficient Product Installation exhibits an improvement in unit cost in 2026 due to higher energy savings and favorable measure mix effects. However, unit costs nearly double in the 2027–2031 average as energy savings decline and program costs increase. This reflects a shift away from high-volume, lower-cost installations toward more expensive measures and reduced overall savings potential.

Affordable housing programs show rising unit costs over time. Unit costs increase between 2025 and the 2027–2031 period, driven by higher heat pump and upgrade costs, and declining heat pump savings. Affordable Multi-Family programs follow a similar pattern, with rising incentives, increased project management costs, and declining savings due to participation changes and measure mix shifts. These trends indicate that, while these programs continue to serve critical policy and equity objectives, they do so at increasing per-unit cost, as the easiest and most cost-effective opportunities likely have been exhausted.

BNI Programs

Business programs show more moderate increases in unit costs than residential programs, though similar structural drivers are evident.

Small Business Energy Solutions experiences a gradual increase in unit cost from 2025 through the 2027–2031 average. This is driven by the elimination of customer direct install, wind-up of lighting measures, and declining energy savings. As with residential programs, the removal of high-savings, low-cost measures materially affects unit cost metrics.

Business Energy Rebates follows a similar trajectory. Unit costs increase as lighting measures are phased out and non-lighting measures make up a larger share of activity. Energy savings decline in the out-years, while total costs fall less proportionally, producing higher unit costs despite overall spending reductions.

Custom and Strategic Energy Management programs remain the most stable business segment, with only modest variation in unit cost over time. While total costs increase in the 2027–2031 period due to higher incentives, expanded participation, and new offerings such as Equity-Deserving Communities, these costs are partially offset by increased energy savings per project. As a result, unit costs remain relatively flat compared to other program categories.

Conclusions

When evaluated in the context of other jurisdictions, E1’s submitted first-year energy efficiency costs for the 2027-2031 Plan are reasonable, prudent, and consistent with industry norms. It should be expected that there will be differences in reported $/kWh values across jurisdictions and utilities due to structural, methodological, and policy factors - including treatment of behavioral programs, lighting, codes and standards, legacy savings, low-income emphasis, and electrification. These are objective analytical factors, not indicators of cost management issues. Despite rising costs, the portfolio remains cost-effective on the basis of PAC test results, demonstrating that the energy efficiency programs continue to deliver dollar benefits that exceed their costs.

First-year costs for E1's 2027-2031 DSM Plan reflect prudent investment decisions, appropriate program evolution in response to maturing markets, and alignment with cost trends observed across North American EE portfolios. The increase in $/kWh costs over prior plan periods is a predictable and well-documented consequence of the structural forces described throughout this memo, including the phase-out of low-cost measures, increased investment in equity and electrification programs, and market transformation effects. These trends are consistent with regulatory findings in comparable jurisdictions that have continued to approve similar cost trajectories as prudent and reasonable. Accordingly, first-year costs should be understood in the context of these dynamics as evidence of a well-designed, evolving portfolio that reflects reasonable and prudent cost levels.

Appendix A – Jurisdictional Scan Results

New Hampshire – 2026 Plan

	Program Budget	Annual kWh Savings	$/kWh
Income Eligible			
Home Energy Assistance	$ 14,273,268	3,763,541	$ 3.79
SubTotal	$ 14,273,268	3,763,541	$ 3.79
Residential			
EnergyStar Homes	$ 3,874,881	2,595,205	$ 1.49
Home Performance	$ 10,850,684	911,058	$ 11.91
EnergyStar Products	$ 9,147,200	10,998,480	$ 0.83
SubTotal	$ 23,872,765	14,504,743	$ 1.65
Commercial & Indstrial			
Large Business Energy Solutions	$ 13,397,106	33,457,888	$ 0.40
Small Business Energy Solutions	$ 12,698,994	38,717,939	$ 0.33
Municipal Programs	$ 2,199,313	3,894,845	$ 0.56
Subtotal	$ 28,295,413	76,070,672	$ 0.37
Total	$ 66,441,446	$ 94,338,956	$ 0.70

Source: https://www.puc.nh.gov/VirtualFileRoom/ShowDocument.aspx?DocumentId=52dd95a5-3d24-46cf-95fc-f379c4854684

Vermont – 2024-2026 Plan

	MWh	%	Budget	$/kWh
Business Existing Facilities	114,451	59%	$ 60,159,434	$ 0.53
Exisitng Homes	5,841	3%	$ 22,517,893	$ 3.86
Efficient Products (Res)	50,747	26%	$ 26,054,862	$ 0.51
Res New Construction	5,459	3%	$ 10,111,956	$ 1.85
Business New Construction	16,703	9%	$ 7,332,078	$ 0.44
Totals	**193,201**	**100%**	**$ 126,176,223**	**$ 0.65**

Source: https://www.efficiencyvermont.com/Media/Default/docs/plans-reports-highlights/2026/efficiency-vermont-2026-update-triennial-plan-2024-2026.pdf

New Brunswick – 2024/25 to 2026/27 Initiatives Update

	Budget	kWh	$/kWh
Residential	$ 10,200,000	$ 8,700,000	$ 1.17
Direct Install	$ 200,000	300,000	$ 0.67
Total Home	$ 8,700,000	7,800,000	$ 1.12
New Home	$ 1,300,000	600,000	$ 2.17
Commercial and Industrial	$ 3,300,000	$ 29,900,000	$ 0.11
Commercial Building Retrofit	$ 900,000	1,200,000	$ 0.75
Commercial New Construction	$ 100,000	100,000	$ 1.00
Business Rebate	$ 400,000	-	
Industrial Program	$ 1,700,000	28,600,000	$ 0.06
Peak Rebate Program	$ 200,000	-	

Source: https://filemaker.nbeub.ca/fmi/webd/NBEUB%20ToolKit13, Matter 0552, NBP02.60

Prince Edward Island – 2024/25 Plan

	Budget ($M)	Gross Savings (Gwh)	Net Savings (Gwh)	$/kWh
Energy Efficienct Equipment Rebates	$ 2.22	5.09	3.97	$ 0.56
Home Insulation Rebates	$ 0.23	1.06	0.84	$ 0.27
Winter Warming	$ 0.26	0.55	0.55	$ 0.47
Instant Energy Savings	$ 0.55	2.66	0.96	$ 0.57
New Home Construction	$ 0.56	1.53	0.95	$ 0.59
Home Comfort	$ 0.61	0.88	0.69	$ 0.88
Residential Subtotal	$ 4.43	11.77	7.96	$ 0.56
Business Energy Rebates	$ 1.27	3.84	2.93	$ 0.43
Community Energy Solutions	$ 0.21	0.29	0.29	$ 0.72
C&I Subtotal	$ 1.48	4.13	3.22	$ 0.46
Demand Response	$ 3.25			
Enabling Strategies	$ 0.46			
Other Subtotal	$ 3.71	-	-	
Total	**$ 9.62**	**15.90**	**11.18**	$ 0.86

Source: https://irac.pe.ca/wp-content/uploads/Exhibit-E-9d-Appendix-A-2022-2025-EEC-Plan-for-PEI-Energy-Corp-REVISED-April-14-2022.pdf

Newfoundland and Labrador Hydro – 2024 Report

	Customer Particiaption	Annual Energy Savings	Annual Energy Savings
	(Customers)	(MWh)	(kWh)
Residential			
Insulation and Air Sealing	39	89	89,000
HRV			-
Energy SaversKits	89	71	71,000
ICEEP (Residential)	124	327	327,000
Commercial Programs			
Business Efficiency Program	7	140	140,000
Isolated Systems Business Efficiency			-
ICEEP (Commercial	61	392	392,000
Industrial EE Program			
Total ALL Program	320	1019	1,019,000

General Costs	**2024**
Education	$ 76,000
Support	$ 25,000
Planning	$ 151,000
Total General Costs	$ 252,000
Program Costs	
Thermostats	$ 7,000
Insulation and Air Sealing	$ 141,000
HRV	$ 17,000
instant Rebates	-$ 2,000
Energy Savers Kits	$ 51,000
Residential Benchmarking	$ -
Business Efficiency Program	$ 154,000
Small Business DI Pilot	$ 3,000
Isolated Systems Business EE Program	$ 11,000
ICEEP	$ 983,000
Industrial EE Porgram	$ 44,000
Total Program Costs	$ 1,409,000

Source: http://www.pub.nf.ca/indexreports/conservation/From%20NLH%20-%202024%20Electrification,%20Conservation%20and%20Demand%20Management%20Report%20-%202025-04-10.PDF

Appendix B – Details of Efficiency Manitoba's Portfolio

2020/21 to 2024/25 Evaluated Savings Electric Energy Savings showing use of Home Energy Reports, lighting, load displacement, and Codes and Standards.

Program	Electric Energy Savings (GWh) 2020/21	2021/22	2022/23	2023/24	2024/25
Residential Sector					
New Homes	1.5	0.6	1.0	1.6	1.5
Home Energy Retrofit	-	-	-	0.2	-0.0
Home Insulation	1.9	1.1	1.3	1.1	1.0
Windows and Doors	-	0.1	0.6	1.1	1.3
Advanced HRV Control	-	0.1	0.1	0.1	0.0
Residential Ground Source Heat Pump	-	0.1	0.2	0.2	0.1
Pool Pump	0.1	0.2	0.2	0.2	-
Air Source Heat Pump	-	-	-0.4	0.0	-0.2
Instant Rebates	4.5	10.9	6.3	8.4	7.5
Home Energy Reports	-	-	-	-	2.6
SAVE MORE	1.7	1.3	-	0.2	-
Appliance Recycling	-	0.8	1.8	2.4	2.1
Residential Sector Total	**9.7**	**15.1**	**11.2**	**15.5**	**15.8**
Income-based Sector					
Energy Efficiency Assistance	0.7	1.0	1.5	1.4	1.9
Income-based Sector Total	**0.7**	**1.0**	**1.5**	**1.4**	**1.9**
Indigenous Sector					
Community Ground Source Heat Pump	-	0.1	-	0.6	0.3
First Nation Energy Efficiency	-	-	0.1	0.1	0.2
Métis Energy Efficiency Offers	-	-	0.1	0.3	0.7
Indigenous Small Business	-	0.1	0.3	0.2	0.2
Indigenous Sector Total	**0.0**	**0.2**	**0.4**	**1.2**	**1.4**
Commercial, Industrial, and Agricultural Sector					
Custom Energy Solutions	6.1	30.2	9.5	9.1	21.6
Strategic Energy Manager Initiative	2.9	0.3	-	1.0	1.2
Commercial Ground Source Heat Pump	-	0.1	0.1	0.1	0.1
HVAC and Controls	0.6	2.0	0.5	0.6	0.8
In-Suite Energy Efficiency	-	0.0	0.9	1.4	1.1
In-Suite Appliance	-	-	-	0.1	0.3
Load Displacement	94.1	91.2	87.4	82.3	78.6
New Buildings	1.0	4.7	10.4	4.0	6.3
Business Lighting	26.4	37.3	61.3	80.1	60.8
Building Envelope	3.5	2.6	2.9	4.4	6.9
Small Business	1.1	0.8	1.1	0.6	0.8
Commercial Kitchen Appliance	-	-	1.1	0.2	0.1
Commercial Refrigeration	1.3	0.4	0.2	0.1	0.4
Strategic Energy Management Cohorts	-	-	-	-	-
Commercial Deep Energy Retrofit	-	-	-	-	-0.1
Commercial, Industrial, and Agricultural Sector Total	**137.0**	**169.4**	**175.4**	**184.0**	**178.8**
Emerging Technology Sector					
Solar Rebate	-	-	0.2	2.1	3.2
Emerging Technology Sector Total	**0.0**	**0.0**	**0.2**	**2.1**	**3.2**
Program Impacts Total	**147.4**	**185.6**	**188.8**	**204.2**	**201.1**
Codes and Standards	80.0	79.6	87.8	78.9	68.0
Portfolio Total	**227.4**	**265.3**	**276.6**	**283.1**	**269.1**
Electric Savings as a Percentage of Load	**1.03%**	**1.22%**	**1.25%**	**1.26%**	**1.20%**
Electric Load Reduction as a Percentage of 1.5% Target	**68.8%**	**81.5%**	**83.3%**	**83.7%**	**80.0%**

* Numbers may not add up due to rounding.

Source: https://www.pubmanitoba.ca/v1/proceedings-decisions/appl-current/pubs/mh-irp/em-02-efficiency-manitoba-information-package.pdf

Request IR-11:

Reference: Exhibit E-1, Application, pages 47–49/71; and Exhibit E-1(ii).

Page 47 of 71, E1 states that:

> **Notably, customer incentives account for 71 percent of total costs in the Preferred Plan, an increase from 66 percent in the 2026 DSM Plan, reflecting the fact that rising costs are directly attributable to the incentives that provide financial support to customers – either through direct rebates or fully funded upgrades – rather than to administrative or overhead cost growth.**

Page 48/71 states that:

> **E1 also worked with a third-party consultant to review the assumptions in E1's incentive setting methodology that was developed in 2017 to ensure these assumptions remained aligned with other DSM administrators.**

Page 49 of 71, E1 states that:

> **E1's investment in customer incentives continues to be the single largest category of spending, as expected in a resource acquisition model where incentives are the primary mechanism for driving customer participation and measure adoption. E1 has implemented a formal Incentive Setting Process, which was an outcome of the CLEAResult study conducted following the 2016–2018 DSM Plan. The incentive setting methodology is used when adding new measures or changing incentive levels on existing measures to confirm incentive levels fall within an acceptable range.**

(a) Please provide a copy of or detailed explanation of the "formal Incentive Setting Process" including how the incentive setting methodology is currently utilized, and address whether any third-party reviews have been completed since it was developed.

(b) Please identify the referenced consultant who reviewed the assumptions and provide a copy of the retainer letter or verbatim scope of work tasked.

(c) Did the third-party consultant review lead to any assumption or methodology changes?

i) If so, please list the changes and provide the rationale for the proposed change.

ii) If not, please provide any changes that were recommended but not adopted and explain the rationale for not adopting.

(d) Please provide a table (in excel format) that compares per unit incentive levels (from Exhibit E-1-(ii)) for each DSM measure from 2023 – 2031.

i) For this table, please include a column that specifies which rate classes are eligible for each DSM measure.

(e) Please explain the rationale for any incentive level changes year-over-year from 2026 to 2031, explaining how the incentive setting methodology led to the decision to change the level of incentive.

(f) From part (d) above, please show the detailed calculation that supports the statement that customer incentive amounts have increased to 71% of the total plan costs from 66% in 2026.

Response IR-11:

(a) EfficiencyOne (E1) has established a formal Incentive Setting Process to support the consistent, transparent, and evidence-based determination of customer incentive levels across its Demand Side Management (DSM) portfolio. E1's Incentive Setting Process was developed following a third-party CLEAResult study conducted after the 2016–2018 DSM Plan.

The purpose of this process is to:

- Establish appropriate incentive levels for DSM measures;
- Support customer participation and uptake of energy efficiency and demand response initiatives; and
- Ensure incentives are reasonable and aligned with program objectives, including cost-effectiveness and portfolio performance.

This process provides a standardized and structured framework to guide incentive decisions across the DSM portfolio. In July 2017, the Nova Scotia Utility and Review Board (as it then was) accepted the Incentive Setting Methodology report and E1 implementation plan as filed on May 11, 2017.[1]

E1 continues to apply the Incentive Setting Process in the development and implementation of the 2027–2031 DSM Plan. Specifically, the methodology is used in the following contexts:

a) Setting incentives for new measures
When introducing new DSM measures, E1 applies the methodology to determine appropriate incentive levels. This ensures that new offerings

[1] M07544, NSUARB Letter, Document 70554, July 18, 2017. "The Board…accepts the Incentive Methodology Report and E1's Implementation Plan as filed on May 11, 2017."

are supported by incentives that are consistent with established parameters and program objectives.

b) Adjusting incentives for existing measures

The methodology is also used when revising incentive levels for existing programs. E1 applies the process to confirm that updated incentives remain within an acceptable range and continue to support program participation.

c) Responding to changing market conditions

E1 utilizes the Incentive Setting Process to respond to evolving market and policy conditions that affect participation. For example:

- Following the conclusion of external funding programs (e.g., federal Greener Homes Grant), E1 increased incentive levels to maintain customer participation and program uptake.

Incentives are the primary mechanism for driving DSM participation and represent the largest portion of DSM expenditures:

- Customer incentives account for approximately 71% of total DSM costs in the 2027–2031 Preferred Plan.

As such, the Incentive Setting Process plays a central role in:

- Achieving energy and demand savings targets;
- Maintaining participation levels; and
- Supporting overall portfolio cost-effectiveness.

Since its initial development, E1 has undertaken additional third-party review of the Incentive Setting Process. Specifically, Research Into Action performed a review and E1 filed its Incentive Setting Evaluation Report, prepared by Research Into Action, as M08604, Research Into Action, Practices and Procedures Evaluation – Volume 1: Incentive Setting. This was included as Exhibit-3 (E-3) as part of the 2019 DSM Resource Plan Application, filed March 29, 2018.[2] In 2018, E1 developed an alternative approach for incentive review templates and updated processes. In Q4 2018, E1 sought comments from CLEAResult on the updated approach prior to implementation. To support the development of the proposed 2027-2031 DSM Plan, E1 worked with a third-party consultant, Apex Analytics, to review the assumptions underlying the incentive setting methodology and to ensure that the assumptions remain aligned with those used by other DSM administrators. E1 has attached the outcomes of Apex Analytics review in Attachment 1 of this IR response.

(b) Please refer to Attachment 1 of this IR response for the Apex Analytics report on the review of E1's incentive setting methodology. The scope of work provided to Apex Analytics was as follows:

- Conduct jurisdictional scans for DSM incentive setting best practices across North America and compare against E1's current incentive setting methodology.
- Provide a report on its findings including recommendations to ensure E1's approach remains robust and aligned with industry best practice.

(c) Please refer to part (b) of this IR response.

i) Apex did not recommend any changes specific to the incentive setting methodology, they concluded that E1's practices were more rigorous than their peers. Apex did recommend improvements that E1 may wish to consider for its internal processes:

[2] M08604, E1 2019 DSM Plan, Exhibit 3, 2017 Program Support Process Evaluation Reports, PDF page 56. (Date Filed: March 29, 2018)

- Utilize a decision tree – In some cases there is rationale for offering incentives for projects with less than a three-year payback. Apex provided a table of these reasons for E1 to consider. E1 intends to incorporate this rationale into its internal processes.
- Publicize a version of the ISP document – E1 has taken this into consideration.
- Integrate prioritization framework – E1 agrees with this recommendation and will consider how to best implement.
- Develop program logic models – E1 has program logic models for all DSM program components.
- Follow emerging trends – E1 will review the incentive setting methodology in advance of each DSM Plan.
- Update the thresholds from the 2017 values – E1 has updated the thresholds in the 2027-2031 DSM Plan.

ii) Please refer to part (c) i) of this IR response.

(d) Please refer to Attachment 2 of this IR response.

i) The measures are not specifically designed by rate class in E1's DSM Plan. Rather, measures within a program component are selected to meet the needs of those customers who meet the project eligibility requirements for a given program component, therefore, available to specific rate classes. For example, the project eligibility requirement for E1's Small Business Energy Solution program component are:

- Annual electrical usage under 600,000kWh;
- The facility must be located in Nova Scotia;
- Retro fit projects only, no new construction; and

- For heating projects are to offset electrical usage so no non-electrically heated facilities are eligible.

(e) As provided in Attachment 2 of this IR response are the list of measures included in the DSM Plan and a comparison of the incentives from 2026 to 2027–2031. Below is a summary of the main themes driving proposed incentive changes.

- Current DSM incentives are low and costs are rising – Please refer to Synapse IR-37 for an example.
- Non-DSM top up incentives are no longer available – Please refer to Synapse IR-37 and Synapse IR-38 for examples.
- Measure characterizations were updated – E1 updated various elements of measure characterizations, such as average installed equipment capacities, which directly impacts prescriptive incentives in program components like Business Energy Rebates. Savings and costs were likewise adjusted for measures, including how mini-split heat pumps are presented in all programs, to provide an updated and more uniform characterization based on Service Provider costs and customer receipts and 2025 program evaluation results.
- Rebates were standardized for like measures – In an effort to make E1 incentives easier for customers and industry to understand, incentive levels for measures like smart thermostats were made uniform across all program pathways where these types of measures are proposed.
- Incentives were increased to support market transformation efforts – Heat pump water heater incentives are being increased to complement the education and awareness work E1 is leading to increase product availability and sales of this high potential measure.
- Incentives were altered as part of PAC and payback threshold reviews – As documented in Appendix A – Attachment 3 – 2027-2031 Energy Efficiency & Solar-

PV Technical Tables, E1 performed PAC and simple payback reviews for all measures. In many cases, E1 reduced incentives compared to current levels to improve cost-effectiveness and lessen support when projected paybacks are less than three years.

(f) Please refer to E1's response to IG IR-12 part (a).

To: Gina Thompson, Kate McDonald, EfficiencyOne
From: Michael Goldman, Matt Nelson, Jodi Hanover, Apex Analytics LLC
Date: May 22, 2026

This memorandum evaluates incentive setting best practices from across North America. For this exercise, Apex Analytics (Apex) interviewed four leading energy efficiency (EE) program administrators (PAs) and performed a structured literature review of publicly available industry guidance. Apex's overarching conclusion from this process is that EfficiencyOne (E1) is a leader in many areas of incentive setting, but there are some areas within the process that E1 may want to consider for improvement.

Apex's primary findings are described in brief below and in more detail throughout this memo.

- **Variability:** There is no standardization across North America in terms of how incentives are set. Different organizations use different methodologies and, even within the same organization, different methodologies are sometimes used based on the program type.
- **Process Documentation:** Most Program Administrators (PAs) do not have a documented incentive setting process. Business procedures are usually passed down verbally from senior to junior staff. Incentive setting also does not tend to be part of onboarding procedures for new staff.
- **Payback Period:** Payback period was not cited as a major criterion when setting incentives or when deciding what measures to offer as part of a demand side management (DSM) portfolio. Payback period was mentioned as being important only in the context of custom incentives for commercial and industrial (C&I) customers.
- **Emerging Trends:** There are several emerging trends around incentive setting that are gaining traction, particularly around transitioning away from equipment-based incentives to performance-based incentives (e.g., developing incentives based on savings calculated from the meter or modeled savings in the case of recent U.S. Department of Energy programs).
- **Market Research:** A best practice noted in the literature and in interviews with other PAs is to rely on market actors, including trade allies, who work directly with customers, to validate the need for incentives and the potential impacts of various incentive levels.

Background

In 2016, E1 engaged CLEAResult, a third-party consulting firm, to develop an incentive setting methodology. The methodology was memorialized in a report that was initially filed in June 2016 with subsequent revisions in March 2017 and May 2017. This methodology was reviewed and ultimately accepted by stakeholders and the Nova Scotia Utility and Review Board (NSUARB or Board). However, in the intervening years, questions have arisen about best practices surrounding setting incentives and whether certain measures should be incentivized at all. These questions, and the regulatory requirements arising from the NSUARB's 2022 decision described below, form the basis for this review.

In September 2022, the NSUARB issued a decision in docket M10473, approving E1's 2023–2025 DSM Plan. In this decision, the NSUARB considered arguments about the prudence of providing incentives for measures that had simple payback periods of less than 36 months. The NSUARB ultimately accepted E1's incentive setting methodology for the 2023–2025 DSM Plan and acknowledged that there are non-financial barriers that must be accounted for when setting incentives. The NSUARB ultimately required E1 to include payback information in its measure level tables and, for those measures with a payback of less than 36 months, E1 was required to provide additional information about what other factors were considered when setting the incentive level.

Overview of Apex Process

E1 engaged Apex in late 2023 to perform several research tasks related to incentive development and incentive setting best practices. Specifically, Apex was engaged to conduct the following tasks:

- **Review E1's existing incentive setting methodology.** Apex staff reviewed CLEAResult's 2016–2017 process evaluation reviewing E1's incentive setting methodology and conducted interviews with key E1 staff to better understand how incentives are set in practice.
- **Review previous Board Decisions and Directives and any relevant stakeholder comments on incentive levels or the incentive setting process.** Apex worked closely with E1 staff to review relevant stakeholder and regulatory comments on the incentive setting process.[1] This review provided context for Apex's recommendations to E1.
- **Conduct primary and secondary research.** Apex performed a jurisdictional scan for DSM incentive setting best practices across North America. Additionally, Apex

[1] Apex reviewed testimony, discovery, and Board Decisions from dockets M06733 (2016-2018 DSM Plan), M09096 (2020-2022 DSM Plan), M10473 (2023-2025 DSM Plan), and M07544 (Incentive Setting Methodology).

conducted primary research by interviewing four leading EE PAs from both the U.S. and Canada. The findings from this research are described in detail in this memo.

- **Provide recommendations on possible changes to the incentive setting process.** Apex provides a description of practices from top-ranked PAs within this memo, complete with recommendations that E1 may want to consider adopting. The interview topics included how to set incentive levels for DSM measures that have a short payback period, whether utilities focus on percentage of incremental costs, if strategies differed by customer types, and whether incentive levels vary by measure technology maturity or other factors.

E1 Incentive Setting Process

E1 has a well-documented Incentive Setting Process (ISP) described in a PDF document and accessible to all staff. All related materials are saved in a central file location. The document was last updated in December 2021. The 12-page document covers critical incentive setting procedures such as internal roles and responsibilities, definitions of incentives, and requirements for when the ISP must be followed. Per the ISP, the Engineering and Planning (E&P) department has responsibility for portions[2] of the ISP with the Services department being responsible for adhering to the ISP.

As it relates to setting incentives, the documentation clearly defines when staff must follow the ISP. The ISP notes that the outlined procedures must be followed when a new measure or program is added or when an existing incentive for a measure or program is updated. The process is based off recommendations from a process evaluation report developed by CLEAResult in 2017 and from subsequent updates from CLEAResult in 2019. The CLEAResult report underwent significant stakeholder and regulatory review before it was ultimately accepted and implemented.

To help facilitate the development and maintenance of incentive levels, E1 (based on information from CLEAResult) developed two spreadsheet tools[3]:

- A spreadsheet tool to be used for adding new measures denoted as “Adding a New Measure or Program Template.”
- A separate spreadsheet tool for updating incentives denoted as “Updating Incentives on Existing Measures or Programs Template.”

