E1 Responses to Industrial Group (IG) Information Requests
NON-CONFIDENTIAL

Request IR-01:

Please file the 2026 DSMAG Extension PowerPoint presentation from April 22, 2025.

Response IR-01:

Please refer to EfficiencyOne's response to part (b) of Synapse IR-04.

Request IR-02:

Preamble: At pages 2-3, E1 outlines its performance targets for the 2026 DSM Extension which appear generally lower than the annual targets under the original 2023-2025 DSM Plan approved by the Board.

(a) Please confirm this understanding or explain otherwise.

(b) Where E1 is relying on the increased prescribed investment amount of $63.75 million for 2026, on what basis does E1 justify a lower performance target with a higher investment for the year?

Response IR-02:

(a) Confirmed.

(b) Please refer to EfficiencyOne's response to NSEB IR-08.

Request IR-03:

Reference: Page 3, Table 1.

With respect to the benefits shown for demand response, please confirm that the negative numbers means that the cost of demand response outweighs its net benefits. If not confirmed, please explain.

Response IR-03:

Confirmed.

Request IR-04:

(a) Please provide a table broken down a) by rate class, b) by year from 2016 through 2024, showing the DSM program budget c) as approved, d) actual expenditures by year and e) variance by year.

(b) Please provide the same data for 2025 Q1 and Q2 actual and forecast to year-end.

Response IR-04:

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

(b) EfficiencyOne (E1) has provided the rate class expenditures for the 2025 year-end forecast compared to DSM planned expenditures with variances in Table 1, below. E1 does not break out the DSM Plan rate class expenditures by quarter so only the 2025 Q1 actual expenditures are provided. 2025 Q2 actual expenditures will not be available until the 2025 Q2 Report is filed (August 25, 2025).

Table 1: 2025 Plan, Forecast, and Q1 2025 Actual Expenditures by Rate Class

Rate Class	2025 Expenditures by Rate Class			Q1 2025 Results		
	2025 Plan as Approved ($ million)	2025 Year-end forecast ($ million)	Variance (Year-end forecast to Plan as Approved) ($ million)	Q1 2025 Actual Expenditures ($ million)	Q1 2025 Actual Expenditures as % of 2025 Plan as Approved	Q1 2025 Actual Expenditures as % of 2025 Year-end forecast
Residential/Charitable (2,3,4)	34.5	33.1	-1.4	9.6	28%	29%
Small General (10)	3.0	3.0	0.0	0.9	29%	28%
General (11)	15.4	16.2	0.9	2.5	16%	15%
Large General (12)	3.1	1.8	-1.3	0.2	5%	10%
Small Industrial (21)	1.9	1.3	-0.6	0.4	22%	32%
Medium Industrial (22)	1.1	2.9	1.8	0.4	38%	15%
Large Industrial (23, 25)	2.4	3.2	0.8	1.2	50%	37%
Municipal (24)	1.1	0.4	-0.6	0.2	19%	48%
Unmetered (999)	0.0	0.0	0.0	0.0	N/A	N/A
Total	62.5	62.0	-0.5	15.4	25%	25%