[2] E&P is responsible for validating technical and energy saving assumptions as part of the ISP.

[3] There is a third spreadsheet tool utilized by the E&P team called the financial simulation tool. The financial simulation tool is used to run an annual review of priority incentive levels. The financial simulation tool is used to compare incentive levels for priority measures against thresholds determined in the CLEAResult report. The tool is critical for allowing staff to flag any measures that may be violating any of the CLEAResult thresholds.

The spreadsheet tools are critical to the ISP. Program Managers (PMs) must input all critical assumptions into the spreadsheet tools, and the tools help determine the bounds of the incentive level, with the PM and Service Delivery Manager (SDM) making the final decision on the incentive level.

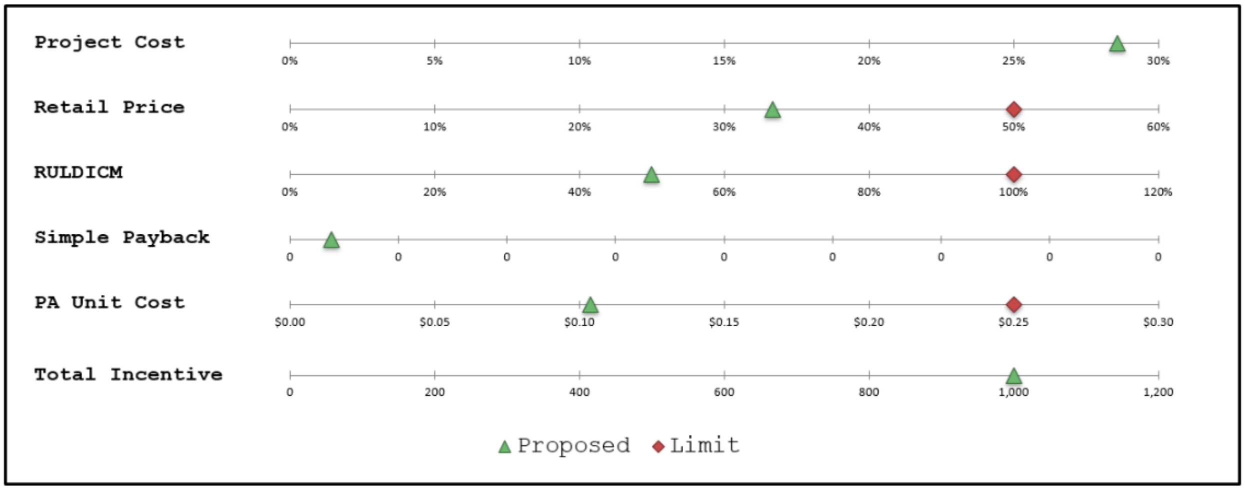
The spreadsheet tools rely on detailed and granular information inputs to inform the incentive level. The spreadsheet tool inputs consist of the following categories:

- **Basic Information.** Description of the measures, what is the base case, programs and markets impacted by the measure(s).
- **Jurisdictional Information.** Information from other jurisdictions where the measure is currently offered to help inform E1 assumptions. These technical assumptions include information such as energy savings values, demand savings values, measure life, incentive level. The tool recommends input from five other jurisdictions.
- **Industry Insights.** Insights gained from performance of due diligence by speaking with key stakeholders to better understand incremental cost, potential incentive levels, market trends, etc.
- **Energy Savings Assumptions.** Base case energy consumption, efficient case energy consumption, base case coincident peak, efficient case coincident peak, measure life, potential operations and maintenance (O&M) savings, any other resource savings.
- **Proposed Incentives.** Net-to-gross ratio, program delivery model, rate code, proposed incentive.

After a PM inputs all of the required information, the spreadsheet tool produces a chart that shows the bounds of the incentive based off the criteria from the CLEAResult report and where the proposed incentive falls within those bounds.[4] Figure 1 below is an illustrative example of what the threshold criteria look like and what a PM would see after inputting all the necessary assumptions.

[4] CLEAResult provided recommendations for upper thresholds in a number of categories, such as program unit cost, total incentive, retail price threshold, project cost, incremental equipment cost, and simple payback.

Figure 1. Spreadsheet Thresholds for Incentive Setting



The necessary steps for a PM to follow when using the spreadsheet tools are clearly articulated in the tool itself and are as follows:

- **Step 1:** Determine if it is necessary to use the template.[5]
- **Step 2:** Save a version of the template in the appropriate folder.
- **Step 3:** Fill out all highlighted tabs that require measure level assumptions.
- **Step 4:** E&P reviews technical assumptions and provides feedback.
- **Step 5:** Review incentive level thresholds and determine proposed incentive level.
- **Step 6:** SDM reviews and signs off.
- **Step 7:** Save the template and notify the Strategic Planning Manager.

According to the ISP, before a new incentive can be offered, the completed spreadsheet tool must be approved by the staff requesting the incentive, the relevant PM, and the SDM.

Since there is no single industry standard practice for setting incentives, incentive setting is frequently described as part art and part science. After reviewing E1's incentive design procedures, Apex found that E1's procedures meet or exceed industry standard procedures for designing and setting incentives, and in several respects represent best-in-class practice relative to the peer PAs reviewed. On this basis, Apex concludes that E1's incentive setting process is prudent, well-documented, and appropriate for approval as part of E1's DSM Plan.

[5] The spreadsheet tool contains a tab titled "When to Complete" that lists scenarios when it is necessary to use the spreadsheet tools and corresponding processes.

Incentive Design Basics

The incentive design research conducted by Apex showed that there are multiple different methodologies that EE PAs are using to set incentives and that there is a general lack of standardization in incentive development. Of the PAs interviewed by Apex, some developed incentives based off incentivizing a percent of incremental cost, while others had a flat $/kWh or $/MMBtu they paid for projects. Others simply set incentives based off conversations with customers and trade allies while making sure that incentive levels did not exceed total portfolio budgets. Some PAs were willing to pay for a percent of project cost or had thresholds in place where they would go up to a certain percent of the project or unit cost.

Secondary research also supports this same conclusion. A report prepared for Xcel Energy in Colorado reviewed lighting and lighting controls for nine different PAs.[6] There was no uniformity in how the incentives were designed, even for the same products. Some PAs provided incentives on a $/kWh-saved basis while others focused on paying a $/watt incentive based on the product's characteristics. In some cases, the incentive varied based on the equipment being replaced, sometimes it did not. Other PAs had a threshold or incentive cap in place where they would pay an incentive based on a $/kWh calculation but would cap it at up to some percent of the installed cost. There were also considerations cited such as incremental cost, cost-effectiveness, and prior participation levels.

Since there is no single industry standard practice for setting incentives, incentive setting is frequently described as part art and part science. After reviewing E1's incentive design procedures, Apex found that E1 considers similar factors as other PAs in setting incentives and is a leader in many areas of incentive setting procedures.

Primary Research

Apex conducted interviews with four EE PAs from across North America, with two located in New England, one located in the Midwest, and one located in Canada. These PAs have similar weather climates and programs to Nova Scotia. The interviews focused on how each of the PAs developed and set incentives across a host of program types that covered all customer types. The key takeaways from the primary research are described below, with subsequent sections going into more detail on the insights provided by the PAs.

Key Takeaways

- **Variability**. None of the PAs with whom Apex spoke set incentives in exactly the same way. Within a single PA, there was variability in terms of how incentives were

[6] https://www.xcelenergy.com/staticfiles/xe-responsive/Company/Rates%20&%20Regulations/04%20-%20Xcel%20Energy_CO%20Lighting%20Efficiency%20_2022%20Final%20Report.pdf

set for different programs and there was variability between the different PAs in terms of how they set incentives for the same type of programs.

- **Budget Considerations.** Most PAs are generally setting incentives to support savings goals while staying within a prescribed budget and maintaining overall portfolio cost-effectiveness.
- **Process Documentation.** None of the PAs interviewed had seen a written incentive setting process. Three of the four PAs acknowledged there was no documented process, while the fourth believed there was some documentation for a specific program type but had never seen it.
- **Payback Period.** None of the PAs used payback period as an explicit criterion for determining incentives. However, all PAs noted that if a customer had a specific payback threshold necessary to move forward with a project, the PA would try to work with the customer to help meet that threshold if possible. This issue was largely brought up in the context of large commercial and industrial customers.
- **Technology Maturity.** Almost all the PAs who were interviewed described the need to offer higher incentives for newer technologies in order to encourage adoption. As the technology matures and the incremental cost shrinks, incentives can correspondingly be reduced.
- **Jurisdictional Scans / Market Research.** The PAs interviewed all stressed the importance of performing market research and jurisdiction scans in order to ensure that incentives were reasonable. Market research could take the form of talking with customers and trade allies to make sure that incentives would have the intended impact. Jurisdictional scans can be used as a check to make sure that incentives are not out of line with what is being offered in other areas.
- **Cost-Effectiveness.** Many of the PAs interviewed cited cost-effectiveness as a main consideration when setting incentive levels. PAs generally have a requirement to ensure that their offerings generate more benefits than costs. An important takeaway is that the PAs interviewed all had flexibility and had program or portfolio cost-effectiveness requirements but not necessarily measure-level cost-effectiveness requirements.
- **Incentive Updates.** A general theme from the interviews was that incentives were not updated frequently. However, there were common checkpoints when incentives would be re-evaluated based on achievement during a plan cycle. Progress review periods, when PAs checked progress towards goals, was a common time to update incentives if savings were too high or low.

Detailed Results of Interviews

General Incentive Setting Process

Throughout the course of the interviews, it became clear that peer PAs do not have a standard methodology for setting incentives. The most common approach involved relying upon market research to understand what customers and trade allies need in terms of incentive level in order to move forward with projects. If a PA was going to set incentives as a percent of incremental cost, one interviewee stated that market research and talking to trade allies are the best ways to understand how much of the incremental cost between the standard and high-efficiency products needs to be covered by the incentive.

For C&I projects, there is a differentiation in methodology between custom and prescriptive incentives. For custom projects, one PA stated that projects are evaluated by end use and then they generally set a $/MWh or $/therm incentive for that end use. That dollar value is based on cost-effectiveness and what has been paid historically. For prescriptive measures, the same PA stated that they target a percent of project cost by end use. The target is normally 40–70% of project cost, with 75% being the highest. The PA might go even higher for certain priority segments and measures. An example of a priority for that PA is to increase small-business weatherization. In that case, the PA might pay a 100% incentive for that measure. A different PA stated that they target 5–10% of project costs but were predominantly focused on making sure they stay within their overall budget when developing incentives.

One interesting methodology described during an interview was a PA who uses willingness-to-pay or market adoption curves developed by external research firms to help understand what incentive levels are necessary to obtain certain levels of participation. This PA triangulates to the desired incentive level by looking at a host of factors in addition to the adoption curves such as jurisdictional scans, talking with their program delivery partners that have experience working in different regions, and setting ranges for a percent of incremental cost they want to cover, which is based on material and installation costs.

Some of the interviewed PAs employ a threshold approach to ensure that incentives are not too high and that the PA doesn't overpay for savings. One PA described a situation where market research suggests a certain prescriptive value but that seems high based on market experience, so they employ a second threshold which is an "up to" amount. This was a frequent strategy employed where incentives would be set at a $/kWh or $/MMBtu basis with a qualifier that the incentive would pay up to some percent of project or unit cost.

Incentive Updates

All interviewed PAs discussed the importance of flexibility and the ability to change incentive levels if necessary. One interviewee indicated that incentives are oftentimes updated when that PA performs a periodic review of achievement vs. planned numbers. In this way they can tell if they are over- or under-performing and can adjust their incentive up or down accordingly. A different PA had a similar position and stated that if they did not see enough adoption of a measure, they would increase the incentive level, but in general they do not evaluate the incentive level frequently throughout the term unless there is significant over- or under-performance, a major law or standard changed, or they are adding a new measure.

One PA stated that they have a fixed review schedule and will review incentives every spring and fall in addition to ad hoc reviews based on program performance. A different PA shared an idea of how they address a short-term need for higher savings. This PA will not necessarily raise the incentive itself but will offer a bonus on top of the existing incentive to temporarily increase participation. This same PA will also occasionally issue Request for Proposals (RFPs) to vendors/contractors/aggregators to see what savings can be obtained at what cost. The PA interviewed believed that this RFP methodology could produce lower costs. The Apex team notes that an RFP process also provides transparency and documentation for costs of certain EE measures and savings.

New Measures

When introducing new measures into a portfolio, the initial incentive setting process can look a bit different. For one PA, the initial incentive setting for a measure will go through a defined new measure process with cost-effectiveness screening and data gathering to ensure that all the details for a Technical Reference Manual (TRM) entry have been obtained. This PA will also look to make sure the incentive is not an order of magnitude higher than in other jurisdictions.

Another interviewed PA described a fuel-agnostic approach to adding measures. This PA has developed a standardized $/MMBtu value they pay for savings. For new measures, this PA will look at how many MMBtu the measure saves and then pay out incentives based on their $/MMBtu incentive rate.

Technology Maturity

All the interviewed PAs discussed the need to offer higher incentives for newer technologies and the willingness to provide enhanced incentives for immature technologies. One PA stated that newer measures that follow a typical adoption curve typically need higher incentives at first but, as technologies mature, their incremental costs should go down and incentives should therefore decrease as well. The one caveat to that statement was that some types of measures, like weatherization retrofits, require the same/consistent incentive levels over time to ensure uptake.

One PA suggested that it is important to look at the total incentive package being offered to a customer, regardless of the maturity of the technology being offered. This PA looks at the total package being offered for a customer, inclusive of the incentive for the measure, financing options, and then any bonuses (such as free insulation). An example given was for a heat pump where there might be a $10,000 rebate, a 0% financing offer for the remainder of cost, and then 100% free weatherization as a bonus. In this case, the incentive is calibrated based on the total offer, making sure that it aligns with where the technology is on its adoption curve.

Key Assumption Updates

Incentives are frequently set based on assumptions of the cost of efficient equipment, the cost of standard/baseline equipment, energy savings values, and the life of the measure. These assumptions need to be updated in order to make sure they are accurate. Apex asked the interviewees how frequently these underlying assumptions get updated. One PA noted that the frequency of updates depended on how quickly the market was maturing/evolving. As an example, when the lighting market was quickly evolving a number of years ago, lighting numbers were updated on an annual basis. That particular PA used internal resources to perform a web scraping exercise for lighting costs on a frequent basis.

Another PA noted that incremental costs are usually updated on an as-needed basis but generally not updated too frequently. Incremental costs are updated by third-party Evaluation, Measurement, and Verification (EM&V) vendors or can be done internally. A different PA had a divergent view and stated that their TRM, which contains all their savings and cost assumptions, is reviewed annually. This PA indicated evaluation changes also take place on a frequent basis, which could impact the savings level for a measure. This same PA noted that most changes have been on the residential side, especially for HVAC measures, and that if evaluation or other studies showed there is high saturation in the market for a particular measure, they will stop offering incentives for it. In addition, for certain measures like custom or HVAC, the measurements may be hard to compare if the program is based on tonnage, SEER rating, custom engineering analysis, and rate structure of various jurisdictions.

Payback Period

Apex asked PAs to discuss their views on using payback as criteria for incentive setting. One PA said they will use payback criteria for specific C&I[7] customers if it is important for that customer. Another PA said that sometimes customers will request enough incentives to meet a certain payback and the sales team will work with them to try to meet that threshold.

Another PA said that they don’t often look at payback period for most customers but on occasion customers will ask about it. For those customers that do ask about it, their typical payback period for a large industrial customer was four years but across the portfolio it is normally one to ten years. This PA noted that customers typically need a two- to three-year payback with no more than four years (generally due to financial position and the average

[7] Throughout this memo, the C&I sector is equivalent to E1’s nomenclature for Business, Non-profit, and Institutional (BNI) sector.

lifetime of businesses)[8]. The PA also cautioned that C&I customers have other capital needs besides energy equipment (e.g., new software, additional employees). One PA recently surveyed industrial customers about their threshold payback periods and found that the majority require a three-year or better payback.

For certain measures, like C&I heating electrification, customers may undertake the retrofit for other reasons besides financial reasons. In the example of C&I heating electrification, a customer may have decarbonization or other sustainability goals they are trying to meet. In this instance, the customer still needs an incentive, but the level needed to go forward with the project is not solely tied to the payback period.

None of the interviewed PAs reported that payback period directly influenced their setting of prescriptive incentives. Further, none of the PAs interviewed had any regulatory requirements to offer (or not offer) incentives based on payback period thresholds. Many PAs interviewed indicated that payback was not a static metric, was influenced by energy rates and equipment savings, and therefore would be difficult to use to uniformly evaluate incentives.

Process Documentation and Controls

None of the interviewed PAs had a formal documented process for setting incentives. Three of the four had no documented incentive setting process while the fourth thought there was a written process for C&I custom incentives but had not seen it. One PA noted that, while there was no formal written documentation, the incentive setting process is shared between staff, with more senior staff communicating the process to junior staff. A different PA noted that, while not documented, there was an internal policy that incentives shouldn't exceed incremental costs.

Many of the PAs did have a process in place for offering enhanced incentives, specifically for custom C&I programs. For one PA, to offer an enhanced incentive, it is necessary for a PM to obtain signoff from three different Directors (Implementation, Finance, and Audit). Another PA stated that there was a robust chain of command for reviewing and approving certain levels of incentives.

Two PAs noted there is a process in place where programs and measures are subject to periodic Benefit Cost Ratio (BCR) reviews. It was mentioned that during this process it

[8] Innovation, Science and Economic Development Canada reports that, across cohorts of new Canadian enterprises entering the market between 2001 and 2022, roughly half were still active after five years and only about a quarter remained active after twenty-one years. See ISED, *Key Small Business Statistics 2025*, available at https://ised-isde.canada.ca/site/sme-research-statistics/en/key-small-business-statistics/key-small-business-statistics-2025. U.S. Bureau of Labor Statistics data show similar attrition patterns. A C&I customer evaluating an efficiency investment against this base rate has a defensible reason to require a payback short enough that the savings stream is realized while the firm is still reasonably likely to be operating — which on a weighted basis points toward a two- to three-year nominal payback.

would become apparent if there were any incentives that were unreasonable or an order of magnitude higher than what they should be.

Jurisdictional Scan

Apex performed a literature review for best practices associated with incentive design and development. The existing literature is rather limited, but the U.S. Department of Energy has published multiple reports focused on incentive best practices that provide useful suggestions. [9] The key takeaways from these reports are presented below.

- **Develop a program logic model.** PAs should develop a program logic model in order to deeply understand the barriers for installing specific efficient equipment. This allows the incentive to be designed in a way to appropriately overcome those barriers. Periodic market assessments are recommended to help update the program theory and logic model.
- **Align incentives to goals**. The PA should determine if the incentive is needed for the customer, contractor, distributor, or some other market actor. Program participation, or lack of participation, can be determined by many factors in the chain of delivery. The type of incentive is also critical—the incentive could be financial in nature if a first-cost barrier is identified as a hinderance to EE measure adoption. In many jurisdictions, even incentives of 100% do not have 100% adoption. The incentive could be structured as a convenience incentive if finding contractors or lack of time/ability is identified as a primary reason for non-participation. This demonstrates the value of a properly designed program logic model.
- **Perform market research.** When setting incentives, performing market research is critical. External parties such as customers or trade allies should be consulted when developing incentives. This lets the PA know if an incentive is potentially too low or too high and validates that the incentive will have the intended effect. Market research also lets a PA know if there are other barriers that need to be overcome in order to drive uptake in an EE program. PAs may want to run focus groups or pilot incentives with smaller groups to make sure the incentive is achieving the desired objective.
- **Calibrate incentives to cost-effectiveness.** Many jurisdictions do not require each individual measure to be cost-effective, but there is a cost-effectiveness requirement at a program, sector, or portfolio level. However, looking at measure-

[9] *Customer Incentives for Energy Efficiency Through Program Offerings*, February 2010, available at https://www.energy.gov/sites/default/files/2023-10/napee-program_incentives_1.pdf and *Designing Incentives Toolkit, Better Buildings Residential Network*, available at https://www.energy.gov/eere/better-buildings-residential-network/articles/voluntary-initiative-designing-incentives.

level cost-effectiveness can provide insight into necessary incentive levels. If a measure is very cost-effective from the participant point of view, then a lower incentive may be more appropriate. However, if a measure is not very cost-effective from a customer perspective, a larger incentive may be necessary.

- **Match incentives to building stock and customer types.** If a particular service territory has predominantly older building stock that may have been constructed before current efficiency codes were promulgated and has older systems, then it may be more appropriate to offer bundled incentives such as HVAC plus envelope incentives. However, if the service territory is mostly newer building stock, more focus on plug load type opportunities may be more appropriate. If a PA has a large percentage of customers that are large C&I customers, then it would be expected that there would be more reliance on custom incentives. If the customer base is mostly smaller C&I and residential customers, a heavier reliance on prescriptive incentives would be appropriate.

E1 Comparison to Peers

After conducting primary research and a jurisdictional scan, Apex compared E1's practices against other PAs and ranked both E1 and peers in terms of its level of rigor and review. Table 1 below summarizes how E1 compares against some of its peers and other best practices that were revealed as part of the literature review. It is important to note that the four interviewees are large PAs who have been consistently ranked in the top quartile in the American Council for an Energy Efficient Economy (ACEEE) or Canadian Energy Efficiency rankings and, as such, represent best-in-class peers.

Table 1. Comparison of E1 to Peers

	Category	Description	Below	Typical	Better	Best
Documentation	Incentive Change Owner	Who reviews and evaluates incentive-level changes?		E1, Peers		
	Process Documentation	How well documented is the incentive setting process?	Peers		E1	
	Incentive Approval	Is the approval process robust?		Peers		E1
Process	Incentive Review Trigger	What drives changes to incentives?		Peers	E1	
	Variability	How uniform is the process for changing incentives?		E1, Peers		
	Incentive Updates	How frequently are incentives updated?		E1	Peers	

	Category	Description	Below	Typical	Better	Best
Motivation	Budget Considerations	Does the PA stay within their budget?			Peers	E1
	Payback Period	Payback period not used for incentive criteria.	Peers		E1	
	Technology Maturity	How are new measures developed and adopted?		E1		Peers
	Third-Party Data	How well-documented is market research?		Peers	E1	

In order to determine the rankings displayed in the table above, Apex reviewed a number of criteria that are described in more detail below.

- **Incentive Change Owner.** There was no PA, including E1, that had a clear uniform process in the evaluation and accounting for incentive levels. This was typically performed by many different groups.
- **Process Documentation.** E1 has clear level-setting documentation, but user interface to the information could be improved. Most other interviewed PAs interviewed have no formal framework.
- **Incentive Approval.** From internal E1 interviews, Apex understands that E1 has a clear chain of command that reviews and approves incentive changes. With other PAs, these changes are often more ad hoc with only one layer of review and approval, usually more related to the budget than the incentive level.
- **Incentive Review Trigger.** The primary driver of changing incentives for PAs and E1 are both motivated by achievement of savings targets. However, while incentives are often changed to increase participation, E1 has a robust process that looks at many programs before this change is made.
- **Variability.** The method of review and change for all PAs varies by program delivery type, and there isn't a central review process that happens when incentive levels change.
- **Incentive Updates.** The review cycle of changing incentives was not as uniform or clear for E1, where many peers had set timing and more detailed processes.
- **Budget Considerations.** PAs often were not proactively concerned with the impact to the overall budget when making an incentive change. E1 has the most rigorous approach to managing budgets and costs across all PAs reviewed.

- **Payback Period.** Only one other PA considers payback period as a metric to review in relation to incentives. E1 is much more acutely aware of this issue and has regulatory requirements in place to view and report payback period.
- **Technology Maturity.** E1 has always had an innovation team and process for new measures, but recently has created a more comprehensive framework and plan for expanding programs to include new measures. Many of E1's peers were committed to consistent testing of new measures and pilots.
- **Third-Party Data**. E1 consistently goes beyond other peers to gather data for programs (for example, Willingness-to-Pay and Market Adoption Curves[10] are best-in-class actions to support incentive levels).

Payback Period Considerations

Throughout the primary and secondary research conducted by Apex, there were no examples of payback period being the primary factor when developing incentive levels. Payback period is one of many important considerations for large C&I customers when considering the viability of an EE or DSM project. However, for many other customer types, payback period does not seem to be an important consideration, and even for large C&I customers there are many other influences besides payback period that contribute to the decision to move forward with an EE/DSM project.

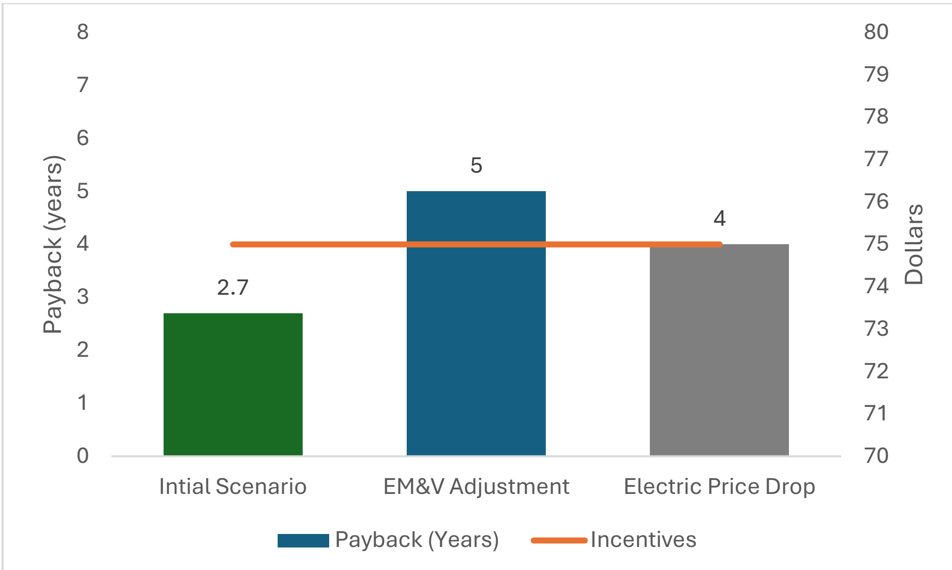
One issue with using payback period in the determination of incentives or whether an incentive should be offered at all for a specific measure is the level of certainty in the assumptions to compute a payback period. Payback period is roughly defined as the incremental cost of a measure divided by its first-year energy savings value multiplied by the value of the energy saved or [incremental cost / (first-year energy saved x value of energy saved)]. Any of these determinants have uncertainty. For instance, a customer may be unsure whether the savings may materialize due to factors like cost of energy changing or behavior affecting savings. It is also likely that the incremental cost of the measure will change over time, and customers may feel that waiting will be beneficial for some measures.

In a simplistic example, an energy-efficient high-speed fan may have an incremental cost of $150 with a $75 incentive already applied and save 372 kWh per year (with a kWh being worth $0.15). The simple payback period for this customer would be $150/(372 kWh x $0.15/kWh) = 2.7 years. However, if an EM&V study was conducted and determined that an efficient high-speed fan only saved 200 kWh, then the payback period changes to $150/(200 kWh x $0.15/kWh) = 5 years. Or a financial crisis causes a drop in natural gas

[10] Market Adoption or Willingness-to-Pay Curves are used to theoretically decide optimal pricing points varying amounts of money that different consumers are willing to pay for a particular product or service at a given time.

prices[11], which impacts electric prices, and the value of avoided electricity drops from $0.15/kWh to $0.10/kWh. The payback period calculation now looks like $150/(372 kWh x $0.10/kWh) = 4 years. Figure 2 illustrates the potential volatility of the payback period due to factors outside of a PA's control, which is why it is a less-than-ideal metric to determine incentives or if an incentive should be offered.

Figure 2. Payback Period Scenarios (Incentives Constant)



If payback period is being considered as a threshold for whether incentives should be offered to mitigate overall portfolio costs, it should be noted that incentives are just one way in which PAs drive participation to their programs. Marketing is another key driver to increasing participation in EE programs. Hypothetically, a PA could increase incentives or marketing as a way to increase participation and increase energy savings numbers. Both strategies impact overall portfolio budget. However, using incentives as a way to encourage more participation results in EE funds flowing back to customers. Limiting incentives or which measures can be offered based on payback period does not inherently change overall portfolio budgets if certain savings targets need to be met.

Throughout the primary and secondary research conducted by Apex, many motivating factors were uncovered for why it may be necessary to provide an incentive for a measure that has a relatively short payback period (defined as 36 months or less). Table 2 below summarizes the various reasons it may be necessary to provide incentives for measures with short payback periods.

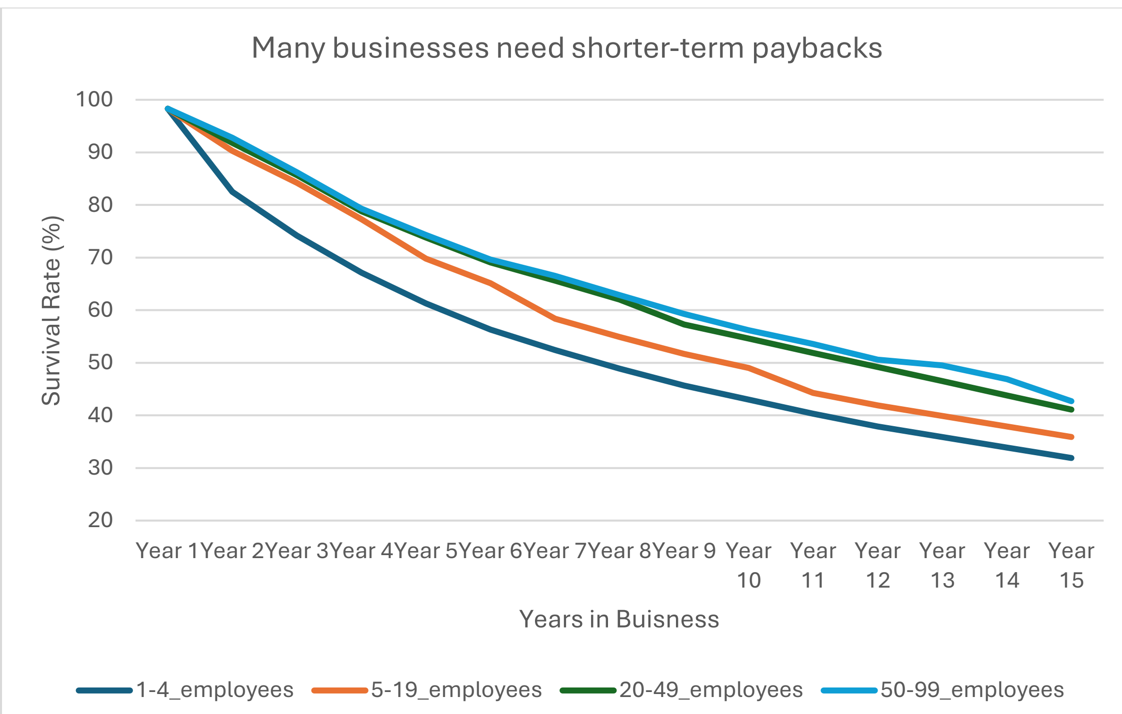
[11] The Henry Hub natural gas price declined from $18.49 on June 01, 2008, to $8.75 on October 1, 2008. This example shows the volatility of commodity process, which eventually impacts electricity prices.

Table 2. Common Need for Incentives

Topic	Justification
Sector/Customer Segment	Certain customer segments, such as small business and low-income, typically need higher incentives due to lack of resources to handle upfront costs.
Maturity of Technology	Customers are less likely to invest in relatively immature technologies because long-term results and performance aren't known.
Technical Awareness	A customer may not be aware of EE opportunities or a measure's performance, so will need an especially attractive incentive to pique their interest.
Program Delivery Model	Turnkey is likely to require higher incentives than an upstream or rebate program, regardless of payback.
Internal Competition for Capital	Even if with a short payback period, customers may have limited capital to deploy.
Energy Efficiency as a Low Priority	Even with a short payback period, if EE is not a priority for an organization or individual, it is more important that the financials are exceedingly strong to make the project move forward.
Tax Treatment of Investment or Equipment	Depreciation treatment of small investments might be treated differently than others, requiring more incentive to make the investment more attractive.
Energy Rates/Volatile Energy Costs	If a customer is unsure how much money they are going to save due to fluctuating commodity prices, they may need higher incentives to ensure they get a reasonable return.
Lack of Necessary Ancillary Equipment	If a customer needs to install new utility metering that has cost in order to implement the EE measure, it may need a higher incentive/shorter payback period to offset the new costs.
Level of Disruption	A measure might be a good financial investment, but if it is highly disruptive, customers may need an even higher incentive to go through the process.
Amount of Time/Effort to Secure Contractors	If additional effort is needed to secure contractors, then a higher return may be necessary.
Equipment Measure Life	Some equipment by nature has a short measure life; the payback period has to be significantly shorter than the equipment's measure life.
Technical Integration with Existing Systems	If a customer needs to upgrade existing systems or update a building management system in order to implement the EE measure, it may need a higher incentive/shorter payback period to offset the other new costs.
Measures That Don't Significantly Impact Bills	For some customers, there may be measures that have meaningful energy savings for the PA, but the customer is so big it is not meaningful to them. Additional incentive(s) may be necessary.

There was a general consensus among the interviewed PAs that payback period was not something explicitly considered in the formation of incentive levels, but it was important for some customers, mainly large C&I customers. PA staff will work with customers that have an internal payback period metric they need to hit in order to move forward with a project. This most commonly comes up in C&I custom programs, where there is some discretion on the incentive level on a project-by-project basis. Interviewees noted that different customers had different payback periods and there was not a single standard. C&I businesses are complex, have different budget cycles, and have other financial considerations that may demand shorter payback periods. Feedback from interviews noted that payback period requirements ranged from one to ten years. Some PAs will not provide incentives for projects with a payback period longer than ten years because it was assumed that the project has other motivations and the incentive would not influence the customer's willingness to move forward with the project. Meanwhile many PAs indicated that C&I customers had competing interests for all their capital investments, not solely energy improvements. PAs indicated that most customers will not install a project with a payback period longer than four years and most customers require a two- to three-year payback period. Figure 3 below shows the rate of survival for new Canadian companies, illustrating that many companies may not last ten or more years and thus highlighting why short payback periods are so critical for many businesses.

Figure 3. Survival Rate of Canadian Businesses by Initial Business Size



Source: Figure 5 Key Small Business Statistics 2019, 2020, 2021 by Innovation, Science, and Economic Development Canada

While payback period was most often mentioned in relation to C&I customers, one interviewee did mention that they believed residential customers made a type of implicit payback period calculation when deciding on EE retrofits. The feedback from the interviewee was that many residential customers don't stay in their home for the assumed lifetime of many measures such as insulation and heating/cooling systems, which can have lifetimes of 20+ years. A customer may not be willing to invest in a measure with a payback period longer than the time the customer is planning to stay in their current home, the logic being that the purchaser of the high-efficiency equipment has to be able to realize the monetary savings from the upgrade or else they may not be interested in pursuing it.

Prioritization Framework

Many different factors can impact the development of an incentive level. Incentive levels are normally based on some combination of incremental cost between the standard and high-efficiency unit, the level of energy savings from the efficient measures based on EM&V studies, and the monetary value of the energy saved from the efficiency measure. These underlying attributes that contribute to incentive calculations need to be updated on a periodic basis and cannot necessarily be updated for every efficiency measure every year due to cost and resource availability. Our research did not uncover a single PA that updates incentive values for every measure on an annual basis. Instead, certain jurisdictions, like Massachusetts, have developed a prioritization framework that helps inform when certain program aspects should be reviewed.[12] While E1 currently utilizes a budget-based prioritization framework to review incentive levels, it may consider reviewing other factors such as those laid out below in order to react to various changing conditions.

- **Importance.** Resources should be focused on those measures that are the most important to the portfolio. Importance could be defined as those measures that have the highest energy or demand savings, have the highest expected future potential savings, are frequently asked about from implementation and service delivery teams, or are highly visible due to stakeholder or regulatory interest.
- **History.** Resources should be focused on measures that have not been updated in a significant amount of time. If the existing information being used is dated and the measure is important as defined above, then that measure should be prioritized for updating the underlying assumptions.
- **Uncertainty.** Measures with uncertain or volatile fundamentals may need to be researched and updated more frequently. If a mature technology has exhibited stable pricing, for example, it may not be necessary to research it as frequently as

[12] https://ma-eeac.org/wp-content/uploads/Exhibit-1-Gas-and-Electric-PAs-Plan-2016-2018-with-App-except-App-U.pdf

other measures. However, if a newer technology with volatile pricing is introduced into the portfolio, it should be reviewed more frequently.

- **Timing**. The lifecycle of the measure should be evaluated when determining whether to expend resources on reviewing it and updating its values. If a measure is likely to be dropped from the portfolio in the near future, it may not make sense to review it. Or, if a measure is too immature to be offered in the portfolio, it similarly may not be worth spending resources reviewing it.

Emerging Trends

The state of California is taking an interesting approach to incentive setting for EE and DSM programs that is worth noting and could potentially serve as a model for E1 at some point in the future. For measures where savings are large enough to be evaluated through a billing analysis, California is moving away from providing prescriptive incentives based off deemed savings values and moving towards paying incentives calculated from close-to-real-time measured performance using advanced metering infrastructure (AMI) data. Instead of paying an upfront incentive based on average savings from the equipment or asset class, California is now using calculated savings from the meter to provide incentives to aggregators and customers. The incentive rate is paid on a per-kWh-saved basis and can be aligned to the value of avoided costs, ensuring that programs are cost-effective. The historical issue with a deemed savings approach for providing incentives is that those savings are more conceptual in nature and based off portfolio wide estimates and not necessarily on specific projects.

One of the main benefits of the California approach is that the EE PAs are able to provide different incentives depending on the value of the service being provided to the grid. Energy and demand reductions that are occurring during peak times may be more valuable than at other times. Calculating savings directly from the meter allows the PAs to time differentiate the savings and pay more for those savings that occur at critical times. This is good for all ratepayers that support EE programs through EE surcharges as it incents aggregators and other EE participants to focus on measures and projects that are most valuable to the grid, which in turn can reduce costs to all ratepayers. However, it does not consider whether the full incentive is needed for motivating the customer to participate.

As more and more jurisdictions increase their efforts to electrify the building thermal sector and other end uses, EE incentives need to be constructed in such a way that they continue to support public policy goals. Traditional EE savings calculations and incentives would potentially penalize a project that increased overall electric usage, but if that project shifted usage away from peak times and resulted in lower overall costs and greenhouse gas emissions then it may still be worth incentivizing that project. EE incentives that encourage electrification and higher electric consumption during times of high renewable output might be broadly beneficial but would need to evolve from the current deemed savings and prescriptive incentive model.

The California model presents some new incentive-related issues that should be considered by any other jurisdiction before implementing something similar. This approach focuses on the value of EE to the grid and less on the value of EE to the customer installing the EE equipment or upgrades. This may result in customer acquisition challenges due to potential issues with the timing of calculating and paying incentives. In the California model, customers are not paid upfront incentives; incentives are paid after performance calculations are complete. This is much different than many existing EE incentive models and may result in some customers shying away from projects if they don't have the upfront capital to spend on the project or are not confident in the savings. To combat this issue, some aggregators and project developers in California are paying half of the anticipated/modeled incentives upfront to customers and then trueing up the remaining portion after the performance calculation is complete. Other contractors are paying customers "at risk" based on the anticipated incentive, which may shift some amount of risk to the contractors.

Another interesting example of emerging incentive design is in Massachusetts, where the EE PAs are paying incentives to commercial new construction buildings striving towards net-zero goals based on target energy use intensity (EUI). Instead of paying incentives based on a per-widget basis, the PAs work with customers to help design their new construction or major renovation project to be ultra-low energy and meet certain EUI thresholds. The PAs then pay an incentive based off a $/square-foot calculation at the end of construction if modeling results show that the building will meet the EUI criteria. There is also an opportunity for customers to earn additional incentives if they provide metering data after a year of occupancy and show that actual usage was below the EUI targets.

Recommendations

Apex's overarching conclusion is that E1 is currently employing many practices that are more rigorous than their peers from an incentive design perspective. E1's documented incentive setting process is detailed and provides clear guidance to Program Managers (PMs) and service delivery staff on how to set incentives for new measures and for updating incentives for existing measures. Interviews with E1 staff confirm that incentive setting practices are in line with processes described by external PAs interviewed by Apex. Based on the totality of Apex's primary and secondary research, it is Apex's opinion that E1's incentive setting methodology is prudent and consistent with or superior to the practices of leading North American peer PAs.

While Apex believes that E1 is a leader in terms of incentive setting practices, our research uncovered additional practices that may benefit E1. This section contains recommendations that E1 may wish to consider.

- **Utilize a decision tree for short payback measures.** Per the Board's Order in docket M10473, E1 must calculate a payback period for all measures being offered. For those measures with a payback period shorter than 36 months, E1 must provide additional justification for why it is appropriate to offer an incentive for that measure. Apex's research and interviews uncovered many reasons why it is still important, and in some instances necessary, to offer an incentive for projects with a payback period shorter than 36 months. Those reasons are described in more detail in Table 2 . When deciding whether or not to offer an incentive for a measure with a payback period shorter than 36 months, E1 should consult Table 2 and determine if there is legitimate justification to offer the incentive.

- **Publicize a version of the ISP document.** Setting incentives for EE and DSM programs can sometimes seem like an opaque process from an external perspective. Interested third parties and stakeholders may not have an understanding of how E1 develops and sets incentives for their DSM programs. However, E1's process goes beyond what Apex found in our research and interviews with other PAs. The process is well documented and supported with spreadsheet tools. E1 may want to consider making a version of the ISP public so that stakeholders can gain a deeper understanding of E1's detailed and standardized process used to develop appropriate incentive levels.
- **Integrate prioritization framework.** As part of the ISP, there is a process to determine which measure incentives to review through the financial simulation tool. The prioritization exercise is based primarily on net savings and achievement vs. plan. However, there may be other reasons to review measure assumptions such as incremental cost or savings values (through third party EM&V studies) that impact incentive levels. E1 may want to consider adopting elements of the Massachusetts EM&V prioritization framework, which focuses on Importance, History, Uncertainty, and Timing. Using these criteria can help E1 determine when and where to expend resources for updating key assumptions.
- **Develop program logic models.** Program logic models can be very helpful for a PA to clearly articulate and define what the program is trying to accomplish, what barriers the program is designed to overcome, and the intended outputs and outcomes from successful delivery of the program. Outcomes are typically classified temporally, with short-term, intermediate, and long-term outcomes mapped against program activities. Leveraging a program logic model can help E1 determine the appropriate type and level of incentive to offer a customer in order to overcome any identified barriers and achieve the desired outcomes.
- **Follow emerging trends.** E1 would benefit from continuing to follow emerging trends in incentive setting and determine if they are relevant for E1, especially trends around using AMI data to pay per-project incentives based on actual savings achieved and for certain C&I projects to transition to paying incentives based on an EUI basis. At some point in the future, E1 should consider whether it is worthwhile to integrate any of these new incentive setting methodologies into their process. Using AMI data to pay a time-differentiated incentive based on savings that occur during peak time period may be especially impactful in helping to lower generation, transmission, and distribution costs.

Additionally, a major finding from Apex's primary and secondary research was an observed lack of standardization in how incentives were set, both within E1 but also with external PAs. This memo represents an effort to document a standardized incentive setting process that can be easily repeated and shared with stakeholders in order to provide an additional layer of transparency to the process. This process is written through the lens of a PM setting incentives for the programs and measures within their individual portfolio, but it is equally applicable for any staff responsible for setting incentives for measures within the wider E1 DSM portfolio.

Apex outlines two proposed complementary processes below, which we have named the Standard Incentive Setting Process and the Exception Process. The Standard Incentive Setting Process should be followed when possible and should serve as the default process when incentives are being set. However, there may be legitimate instances when the Standard Incentive Setting Process is not appropriate and, in those instances, the Exception Process can serve as an alternative method for setting incentives. The Standard Incentive Setting Process is outlined in Figure 4, and the Exception Process is outlined in Figure 5. As part of this process, the Incentive Setting Specialist (ISS) should retain any documentation or workpapers created during the development of incentives.

It should be noted that not all programs require the development of an incentive. Certain programs, such as Direct Install programs, typically pay the full cost of the measure. Vendors that participate in these types of programs are normally selected through a competitive solicitation process that helps maintain cost controls. Once a vendor is selected, measures are installed at a customer's home or facility and E1 is billed at cost for those installations. No direct incentive is set for the end customer in this scenario.

Standard Incentive Setting Process

Step 1: Determine what type of program or measure is being assessed.

The customer's Decision Type (i.e., whether the measure is Replace on Burnout [ROB], New Construction [NEW], or Retrofit [RET]) impacts whether project cost or incremental cost should be used as the basis for setting the incentive. For a RET, or early replacement (ER), Project Cost should be used as the basis for the incentive. From the customer's perspective, the Incremental Cost of the project is the full Project Cost because the counterfactual is to maintain the status quo. In this scenario, there is no immediate need for the customer to upgrade equipment, so the full project cost forms the basis for calculating the incentive needed to motivate the customer to move forward. For new measures, NEW, or ROB measures, Incremental Cost forms the incentive basis. In this scenario, there is an immediate need for the customer to undertake some action (e.g., replace a failed hot water heater) and the incentive is meant to motivate the customer to install the more efficient alternative. The incentive is designed to cover a portion of the incremental cost between the standard and efficient option.

Step 2: Identify the appropriate incentive ranges in the Incentive Matrix.

Apex has developed an Incentive Matrix based on measure and program delivery attributes. Each type of measure (and corresponding Program) is presented in the Incentive Matrix with a range of percentages of either incremental costs or project costs that are typically covered by an incentive in DSM programs. The Incentive Matrix also contains a maximum Upper Limit of incentive that should be offered for a given measure type.[13]

PMs should identify the measure and program attributes in the Incentive Matrix presented in Table 3 that most closely resemble the attributes of the measure they are assessing. This methodology allows for staff to use judgement in setting the incentive percentage within the recommended range while not exceeding the Upper Limit and multiply that percentage by the appropriate incremental or project cost to arrive at an initial dollar incentive value.

Step 3: Compare incentive to historic levels.

This step is critical to ensure there are not unintended disruptions or shocks to the market by unknowingly increasing or decreasing the incentive significantly from historical levels. While significant increases or decreases may be warranted in some cases, it should be done deliberately, with careful consideration of the potential impacts on the marketplace.

If the new incentive is reasonably close to historic levels, staff should proceed to Step 5. If markedly different, Step 4 should be followed. There is not necessarily a defined percentage deviation that should automatically trigger additional review. Rather, this step is to allow the PM an opportunity to use their professional judgement to determine if the new incentive will potentially disrupt the existing marketplace.

Step 4: Discuss alternatives with the ISS and SDM.[14]

If the new incentive value differs significantly from historical values, the PM has several options that they can explore in consultation with the ISS and their SDM.

Option 1: Together, the PM, ISS, and/or SDM may agree to revise the incentive and go back to Step 2 of the process.

Option 2: Together, the PM, ISS, and /or SDM may agree that it is necessary to develop a unique incentive and proceed to the Exception Process. The reasoning for the unique incentive will be documented as part of the Exception Process.

Option 3: Together, the PM, ISS, and/or SDM may determine that the incentive as recommended by the PM is appropriate and proceed to Step 5. In this instance, staff have deliberately and affirmatively determined that it is appropriate to offer an incentive that is significantly different from historic levels and the reasoning should be documented.

[13] The ranges and upper limits were developed by examining over 4,000 measures from different DSM program administrators across multiple years and program types.
[14] Initially the PM should consult with both the ISS and SDM. As the role of the ISS develops, this process may be revisited to determine if it is necessary to consult with the SDM or if it is sufficient to just work with the ISS.

Step 5: Add or subtract from base incentive level.

By this step, the PM has determined a base incentive level and confirmed it is reasonable given historic precedent. It may be appropriate to make alterations to the base incentive level to consider measure or technology specific considerations. Staff may wish to increase the incentive level for newer technologies or for measures with limited historical uptake. Staff may wish to lower the incentive level for mature technologies or if historical participation met or exceeded expectations. Any alterations to the incentive level should be documented. After any alterations are made as part of Step 5, the staff member setting the incentive now has a preliminary incentive level that can be further vetted for appropriateness.

Step 6: Thoroughly vet proposed incentive level.

Validation 1 – Ensure incentive leads to sufficient savings.

The PM will work with members from the E&P team to model expected savings based on participation derived from customer adoption curves in the DSM Plan model. If the proposed incentive level does not result in high enough adoption and therefore savings, staff should return to Step 2 and increase the incentive accordingly.

Validation 2 – Review the incentive in the context of the budget.

Once staff has an estimate of proposed incentive levels and participation levels based on the DSM Plan model, the incentives budget can be calculated. If the proposed incentive leads to a measure or overall program budget that is larger than expected or significantly larger than historical values, the PM should consult with the SDM to see if there is additional budget available for the measure. The PM and SDM may also wish to consult with the Finance team about available budget before staff returns to Step 2 and adjusts the incentive accordingly.

Validation 3 – Ensure the incentive level is in line with incentives from jurisdictional scans.

Staff perform a final check on the reasonableness of the proposed incentive level. This last check could include comparing the proposed incentive to incentives for similar measures in other jurisdictions. The jurisdictional scan may be performed by a third party or by the staff member setting the incentive. If the proposed incentive level is not in line with incentive levels in other jurisdictions, the staff member setting the incentive level may wish to return to Step 2 or consult with the ISS and/or SDM to utilize the Exception Process.

Step 7: Final sign off.

Once all steps have been completed, the PM, SDM, and ISS will all sign off on the incentive level. The ISS will retain all documentation and workpapers related to the setting of the incentive and have them readily available if needed for regulatory purposes.