Rate class	Plan As Approved Expenditures ($ million)										Actual Expenditures ($ million)										Variances (Actual Expenditures to Plan as Approved) ($million)									
	2016	2017	2018	2019	2020	2021	2022	2023	2024	**2016-2024**	2016	2017	2018	2019	2020	2021	2022	2023	2024	**2016-2024**	2016	2017	2018	2019	2020	2021	2022	2023	2024	**2016-2024**
Residential/Charitable (2,3,4)	16.6	17.5	15.9	17.0	16.0	17.1	18.1	28.2	31.7	**178.1**	16.8	14.8	15.3	15.9	13.7	16.2	20.4	24.1	37.5	**174.7**	0.2	-2.8	-0.6	-1.1	-2.3	-0.9	2.3	-4.1	5.8	**-3.4**
Small General (10)	1.3	1.1	1.0	1.0	1.0	1	1.1	2.7	2.8	**13.1**	1.0	0.9	2.2	1.7	1.5	2.2	1.9	2.7	3.8	**17.9**	-0.3	-0.2	1.2	0.7	0.6	1.2	0.8	0.0	1.0	**4.8**
General (11)	8.7	10.1	10.3	9.2	10.3	10.8	11.8	13.8	14.3	**99.2**	8.2	9.0	10.8	11.5	8.7	12.0	13.8	10.2	17.4	**101.4**	-0.5	-1.1	0.5	2.3	-1.6	1.2	2.0	-3.6	3.1	**2.2**
Large General (12)	1.8	1.1	1.5	1.4	1.8	1.9	2.1	2.4	2.4	**16.5**	1.0	1.3	1.4	0.8	1.3	1.3	1.9	1.1	0.8	**10.8**	-0.8	0.2	-0.1	-0.6	-0.6	-0.6	-0.2	-1.3	-1.6	**-5.6**
Small Industrial (21)	0.9	1.2	1.3	1.3	1.4	1.5	1.6	1.8	1.8	**12.8**	1.1	1.1	1.1	1.0	1.2	2.0	1.5	0.7	1.3	**11.0**	0.2	-0.1	-0.1	-0.3	-0.2	0.5	-0.1	-1.1	-0.6	**-1.9**
Medium Industrial (22)	1.0	1.2	1.1	1.6	1.1	1.2	1.3	1.0	1.1	**10.5**	0.9	0.9	1.1	1.0	0.1	0.6	0.8	2.0	1.9	**9.3**	-0.1	-0.3	0.0	-0.6	-1.0	-0.6	-0.5	1.0	0.8	**-1.2**
Large Industrial (23, 25)	2.1	1.7	1.7	1.6	1.5	1.6	1.7	2.2	2.3	**16.4**	1.1	1.3	1.2	1.6	1.3	1.4	1.9	4.1	2.3	**16.1**	-1.0	-0.5	-0.5	0.0	-0.2	-0.2	0.2	1.8	0.0	**-0.3**
Municipal (24)	0.7	0.7	1.2	0.9	1.3	1.3	1.4	1.0	1.0	**9.4**	0.8	1.0	0.8	0.6	0.6	0.3	0.4	0.5	0.8	**5.8**	0.1	0.3	-0.4	-0.3	-0.7	-1.0	-1.0	-0.5	-0.2	**-3.6**
Unmetered (999)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.1**	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	**0.1**	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	**0.1**
Total	**33.2**	**34.6**	**33.9**	**34.1**	**34.4**	**36.5**	**39.1**	**53.1**	**57.5**	**356.3**	**30.8**	**30.3**	**33.9**	**34.0**	**28.4**	**36.0**	**42.7**	**45.3**	**65.7**	**347.2**	**-2.4**	**-4.3**	**0.0**	**0.0**	**-6.0**	**-0.5**	**3.6**	**-7.8**	**8.2**	**-9.1**

Request IR-05:

(a) Please define quantitatively what E1 considers a "substantial change to any customer class on an annual basis".

(b) What efforts is E1 taking to avoid such changes and resultant rate impacts at the time of true-up for the four-year plan (and in future)?

Response IR-05:

(a) At this time EfficiencyOne (E1) has not quantitatively defined what constitutes a substantial change both at the rate class expenditure and on a per customer basis. E1 continues to evaluate this issue not only at the total expenditure but also the number of customers within each rate class to comprehensively understand the impact on each individual customer. Customers who participate in E1 programs do accrue benefits over the lifetime of measures installed or upgrades completed. This must also be considered.

(b) Please refer to EfficiencyOne's response to IG IR-08 part (b).

Request IR-06:

Reference: Page 4.

> **This process is already well underway, given the consultation sessions that have already taken place for the 2026-2030 DSM Plan.**

Preamble: The extension application further includes at Appendix A, Table 22, that the "Other Enabling Strategies" budget for 2026 is $3 million which includes: DSM Plan development and reporting, stakeholder engagement, regulatory initiatives, the development of the 2027-2031 DSM Resource Plan, etc. E1 further states E1 has increased the budget "to support the development of the 2027-2031 DSM Resource Plan and initiation of an updated Potential Study to inform the new Independent Energy System Operator's first IRP"".

(a) Please confirm the original budget approved in the 2023-2025 DSM Plan for the development of the 2026-2030 DSM Plan, including the anticipated regulatory expenses in relation to that Plan?

(b) How much of that budget has already been spent?