Figure 4. Standard Incentive Setting Process

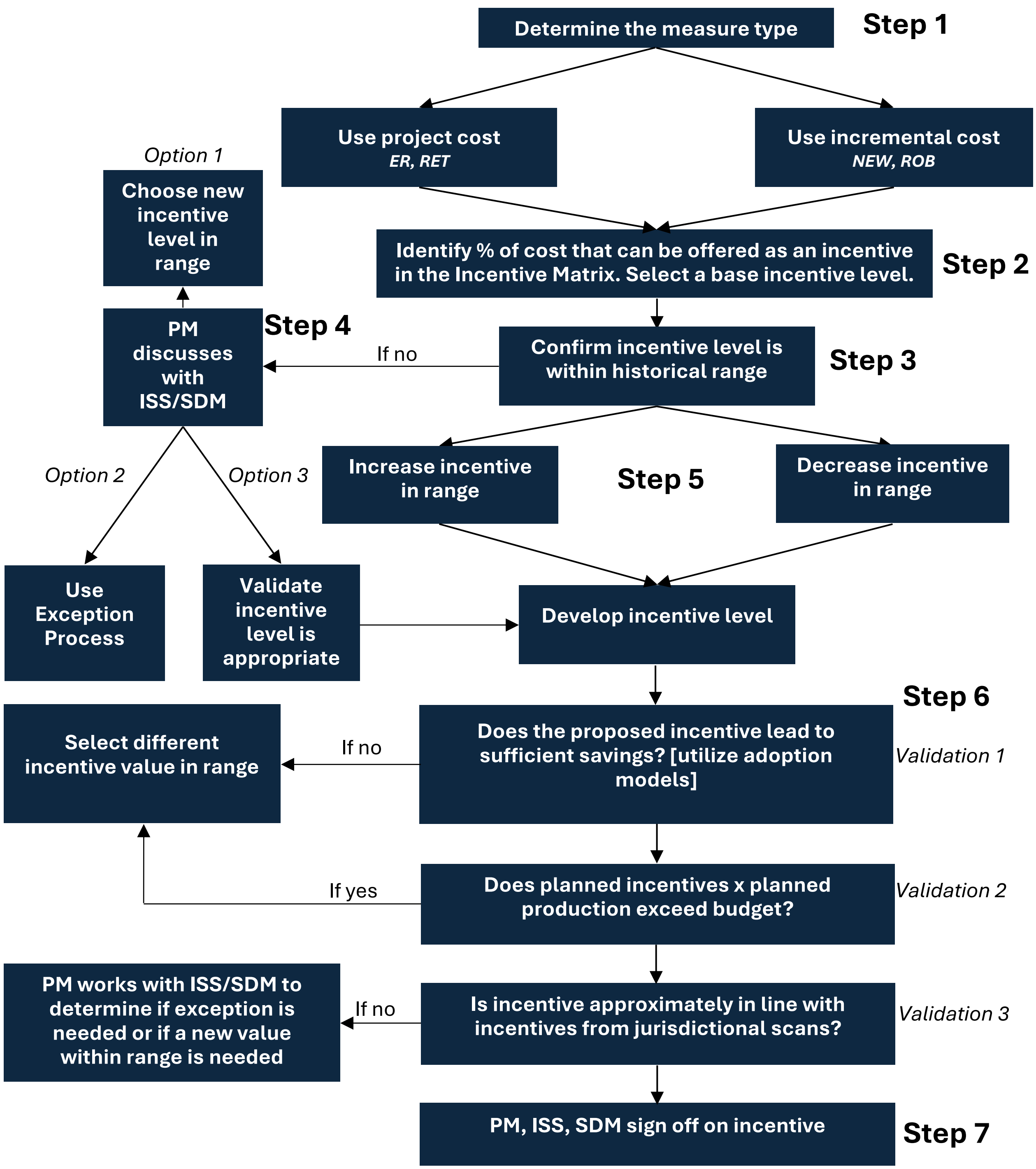


Table 3. Incentive Setting Matrix

Sector	Delivery	Replacement Type	Suggested Basis	Range	Suggested Upper Limit
Res	Rebate	Retrofit	Project Cost	30-75%	100%
Res	Rebate	ROB	Incremental Cost	30-75%	100%
Res	DI	Retrofit	Project Cost	75-100%	100%
Res	DI	ROB	Incremental Cost	75-100%	100%
Large BNI	Rebate	Retrofit	Project Cost	30-80%	90-100%
Large BNI	Rebate	ROB	Incremental Cost	15-100%	90-100%
Small BNI	Rebate	Retrofit	Project Cost	30-75%	90-100%
Small BNI	Rebate	ROB	Incremental Cost	30-75%	90-100%
Small BNI	DI	Retrofit	Project Cost	30-100%	90-100%
Large BNI	Custom	N/A	Project Cost	$.08-$0.25/kWh	70%
Small BNI	Custom	N/A	Project Cost	$0.20-$0.70/kWh	100%
AMH	Rebate	N/A	Project Cost	30-80%	100%

Res = Residential
BNI = Business, Non-Profit, and Institutional
DI = Direct Install
AMH = Affordable Multifamily Housing
ROB = Replace on Burnout

The Small Business Energy Solutions (SBES) program at E1 offers incentives on a $/kWh basis similar to the Large BNI Custom program. Due to this, each project fundamentally has a custom incentive developed for the project based on the measure mix that comprise each individual project. In order to more closely align planning and reporting with how the SBES program is designed and implemented, Apex is recommending the categories shown in Table 4 for planning and to report based on similarly grouped projects.

Table 4. SBES Project Categories

Project Categories	Estimated $/kWh based on 2023
SBES Custom - Agriculture	$0.25
SBES Custom	$0.20
SBES Custom - HVAC	$0.40
SBES Custom - Kitchen	$0.25
SBES Custom - Lighting	$0.40
SBES Custom - Motors	$0.25
SBES Custom - Refrigeration	$0.25
SBES Custom - Water Heating	$0.27

Exception Process

In limited and unique circumstances, the PM, in consultation with the ISS and SDM, may determine that the Standard Incentive Setting Process is not appropriate for the specific measure being evaluated. In these circumstances, it may be appropriate to utilize the Exception Process as defined below. Reasons why the Exception Process may be necessary could include market intelligence or stakeholder feedback indicating that a specific incentive value is necessary to move customers to the efficient measure or that the new value derived through the Standard Incentive Setting Process would be a large departure from the prior incentive value, which in turn would cause a market disruption.

Step 1: PM documents why the Exception Process is being utilized.

The PM should provide a detailed explanation about why the Exception Process was necessary and why the Standard Incentive Setting Process was insufficient.

Step 2: PM documents how the alternative incentive value was developed.

The PM should provide a detailed explanation about how the alternative incentive value derived through the Exception Process was developed. Alternative methodologies could include using historic levels and increasing those values by inflation rates, using proxy values from other similar jurisdictions, using research specific to E1 territory, or using incentive values for similar measures from other E1 or Provincial DSM programs.

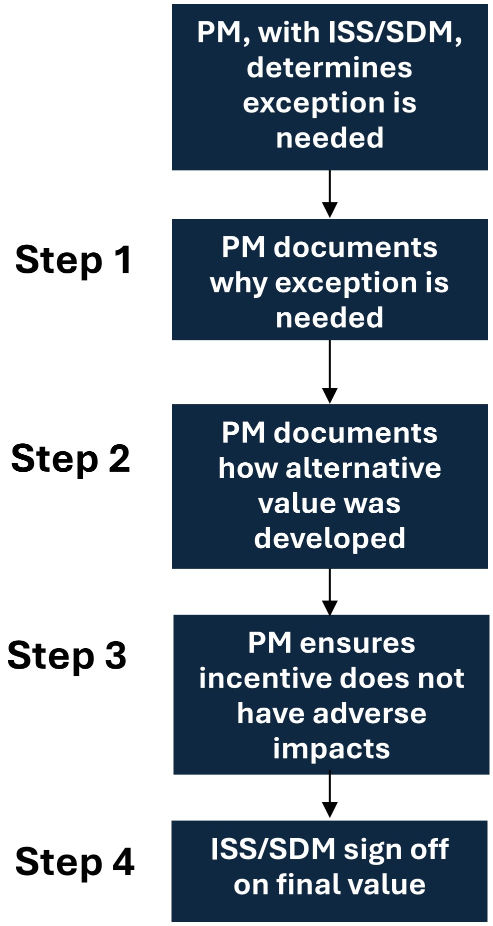
Step 3: PM ensures no unintended adverse impacts.

The PM should consult with the E&P and Regulatory teams and the ISS to ensure that the new proposed incentive level does not inadvertently cause any unintended adverse impacts. Special care should be given to ensure that the proposed incentive level does not exceed budgetary limits or that cost-effectiveness thresholds are violated.

Step 4: Final sign off.

Once all steps have been completed, the PM, the SDM, and the ISS will all sign off on the incentive level. The ISS will retain all documentation and workpapers related to the setting of the incentive and have them readily available if needed for regulatory purposes.

Figure 5. Exception Process



Request IR-12:

Reference: Exhibit E-1, Application, pages 47 and 49/71.

(a) Please provide a table comparing the 2026 DSM Extension to each year of the 2027–2031 Preferred Plan, and to the 2027–2031 five-year total, showing the following information:

i) Total planned expenditures, broken out by major cost category, including at minimum: customer incentives, labour/FTE staffing costs, third-party delivery costs, enabling strategies, evaluation/EM&V, marketing, administration/overhead, and any other material cost category used by E1;

ii) The dollar increase or decrease and percentage increase or decrease in each cost category relative to the 2026 DSM Extension;

iii) The amount of each cost category allocated to each customer class;

iv) The basis/allocator used to allocate each cost category to DSM measures and by extension customer classes, including whether costs are allocated based on forecast participation, forecast savings, direct assignment, rate-class spending, etc.; and

v) Where customer incentive spending increases while FTE staffing or enabling strategy spending decreases, please explain whether and how E1 assessed the impact of those changes on program delivery, customer participation, measure uptake, and realized savings for each affected customer class.

(b) Please explain the allocation methodology used to allocate each category of expenditure to each customer class (and/or program/measure).

Response IR-12:

(a) EfficiencyOne's (E1) Statement of Operations are being provided in Attachments 1, 2, and 3 of this IR response, which outlines the proposed 2027–2031 DSM Plan's anticipated expenses by cost category. Please note that incentives costs include all financial support that is provided to customers. This includes direct incentives, which are provided by measure in the Technical Tables, Attachment 3 and 4 to Appendix A in the 2027-2031 DSM Plan Application, and other third-party costs, for example energy audit costs and other customer support funded by E1. Program support costs include costs related to regulatory primarily, such as the Nova Scotia Energy Board's (NSEB) annual assessment, flow through costs from the Consumer Advocate and their consultants, Small Business Advocate and their consultants, NSEB's counsel and their consultants, and E1's third party DSM consultants.

i) Please refer to Attachment 1 of this IR response.

ii) Please refer to Attachment 2 of this IR response.

iii) Please refer to Attachment 3 of this IR response.

iv) E1 follows the ENSC Cost Allocation Methodology (CAM) as approved by the Board in 2011, for the allocation of expenditures to each program component. All direct costs, for example, incentives, evaluation, and marketing, which are clearly identified by a program component are allocated as the first step. The remaining shared costs are allocated either by the FTE allocator or the Direct allocator. These allocators are assigned to each expense category on the basis of causality. E1's CAM is audited on an annual basis as part of the financial statement audit and subject to regular review by the NSEB.

v) In the development of the DSM Plan, a primary consideration is achievability of the proposed plan. As such, E1 does not believe that the reductions in 2027 to 2031 as compared to 2026 of the FTEs and enabling strategies spending, present a risk to achieving the proposed performance targets.

(b) Estimated investment for the proposed 2027–2031 DSM Plan was allocated to the rate classes using the program component expenditures and did not allocate to rate classes based on the cost category breakdown of expenditures. Please refer to Synapse IR-39 for further details on the rate class spending allocation methodology.

DSM Statement of Operations ($ millions)	2026	% of Total	2027	% of Total	2028	% of Total	2029	% of Total	2030	% of Total	2031	% of Total	2027-2031	% of Total
Direct Costs														
Incentives	$ 41.88	65.7%	$ 46.48	72.9%	$ 46.04	72.2%	$ 44.53	69.8%	$ 43.82	68.7%	$ 44.14	69.2%	$ 225.01	70.6%
Evaluation & Verification	1.25	2.0%	1.23	1.9%	1.22	1.9%	1.23	1.9%	1.24	1.9%	1.19	1.9%	6.10	1.9%
Program Support	2.33	3.7%	0.30	0.5%	0.25	0.4%	1.50	2.4%	1.65	2.6%	0.85	1.3%	4.55	1.4%
	45.46	71.3%	48.01	75.3%	47.51	74.5%	47.25	74.1%	46.71	73.3%	46.18	72.4%	235.66	73.9%
Other Program & Administrative Costs														
Amortization	0.10	0.2%	0.10	0.2%	0.10	0.2%	0.10	0.2%	0.10	0.2%	-	0.0%	0.41	0.1%
Information Technology	1.27	2.0%	1.09	1.7%	1.13	1.8%	1.06	1.7%	1.05	1.7%	1.16	1.8%	5.49	1.7%
Marketing, Outreach, Education & Research	2.60	4.1%	1.92	3.0%	1.92	3.0%	1.80	2.8%	1.83	2.9%	1.79	2.8%	9.26	2.9%
Meetings & Travel	0.23	0.4%	0.10	0.2%	0.10	0.2%	0.10	0.2%	0.10	0.2%	0.11	0.2%	0.51	0.2%
Office & Insurance	0.30	0.5%	0.20	0.3%	0.20	0.3%	0.21	0.3%	0.21	0.3%	0.22	0.3%	1.03	0.3%
Professional Fees & Consulting	1.60	2.5%	0.30	0.5%	0.30	0.5%	0.31	0.5%	0.32	0.5%	0.32	0.5%	1.55	0.5%
Rent	0.30	0.5%	0.32	0.5%	0.32	0.5%	0.32	0.5%	0.32	0.5%	0.32	0.5%	1.60	0.5%
Salaries & Benefits	11.59	18.2%	11.52	18.1%	11.96	18.8%	12.40	19.4%	12.90	20.2%	13.44	21.1%	62.21	19.5%
Training & Development	0.30	0.5%	0.20	0.3%	0.20	0.3%	0.21	0.3%	0.21	0.3%	0.22	0.3%	1.03	0.3%
	18.29	28.7%	15.74	24.7%	16.24	25.5%	16.50	25.9%	17.04	26.7%	17.56	27.6%	83.09	26.1%
Total Costs	**$ 63.75**		**$ 63.75**		**$ 63.75**		**$ 63.75**		**$ 63.75**		**$ 63.75**		**$ 318.75**	

DSM Statement of Operations ($ millions)																
	2026	**2027**	**Variance Prior Year**	**% Change**	**2028**	**Variance Prior Year**	**% Change**	**2029**	**Variance Prior Year**	**% Change**	**2030**	**Variance Prior Year**	**% Change**	**2031**	**Variance Prior Year**	**% Change**
Direct Costs																
Incentives	$ 41.88	$ 46.48	4.60	11%	$ 46.04	(0.44)	-1%	$ 44.53	(1.51)	-3%	$ 43.82	(0.71)	-2%	$ 44.14	0.32	1%
Evaluation & Verification	1.25	1.23	(0.02)	-2%	1.22	(0.01)	0%	1.23	0.01	0%	1.24	0.01	1%	1.19	(0.05)	-4%
Program Support	2.33	0.30	(2.03)	-87%	0.25	(0.05)	-17%	1.50	1.25	500%	1.65	0.15	10%	0.85	(0.80)	-48%
	45.46	48.01	2.54	6%	47.51	(0.50)	-1%	47.25	(0.25)	-1%	46.71	(0.55)	-1%	46.18	(0.53)	-1%
Other Program & Administrative Costs																
Amortization	0.10	0.10	0.00	2%	0.10	(0.00)	0%	0.10	-	0%	0.10	-	0%	-	(0.10)	-100%
Information Technology	1.27	1.09	(0.18)	-15%	1.13	0.04	4%	1.06	(0.07)	-6%	1.05	(0.00)	0%	1.16	0.11	10%
Marketing, Outreach, Education & Research	2.60	1.92	(0.68)	-26%	1.92	(0.00)	0%	1.80	(0.12)	-6%	1.83	0.03	2%	1.79	(0.04)	-2%
Meetings & Travel	0.23	0.10	(0.13)	-58%	0.10	0.00	2%	0.10	0.00	2%	0.10	0.00	2%	0.11	0.00	2%
Office & Insurance	0.30	0.20	(0.10)	-34%	0.20	0.00	2%	0.21	0.00	2%	0.21	0.00	2%	0.22	0.00	2%
Professional Fees & Consulting	1.60	0.30	(1.30)	-81%	0.30	0.01	2%	0.31	0.01	2%	0.32	0.01	2%	0.32	0.01	2%
Rent	0.30	0.32	0.02	7%	0.32	(0.00)	0%	0.32	-	0%	0.32	-	0%	0.32	-	0%
Salaries & Benefits	11.59	11.52	(0.07)	-1%	11.96	0.44	4%	12.40	0.44	4%	12.90	0.50	4%	13.44	0.54	4%
Training & Development	0.30	0.20	(0.10)	-34%	0.20	0.00	2%	0.21	0.00	2%	0.21	0.00	2%	0.22	0.00	2%
	18.29	15.74	(2.55)	-14%	16.24	0.50	3%	16.50	0.25	2%	17.04	0.55	3%	17.56	0.53	3%
Total Costs	**$ 63.75**	**$ 63.75**			**$ 63.75**			**$ 63.75**			**$ 63.75**			**$ 63.75**		

DSM Statement of Operations ($ millions) by Program Component by Year																			
	2026	**Instant Savings**	**Affordable Multifamily**	**Affordable Single Family**	**Efficient Product Installation**	**Residential Behaviour**	**Home Energy Assessment**	**MHEEP**	**Advanced New Homes**	**Business Energy Rebates**	**Custom**	**SEM**	**Solar**	**Small Business Energy Solutions**	**Education & Outreach**	**Dev't & Research**	**Other Enabling**	**Market Transformation**	**Demand Response**
Direct Costs																			
Incentives	$ 41.88	$ 1.76	$ 1.40	$ 6.95	$ 4.60	$ 1.30	$ 4.14	$ 0.78	$ -	$ 5.57	$ 6.03	$ 0.61	$ -	$ 3.64	$ -	$ -	$ -	$ -	$ 5.09
Evaluation & Verification	1.35	0.06	0.03	0.08	0.12	0.11	0.04	0.03	-	0.14	0.31	0.06	-	0.13	-	-	-	0.10	0.13
Program Support	2.33	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.98	1.35	-	-
	45.56	1.83	1.43	7.03	4.72	1.42	4.18	0.82	-	5.71	6.33	0.67	-	3.77	-	0.98	1.35	0.10	5.22
Other Program & Administrative Costs																			
Amortization	-																		
Information Technology	1.27	0.05	0.03	0.05	0.04	0.04	0.05	0.02	-	0.16	0.26	0.02	-	0.14	0.08	0.04	0.11	0.03	0.16
Marketing, Outreach, Education & Research	2.53	0.08	0.06	0.04	0.09	0.12	0.08	0.04	-	0.36	0.10	0.02	-	0.15	0.65	0.13	-	0.30	0.31
Meetings & Travel	0.23	0.01	0.00	0.01	0.01	0.01	0.01	0.00	-	0.03	0.05	0.00	-	0.03	0.01	0.01	0.02	0.00	0.03
Office & Insurance	0.34	0.01	0.01	0.01	0.01	0.01	0.01	0.01	-	0.04	0.07	0.00	-	0.04	0.02	0.01	0.03	0.01	0.04
Professional Fees & Consulting	1.61	0.06	0.03	0.06	0.05	0.05	0.07	0.03	-	0.20	0.33	0.02	-	0.18	0.10	0.05	0.14	0.03	0.21
Rent	0.30	0.01	0.01	0.01	0.01	0.01	0.01	0.01	-	0.04	0.06	0.00	-	0.03	0.02	0.01	0.03	0.01	0.04
Salaries & Benefits	11.60	0.44	0.24	0.42	0.35	0.37	0.49	0.20	-	1.42	2.39	0.17	-	1.31	0.70	0.34	1.01	0.24	1.49
Training & Development	0.32	0.01	0.01	0.01	0.01	0.01	0.01	0.01	-	0.04	0.07	0.00	-	0.04	0.02	0.01	0.03	0.01	0.04
	18.19	0.67	0.39	0.61	0.56	0.62	0.74	0.31	-	2.28	3.34	0.25	-	1.92	1.59	0.59	1.37	0.62	2.32
Total Costs	**$ 63.75**	**$ 2.50**	**$ 1.82**	**$ 7.64**	**$ 5.28**	**$ 2.04**	**$ 4.92**	**$ 1.13**	**$ -**	**$ 7.99**	**$ 9.67**	**$ 0.92**	**$ -**	**$ 5.69**	**$ 1.59**	**$ 1.57**	**$ 2.72**	**$ 0.72**	**$ 7.54**
Direct FTEs	66.3	2.5	1.4	2.4	2.0	2.1	2.8	1.2	-	8.1	13.7	1.0	-	7.5	4.0	1.9	5.8	1.4	8.5

DSM Statement of Operations ($ millions) by Program Component by Year	2027	Instant Savings	Affordable Multifamily	Affordable Single Family	Efficient Product Installation	Residential Behaviour	Home Energy Assessment	MHEEP	Advanced New Homes	Business Energy Rebates	Custom	SEM	Solar	Small Business Energy Solutions	Education & Outreach	Dev't & Research	Other Enabling	Market Transformation	Demand Response
Direct Costs																			
Incentives	$ 46.48	$ 1.57	$ 1.35	$ 8.39	$ 6.56	$ -	$ 2.52	$ 0.29	$ 0.01	$ 2.21	$ 13.31	$ 0.74	$ -	$ 4.97	$ 0.03	$ 0.54	$ -	$ -	$ 3.99
Evaluation & Verification	1.23	0.07	0.07	0.07	0.04	-	0.13	0.04	-	0.18	0.31	0.08	-	0.04	-	-	-	0.05	0.15
Program Support	0.30	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.30	-	-
	48.01	1.64	1.42	8.46	6.60	-	2.65	0.33	0.01	2.39	13.62	0.82	-	5.01	0.03	0.54	0.30	0.05	4.14
Other Program & Administrative Costs																			
Amortization	0.10	0.00	0.00	0.00	0.00	-	0.00	0.00	0.00	0.01	0.03	0.00	-	0.01	0.01	0.00	0.01	0.00	0.01
Information Technology	1.09	0.03	0.04	0.04	0.04	-	0.04	0.01	0.02	0.12	0.28	0.02	-	0.12	0.06	0.04	0.10	0.04	0.09
Marketing, Outreach, Education & Research	1.92	0.20	0.03	0.04	0.18	-	0.13	0.03	0.03	0.22	0.05	0.02	-	0.20	0.38	0.16	-	0.22	0.06
Meetings & Travel	0.10	0.00	0.00	0.00	0.00	-	0.00	0.00	0.00	0.01	0.03	0.00	-	0.01	0.01	0.00	0.01	0.00	0.01
Office & Insurance	0.20	0.01	0.01	0.01	0.01	-	0.01	0.00	0.00	0.02	0.05	0.00	-	0.02	0.01	0.01	0.02	0.01	0.02
Professional Fees & Consulting	0.30	0.01	0.01	0.01	0.01	-	0.01	0.00	0.00	0.03	0.08	0.01	-	0.03	0.02	0.01	0.03	0.01	0.02
Rent	0.32	0.01	0.01	0.01	0.01	-	0.01	0.00	0.01	0.04	0.08	0.01	-	0.04	0.02	0.01	0.03	0.01	0.03
Salaries & Benefits	11.52	0.32	0.42	0.42	0.42	-	0.42	0.13	0.18	1.27	2.97	0.24	-	1.27	0.64	0.45	1.02	0.39	0.95
Training & Development	0.20	0.01	0.01	0.01	0.01	-	0.01	0.00	0.00	0.02	0.05	0.00	-	0.02	0.01	0.01	0.02	0.01	0.02
	15.74	0.58	0.53	0.55	0.68	-	0.64	0.18	0.24	1.74	3.61	0.31	-	1.72	1.14	0.71	1.22	0.68	1.20
Total Costs	**$ 63.75**	**$ 2.23**	**$ 1.95**	**$ 9.01**	**$ 7.28**	**$ -**	**$ 3.29**	**$ 0.50**	**$ 0.25**	**$ 4.13**	**$ 17.23**	**$ 1.12**	**$ -**	**$ 6.73**	**$ 1.18**	**$ 1.25**	**$ 1.52**	**$ 0.73**	**$ 5.34**
Direct FTEs	54.3	1.5	2.0	2.0	2.0	-	2.0	0.6	0.9	6.0	14.0	1.1	-	6.0	3.0	2.1	4.8	1.8	4.5

DSM Statement of Operations ($ millions) by Program Component by Year	2028	Instant Savings	Affordable Multifamily	Affordable Single Family	Efficient Product Installation	Residential Behaviour	Home Energy Assessment	MHEEP	Advanced New Homes	Business Energy Rebates	Custom	SEM	Solar	Small Business Energy Solutions	Education & Outreach	Dev't & Research	Other Enabling	Market Transformation	Demand Response
Direct Costs																			
Incentives	$ 46.04	$ 2.63	$ 1.90	$ 8.02	$ 6.80		$ 3.21	$ -	$ 0.88	$ 2.26	$ 9.29	$ 0.74	$ 0.55	$ 5.00	$ 0.03	$ 0.59	$ -	$ -	$ 4.13
Evaluation & Verification	1.22	0.05	0.05	0.04	0.04		0.06	0.04	0.05	0.16	0.36	0.08	0.01	0.07	-	-	-	0.05	0.16
Program Support	0.25	-	-	-	-		-	-	-	-	-	-	-	-	-	-	0.25	-	-
	47.50	2.68	1.95	8.06	6.84	-	3.27	0.04	0.93	2.42	9.65	0.82	0.56	5.07	0.03	0.59	0.25	0.05	4.29
Other Program & Administrative Costs																			
Amortization	0.10	0.00	0.00	0.00	0.00		0.00	-	0.00	0.01	0.03	0.00	0.00	0.01	0.01	0.00	0.01	0.00	0.01
Information Technology	1.13	0.03	0.04	0.04	0.04		0.04	-	0.02	0.12	0.29	0.02	0.01	0.12	0.06	0.04	0.10	0.04	0.09
Marketing, Outreach, Education & Research	1.92	0.20	0.03	0.02	0.18		0.13	0.02	0.03	0.23	0.05	0.02	-	0.20	0.39	0.16	-	0.21	0.06
Meetings & Travel	0.10	0.00	0.00	0.00	0.00		0.00	-	0.00	0.01	0.03	0.00	0.00	0.01	0.01	0.00	0.01	0.00	0.01
Office & Insurance	0.20	0.01	0.01	0.01	0.01		0.01	-	0.00	0.02	0.05	0.00	0.00	0.02	0.01	0.01	0.02	0.01	0.02
Professional Fees & Consulting	0.30	0.01	0.01	0.01	0.01		0.01	-	0.00	0.03	0.08	0.01	0.00	0.03	0.02	0.01	0.03	0.01	0.03
Rent	0.32	0.01	0.01	0.01	0.01		0.01	-	0.01	0.04	0.08	0.01	0.00	0.04	0.02	0.01	0.03	0.01	0.03
Salaries & Benefits	11.97	0.33	0.44	0.44	0.44		0.44	-	0.19	1.32	3.08	0.25	0.15	1.32	0.66	0.47	1.06	0.39	0.99
Training & Development	0.20	0.01	0.01	0.01	0.01		0.01	-	0.00	0.02	0.05	0.00	0.00	0.02	0.01	0.01	0.02	0.01	0.02
	16.25	0.60	0.55	0.55	0.70	-	0.66	0.02	0.25	1.81	3.74	0.32	0.18	1.78	1.18	0.73	1.27	0.68	1.24
Total Costs	**$ 63.75**	**$ 3.28**	**$ 2.50**	**$ 8.61**	**$ 7.55**		**$ 3.93**	**$ 0.06**	**$ 1.18**	**$ 4.23**	**$ 13.39**	**$ 1.14**	**$ 0.75**	**$ 6.85**	**$ 1.21**	**$ 1.32**	**$ 1.52**	**$ 0.73**	**$ 5.53**
Direct FTEs	54.4	1.5	2.0	2.0	2.0		2.0	-	0.9	6.0	14.0	1.1	0.7	6.0	3.0	2.1	4.8	1.8	4.5

DSM Statement of Operations ($ millions) by Program Component by Year	2029	Instant Savings	Affordable Multifamily	Affordable Single Family	Efficient Product Installation	Residential Behaviour	Home Energy Assessment	MHEEP	Advanced New Homes	Business Energy Rebates	Custom	SEM	Solar	Small Business Energy Solutions	Education & Outreach	Dev't & Research	Other Enabling	Market Transformation	Demand Response
Direct Costs																			
Incentives	$ 44.53	$ 4.13	$ 1.72	$ 8.31	$ 7.04		$ 4.67	$ -	$ 0.89	$ 1.60	$ 7.04	$ 0.75	$ 0.55	$ 2.85	$ 0.03	$ 0.57	$ -	$ -	$ 4.37
Evaluation & Verification	1.23	0.05	0.04	0.08	0.05		0.09	-	0.05	0.18	0.31	0.08	0.01	0.07	-	-	-	0.05	0.16
Program Support	1.50	-	-	-	-		-	-	-	-	-	-	-	-	-	-	1.50	-	-
	47.25	4.18	1.76	8.39	7.09	-	4.76	-	0.94	1.78	7.35	0.83	0.56	2.92	0.03	0.57	1.50	0.05	4.53
Other Program & Administrative Costs																			
Amortization	0.10	0.00	0.00	0.00	0.00		0.00	-	0.00	0.01	0.03	0.00	0.00	0.01	0.01	0.00	0.01	0.00	0.01
Information Technology	1.06	0.03	0.04	0.04	0.04		0.04	-	0.02	0.12	0.27	0.02	0.01	0.12	0.06	0.04	0.09	0.03	0.09
Marketing, Outreach, Education & Research	1.80	0.21	0.03	0.02	0.18		0.13	-	0.03	0.08	0.05	0.02	0.01	0.20	0.42	0.16	-	0.21	0.06
Meetings & Travel	0.10	0.00	0.00	0.00	0.00		0.00	-	0.00	0.01	0.03	0.00	0.00	0.01	0.01	0.00	0.01	0.00	0.01
Office & Insurance	0.21	0.01	0.01	0.01	0.01		0.01	-	0.00	0.02	0.05	0.00	0.00	0.02	0.01	0.01	0.02	0.01	0.02
Professional Fees & Consulting	0.31	0.01	0.01	0.01	0.01		0.01	-	0.00	0.03	0.08	0.01	0.00	0.03	0.02	0.01	0.03	0.01	0.03
Rent	0.32	0.01	0.01	0.01	0.01		0.01	-	0.01	0.04	0.08	0.01	0.00	0.04	0.02	0.01	0.03	0.01	0.03
Salaries & Benefits	12.40	0.34	0.46	0.46	0.46		0.46	-	0.19	1.37	3.19	0.26	0.16	1.37	0.68	0.49	1.09	0.40	1.03
Training & Development	0.21	0.01	0.01	0.01	0.01		0.01	-	0.00	0.02	0.05	0.00	0.00	0.02	0.01	0.01	0.02	0.01	0.02
	16.50	0.61	0.57	0.56	0.72	-	0.67	-	0.26	1.70	3.83	0.32	0.20	1.82	1.23	0.74	1.30	0.69	1.28
Total Costs	**$ 63.75**	**$ 4.79**	**$ 2.33**	**$ 8.96**	**$ 7.80**		**$ 5.43**	**$ -**	**$ 1.20**	**$ 3.48**	**$ 11.19**	**$ 1.16**	**$ 0.76**	**$ 4.74**	**$ 1.27**	**$ 1.31**	**$ 2.80**	**$ 0.74**	**$ 5.81**
Direct FTEs	54.4	1.5	2.0	2.0	2.0	-	2.0	-	0.9	6.0	14.0	1.1	0.7	6.0	3.0	2.1	4.8	1.8	4.5

DSM Statement of Operations ($ millions) by Program Component by Year

	2030	Instant Savings	Affordable Multifamily	Affordable Single Family	Efficient Product Installation	Residential Behaviour	Home Energy Assessment	MHEEP	Advanced New Homes	Business Energy Rebates	Custom	SEM	Solar	Small Business Energy Solutions	Education & Outreach	Dev't & Research	Other Enabling	Market Transformation	Demand Response
Direct Costs																			
Incentives	$ 43.83	$ 4.40	$ 1.75	$ 7.94	$ 7.52		$ 4.77	$ -	$ 0.88	$ 1.22	$ 6.44	$ 0.58	$ 0.50	$ 2.62	$ 0.04	$ 0.52	$ -	$ -	$ 4.66
Evaluation & Verification	1.24	0.05	0.04	0.04	0.09		0.13	-	0.05	0.16	0.32	0.08	0.01	0.04	-	-	-	0.05	0.16
Program Support	1.65	-	-	-	-		-	-	-	-	-	-	-	-	-	-	1.65	-	-
	46.72	4.45	1.79	7.98	7.61	-	4.90	-	0.93	1.38	6.76	0.66	0.51	2.66	0.04	0.52	1.65	0.05	4.82
Other Program & Administrative Costs																			
Amortization	0.10	0.00	0.00	0.00	0.00		0.00	-	0.00	0.01	0.03	0.00	0.00	0.01	0.01	0.00	0.01	0.00	0.01
Information Technology	1.05	0.03	0.04	0.04	0.04		0.04	-	0.02	0.12	0.27	0.02	0.01	0.12	0.06	0.04	0.09	0.03	0.09
Marketing, Outreach, Education & Research	1.82	0.19	0.03	0.04	0.18		0.13	-	0.03	0.08	0.04	0.02	0.01	0.20	0.47	0.16	-	0.19	0.06
Meetings & Travel	0.10	0.00	0.00	0.00	0.00		0.00	-	0.00	0.01	0.03	0.00	0.00	0.01	0.01	0.00	0.01	0.00	0.01
Office & Insurance	0.21	0.01	0.01	0.01	0.01		0.01	-	0.00	0.02	0.05	0.00	0.00	0.02	0.01	0.01	0.02	0.01	0.02
Professional Fees & Consulting	0.32	0.01	0.01	0.01	0.01		0.01	-	0.00	0.03	0.08	0.01	0.00	0.03	0.02	0.01	0.03	0.01	0.03
Rent	0.32	0.01	0.01	0.01	0.01		0.01	-	0.01	0.04	0.08	0.01	0.00	0.04	0.02	0.01	0.03	0.01	0.03
Salaries & Benefits	12.90	0.36	0.47	0.47	0.47		0.47	-	0.20	1.42	3.32	0.27	0.17	1.42	0.71	0.51	1.14	0.42	1.07
Training & Development	0.21	0.01	0.01	0.01	0.01		0.01	-	0.00	0.02	0.05	0.00	0.00	0.02	0.01	0.01	0.02	0.01	0.02
	17.03	0.61	0.59	0.60	0.74	-	0.69	-	0.26	1.76	3.96	0.34	0.21	1.87	1.31	0.76	1.34	0.68	1.32
Total Costs	**$ 63.75**	**$ 5.06**	**$ 2.38**	**$ 8.58**	**$ 8.35**	**$ -**	**$ 5.60**	**$ -**	**$ 1.19**	**$ 3.14**	**$ 10.71**	**$ 1.00**	**$ 0.72**	**$ 4.54**	**$ 1.35**	**$ 1.28**	**$ 2.99**	**$ 0.73**	**$ 6.14**
Direct FTEs	54.4	1.5	2.0	2.0	2.0		2.0	-	0.9	6.0	14.0	1.1	0.7	6.0	3.0	2.1	4.8	1.8	4.5

DSM Statement of Operations ($ millions) by Program Component by Year	2031	Instant Savings	Affordable Multifamily	Affordable Single Family	Efficient Product Installation	Residential Behaviour	Home Energy Assessment	MHEEP	Advanced New Homes	Business Energy Rebates	Custom	SEM	Solar	Small Business Energy Solutions	Education & Outreach	Dev't & Research	Other Enabling	Market Transformation	Demand Response
Direct Costs																			
Incentives	$ 44.14	$ 4.53	$ 1.52	$ 7.96	$ 7.78		$ 5.41	$ -	$ 0.86	$ 1.31	$ 5.65	$ 0.59	$ 0.40	$ 2.66	$ 0.04	$ 0.53	$ -	$ -	$ 4.91
Evaluation & Verification	1.19	0.05	0.04	0.04	0.05		0.06	-	0.05	0.16	0.32	0.09	0.01	0.04	-	-	-	0.10	0.17
Program Support	0.85	-	-	-	-		-	-	-	-	-	-	-	-	-	-	0.85	-	-
	46.18	4.58	1.56	8.00	7.83	-	5.47	-	0.91	1.47	5.97	0.68	0.41	2.70	0.04	0.53	0.85	0.10	5.08
Other Program & Administrative Costs																			
Amortization	-	-	-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-
Information Technology	1.16	0.03	0.04	0.04	0.04		0.04	-	0.02	0.13	0.30	0.02	0.01	0.13	0.06	0.05	0.10	0.04	0.10
Marketing, Outreach, Education & Research	1.79	0.21	0.03	0.02	0.18		0.07	-	0.03	0.08	0.04	0.02	0.01	0.20	0.68	0.16	-	-	0.06
Meetings & Travel	0.11	0.00	0.00	0.00	0.00		0.00	-	0.00	0.01	0.03	0.00	0.00	0.01	0.01	0.00	0.01	0.00	0.01
Office & Insurance	0.22	0.01	0.01	0.01	0.01		0.01	-	0.00	0.02	0.06	0.00	0.00	0.02	0.01	0.01	0.02	0.01	0.02
Professional Fees & Consulting	0.32	0.01	0.01	0.01	0.01		0.01	-	0.01	0.04	0.08	0.01	0.00	0.04	0.02	0.01	0.03	0.01	0.03
Rent	0.32	0.01	0.01	0.01	0.01		0.01	-	0.01	0.04	0.08	0.01	0.00	0.04	0.02	0.01	0.03	0.01	0.03
Salaries & Benefits	13.44	0.37	0.49	0.49	0.49		0.49	-	0.21	1.48	3.46	0.28	0.17	1.48	0.74	0.53	1.19	0.43	1.11
Training & Development	0.21	0.01	0.01	0.01	0.01		0.01	-	0.00	0.02	0.06	0.00	0.00	0.02	0.01	0.01	0.02	0.01	0.02
	17.56	0.65	0.61	0.60	0.76		0.66	-	0.27	1.82	4.10	0.35	0.21	1.94	1.55	0.78	1.39	0.51	1.37
Total Costs	**$ 63.75**	**$ 5.23**	**$ 2.17**	**$ 8.60**	**$ 8.58**		**$ 6.13**	**$ -**	**$ 1.18**	**$ 3.29**	**$ 10.07**	**$ 1.02**	**$ 0.62**	**$ 4.64**	**$ 1.58**	**$ 1.31**	**$ 2.24**	**$ 0.61**	**$ 6.44**
Direct FTEs	54.4	1.5	2.0	2.0	2.0		2.0	-	0.9	6.0	14.0	1.1	0.7	6.0	3.0	2.1	4.8	1.8	4.5

IG Request IR-13:

Reference: Exhibit E-1, Application, Table 9 (Program Budgets), page 58/71; and Appendix B, Attachment 2.

Preamble: Table 9 of the Application presents Enabling Strategies (ES) spending of $29.1M over 2027–2031 without benefits or savings attributed to any specific rate class.

Please provide:

(a) The specific allocator(s) used to apportion each category of Enabling Strategies spending (Education & Outreach; Development & Research; Other Enabling Strategies; Market Transformation) across rate classes, and confirmation of whether the same allocator is used for all ES sub-categories;

(b) A quantified mapping of each ES activity or sub-category to the expected direct or indirect benefits for Medium Industrial and Large Industrial customers specifically;

(c) Any metrics or key performance indicators E1 uses or proposes to use to track and report on the benefits delivered by Enabling Strategies to each rate class;

(d) E1's position on whether the allocation of Enabling Strategies costs is consistent with the "beneficiary pays" principle that is stated to govern the allocation of program costs, and, if E1 considers ES to be an exception, a full justification; and

(e) The dollar amounts allocated to Medium Industrial and Large Industrial for each ES sub-category for each year of the Plan period.

Response IR-13:

(a) Enabling Strategies costs for the Development and Research and Other Enabling Strategies categories were allocated to the rate classes according to the percentage of total program costs each rate class represents. Industrial rate classes (Small, Medium, and Large) were excluded from the costs associated with the Education and Outreach category as those activities are primarily focused on residential and non-industrial BNI customers; and the Market Transformation category is allocated 100% to the Residential rate class, as that sector is the focus of market transformation activities. The specific percentage allocators used for costs associated with each Enabling Strategies category are detailed in Tables 1-4.

Table 1: Enabling Strategies Allocators for Education and Outreach Category

Year	Residential	Small General	General	Large General	Small Industrial	Medium Industrial	Large Industrial	Municipal	Unmetered	TOTAL
2027	54%	6%	36%	3%	0%	0%	0%	1%	0%	**100%**
2028	59%	6%	32%	3%	0%	0%	0%	1%	0%	**100%**
2029	67%	5%	25%	2%	0%	0%	0%	1%	0%	**100%**
2030	68%	4%	24%	2%	0%	0%	0%	1%	0%	**100%**
2031	69%	4%	23%	2%	0%	0%	0%	1%	0%	**100%**

Table 2: Enabling Strategies Allocators for Development and Research Category

Year	Residential	Small General	General	Large General	Small Industrial	Medium Industrial	Large Industrial	Municipal	Unmetered	TOTAL
2027	47%	5%	31%	3%	3%	2%	8%	1%	0%	**100%**
2028	52%	5%	28%	2%	2%	2%	7%	1%	0%	**100%**
2029	60%	4%	23%	2%	2%	2%	6%	1%	0%	**100%**
2030	61%	4%	22%	2%	2%	2%	6%	1%	0%	**100%**
2031	63%	4%	21%	2%	2%	2%	6%	1%	0%	**100%**

Table 3: Enabling Strategies Allocators for Other Enabling Strategies Category

Year	Residential	Small General	General	Large General	Small Industrial	Medium Industrial	Large Industrial	Municipal	Unmetered	TOTAL
2027	47%	5%	31%	3%	3%	2%	8%	1%	0%	**100%**
2028	52%	5%	28%	2%	2%	2%	7%	1%	0%	**100%**
2029	60%	4%	23%	2%	2%	2%	6%	1%	0%	**100%**
2030	61%	4%	22%	2%	2%	2%	6%	1%	0%	**100%**
2031	63%	4%	21%	2%	2%	2%	6%	1%	0%	**100%**

Table 4: Enabling Strategies Allocators for Market Transformation Category

Year	Residential	Small General	General	Large General	Small Industrial	Medium Industrial	Large Industrial	Municipal	Unmetered	TOTAL
2027	100%	0%	0%	0%	0%	0%	0%	0%	0%	**100%**
2028	100%	0%	0%	0%	0%	0%	0%	0%	0%	**100%**
2029	100%	0%	0%	0%	0%	0%	0%	0%	0%	**100%**
2030	100%	0%	0%	0%	0%	0%	0%	0%	0%	**100%**
2031	100%	0%	0%	0%	0%	0%	0%	0%	0%	**100%**

Allocators are applied at the Enabling Strategies category level and not to the individual sub-categories (areas of focus) that roll up into the four Enabling Strategies categories.

(b) The Other Enabling Strategies category encompasses all regulatory costs associated with the development and execution of DSM Plans and E1's participation in regulatory matters and proceedings. As a public utility regulated by the Nova Scotia Energy Board (NSEB), E1's regulatory costs are a required part of its operation, and those costs are allocated to each rate class according to the percentage of total program costs each rate class represents. The Development and Research category encompasses activities – innovation, codes and standards, research, data and analytics support, and program harmonization – are designed to serve all rate classes, and costs are allocated to each rate class according to the percentage of total program costs each rate class represents.

(c) While not specific to rate classes, E1 reports on its Enabling Strategies activities in its quarterly and annual DSM reports. In 2025, E1 enhanced its Enabling Strategies quarterly and annual reporting to include forecast and year-to-date spending by Enabling Strategies categories and discussion about variances to Plan, consistent with the process for other programs (energy efficiency and demand response). This enhanced reporting will continue throughout the 2027–2031 Plan period. E1 will also provide updates in its annual reports on the measures of success identified for each area of focus in the 2027–2031 Preferred Plan.

(d) E1's position is that the allocation of Enabling Strategies is consistent with the "beneficiary pays" principle.

(e) Allocators are applied at the Enabling Strategies category level and not to the individual sub-categories (areas of focus) that roll up into the four Enabling Strategies categories. However, to respond to this IR, costs by area of focus have been estimated by applying the appropriate category-level allocators for the Medium Industrial and Large Industrial rate classes to the respective areas of focus. As detailed in (a), no expenditures from the Education and Outreach and the Market Transformation categories (and their respective sub-categories) are allocated to the Medium Industrial and Large Industrial rate classes in the 207-2031 Plan period. The total expenditures from the Development and Research, and Other Enabling Strategies categories that are allocated to the Medium Industrial and Large Industrial rate classes, are estimated in Table 5 (Medium Industrial), and Table 6 (Large Industrial).

Table 5: Medium Industrial expenditures by areas of focus and total

Year	Development and Research			Other Enabling Strategies			
	Areas of Focus		Total Investment ($)	Areas of Focus			Total Investment ($)
	Information & Analytics ($)	Innovation ($)		DSM Planning ($)	Regular DSM Matters ($)	Other Regulatory Matters ($)	
2027 Total	9,757	26,216	35,973	0	32,931	4,144	37,075
2028 Total	8,699	24,874	33,574	0	30,173	2,720	32,893
2029 Total	3,775	22,707	26,482	28,354	14,552	13,272	56,179
2030 Total	3,504	20,499	24,002	40,521	13,878	3,370	57,768
2031 Total	3,414	20,425	23,839	28,345	13,897	2,488	44,730
2027–2031 Total	29,148	114,721	143,869	97,220	105,431	25,994	228,645

Table 6: Large Industrial expenditures by areas of focus and total

Year	Development and Research			Other Enabling Strategies			
	Areas of Focus		Total Investment ($)	Areas of Focus			Total Investment ($)
	Information & Analytics ($)	Innovation ($)		DSM Planning ($)	Regular DSM Matters ($)	Other Regulatory Matters ($)	
2027 Total	34,182	91,843	126,025	0	115,369	14,517	129,885
2028 Total	29,172	83,413	112,585	0	101,182	9,120	110,302
2029 Total	12,443	74,849	87,292	93,465	47,969	43,749	185,183
2030 Total	11,703	68,471	80,174	135,349	46,354	11,257	192,960
2031 Total	11,235	67,215	78,450	93,279	45,732	8,189	147,200
2027–2031 Total	98,734	385,791	484,525	322,093	356,606	86,831	765,530

Request IR-14:

Reference: Exhibit E-1, Application, pages 61–64/71.

Preamble: E1 acknowledges Board concerns, including those raised by the Industrial Group, that unrestrained mid-course adjustments could prejudice the rate classes funding DSM activities, and proposes to add rate-class spending tracking to the MCA process. E1 also proposes a 15% rate-class spending change threshold requiring explanations to the Board, and a 20% threshold for program-level changes, with DSMAG review of proposed draft MCAs before filing.

(a) Please provide the working draft of the MCA text, including identifying any amendments to the Standardized Filing Framework that E1 proposes to incorporate to give effect to the enhanced rate-class reporting and thresholds. If this text is not yet finalized, please provide the most current draft.

(b) Please elaborate on the rationale for selecting 20% (program level) and 15% (rate-class level) as thresholds, including any analysis or modelling supporting those figures.

(c) Regarding the proposed 15% rate-class spending change threshold:

- **i) What is the baseline against which the 15% change is measured (e.g., Board-approved plan, prior year actual, or rolling average), and over what time period?**
- **ii) Is the threshold measured annually, cumulatively over the plan period, or both?**
- **iii) Does the threshold apply to each rate class independently, or only to the aggregate rate-class allocation and how will that spending be tracked in real time; and**

iv) What obligation, if any, does E1 have to seek prior Board approval (rather than merely provide explanation after the fact) where the threshold is forecasted to be exceeded?

(d) Please provide E1's anticipated timeline for the DSMAG review and engagement process outlined.

Response IR-14:

(a) Please refer to Attachment 1 of this IR Response for EfficiencyOne's (E1) draft proposed Mid-Course Adjustments (MCA) text for the Standardized Filing Framework.

(b) Please refer to E1's response to NSEB IR-30.

(c) Please refer to part (a) of this IR response.

i) The 15% threshold is measured against the Nova Scotia Energy Board- (NSEB) approved rate class spending as set out in the approved DSM Plan at the end of the Plan. The threshold is reported on an annual basis, consistent with the MCA mechanism which is prepared annually and reflects changes within a given DSM Plan year only. Please also refer to part (a) of this IR response. E1 will provide additional information in its Quarterly and Annual Progress Report of the cumulative rate class spending measured against the 15% threshold during the implementation of the DSM Plan.

ii) The results for the MCA will be provided for the current year. The MCA is prepared on an annual basis and is intended to reflect changes within a given DSM Plan year only; it does not carry forward year to year. Spending variances across the full plan period are addressed through the Balance Adjustment (BA) true-up process at the end of the DSM Plan period. Please also refer to part (a) of this IR response.

iii) The 15% threshold applies to rate class spending changes at the rate class level, consistent with the definition of "Threshold" in the draft Standardized Filing Framework, which refers to variance from the NSEB approved spending for each rate class individually. Rate class actual spending by program is reported in E1's Annual Progress Report. E1 also prepares a quarterly updated forecast that includes spending by program, which is compared to the approved DSM Plan and the MCA. Enhanced rate class reporting - including year-end forecast and Plan-period forecast - will provide an outlook on projected rate class expenditures and anticipated variances from the approved DSM Plan. Please also refer to part (a) of this IR response.

iv) Please refer to part (a) of this IR response.

(d) Please refer to part (a) of this IR response.

DRAFT

4.6 – Mid-Course Adjustments

A. Definitions

Mid-Course Adjustment –The Mid-Course Adjustment (MCA) is a mechanism that provides E1 with an opportunity to reallocate savings and investments by program for any given DSM Plan year to allow for changes that occur during the implementation of the DSM Plan. The MCA does not change E1’s performance targets or approved spending nor does the MCA influence the BA calculation. The MCA is prepared annually and is intended to update the Energy Board and DSM Advisory Group members on where the spending and savings by program are projected or forecast to be in any given year. The MCA does not carry forward year to year.

Balance Adjustment – The Balance Adjustment (BA) is the mechanism within the DCRR that trues up the rate class spending and rate class collections. E1 is responsible for providing information to inform the spending true-up for each rate class. This true-up compares the spending by rate class as approved in the DSM Plan to the actual spending by rate class for the same Plan period. The true up is completed at the end of the DSM Plan period, not on an annual basis, typically two years after the DSM Plan completion.

DSM Cost Recovery Rider – The DSM Cost Recovery Rider (DCRR) is the mechanism by which NS Power recovers the costs of E1’s Energy Board approved DSM Plan. The DCRR is comprised of the Program Cost Recovery (PCR) and a Balance Adjustment (BA).

Program Cost Recovery – the Program Cost Recovery (PCR) is the mechanism within the DCRR that NS Power uses to calculate the recovery from ratepayers to fund the DSM Plan. E1 provides NSP with the spending by rate class by year that has been approved by the Energy Board as part of the DSM Plan Application.

DSM forecast – E1 prepares an updated forecast that includes both spending and savings by program each quarter. These are compared to both the DSM Plan as approved and the MCA.

Program Spending and Targets – Program spending and performance targets as approved by the NSEB, for all program components, as part of E1’s DSM Plan Application. Progress on the program spending and targets are included in the DSM Quarterly Reports.

Rate Class actual spending – Rate class actual spending by program is reported in E1’s Annual Progress Report. E1 also provides this information to NS Power upon request.

DSM Plan – The approved DSM Plan establishes E1’s performance targets, program spending and targets, and the rate class spending for each of the years included in the DSM Plan.

Threshold – The threshold represents an approved percentage that E1 can vary from the Energy Board approved spending (program or rate class) and program targets without providing a detailed explanation for the variance.

B. Rationale for MCA

The mid-course adjustment process provides E1 with an opportunity to reallocate savings and investments by program for any given DSM Plan year to allow for changes that occur during the implementation of the DSM Plan. The rationale for these changes includes updated information from customers on project completion dates; challenges customers may be facing with supply chain issues such as product availability; industry capacity that affects contractor availability; and E1's third-party evaluation results. The mid-course adjustment process is intended to provide E1 with the necessary flexibility in ensuring performance targets are met. The process is not intended to change performance targets.

The MCA is intended to reflect only changes in a given year and not reflect changes that may occur over the DSM Plan period. The MCA does not impact spending variances that are incorporated into the true-up or BA at the end of the DSM Plan. It is to provide information to the Energy Board and the DSM Advisory Group of where E1 is projecting the program spending and savings for the year. E1 agrees that rate class spending projections should also be provided as part of the MCA going forward.

C. E1's commitment in the 2026 DSM Extension matter
During the 2026 DSM Extension proceeding, E1 agreed to the following enhancements:
- Improve the accuracy of estimates used for the rate class allocation of expenditures in the DSM Plan by using a minimum of three years of historical data;
- Provide enhanced rate class reporting to address concerns, for example, year-end forecast and Plan period forecast to provide an outlook on projected rate class expenditures for the entire Plan period and the anticipated variances from the approved DSM Plan; and
- Monitor program spending against the DSM Plan and to clarify any variances within the approved thresholds.

D. Spending Thresholds
E1 will continue to have the ability to make program changes, both investment and savings, but must provide explanations for those changes higher than 20 percent. In addition, E1 will have the ability to make rate class spending changes but must provide explanations for those changes higher than 15 percent.

E. DSMAG Engagement
E1 will give written notice of intent to prepare any mid-course adjustments in the Annual Progress Report. The DSM Advisory Group will be provided the draft mid-course adjustments with explanations and given a two-week comment period. E1 will respond to the comments prior to E1 including the mid-course adjustment in the Q1 Report.

F. The MCA will be filed with the NSEB in E1's Q1 DSM report and subject to regulatory activities or proceedings as the NSEB deems appropriate.

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Request IR-15:

Reference: Exhibit E-1, Application page 65/71, lines 4-10.

> **The mid-term check-in proposed below is intended to enhance transparency and stakeholder engagement during plan implementation, but does not constitute a full plan reopening or amendment process, nor does it alter E1's approved performance targets or total spending authority. To treat the mid-term check-in as a vehicle for reopening the approved Plan would frustrate the Legislature's express purpose in extending the DSM plan term from three to five years, which, as noted in Section 2.1.1 of this Evidence, was specifically intended to save time, money, and resources by reducing the frequency of full regulatory proceedings.**

And Reference: Exhibit E-1, Application page 66/71 lines 10-16.

> **Should circumstances arise during plan implementation that, in E1's reasonable assessment, may necessitate changes to approved investment levels, performance targets, or other material plan elements requiring NSEB approval, E1 will provide advance notice to the DSMAG and file an appropriate application with the NSEB in accordance with the PUA. Such circumstances might include, for example, significant and unforeseen changes in avoided costs, material shifts in market conditions or technology availability, legislative or regulatory changes affecting DSM delivery, or other extraordinary events materially impacting plan feasibility or ratepayer value.**

(a) Please explain how the proposed mid-term check-in provides meaningful regulatory or stakeholder value beyond information-sharing if it cannot, itself, inform, recommend, or support changes to improve the effectiveness, efficiency, or cost-effectiveness of the DSM Plan.

(b) Given E1's statement that some changes to investment levels or performance targets would be addressed through a separate application to the NSEB, please explain how insights or issues identified during the mid-term check-in would be distinguished from, or inform the need for, such an application.

(c) Does E1 agree that identifying evidence during the mid-term check-in that supports reductions, reallocation, or reprioritization of DSM investments—where such changes would benefit ratepayers—would be consistent with, and not contrary to, the Legislature's intent in approving a five-year DSM Plan term? Please explain.

(d) Please elaborate on why allowing the mid-term check-in to substantively inform potential adjustments through a subsequent NSEB filing would undermine legislative intent, taking into consideration that E1 already contemplates the possibility of filing applications during the five-year term when circumstances warrant.

(e) If E1 does not anticipate that the mid-term check-in will influence decisions regarding program design, funding levels, or performance expectations in any material way, please explain the purpose of the check-in from a regulatory perspective (especially considering the enhanced reporting proposed annually).

(f) Please outline the threshold at which E1 views "significant and unforeseen changes in avoided costs, material shifts in market conditions or technology availability, legislative or regulatory changes affecting DSM delivery, or other extraordinary events materially impacting plan feasibility or ratepayer value" as warranting an application to the NSEB, what input stakeholders may have in making that determination, and identify the source(s) or reasoning for that threshold.

Response IR-15:

(a) Please refer to EfficiencyOne's response to Synapse IR-72.

(b) Please refer to part (a) of this response.

(c) Please refer to part (a) of this response.

(d) Please refer to part (a) of this response.

(e) Please refer to part (a) of this response.

(f) Please refer to part (a) of this response.

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Request IR-16:

Reference: Exhibit E-1, Application, Appendix A, Section 4.7, pages 40–42/112; Exhibit E-1, Appendix B, Attachment 2.

Preamble: E1 states that the rate-class allocation of expenditures was developed using three years of historical data (2022–2024), customer commitments for projects, and assumptions for program changes impacting specific rate classes.

(a) Please provide:

- **i) The complete rate-class allocation methodology, step by step, including all allocators, weighting factors, and normalization steps applied to derive the percentage share of total annual spending allocated to each rate class;**
- **ii) The underlying annual datasets for 2022, 2023, and 2024 used to generate the historical allocators, showing spending by program and by rate class for each year;**
- **iii) A reconciliation from the historical average allocators to the year-by-year spending percentages applied in the 2027–2031 Preferred Plan, with explanations for any year-over-year variation within the Plan period; and**
- **iv) Confirmation of which programs or measures required bespoke assumptions (i.e., were not derived from the three-year historical average), and the rationale for each such assumption.**

(b) Where a mid-course adjustment shifts spending to a program for which 100% of allocation is assigned to classes that directly benefit from that program (i.e., classes that are eligible participants), please confirm:

i) How that allocation shift affects the non-participating or non-eligible classes (such as Medium and Large Industrials where they do not benefit from a residential program receiving increased allocation); and

ii) What limits, if any, apply to such reallocations that would increase the cost burden on non-eligible rate classes.

Response IR-16:

(a)

i) The first step in the 2027–2031 rate class allocation methodology was calculating the average spending by rate class percentages from the previous three years (2022, 2023, and 2024) for each existing program component.

For most program components – Instant Savings, Affordable Multifamily Housing, Efficient Product Installation, Home Energy Assessment, the Mi’kmaw Home Energy Efficiency Project, Business Energy Rebates, Custom, Strategic Energy Management, and Small Business Energy Solutions – the average spending by rate class percentage from the previous three years (2022, 2023, and 2024) was then applied to the 2027, 2028, 2029, 2030, and 2031 total costs for that program component to establish the total expenditures for each rate class for each year. Customer commitments for projects and assumptions for program changes impacting specific rate classes were reviewed and considered alongside the rate class allocations that were calculated using the three-year historical averages for each of these program components, and were in alignment.

The program components where a different methodology was used are as follows:

- For the Affordable Single-family Homes program component, the three-year historical average spending by rate class percentage from the Home Energy Assessment program component was applied, as following review, that allocator was considered more reflective of expectations for Affordable Single-family Homes over the course of the five-year plan.
- For the Residential Demand Response program component, all spending was allocated to the Residential rate class, as it serves that rate class exclusively.
- For the BNI Demand Response program component, the rate class spending allocations were calculated using the following inputs:
  - average historical rate class results from E1's first two demand response seasons (2023 & 2024);
  - tracked results from E1's 2025 season;
  - expectations and enrolled participation for commercial and industrial curtailment participants for the 2026 demand response season (at that time); and
  - expectations and enrolled participation for commercial and industrial curtailment back-up generator participants, specifically, for the 2026 demand response season (at that time).
- For Residential Solar-PV, a new program component, all spending was allocated to the Residential rate class, as it will serve that rate class exclusively.
- For Mi'kmaw New Home Construction, a new program component, the three-year historical average spending by rate class percentages from the Home Energy Assessment program component was applied, as that allocator was considered to be most in line with expectations for participation in Mi'kmaw New Home Construction over the course of the five-year plan.

Enabling Strategies costs for the Development and Research and Other Enabling Strategies categories were allocated to the rate classes according to the percentage of total program costs each rate class represents. Industrial classes (Small, Medium, and Large) were excluded from the Education and Outreach category as those activities are primarily focused on residential and non-industrial BNI customers; and the Market Transformation category was allocated 100 percent to the Residential rate class, as that sector is the focus of market transformation activities.

The final step in the rate class methodology was to sum the rate class allocations calculated by program component and the rate class allocations for Enabling Strategies to determine the total investment allocations for each rate class at the portfolio level.

ii) Please refer to Attachment 1 of E1's response to IG IR-21.

iii) Please refer to part (a) of this IR response.

iv) Please refer to part (a) of this IR response.

(b)

i) Where a mid-course adjustment shifts spending to a residential program from a BNI program (all else being equal) as compared to the Plan as Approved investment amounts for those programs, it would generally be expected to result in additional savings, participation and spending in the residential program and less in the BNI program as compared to the Plan as Approved estimates. It is the net impact of these annual shifts through the mid-course adjustment, over the Plan period that may result in a balance adjustment at the end of the Plan period.

E1 has modified the program variance thresholds and introduced new rate class variance thresholds as part of its proposed mid-course adjustment process in its 2027–2031 DM Plan Application. The updated process is more fully described in E1's response to NSEB IR-30.

ii) Please refer to part (b) i) of this IR response.

Request IR-17:

Reference: Exhibit E-1, Appendix A, Table 57, page 96 of 112, "Other Regulatory Matters".

1. Update E1's 2026 potential study: Together with its consultants, E1 will complete an update of its 2026 potential study during the 2027–2031 Plan period, both to inform its 2032-2036 DSM Plan and to contribute to an expected Integrated Resource Plan Evergreen process by the Nova Scotia Independent Energy System Operator during the 2027–2031 Plan period.

(a) Please provide the current iteration of the DSM Potential Study that E1 references it plans to update.

(b) Please outline any planned updates to its 2026 DSM Potential Study that would relate to or impact Industrial customer alternative program designs, enhanced incentives, dedicated technical assistance, pay-for-performance structures, industrial energy-manager models, or process-specific offerings.

(c) Do the objectives of E1's DSM Potential Study include improving participant rate benefits for Medium and Industrial customer participants? Please explain.

Response IR-17:

(a) EfficiencyOne (E1) has engaged a consultant to complete 2026 DSM Potential Study that will provide updated DSM potential projections to inform the Nova Scotia Independent Energy System Operator's (NSIESO) 2026 Integrated Resource Plan (IRP). The referenced statement reflects E1's expectations that there will be an update to the 2026 DSM Potential

Study to inform the 2032–2036 DSM Plan and an anticipated IRP process led by the NSIESO during the 2027–2031 Plan period.

(b) E1 has not developed the scope for the potential study update expected to take place during the 2027–2031 DSM plan period to the 2026 DSM Potential Study. Please refer to part (a) of this IR response.

(c) The primary objective of a DSM potential study is to project the technically achievable and cost-effective DSM potential available across customer classes and sectors over a defined planning horizon, to support IRP and DSM resource planning. The potential study is a planning tool focused on estimating what DSM can deliver from a system and resource perspective; it is not designed to assess customer rate or bill impacts at the program or participant level.

(d) Direct assessment of the impacts of DSM programs on customer rates and bills is conducted through the Rate and Bill Impact Analysis (RBIA), which E1 files as part of its DSM Plan Application pursuant to the Standardized Filing Framework. Accordingly, improving participant rate benefits for Medium and Industrial customers is not a stated objective of the 2026 DSM Potential Study, but the study contributes to an IRP and planning process whose broader purpose is to minimize long-term electricity costs for all ratepayers.

Request IR-18:

Reference: Exhibit E-1, Appendix A, Table 46, page 81-82/112.

Preamble: E1 describes BNI Demand Response (marketed as "Smart Synergy") as targeting commercial and industrial curtailment. In 2025, Medium Industrial achieved 3.3 MW of available DR capacity and incurred $0.9M in Smart Synergy expenditure, while Large Industrial achieved 0.0 MW of available DR capacity with participation from one customer and $0.0M recorded in expenditures.

(a) Please confirm which rate classes (and rate class codes) are eligible to participate in and receive incentives through Smart Synergy (BNI Demand Response) in the 2027–2031 plan.

(b) Please explain both why "interruptible customers have not been eligible to participate in the past", and who determined that ineligibility?

(c) Does E1 anticipate that Large Industrial Interruptible customers may be eligible for this program during the 2027-2031 DSM Plan period, where incentives would be limited to incremental voluntary curtailments that are separate from, and additional to, the customer's interruptible tariff obligation in priority?

(d) Would E1 object to exploring eligibility for Large Industrial Interruptible customers during this 2027-2031 Plan period?

(e) Are there written eligibility criteria (e.g., minimum demand, metering requirements, curtailment capability), and if so, please provide.

(f) Please provide a table that compares E1 Smart Synergy provisions for BNI participants versus NSPI's Large Industrial Interruptible program (and separately provide for telemetry vs. non-telemetry customers) that compares the following:

i) Notice period for interruptions;

ii) Maximum number and length of interruptions allowable;

iii) Dollar value of credit (including any capacity and variable credits);

iv) Notice period to exit program;

v) Timeframes and constraints for interruptible periods;

vi) Requirement vs. optional interruption ability;

vii) Penalties for non-compliance;

viii) Minimum load to participate; and

ix) How participating load reduction is quantified and if there are any load factor adjustments applied in the credit calculation (i.e. how the credit is calculated for each interruption).

(g) Please provide, for 2027–2031 by year, the projected Smart Synergy program costs (incentives, administration, delivery, metering) allocated to Medium Industrial, and Large Industrial rate classes (separately).

(h) As the subclass of Large Industrial Interruptible customers are not eligible to participate presently in the Smart Synergy program and do not receive the benefit of participation, what is E1 justification for allocating the cost of this program to this subclass?

(i) Does E1 have any data on whether this program impacts or influences any calls for interruptions for the Large Industrial Interruptible class in prior years of the program? If so, how?

Response IR-18:

(a) The eligible rate classes for Smart Synergy are business, non-profit, and institutional electricity customers served under the following NS Power rate codes: 10, 11, 12, 21, 22, or 23. Other program eligibility requirements also apply, including that the customer must not already be participating in and/or receiving incentives from an existing demand response or demand reduction program.

(b) Interruptible customers have not been eligible to participate in Smart Synergy because they are already subject to the Large Industrial Interruptible Rider. Under the rider, customers receive a demand charge reduction for billed interruptible demand and are required to reduce available interruptible system load when requested by NS Power. EfficiencyOne (E1) understands that NS Power does not plan firm capacity requirements on the basis of interruptible load above the customer's contracted firm demand requirements. As a result, E1 has not treated that interruptible load as eligible incremental demand response capacity under Smart Synergy. This ineligibility was established by E1 through the Smart Synergy program eligibility requirements, in coordination with NS Power's treatment of interruptible customers under the Large Industrial Interruptible Rider.

(c) E1 has not determined at this time that Large Industrial Interruptible customers will be eligible for Smart Synergy during the 2027–2031 DSM Plan period. As noted in Appendix A of E1's 2027–2031 DSM Resource Plan Application, the potential for interruptible customers to become eligible was raised through DSM Advisory Group (DSMAG) discussions, and E1 is committed to further discussions to assess incremental value and appropriateness. Any potential eligibility would need to ensure that incentives are limited to incremental voluntary curtailments that are separate from, and additional to, the customer's interruptible tariff obligation.

(d) Please refer to part (c) of this IR response.

(e) Please refer to part (a) of this IR response.

(f) The following IR response in relation to NS Power's Large Industrial Interruptible Rider (LIIR) has been provided by NS Power.

Item	E1 Smart Synergy / BNI Participants	NS Power Large Industrial Interruptible Rider (LIIR)
i) Notice period for interruptions	16 hours	No set timeframe for notifications. Advisories and Alerts are issued in advance of the interruption request, as system capacity shortfall worsens. LIIR customers have 10 minutes to reduce load following the issuance of an Interruption request.
ii) Maximum number and length of interruptions allowable	12 events per program season, 4 hours per event	Interruption is limited to 16 hours per day and 5 days per week to a maximum of 30% of the hours per month and 15% of the hours in a year.
iii) Dollar value of credit, including capacity and variable credits	Incentive payment based on average performance over season paid at $100/kW	Reduction per kilovolt ampere reduction in demand charge: • Effective May 1, 2026, $7.638 i) Effective January 1, 2027, $7.667
iv) Notice period to exit program	Voluntary program	Five (5) year advance notice to return to firm service.
v) Timeframes and constraints for interruptible periods	N/A	Subject to the maximum as described in subpart (ii).
vi) Requirement vs. optional interruption ability	Optional. Customers may choose to not participate in an event but this will reduce their incentive payment at the end of the season	All customer load subscribed to the LIIR is subject to interruption – no optional load interruptibility.
vii) Penalties for non-compliance	There are no penalties for non-compliance. Non-compliance in an event would result in a lower incentive at the end of the program season.	Threshold Penalty at the cost of the appropriate firm billing effective at that time plus Performance Penalty based on the customer's performance during the interruption. Total Penalty is capped at two times the cost of the appropriate firm billing.

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Item	E1 Smart Synergy / BNI Participants	NS Power Large Industrial Interruptible Rider (LIIR)
viii) Minimum load to participate	No specific written requirement.	Any industrial customer having a regular billing demand of 2,000 kVA or 1,800 kW and over.
ix) How participating load reduction is quantified and whether load factor adjustments are applied in the credit calculation	Smart Synergy load reduction is quantified using an approved event baseline methodology, typically an X-in-X day-matching approach using recent non-event operating days. Event-period demand is compared to the baseline for the same interval(s), and the difference is the verified demand reduction. No load factor adjustment is applied.	Participating load must meet the availability requirements of the Large Industrial Tariff and the LIIR. The interruptible credit is designed to mimic the operation of a combustion turbine (CT) operating as a peaking facility. As such, NS Power calculates the LIIR credit using the avoided cost of a CT to reflect the avoidance, or deferral, of future generation capacity costs that NS Power would otherwise need to incur to serve the interruptible load (if that load were firm, rather than interruptible). No load factor adjustments are applied to the LIIR credit.

(g) Please refer to Table 1 of this IR response for Medium Industrial costs and Table 2 for Large Industrial costs.

Table 1: Smart Synergy Costs by Year and Category - Medium Industrial

Year	Incentives	Program Delivery Cost	Program Administrative Cost	Marketing & Recruitment Cost	Total
2027	$911,989	$191,914	$439,784	$14,868	$1,558,555
2028	$1,033,565	$217,498	$458,832	$14,983	$1,724,879
2029	$1,156,078	$243,279	$478,086	$15,080	$1,892,524
2030	$1,278,342	$269,008	$496,957	$15,157	$2,059,463
2031	$1,400,056	$294,621	$516,134	$15,221	$2,226,032

Table 2: Smart Synergy Costs by Year and Category - Large Industrial

Year	Incentives	Program Delivery Cost	Program Administrative Cost	Marketing & Recruitment Cost	Total
2027	$11,213	$2,360	$5,408	$183	$19,163

Year	Incentives	Program Delivery Cost	Program Administrative Cost	Marketing & Recruitment Cost	Total
2028	$13,490	$2,839	$5,987	$196	$22,511
2029	$15,778	$3,320	$6,525	$206	$25,829
2030	$18,032	$3,795	$7,011	$214	$29,051
2031	$20,286	$4,269	$7,478	$221	$32,253

Metering costs for BNI Demand Response are a service delivery fee of $15/kW to $20/kW depending on whether basic metering is required or a power meter.

(h) Smart Synergy is a demand-side resource intended to reduce system peak demand and provide system benefits that are not limited to participating customers. Although Large Industrial Interruptible customers are not presently eligible to participate in Smart Synergy and do not receive participant incentives, the program can still provide broader system benefits through reduced peak demand and avoided or deferred capacity-related costs.

(i) E1 does not have data on the operation of the Large Industrial Interruptible Rider or on whether Smart Synergy has impacted or influenced calls for interruptions for the Large Industrial Interruptible class in prior years of the program.

Request IR-19:

Reference: Exhibit E-1, Appendix A, pages 66–68/112, Table 35.

Preamble: Custom incentives are available to non-profit, institutional, commercial and industrial customers, consisting of two programs: custom and strategic energy management.

E1 states that the objectives of these programs include reducing barriers to implementing complex, customer energy efficiency projects by providing technical and financial support. The barriers these programs help overcome include upfront costs, internal competition for capital, payback requirements, limited internal capacity, lack of internal commitment and technical expertise, and third-party consultants being unfamiliar with customer offerings and processes.

Table 36 provides the total custom program components:

Table 36: 2027–2031 Custom Program Component

Custom				
Annual Plan	Investment ($M)	Energy Savings (GWh)	Demand Savings (MW)	Participation (projects)
2027 Total	17.1	73.2	10.7	191
2028 Total	13.3	50.7	7.1	132
2029 Total	11.1	35.0	4.6	91
2030 Total	10.6	32.1	4.1	84
2031 Total	10.0	27.7	3.6	72
2027–2031 Total	62.1	218.7	30.1	570

Comparatively, the table below pulls some figures from Exhibit E-1-(ii) (Appendix A, Attachment 3 from the 2026 DSM Plan) on the custom program components:

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	2026 Proposed					2027 Preferred Plan					2028 Preferred Plan				
Measure Name	First Year Savings (MWh)	Per Unit Incentive	Participation Units	Total Incentive	PAC Ratio	First Year Savings (MWh)	Per Unit Incentive	Participation Units	Total Incentive	PAC Ratio	First Year Savings (MWh)	Per Unit Incentive	Participation Units	Total Incentive	PAC Ratio
Custom															
Custom - Pay for Performance	4,141.85	$150,000	5	$681,000	6.81	975.95	$150,000	1	$150,000	9.10	975.95	$150,000	1	$150,000	9.21
Custom - New Construction	13,175.34	$150,000	18	$2,700,000	8.66	39,579.07	$150,000	46	$6,825,000	11.15	23,138.53	$150,000	27	$3,990,000	10.40
Custom - Industrial Retrofit	10,888.81	$130,000	13	$1,690,000	5.25	22,446.88	$170,000	23	$3,910,000	4.87	15,859.21	$170,000	16	$2,762,500	5.35
Custom - Commercial Retrofit	4,188.00	$150,000	5	$750,000	4.55	6,343.68	$150,000	7	$975,000	5.55	5,855.71	$150,000	6	$900,000	6.09
Custom - Building Optimization	1,621.78	$120,000	2	$201,600	6.74	1,930.69	$120,000	2	$240,000	0.25	1,930.69	$120,000	2	$240,000	0.58
Equity Deserving Retrofits						1,951.90	$180,000	2	$360,000	4.60	2,927.85	$180,000	3	$540,000	5.31
Total Custom	**34,015.78**		**42.22**	**$6,022,600**		**71,276.27**		**78.00**	**$12,100,000**		**47,760.09**		**51.85**	**$8,042,500**	
SEM															
Custom - Strategic Energy Management	3,976.47	$160,000	4.0	$640,000	4.61	4,188.79	$60,000	4	$240,000	9.39	4,188.79	$60,000	4.0	$240,000	11.90

	2029 Preferred Plan					2030 Preferred Plan					2031 Preferred Plan				
Measure Name	First Year Savings (MWh)	Per Unit Incentive	Participation Units	Total Incentive	PAC Ratio	First Year Savings (MWh)	Per Unit Incentive	Participation Units	Total Incentive	PAC Ratio	First Year Savings (MWh)	Per Unit Incentive	Participation Units	Total Incentive	PAC Ratio
Custom															
Custom - Pay for Performance	975.95	$170,000	1	$170,000	9.29	975.95	$170,000	1	$170,000	9.60	10,929.03	$170,000	1.0	$170,000	9.65
Custom - New Construction	13,048.04	$170,000	15	$2,550,000	11.00	11,134.33	$170,000	13	$2,176,000	11.26	183,503.78	$170,000	11.1	$1,887,000	11.31
Custom - Industrial Retrofit	10,247.49	$170,000	11	$1,785,000	6.19	9,271.54	$170,000	10	$1,615,000	6.61	71,002.41	$170,000	8.0	$1,360,000	6.75
Custom - Commercial Retrofit	4,879.76	$170,000	5	$850,000	6.22	4,879.76	$170,000	5	$850,000	6.64	31,063.55	$170,000	3.5	$595,000	6.78
Custom - Building Optimization	2,896.03	$130,000	3	$390,000	1.11	2,896.03	$130,000	3	$390,000	1.62	5,085.43	$130,000	3.0	$390,000	1.76
Equity Deserving Retrofits	2,927.85	$200,000	3	$600,000	5.26	2,927.85	$200,000	3	$600,000	5.62	26,625.90	$200,000	3.0	$600,000	5.74
Total Custom	**32,047.27**		**34.50**	**$5,745,000**		**29,157.61**		**31.30**	**$5,201,000**		**301,584.20**		**26.60**	**$4,402,000**	
SEM															
Custom - Strategic Energy Management	4,188.79	$60,000	4	$240,000	13.64	3,141.59	$60,000	3	$180,000	14.81	18,252.65	$60,000	3.0	$180,000	15.03

(a) Please confirm Table 36 values are consolidated from Exhibit E-1-(ii) for 2026 values, and if not please update.

(b) Please explain the decrease in Strategic Energy Management per unit incentive from $160,000 in 2026 to $60,000 in the 2027-2031 Plan. Specify how and why the incentive setting methodology led to the decision.

(c) Comparing 2026 to 2027+, please explain the rationale behind increasing Industrial Retrofit and Pay for Performance participation levels so substantially.

i) Please provide any consultations, surveys or due diligence E1 has undertaken to ensure this level of participant increase is achievable.

(d) Please reconcile Table 36 values, specifically investment, energy savings and participation with the values in Exhibit E-1-(ii).

(e) Please confirm that Strategic Energy Management is not included in the "Custom" Table 36. If not confirmed, please explain why it is separated in the Exhibit E-1-(ii) tables.

(f) Please explain the decrease in Strategic Energy Management participation from 4 participants to 3 in 2030 (considering this program is usually provided on an annual ongoing basis).

(g) Please break down Table 36 and Exhibit E-1-(ii) custom programs (including Strategic Energy Management) split by all rate classes included in the BNI programming.

(h) Please explain how the incentive levels were established for custom programs, particularly for Medium and Large Industrial customers.

Response IR-19:

(a) Table 36, 2027–2031 Custom Program Component taken from Appendix A, 2027-2031 DSM Plan Application does not contain the 2026 Custom Incentives program energy savings, spending or participants. It represents the 2027-2031 proposed plan for the Custom program component. (The Custom program component is one of two program components that comprise the Custom Incentives program).

(b) The Strategic Energy Management incentive is not changing between 2026 and the 2027-2031 Plan; however, EfficiencyOne (E1) has adjusted how program costs are presented in the model. Strategic Energy Management participants work with an E1 contracted Service Provider who educates and guides them toward making operational changes that save energy. The cost of this service was previously listed under direct incentives but was moved to the category of other incentives which has been captured in the model input for the 2027–2031 DSM Plan as program administration. This approach ensures consistency between program components in how these types of incentive costs are categorized.

(c) Participation increases in New Construction and Industrial Retrofit are the result of substantial groundwork laid by E1 in recent years. E1 has worked closely with key accounts and partners to identify projects early, quantify savings, offer incentives, and assist companies with enrolling in the Custom program component. The increase in 2027 is driven by committed multi-year projects, supported by energy modeling and feasibility studies which are expected to close in the early part of the 2027–2031 Plan period.

Pay for Performance participation remains low in the Plan. This reflects historical program uptake, as most customers have opted to participate in other streams of this program component.

(d) Please see Table 1 below for a consolidated view of investment, savings, and participation in the Custom Incentives program. Please note there was an error in the "Total Custom" row calculation in Exhibit E-1-(ii) that has been corrected. Also note that the participation units from Exhibit E-1-(ii) are a proxy for first year energy savings used in Plan modelling and not a reflection of the number of projects E1 expected to participate, which is listed in Table 36 and broken down further in the table below.

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Table 1: Custom Incentives Program: Investment, Savings, and Participation

Custom Incentives Program								
Year	Program Component	Measure	Investment ($M)			First Year Energy Savings (GWh)	Demand Savings (MW)	Participation (projects)
			Incentives	Administration	Total			
2027	Custom	Pay for Performance	$ 150,000.00	Administration	$ 150,000.00	0.98	0.20	Participation is
		New Construction	$ 6,825,000.00	costs are not	$ 6,825,000.00	39.58	7.34	not separated
		Industrial Retrofit	$ 3,910,000.00	separated by	$ 3,910,000.00	22.45	2.27	by measure in
		Commercial Retrofit	$ 975,000.00	measure in the	$ 975,000.00	6.34	0.65	the model
		Building Optimization	$ 240,000.00	model Please see	$ 240,000.00	1.93	0.09	Please see
		Equity Deserving Groups	$ 360,000.00	Custom total.	$ 360,000.00	1.95	0.20	Custom total.
		Custom Total	$ 12,460,000.00	$ 4,664,940.00	$ 17,124,940.00	73.23	10.75	191
	SEM	SEM	$ 240,000.00	$ 872,876.00	$ 1,112,876.00	4.19	0.50	7
	Total	n/a	$ 12,700,000.00	$ 5,537,816.00	$ 18,237,816.00	77.42	11.25	198
2028	Custom	Pay for Performance	$ 150,000.00	Administration	$ 150,000.00	0.98	0.20	Participation is
		New Construction	$ 3,990,000.00	costs are not	$ 3,990,000.00	23.14	4.29	not separated
		Industrial Retrofit	$ 2,762,500.00	separated by	$ 2,762,500.00	15.86	1.60	by measure in
		Commercial Retrofit	$ 900,000.00	measure in the	$ 900,000.00	5.86	0.60	the model
		Building Optimization	$ 240,000.00	model Please see	$ 240,000.00	1.93	0.09	Please see
		Equity Deserving Groups	$ 540,000.00	Custom total.	$ 540,000.00	2.93	0.30	Custom total.
		Custom Total	$ 8,582,500.00	$ 4,684,369.00	$ 13,266,869.00	50.69	7.08	132
	SEM	SEM	$ 240,000.00	$ 889,400.00	$ 1,129,400.00	4.19	0.50	7
	Total	n/a	$ 8,822,500.00	$ 5,573,769.00	$ 14,396,269.00	54.88	7.58	139
2029	Custom	Pay for Performance	$ 170,000.00	Administration	$ 170,000.00	0.98	0.20	Participation is
		New Construction	$ 2,550,000.00	costs are not	$ 2,550,000.00	13.05	2.42	not separated
		Industrial Retrofit	$ 1,785,000.00	separated by	$ 1,785,000.00	10.25	1.04	by measure in
		Commercial Retrofit	$ 850,000.00	measure in the	$ 850,000.00	4.88	0.50	the model
		Building Optimization	$ 390,000.00	model Please see	$ 390,000.00	2.90	0.13	Please see
		Equity Deserving Groups	$ 600,000.00	Custom total.	$ 600,000.00	2.93	0.30	Custom total.
		Custom Total	$ 6,345,000.00	$ 4,766,248.00	$ 11,111,248.00	34.98	4.59	91
	SEM	SEM	$ 240,000.00	$ 906,407.00	$ 1,146,407.00	4.19	0.50	7
	Total	n/a	$ 6,585,000.00	$ 5,672,655.00	$ 12,257,655.00	39.16	5.09	98
2030	Custom	Pay for Performance	$ 170,000.00	Administration	$ 170,000.00	0.98	0.20	Participation is
		New Construction	$ 2,176,000.00	costs are not	$ 2,176,000.00	11.13	2.06	not separated
		Industrial Retrofit	$ 1,615,000.00	separated by	$ 1,615,000.00	9.27	0.94	by measure in
		Commercial Retrofit	$ 850,000.00	measure in the	$ 850,000.00	4.88	0.50	the model
		Building Optimization	$ 390,000.00	model Please see	$ 390,000.00	2.90	0.13	Please see
		Equity Deserving Groups	$ 600,000.00	Custom total.	$ 600,000.00	2.93	0.30	Custom total.
		Custom Total	$ 5,801,000.00	$ 4,819,184.00	$ 10,620,184.00	32.09	4.14	84
	SEM	SEM	$ 180,000.00	$ 814,753.00	$ 994,753.00	3.14	0.38	5
	Total	n/a	$ 5,981,000.00	$ 5,633,937.00	$ 11,614,937.00	35.23	4.51	89
2031	Custom	Pay for Performance	$ 170,000.00	Administration	$ 170,000.00	0.98	0.20	Participation is
		New Construction	$ 1,887,000.00	costs are not	$ 1,887,000.00	9.66	1.79	not separated
		Industrial Retrofit	$ 1,360,000.00	separated by	$ 1,360,000.00	7.81	0.79	by measure in
		Commercial Retrofit	$ 595,000.00	measure in the	$ 595,000.00	3.42	0.35	the model
		Building Optimization	$ 390,000.00	model Please see	$ 390,000.00	2.90	0.13	Please see
		Equity Deserving Groups	$ 600,000.00	Custom total.	$ 600,000.00	2.93	0.30	Custom total.
		Custom Total	$ 5,002,000.00	$ 4,958,369.00	$ 9,960,369.00	27.68	3.56	72
	SEM	SEM	$ 180,000.00	$ 832,971.00	$ 1,012,971.00	3.14	0.38	5
	Total	n/a	$ 5,182,000.00	$ 5,791,340.00	$ 10,973,340.00	30.82	3.94	77
2027-2031 Total	Custom	Pay for Performance	$ 810,000.00	Administration	$ 810,000.00	4.88	1.01	Participation is
		New Construction	$ 17,428,000.00	costs are not	$ 17,428,000.00	96.56	17.91	not separated
		Industrial Retrofit	$ 11,432,500.00	separated by	$ 11,432,500.00	65.63	6.63	by measure in
		Commercial Retrofit	$ 4,170,000.00	measure in the	$ 4,170,000.00	25.37	2.61	the model
		Building Optimization	$ 1,650,000.00	model Please see	$ 1,650,000.00	12.55	0.58	Please see
		Equity Deserving Groups	$ 2,700,000.00	Custom total.	$ 2,700,000.00	13.66	1.38	Custom total.
		Custom Total	$ 38,190,500.00	$ 23,893,110.00	$ 62,083,610.00	218.66	30.12	570
	SEM	SEM	$ 1,080,000.00	$ 4,316,407.00	$ 5,396,407.00	18.85	2.26	31
	Total	n/a	$ 39,270,500.00	$ 28,209,517.00	$ 67,480,017.00	237.51	32.38	601

(e) Confirmed. Table 36 covers the Custom program component, not the entire Custom Incentives program. Please see the table listed in our response sub-question (d) for a total view of the Custom Incentives program which is comprised of two program components, Custom and Strategic Energy Management (SEM).

(f) Strategic Energy Management is suitable for a specific, limited customer base in Nova Scotia. Most program participants have been leveraging the program for several years and will eventually address most energy efficiency opportunities for their operations. The Preferred Plan assumes some natural attrition, which is reflected in the participation.

(g) Please see Table 2 below for a breakdown of the Custom Incentives program by rate class and program component.

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Table 2: 2027–2031 Breakdown of Custom Incentives Program by Rate Class and Program Component

2027-2031 Custom Incentives Program													
		Custom Program Component				Strategic Energy Management Program Component				Total			
Rate Class	Year	Investment ($ million)	First-Year Energy Savings (GWh)	Demand Savings (MW)	Participation (projects)	Investment ($ million)	First-Year Energy Savings (GWh)	Demand Savings (MW)	Participation (projects)	Investment ($ million)	First-Year Energy Savings (GWh)	Demand Savings (MW)	Participation (projects)
Residential/Charitable (2,3,4)*	2027	0.6	1.9	0.2	13	0	0	0	0	0.6	1.9	0.2	13
	2028	0.4	1.3	0.1	9	0	0	0	0	0.4	1.3	0.1	9
	2029	0.4	0.9	0.1	6	0	0	0	0	0.4	0.9	0.1	6
	2030	0.3	0.8	0.1	6	0	0	0	0	0.3	0.8	0.1	6
	2031	0.3	0.7	0.1	5	0	0	0	0	0.3	0.7	0.1	5
	2027-2031	2	5.7	0.5	39	0	0	0	0	2	5.7	0.5	39
Small General (10)	2027	0.9	3.2	0.2	25	0	0	0	1	0.9	3.2	0.2	26
	2028	0.7	2.2	0.1	17	0	0	0	1	0.7	2.2	0.1	18
	2029	0.6	1.5	0.1	12	0	0	0	1	0.6	1.5	0.1	13
	2030	0.6	1.4	0.1	11	0	0	0	1	0.6	1.4	0.1	12
	2031	0.5	1.2	0.1	9	0	0	0	1	0.5	1.2	0.1	10
	2027-2031	3.3	9.7	0.5	74	0	0	0	5	3.3	9.7	0.5	79
General (11)	2027	9.3	30.2	6.3	102	0	0	0	4	9.3	30.2	6.3	106
	2028	7.2	20.9	4.2	71	0	0	0	4	7.2	20.9	4.2	75
	2029	6.1	14.4	2.7	49	0	0	0	4	6.1	14.4	2.7	53
	2030	5.8	13.2	2.4	45	0	0	0	3	5.8	13.2	2.4	48
	2031	5.4	11.4	2.1	39	0	0	0	3	5.4	11.4	2.1	42
	2027-2031	33.8	90.1	17.7	306	0	0	0	18	33.8	90.1	17.7	324
Large General (12)	2027	1.4	6.2	0.6	2	0	0	0	0	1.4	6.2	0.6	2
	2028	1.1	4.3	0.4	1	0	0	0	0	1.1	4.3	0.4	1
	2029	0.9	3	0.3	1	0	0	0	0	0.9	3	0.3	1
	2030	0.9	2.7	0.2	1	0	0	0	0	0.9	2.7	0.2	1
	2031	0.8	2.3	0.2	1	0	0	0	0	0.8	2.3	0.2	1
	2027-2031	5	18.5	1.8	6	0	0	0	0	5	18.5	1.8	6
Small Industrial (21)	2027	0.9	4.2	0.2	13	0	0	0	0	0.9	4.2	0.2	13
	2028	0.7	2.9	0.1	9	0	0	0	0	0.7	2.9	0.1	9
	2029	0.6	2	0.1	6	0	0	0	0	0.6	2	0.1	6
	2030	0.5	1.8	0.1	6	0	0	0	0	0.5	1.8	0.1	6
	2031	0.5	1.6	0.1	5	0	0	0	0	0.5	1.6	0.1	5
	2027-2031	3.1	12.4	0.5	39	0	0	0	0	3.1	12.4	0.5	39
Medium Industrial (22)	2027	0.8	4.6	0.6	20	0.3	0.8	0.1	1	1.1	5.4	0.7	21
	2028	0.6	3.2	0.4	14	0.3	0.8	0.1	1	0.9	4	0.5	15
	2029	0.5	2.2	0.3	10	0.3	0.8	0.1	1	0.8	3	0.4	11
	2030	0.5	2	0.2	9	0.3	0.6	0.1	1	0.8	2.6	0.3	10
	2031	0.4	1.8	0.2	8	0.3	0.6	0.1	1	0.7	2.4	0.3	9
	2027-2031	2.7	13.9	1.8	61	1.6	3.5	0.4	5	4.3	17.4	2.2	66
Large Industrial (23, 25)	2027	3.3	22.8	2.6	15	0.7	3.3	0.4	1	4	26.1	3	16
	2028	2.6	15.8	1.7	10	0.7	3.3	0.4	1	3.3	19.1	2.1	11
	2029	2.2	10.9	1.1	7	0.8	3.3	0.4	1	3	14.2	1.5	8
	2030	2.1	10	1	7	0.7	2.5	0.3	0	2.8	12.5	1.3	7
	2031	1.9	8.6	0.9	6	0.7	2.5	0.3	0	2.6	11.1	1.2	6
	2027-2031	12.1	68.2	7.3	45	3.6	14.8	1.8	3	15.7	83	9.1	48
Municipal (24)	2027	0	0	0	0	0	0.1	0	0	0	0.1	0	0
	2028	0	0	0	0	0	0.1	0	0	0	0.1	0	0
	2029	0	0	0	0	0	0.1	0	0	0	0.1	0	0
	2030	0	0	0	0	0	0.1	0	0	0	0.1	0	0
	2031	0	0	0	0	0	0.1	0	0	0	0.1	0	0
	2027-2031	0	0.1	0	0	0.2	0.5	0.1	0	0.2	0.6	0.1	0
Unmetered (999	2027	0	0	0	0	0	0	0	0	0	0	0	0
	2028	0	0	0	0	0	0	0	0	0	0	0	0
	2029	0	0	0	0	0	0	0	0	0	0	0	0
	2030	0	0	0	0	0	0	0	0	0	0	0	0
	2031	0	0	0	0	0	0	0	0	0	0	0	0
	2027-2031	0	0	0	0	0	0	0	0	0	0	0	0
Total		62.1	218.7	30.1	570	5.4	18.8	2.3	31	67.5	237.5	32.4	601

(h) E1 has customer agreements in place for many Custom projects that are expected to be completed in the early years of the Preferred Plan at current incentive levels. The program delivery structures, types of projects, and associated incentives vary but this pipeline of projects provides more certainty around near-term (2027–2028) costs. Longer-term (2029–2031), E1 expects more complex projects to be a focus for Custom support to further diversify and mitigate Savings Verification risks. As such, E1 looked at its current average incentives when excluding these lower cost projects (e.g., compressed air leak audits) and increased future incentives to those amounts.

Request IR-20:

Reference: Exhibit E-1, Appendix B, pages 11–12 of 23.

Preamble: Table 1 shows rate and bill impact as a result of the 2027 – 2031 Preferred Plan, which shows markedly lower participant bill impact benefits for Medium Industrial and Large Industrial classes compared to most other rate classes.

On pages 11-12, E1 states that participant savings vary by class because simple lighting, heating, and hot water measures have a larger bill impact for lower-consumption classes, while for higher-consumption classes, "particularly medium and large industrial," the same measures lower bills by a smaller proportion because a significant portion of consumption is tied to more complex industrial processes.

(a) Provide a similar Table 1 analysing Rate and Bill Impacts for the Alternate Scenario.

(b) Please provide the analysis, assumptions, or workpapers that support E1's conclusion that the lower participant bill impacts for Medium Industrial and Large Industrial customers are attributable to the proportion of consumption tied to "complex industrial processes".

(c) Please explain whether E1 considers participant average bill impacts of approximately 4% to represent a sufficient participant value proposition for Medium Industrial and Large Industrial customers, and identify any benchmarks, customer feedback, or prior program experience relied on to support that conclusion.

i) Does E1 view this level of participant payback as a barrier for participation? Please explain.

(d) For the Medium Industrial and Large Industrial rate classes, please provide the assumed average participant load profile (including load factor), average annual consumption, average savings per participant, and average bill reduction used to calculate the participant average bill impacts.

ii) Please similarly provide non-participant average bill impact.

(e) Approximately how much (in customer numbers and overall load) of each rate class are participants vs. non-participants.

(f) For Medium Industrial customers, please explain (qualitatively and with supporting calculations) how non-participants are anticipated to see bill savings of 0.1%.

Response IR-20:

(a) Please refer to Table 1 of this IR response.

Table 1: Rate and Bill Impacts by Rate Class as a Result of 2027 - 2031 DSM Alternate Scenario Activities.

Rate Class	Rate Codes	Average Rate Impact (%)	Average Rate Impact (cents/kWh)	Participant Average Bill Impact	Non-Participant Average Bill Impact	Total Class Average Bill Impact
Residential	2, 3, 6, 9, 16 (Domestic)	0.55%	0.09	-16.30%	0.48%	-0.74%
Small General	10	0.88%	0.14	-37.30%	0.79%	-1.99%
General	11	0.74%	0.11	-11.64%	0.74%	-3.12%
Large General	12	0.33%	0.04	-3.48%	0.33%	-3.30%
Small Industrial	21	0.76%	0.11	-27.51%	0.76%	-3.09%
Medium Industrial	22	-0.12%	-0.03	-4.30%	-0.12%	-2.19%
Large Industrial	23, 25, one-part high voltage real time pricing tariff	0.58%	0.05	-3.97%	0.58%	-3.42%
Municipal	24	0.26%	0.03	-0.03%	0.26%	-0.03%

In preparing this response, E1 identified an error in the referenced table from Appendix B. The Average Rate Impact (cents/kWh) for the Municipal rate class has been revised from 0.05 to 0.03. See NSEB IR-58 for a revised version of the table.

(b) E1 maintains that the bill savings achieved in the Medium Industrial and Large Industrial customers are meaningful. The referenced statement in the RBIA report was intended to contextualize why percentage bill reductions in these rate classes may be lower than those observed in smaller commercial or residential classes, rather than to suggest that savings are insignificant.

The primary assumption underpinning this conclusion is that industrial electricity consumption is disproportionately concentrated in process-related end uses ("complex industrial processes"), which present fewer and more constrained opportunities for energy efficiency improvements relative to non-process loads.

This assumption is supported by data from the 2022 U.S. Energy Information Administration (EIA) Manufacturing Energy Consumption Survey (MECS)[1], which indicates that:

- 78 percent of electricity consumption in manufacturing is attributable to direct process end uses (i.e., energy used for core production activities).
- 18 percent is associated with direct non-process end uses (e.g., lighting, HVAC, and facility support systems). These are end uses that may also be found on commercial, residential, or other sites.
- The remaining 4 percent was attributed to indirect uses or not reported.

[1] 2022 U.S. Energy Information (EIA) Manufacturing Energy Consumption Survey (MECS). Table 5.3. U.S. Energy Information Administration - EIA - Independent Statistics and Analysis

By comparison, commercial and residential customers typically have a much larger share of consumption tied to non-process loads (e.g., lighting, and HVAC), where well-established efficiency measures can achieve relatively deeper energy reductions. This structural difference can lead to comparatively higher percentage bill savings in those sectors.

For industrial customers, the dominance of process loads can limit the achievable savings because:

1. Process end uses are production-critical

These loads are directly tied to transforming raw materials into finished goods. Energy reductions are therefore constrained by requirements for throughput, quality, and product specifications.

2. Technical limitations on efficiency improvements

- Process heating (often ≥100°C): High-temperature applications have limited commercially viable high-efficiency alternatives. Emerging solutions (e.g., high-temperature heat pumps) remain constrained by efficiency losses, material limits, and system integration challenges.
- Chemical processes: Energy use is often dictated by thermodynamic and chemical requirements (e.g., cement production, pulp and paper, or laboratory processes). Efficiency gains may require fundamental process redesign, making them more complex, capital-intensive, and less widely applicable.
- Machine drive systems: While improvements (e.g., variable frequency drives, high-efficiency motors) are available, many facilities have already adopted these measures, reducing remaining savings potential.

3. Savings opportunities are concentrated in ancillary systems

Energy efficiency programs can achieve savings through non-process and support systems (e.g., compressed air, pumping, refrigeration). However, these systems typically represent a smaller share of total energy use in industrial facilities, which constrains overall bill impact.

Given these characteristics, E1's conclusion is that lower percentage bill impacts for Medium and Large Industrial customers are consistent with the underlying energy use profile of these sectors, relative to other sectors.

This rationale also supports the need for specialized program offerings tailored to industrial customers, such as:

- Custom retrofit program
- Strategic Energy Management (SEM)
- Industrial Energy Manager program

(c) Yes, E1 considers a reduction in electricity bills to be of value to customers.

The RBIA bill impact is measured compared to a No DSM scenario, meaning it already accounts for DSM-related costs, including bill impacts associated with higher rates. As a result, the estimated bill impacts are net of these effects.

In practice, an average participant's bill savings would likely be greater when calculated using their actual rates, rather than compared to a counter-factual No DSM scenario.

i) The RBIA confirms that for the average Large Industrial and Medium Industrial participant, energy savings more than offset any rate impacts associated with DSM. E1 does not view this as a barrier to participation.

(d) The following IR response was provided by Elenchus.

The requested information is provided in Table 2 of this IR response. Values are 5-year averages from 2027 to 2031. The load factors for participants and non-participants are calculated based on average energy requirement and coincident peak data provided by NS Power. The high Medium Industrial participant load factor is mostly attributable to demand response and is 80.6% when demand response is excluded. All Large Industrial customers are participants from 2028 to 2031 so the load factors values are for 2027 only. Large Industrial non-participant average annual consumption, average savings, and average bill impacts reflect a hypothetical non-participant.

i) The following IR response was provided by Elenchus.

Please refer to Table 2 of this IR response.

Table 2: Medium Industrial and Large Industrial Participant and Non-Participant Characteristics

	Medium Industrial		Large Industrial	
	Participant	Non-Participant	Participant	Non-Participant
Load Factor %	129.6%	80.8%	102.0%	100.0%
Average Annual Consumption (MWh)	2,607	2,742	21,952	23,774
Average Annual Savings (MWh)	135		1,822	
Average Bill Impact %	-7.0%	1.6%	-3.3%	4.7%

(e) Please refer to Tables 3 and 4 of this IR response.

Table 3: Medium Industrial Active Participants, Non-Participants & Associated Load

	2027	2028	2029	2030	2031
Total Customers	184	185	186	187	188

Active Participants	48	74	94	113	132
Active Non-Participants	136	111	92	74	56
Participant Monthly Usage (kWh)	218,650	215,579	216,527	217,345	218,312
Non-Participant Monthly Usage (kWh)	228,421	226,868	228,201	229,062	229,944
Participant Sales (GWh)	127	191	245	295	345
Non-Participant Sales (GWh)	372	302	251	203	156
Total Sales (GWh)	499	493	496	498	501

Table 4: Large Industrial Active Participants, Non-Participants & Associated Load

	2027	2028	2029	2030	2031
Total Customers	32	32	32	32	32
Active Participants	30	32	32	32	32
Active Non-Participants	2	0	0	0	0
Participant Monthly Usage (kWh)	1,869,060	1,828,375	1,822,267	1,816,219	1,810,584
Non-Participant Monthly Usage (kWh)	1,943,323	1,947,915	1,979,369	2,005,887	2,029,375
Participant Sales (GWh)	662	702	700	697	695
Non-Participant Sales (GWh)	58	0	0	0	0
Total Sales (GWh)	720	702	700	697	695

(f) Non-participants will experience bill savings when DSM has a negative rate impact. This is the case for the Medium Industrial rate class, where in the proposed 2027–2031 DSM Preferred Plan the average rate impact is -0.12%.

E1 has provided the calculation of the Medium Industrial Non-Participant Bill Impact for 2032 below. 2032 was selected to highlight a year where rate impacts and non-participant bill impacts are negative since there is year-to-year variability. This calculation can also be found in the RBIA model (Appendix B – Attachment 9, tab 'MI-Bills').

$$M.Bill\ Impact = M.Bill_{DSM} - M.Bill_{No\ DSM}$$

$$M.Bill_{DSM} = M.Usage_{DSM} * Rate_{DSM} + M.Customer\ Charge$$

$$M.Bill_{No\ DSM} = M.Usage_{No\ DSM} * Rate_{No\ DSM} + M.Customer\ Charge$$

Variable	Unit	Definition / Explanation	Value
M.Bill Impact	\$/month	Difference between monthly bills in the DSM scenario compared to the No DSM scenario.	-\$371
$M.Bill_{DSM}$	\$/month	Monthly bill in the DSM scenario (non-participant)	\$32,093
$M.Bill_{No\ DSM}$	\$/month	Monthly bill in the No DSM scenario.	\$32,464
$M.Usage_{DSM}$	kWh	Monthly usage in the DSM scenario for a non-participant.	229,902
$M.Usage_{No\ DSM}$	kWh	Monthly usage in the No DSM scenario. Non-participants have the same usage in both scenarios.	229,902
$Rate_{DSM}$	\$/kWh	Electricity rate in the DSM scenario. Includes demand costs.	0.13959
$Rate_{No\ DSM}$	\$/kWh	Electricity rate in the No DSM scenario. Includes demand costs.	0.14121
M.Customer Charge	\$/month	Monthly customer charge. Same in the DSM and No DSM scenarios. Only applies to Residential and Small General rate classes.	\$0

Note: the RBIA model uses the following terminology: ‘Base scenario’ (No DSM scenario) and ‘Alternate scenario’ (DSM scenario).

Request IR-21:

Reference: Exhibit E-1, Application, Appendix B, Attachment 2, Tables 7 and 15.

Preamble: Table 15 of Appendix B, Attachment 2 provides planned rate-class savings and expenditures at the portfolio level for the 2027–2031 Preferred Plan.

Please provide:

(a) A version of Table 15 disaggregated by individual program component (e.g., Custom Incentives, BNI Efficient Product Rebates, BNI Demand Response including Smart Synergy, Enabling Strategies sub-categories, Solar PV, etc.) for each rate class and each year of the Plan period; and

(b) The equivalent program-level, rate-class-level breakdown for 2023, 2024, 2025 (actual), and 2026 (forecast/approved).

Response IR-21:

(a) Table 15 of Appendix A, is disaggregated by individual programs (Residential Efficient Product Rebates, Existing Residential, New Residential, BNI Efficient Product Rebates, Custom Incentives, Direct Installation, Demand Response, Solar-PV, and Enabling Strategies) in Appendix A, Attachment 2 of the 2027–2031 DSM Resource Plan application.

A version of Table 15 disaggregated by individual program components is provided in Attachment 1 of this IR response.

(b) Please refer to Attachment 1 of this IR response.

Request IR-22:

Reference: Exhibit E-1, Appendix D, Schedule B (Compensation).

(a) Please explain the rationale for changing the language in the compensation schedule from "surplus" to "underspend". What are the practical and legal implications arising from this change?

(b) Footnote 1 notes that the amount refunded to NSPI will include interest earned by E1. Please provide: (i) the interest earned during the 2023–2026 Plan period; (ii) the rate(s) used to calculate/apply interest; and (iii) the interest rate E1 anticipates accruing on any "underspend" during the 2027–2031 DSM Plan period.

i) Does E1 anticipate providing any reporting on the interest accrued, and if not, is E1 opposed to this reporting?

(c) Please explain why the contract no longer includes confirmation that any "surplus" or "underspend" will be refunded to NSPI in the first year of the new Plan and applied to the payment amounts planned for E1?

(d) Does E1 take the position that any "underspend" is only owed to NSPI on a cumulative basis over the full five-year period, or will it be paid/refunded once the amount is confirmed within the first year of the plan? Please explain.

(e) Please provide the anticipated payment schedule from NSPI to E1 throughout the duration of the Plan.

Response IR-22:

(a) In preparing the response to this IR, EfficiencyOne (E1) acknowledges that the use of the term "underspend" in Exhibit E-1, Appendix D, Schedule B is an error and should read “surplus" throughout. E1 confirms that this correction will be made consistently throughout the final Purchase Agreement prior to execution.

(b) E1 has reported in its Audited Financial Statements the following DSM interest earned on restricted DSM cash balances (in thousands of Canadian dollars): 2023 - $768; 2024 - $885; 2025 - $243. These statements are filed annually with the Nova Scotia Energy Board (NSEB) in April. The 2026 interest figure will not be available until the 2026 Financial Statements have been audited and approved by E1’s Board of Directors. Interest is calculated using the bank's prevailing interest rate applicable to the restricted DSM cash balances, which may fluctuate during any given period. Accordingly, E1 is unable to forecast the interest that may be earned during the 2027–2031 DSM Plan period.

i) E1 is not opposed to providing information on interest in its annual reporting.

(c) The 2019 surplus referenced in the 2023–2025 Supply Agreement was an anomaly relative to E1's historical practice. Consistent with past practice, all DSM Plan surpluses have historically been returned in the second year of the applicable DSM Plan. The surplus amount from the 2023–2026 DSM Plan will not be available until April 2027, following the audit and approval of the 2026 Financial Statements by E1’s Board of Directors. As this occurs after NS Power has filed its 2027 Demand Side Management Cost Recovery Rider (DCRR) application, the surplus will be applied to the 2028 DCRR application.

(d) E1's position is that any surplus will be returned in the second year of the 2027–2031 DSM Plan period, calculated on a cumulative basis over the full 2023–2026 DSM Plan period and inclusive of interest earned on restricted DSM cash balances during that period. DSM Plan spending and targets are approved for a five-year period - the duration of the agreement - and are not assessed or settled on an annual basis.

(e) Consistent with past practice, the payment schedule will be completed upon the NSEB’s approval of the DSM Plan.

Request IR-23:

Reference: Exhibit E-1, Appendix D, Schedule C (Performance Requirements).

(a) The contract appears to remove the "trigger" for a regulatory process previously outlined in section (a)(ii), where performance dips below the target by 10%. Please confirm.

(b) If the trigger is removed, please explain the significance of this change, including E1's understanding of how the Board may exercise its discretion in such circumstances?

(c) Please provide the rationale for this change and describe the circumstances in which E1 must apply to the Board in relation to performance variances.

Response IR-23:

(a) EfficiencyOne (E1) confirms that the revised contract language does not include a mandatory trigger for a regulatory process where performance falls below the target by 10%, as was previously outlined in section (a)(ii). The prior draft created an automatic procedural obligation upon the occurrence of that performance variance. The revised language instead vests discretion in the Nova Scotia Energy Board (the "Board") to determine whether a performance variance of that nature warrants the initiation of a regulatory process. E1 understands that the Board may exercise this discretion having regard to the nature, cause, and duration of the variance, as well as any relevant contextual factors, including whether E1 has taken or is taking corrective action. E1 acknowledges that the Board retains broad authority under the applicable regulatory framework to initiate a process at any time it considers appropriate, and that the absence of a mandatory trigger does not limit or fetter that authority.

(b) Please refer to E1's response to (a).

(c) Please refer to E1's response to (a).

Request IR-24:

Reference: **Exhibit E-1(iv), “Preferred Plan” tab and “Alternate Scenario” tab.**

Preamble: **The following tables have been copied from the “Preferred Plan” tab:**

DSM (All Resources)

Rate Impacts								
	Residential	Small General	General	Large General	Small Industrial	Medium Industrial	Large Industrial	Municipal
2027	3.73%	5.13%	5.14%	4.09%	4.35%	2.60%	6.26%	2.62%
2028	4.30%	5.27%	5.07%	3.91%	4.54%	2.66%	6.02%	3.13%
2029	4.33%	4.48%	4.14%	3.25%	3.81%	2.09%	5.18%	2.89%
2030	3.27%	3.32%	2.91%	1.92%	2.60%	0.67%	3.45%	1.82%
2031	2.79%	2.73%	2.33%	1.26%	2.05%	-0.02%	2.62%	1.36%

Demand Response

Rate Impacts								
	Residential	Small General	General	Large General	Small Industrial	Medium Industrial	Large Industrial	Municipal
2027	-0.02%	-0.10%	-0.11%	-0.08%	-0.15%	-0.26%	0.04%	-0.14%
2028	-0.04%	-0.11%	-0.14%	-0.14%	-0.18%	-0.37%	0.04%	-0.15%
2029	-0.05%	-0.11%	-0.15%	-0.20%	-0.20%	-0.49%	0.04%	-0.15%
2030	-0.06%	-0.12%	-0.17%	-0.26%	-0.23%	-0.60%	0.04%	-0.16%
2031	-0.06%	-0.12%	-0.19%	-0.31%	-0.25%	-0.71%	0.03%	-0.17%

The following tables have been copied from the “Alternate Scenario” tab:

DSM (All Resources)

Rate Impacts								
	Residential	Small General	General	Large General	Small Industrial	Medium Industrial	Large Industrial	Municipal
2027	3.63%	5.13%	5.14%	4.09%	4.35%	2.60%	6.23%	2.63%
2028	4.21%	5.27%	5.07%	3.91%	4.54%	2.66%	5.99%	3.14%
2029	4.25%	4.48%	4.14%	3.25%	3.81%	2.09%	5.15%	2.90%
2030	3.18%	3.32%	2.91%	1.92%	2.60%	0.67%	3.43%	1.82%
2031	2.70%	2.73%	2.33%	1.25%	2.05%	-0.02%	2.59%	1.36%

Demand Response								
Rate Impacts								
	Residential	Small General	General	Large General	Small Industrial	Medium Industrial	Large Industrial	Municipal
2027	-0.12%	-0.10%	-0.11%	-0.08%	-0.15%	-0.27%	0.02%	-0.13%
2028	-0.13%	-0.11%	-0.14%	-0.14%	-0.18%	-0.37%	0.01%	-0.14%
2029	-0.14%	-0.11%	-0.15%	-0.20%	-0.21%	-0.49%	0.01%	-0.15%
2030	-0.14%	-0.12%	-0.17%	-0.26%	-0.23%	-0.60%	0.01%	-0.16%
2031	-0.15%	-0.13%	-0.19%	-0.31%	-0.25%	-0.71%	0.01%	-0.16%

(a) Please confirm that Large Industrial customers under the Preferred Plan will see a rate impact of 6.26% in 2027 and 6.02% in 2028.

i) If not confirmed, please explain how to interpret this table.

(b) Please provide a table showing the annual impact of the Preferred Plan on the DSM rate rider for each year from 2026 through 2032, inclusive. State all assumptions.

i) Please provide the same table for the Alternate Scenario.

(c) Please provide a version of these Rate Impact tables (in excel format) for both the Preferred and Alternate Plan that combines historical RBIA with forecasts such that combined annual rate impacts from 2011 to 2046 include all DSM plan years from 2011 to 2031 (i.e. include 2023 – 2026 years).

i) From these tables, please calculate the cumulative rate impacts for each rate class as a result of actual and forecast DSM rate impacts from 2011 to 2046.

(d) Please explain why under both the Preferred and Alternate Plans, Large Industrial customers will see rate increases over the DSM plan period for Demand Response when every other customer class will see rate decreases?

Response IR-24:

(a) The Rate and Bill Impact Analysis (RBIA) estimates a Large Industrial rate impact of 6.26 percent in 2027 and 6.02 percent in 2028.

i) The following context helps interpret these results and the impacts that customers will experience:

- RBIA rate impacts are measured relative to a No DSM scenario and are not incremental.
- Rate impacts reflect the combined effects of program cost recovery, lost revenue, and avoided costs. The RBIA assumes these effects are fully incorporated into rates each year. While this assumption generally holds for program cost recovery, lost revenues and avoided costs may not be fully reflected outside of a General Rate Application (GRA).
- The RBIA typically shows the highest rate impacts in 2027–2028, followed by a gradual decline from 2029 to 2031, and then a more significant drop beyond 2031. The elevated impacts in 2027–2028 are partly driven by the annual avoided cost assumptions provided by NS Power, which indicate very low avoided energy costs in those years. The decline after 2031 reflects the end of program cost recovery for the 2027–2031 DSM Plan.

(b) Please refer to EfficiencyOne's (E1) response to IG IR-09, part (c).

i) Please refer to E1's response to IG IR-09, part (c).

(c) Attachment 1 to this IR response was prepared by Elenchus.

Please refer to Attachment 1 of this IR response for combined rate impacts of historic DSM activities (2011 – 2026) and DSM Plan activities (2027 – 2031).

i) Rate impacts are compared to a No DSM scenario and are not cumulative.

(d) The following IR response was provided by Elenchus.

Large Industrial customers have rate increases over the DSM plan period for Demand Response because the impact of reallocating demand-related costs to the Large Industrial class exceeds the impact of reduced demand-related costs. The Demand Response program reduces Large Industrial peak demand by an average of 0.17 percent through the DSM plan period, compared to an average total system peak demand reduction of 1.09 percent, so a higher percentage of all demand-related costs are allocated to the Large Industrial class. The reduction in peak demand also increases the system load factor, which increases the share of costs classified as energy-related. The Large Industrial class receives a higher allocation of energy-related costs than demand-related costs.

Request IR-25:

Reference: Exhibit E-1(i), Excel File, Tab "Key Model Assumptions".

Preamble: Energy and Demand line loss factors are used as an input. E1 states:

> **Line loss factors were developed by E1 using rate-class level line loss data provided by NSPI as part of its 2014 Cost of Service Study (COSS) and applied in the modelling of DSM resources.**

In NSPI's Cost of Service Study, filed and approved as part of the 2026/27 GRA, Matter M12451, energy and demand line losses were updated via a study performed by externally hired consultant BBA.

(a) Please explain all calculations for which line losses are included as an input.

i) Please include the formula used in each of these calculations.

(b) Please update the values in question (a) for the updated 2024 line loss study results.

Response IR-25:

(a) Energy and demand measure inputs are characterized at the meter. However, EfficiencyOne's (E1) performance targets, as well as the cost-effectiveness benefits (avoided costs) from savings are characterized at the generator. Line losses bridge this gap, bringing everything to an at generator basis for all resources, energy efficiency energy and demand savings, demand response available capacity and solar-PV generation.

Line loss factors are also used in the Rate and Bill Impact Analysis (RBIA) for the same purpose, to convert impacts between at meter and at generator.

i) Line losses are a direct input to the modelling software and are applied within the modelling process.

(b) Table 1 of this IR response provides the estimated impact of the 2026 GRA line losses on key 2027–2031 DSM Plan outputs. These results were not generated by the Guidehouse ProCESS or DRSim model; rather, they were produced through a manual calculation performed by E1 outside the model, using the same underlying data as the DSM Plan, but substituting the 2014 COSS line loss factors used in the proposed 2027–2031 DSM Plan as filed, with the 2027 line loss factors filed in NS Power's 2026 General Rate Application matter M12451.[1] While this approach provides a reasonable estimate, it should be understood as an approximation.

Table 1: Estimated Impact of 2026 GRA Line Losses on Key 2027–2031 DSM Plan Outputs

	First-Year Energy Savings (GWh)	Lifetime Energy Savings (GWh)	Peak Demand Savings (MW)	Available Demand Response Capacity (MW)	Solar-PV Generation (GWh)
2027–2031 DSM Plan *As Filed*	435.4	5,335.1	85.0	29.3	1.7
2027–2031 DSM Plan *2026 GRA Line Losses*	435.1	5,340.8	86.3	30.3	1.7
Difference	-0.4	5.7	1.3	1.0	0.0
Percent Change (%)	-0.1%	0.1%	1.6%	3.4%	-1.1%

[1] M12451, Nova Scotia Power Inc. 2026 General Rate Application, Exhibit N-92, 2026-2027 GRA Compliance Filing, April 7, 2026, SR-01 Attachment 3, Page 67 of 102.

Request IR-26:

Reference: E-2, 2025 Annual Progress Report, Table 7, at page 6; and page 9

(a) Please update Table 7 in E-2, and provide the 2025 Smart Synergy participation and results broken out by individual rate class showing also:

i) Enrolled capacity (MW) by rate class;

ii) Available capacity achieved (MW), by event and on average;

iii) Incentives paid; and

iv) Event non-participation rate.

(b) When and how is an event called in relation to the Smart Synergy program; and does E1 anticipate any changes to the practices from 2025?

(c) E1 identifies an enhancement of 48-hour notice for events (page 9/112). Has the move to 48-hour notice been implemented, and what impact does E1 project this will have on participation rates in 2027–2031? Please provide supporting analysis.

(d) Where E1 reports that Medium Industrial participants represented more than half of both incentives paid and available capacity achieved in BNI Demand Response in 2025, please explain:

i) how the Smart Synergy program and its associated costs serve the interests of the broader BNI rate classes funding it; and

ii) what steps E1 is taking to diversify Smart Synergy participation.

Response IR-26:

(a) Please refer to Attachment 1 of this IR Response.

i) Please refer to Attachment 1 of this IR Response.

ii) Please refer to Attachment 1 of this IR Response.

iii) Please refer to Attachment 1 of this IR Response.

iv) Please refer to Attachment 1 of this IR Response.

(b) Demand response events are called by NS Power based on their forecasting of times of high load, often corresponding with colder temperatures. NS Power provides the notice to EfficiencyOne's (E1) aggregator partner, who then during the event, either remotely controls some energy consuming systems in participant buildings or they contact participants to deploy their load reduction procedure that was developed with support from the aggregator. No changes to this practice are currently anticipated by E1.

(c) In the 2025 demand response season, the amount of advanced notice (16 hours) of demand response events provided by NS Power was identified by industrial participants as a challenge in them participating at the level anticipated. In advance of the 2026 demand response season, E1 worked with NS Power to secure more advance notice with a goal of 48 hours. In the most recent demand response season (the 2026 season that ran from December 1, 2025 to February 28, 2026), the typical notice provided by NS Power was ≥24 hours, with efforts continuing to increase notice to 48 hours in advance, or more, where possible, in future seasons. Demand response events are called by NS Power, so the level of advance notice is ultimately in their control and could be impacted by a variety of factors for specific events.

While increased advanced notice was only one of several factors that contributed to improved results in the BNI Demand Response program component (Smart Synergy) in 2026, it did play a role in the level many participants were able to participate at, and the resulting available capacity achieved in 2026 (tracked results show 13.0 MW was achieved in 2026, compared to 5.9 MW in 2025).

(d) Please refer to parts i) and ii) of this response.

i) The Smart Synergy program and its associated costs are funded by the rate classes participating in it. Rate classes that don’t have participants are not allocated expenditures. For example, the Large Industrial rate class had no participation in the program in the 2023 and 2024 demand response seasons and no expenditures were allocated to the Large Industrial rate classes in those two years. In the 2025 season, Large Industrial participation was minimal and expenditures allocated to that rate were also minimal ($8,000).

ii) Over the course of the 2027–2031 Plan period, E1 will work to manage and monitor Smart Synergy participation levels, in accordance with the rate class allocations and spending in the 2027–2031 Preferred Plan.

	2025 Results - BNI Demand Response (Smart Synergy)																						
	Available Capacity (MW)		**Available capacity achieved by event (MW)**									**Non-participation rate by event (%)**									**Expenditures**		**Participation (#)**
	Enrolled	Achieved	Event 1	Event 2	Event 3	Event 4	Event 5	Event 6	Event 7	Event 8	Average across all events	Event 1	Event 2	Event 3	Event 4	Event 5	Event 6	Event 7	Event 8	Average across all events	Total Expenditures ($ million)	Incentives paid ($ million)	Participation (#)
Residential/Charitable (2,3,4)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-	-	-	-	-	-	-	-	-	-	-	-
Small General (10)	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	80%	66%	89%	81%	46%	39%	66%	35%	63%	0.0	0.0	2
General (11)	8.8	1.8	1.4	1.9	2.2	1.4	1.7	1.8	2.4	1.6	1.8	85%	78%	75%	85%	81%	79%	73%	81%	80%	0.5	0.2	100
Large General (12)	1.0	0.6	0.8	0.9	0.9	0.3	0.4	0.5	0.6	0.7	0.6	27%	13%	17%	71%	58%	54%	43%	33%	40%	0.2	0.1	4
Small Industrial (21)	2.0	0.2	0.0	0.0	0.0	0.0	0.3	0.6	0.3	0.3	0.2	99%	99%	98%	100%	84%	69%	86%	83%	90%	0.0	0.0	4
Medium Industrial (22)	10.1	3.3	3.0	4.9	2.9	2.2	4.2	2.0	2.2	4.8	3.3	71%	52%	71%	78%	58%	80%	79%	53%	68%	0.9	0.4	32
Large Industrial (23, 25)	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.1	0.0	0.0	100%	100%	100%	100%	100%	100%	100%	100%	100%	0.0	0.0	1
Municipal (24)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-	-	-	-	-	-	-	-	-	0.0	0.0	0
Unmetered (999)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-	-	-	-	-	-	-	-	-	0.0	0.0	0
Total	22.1	5.9	5.1	7.8	6.1	3.9	6.7	5.0	5.5	7.5	5.9	77%	68%	75%	86%	71%	70%	74%	64%	73%	1.6	0.7	143

Request IR-27:

Reference: Exhibit E-2, 2025 Report; and Exhibit E-1(ii).

(a) Please provide a version of Exhibit E-1-(ii), in excel format, for the 2025 actual results (reported in Exhibit E-2) by measure.

(b) Please split BNI custom programs by customer class (Large General, Small Industrial, Medium Industrial, Large Industrial, etc.), including for measure level PAC results (as provided in Exhibit E-1-(ii).

Response IR-27:

(a) EfficiencyOne (E1) is unable to accurately present the 2025 actual results in a manner consistent with the 2027–2031 measure level technical tables due to fundamental differences between planning constructs and reporting frameworks. Specifically:

- The 2027–2031 technical tables are forward-looking modelling outputs, developed using assumptions and measure mixes for planning and cost-effectiveness purposes.
- By contrast, 2025 actual results are evaluation-based results, produced through established reporting processes (e.g., Annual Progress Reports and Evaluation Reports) and validated through independent evaluation, measurement and verification (EM&V). E1's 2025 Evaluation Reports does provide additional results and detail at a more granular level.
- E1's reporting framework is program- and portfolio-oriented, and does not track or validate results at the same measure-level granularity or definitions used in the

2027–2031 DSM plan modelling and as presented in the measure level technical tables in Appendix A, Attachment 3 of E1's 2027–2031 DSM Plan Application.

- Additionally, changes in measure definitions, program structures, and resource categories between planning cycles further limit the ability to map historical results to the new technical table format.
- Finally, the technical tables are designed to support portfolio-level performance targets over the full plan term, rather than retrospective year-specific reporting.

As a result, attempting to restate 2025 evaluated results in the format of the 2027–2031 measure-level technical tables would require reconstruction using assumptions that are not part of the evaluated results framework and E1's established reporting processes.

(b) Measure-level results represent the most detailed level available and do not vary by rate class. In contrast, program component results can vary depending on how first-year energy savings, lifetime energy savings, demand savings, and expenditures are allocated across rate classes. For the reasons described in part (a) of this IR response, E1 is unable to provide the 2025 results at the rate class level in the same measure level format as presented in Appendix A, Attachment 3 measure level technical tables. Table 1 of this IR response provides the actual 2025 PAC results for the Custom and Strategic Energy Management (SEM) program components by rate class.

Table 1 provides Custom and SEM 2025 actual PAC results by rate class.

Table 1: Custom and SEM 2025 Actual PAC Results by Rate Class

Rate Class	Custom Actual PAC	SEM Actual PAC
Residential/Charitable (2,3,4)	1.3	-
Small General (10)	7.5	-
General (11)	6.9	-

Rate Class	Custom Actual PAC	SEM Actual PAC
Large General (12)	4.3	-
Small Industrial (21)	5.2	-
Medium Industrial (22)	7.7	2.6
Large Industrial (23, 25)	5.5	3.6
Municipal (24)	7.8	0.6
Unmetered (999)	-	-

Request IR-28:

Reference: N-3, DSM Evaluation Report.

(a) With respect to the Custom Incentives and SEM, please explain the drivers for the change in net-to-gross ratios (NTGRs) compared to earlier evaluations.

(b) Please confirm that these changes to the NTGR affect credited savings and the calculation of customer incentives? If not, please explain.

(c) In practice, when are customer incentives paid in relation to the Evaluation and is there a mechanism to account for differences? Please explain.

Response IR-28:

(a) The following IR response for (a) has been provided by Econoler.

Table 1 below provides the net-to-gross ratios (NTGRs) taken from the 2024 and 2025 Custom Incentives Evaluation reports[1], for the two program components of the Custom Incentives program, Custom and SEM (Strategic Energy Management).

[1] M12186, Exhibit 2, E1 2024 DSM Programs Evaluation Reports, March 31, 2025 and M12780, Exhibit 3, E1 2025 DSM Programs Evaluation Reports, March 31, 2026.

Table 1: Net-to-gross ratios (NTGRs) taken from the 2024 and 2025 Custom Incentives Evaluation

Program component	Service	Project Category	2024 NTGR	2025 NTGR	Change	Explanation
Custom	Building Optimization	N/A	0.91	0.91	-	No change. Established both years using results from the 2021 evaluation.
	Retrofit	Regular Retrofit	0.85	0.92	0.07	NTGR updated with 2025 results. Free-ridership and spillover were measured through participant phone interviews on a sample of projects. NTGR increased, due to a reduction in free-ridership observed in 2025.
		Solar-PV	0.63	0.63	-	No change. Established both years using results from the 2023 evaluation.
		Compressed Air Leak Audit	0.84	0.92	0.08	NTGR updated with 2025 results. Free-ridership and spillover were measured through participant phone interviews on a sample of projects. NTGR increased, due to a reduction in free-ridership observed in 2025.
	Pay-for-Performance	N/A	N/A	0.92	N/A	NTGR updated with 2025 results. Free-ridership and spillover were measured through participant phone interviews (census). No projects generated savings in 2024 for this service.
	New Construction	N/A	0.72	0.82	0.10	NTGR updated with 2025 results. Free-ridership was measured through participant phone interviews on a sample of projects. NTGR increased, due to a reduction in free-ridership observed in 2025. Spillover is assumed to be nil for this service.
SEM	N/A	N/A	1	1	-	No change; NTGR for SEM was assumed to be 1.

(b) Changes to the NTGR affect the credited savings for the Custom Incentives program (comprised of the Custom and Strategic Energy Management (SEM) program components), but they do not impact the calculation of customer incentives. Customer incentives are calculated based on the expected gross energy savings at the customer's meter. The NTGR is then applied to determine the net energy savings that are credited. Basing the total incentive amount on gross savings is understandable and relatable to customers. The gross savings are what the customer experiences, allowing customers to more easily understand their total incentive calculation.

(c) For Custom Retrofit, customer incentives are paid prior to Evaluation. If the savings for a particular project are revised through the evaluation process, it does not impact the incentive for the project and no mechanism is needed to account for these differences. For SEM, customers are typically paid incentives after Evaluation. Because each customer wraps up their year of engagement in the program at the end of each calendar year, most Measurement and Verification reports are received in late December. The Evaluation process is then completed in Q1 of the following year and incentives are then paid out to each customer based on the final evaluated savings.

Request IR-29:

Reference: N-3, DSM Evaluation Report.

(a) Please confirm that the Econoler Evaluation of demand response capacity revealed that in 2025, per participant capacity collapsed from approximately 106kW to approximately 42 kW and non-participant rates rose to approximately 60%.

(b) Has E1 addressed all the structural barriers identified by Econoler (short notice windows, morning events performed better than evening and AMI data unavailability required costly independent metering)? Please explain.

(c) Does E1 collect customer surveys after the DR season regarding the expectations and performance of the Smart Synergy program? If so, please provide.

Response IR-29:

(a) The following response has been provided by Econoler.

Confirmed. As shown in Subsection 6.3 of the 2025 Demand Response (DR) Program evaluation report, Business, Non-profit, Institutional (BNI) DR went from an average available DR capacity per participant of 106 kW in 2024 to 42 kW in 2025, while the average non-participation rate went from 31 percent in 2024 to 60 percent in 2025.[1]

[1] M12780, Exhibit-3, E1 2025 DSM Programs Evaluation Reports, Demand Response Program, page 56.

(b) E1 has addressed these barriers to the extent possible through program delivery improvements, although some barriers remain dependent on NS Power system operations and customer load characteristics.

For short notice windows, E1 has been working proactively with NS Power to improve advance notice where possible. A potential peak event notification has been used in the 2026 season. E1 was able to provide up to approximately 48 hours of notice in some cases, which is an improvement from the previous 16 hours of notice.

With respect to morning versus evening event performance, E1 understands this to be a function of available load within the participating customer base. Most facilities are operating in the morning, while some commercial buildings have limited evening load. However, most industrial customers enrolled in the program have evening load, and E1 expects this to improve as the customer mix evolves. E1 is also tracking customer event-window preferences to monitor available capacity of both morning and evening event capabilities.

With respect to advanced metering infrastructure (AMI) data availability, E1 has addressed the issue through the use of independent metering where required. E1 right-sizes metering to reduce cost as appropriate but does not control AMI data availability.

(c) With the program changes in 2025 program season, E1 did not collect a survey after the DR season for Smart Synergy. E1 is planning to survey the participants from the 2026 season as part of the evaluation process. The survey is part of the BNI DR evaluation process and is being used to collect participant feedback on program satisfaction, barriers, support, communications, incentives, and opportunities for improvement.