(c) Has E1 taken into account any underspend from 2025 in relation to the planning and development of the five-year DSM Plan which has now been deferred to 2026? Please explain.

(d) Please confirm the specific budget in the 2026 DSM Extension that is related to the development of the 2027-2031 DSM Plan, along with the overall regulatory budget for the year.

(e) Where E1 notes that much of the process for the development of the new DSM Plan has already taken place, please explain why the budget would need to be increased, rather than decreased for 2026?

Response IR-06:

(a) EfficiencyOne (E1) included in the 2023-2025 DSM Plan an estimate of $4.0 million for the development of the 2026-2028 DSM Plan and the subsequent regulatory approval process. The estimate included E1's directly incurred costs as well as flow through costs related to the Nova Scotia Utility and Review Board's (NSUARB) counsel and their consultants, the Consumer Advocate and their consultants, and the Small Business Advocate and their consultants. Since the 2023-2025 DSM Plan was submitted, two key factors have significantly impacted the work outlined in the plan for this period, leading to unforeseen additional costs: legislative changes and the development of a new Benefit Cost Analysis framework.

Legislation was introduced in October 2022 to amend the Public Utilities Act (Bill 228)[1] that expanded the term of future DSM Plans to five years rather than three years, meaning E1's next DSM Plan would be for 2026-2030 rather than 2026-2028, and the expansion of E1's mandate to include strategic electrification. As a result, there have been additional costs incurred by E1 in the development of the next DSM Plan, which include engagement of a third-party consultant to provide strategic support for strategic electrification and changes to modelling, including both model inputs and outputs to accommodate strategic electrification, changes to the Rate and Bill Impact Analysis model to incorporate new resources being explored for E1's five year DSM Plan (e.g., solar-PV and strategic

[1] Nova Scotia Legislature - Bill 228 - Public Utilities Act (amended) - RA

electrification) and additional support for development of a five-year Plan rather than three years. Additionally, in February 2025, legislation (Bill 6) [2] amended the Public Utilities Act to extend the Board approved 2023-2025 DSM Plan to include 2026. E1 was required to file performance targets for approval for 2026. The costs associated with the development of the 2026 DSM Extension Application were incremental to the Board approved 2023-2025 Plan costs, and to the development of the new 2027-2031 DSM Plan. Work related to the 2027-2031 DSM Plan is continuing.

The NSUARB's Decision on the 2023-2025 DSM Plan included a directive for E1 to work with the Demand Side Management Advisory Group (DSMAG) to "assess and develop an optimal DSM cost-effectiveness testing methodology"[3] or benefit cost analysis (BCA). E1 engaged Energy Futures Group (EFG) to lead the work with the DSMAG through a comprehensive engagement process including several workshops and one-on-one meetings; to prepare the final report; to provide support for E1's Application to the Nova Scotia Energy Board; and to provide support for the subsequent regulatory process. This directive was not anticipated at the time of the 2023-2025 DSM Plan filing. Accordingly, the related costs were not included in the 2023-2025 DSM Plan cost estimates.

Flow through costs from the Regulator's counsel and their consultants, Consumer Advocate and their consultants, and the Small Business Advocate and their consultants have also increased as a result of both the legislative changes and the development of the new BCA.

[2] Bill 6 - An Act Respecting Agriculture, Energy and Natural Resources Chapter 4 Acts of 2025, s. 20, Part IV Public Utilities Act, Chapter 380 Amendments, Royal Assent, March 26, 2025 Nova Scotia Legislature - Bill 6 - Agriculture, Energy and Natural Resources, An Act Respecting - RA.
[3] M10473, E1 2023-2025 DSM Plan, NSUARB Decision, September 6, 2022, para 197 (d).

(b) E1 is forecasting that for 2023-2025, the costs associated with the next DSM Plan development, the subsequent regulatory process, and the BCA activities will exceed the estimates included in the 2023-2025 DSM Plan by $1.8 million due to the factors described in part (a).

Despite the increases in costs for the DSM Plan process, E1 is aware that these increases are required to be offset in other areas of the business and that E1 must continue to manage spending within the NSUARB approved investment level for the 2023-2025 DSM Plan.

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

(d) Please refer to E1's IR Response to Synapse IR-28 part (a).

(e) E1 has considered the work already undertaken in the development of the 2026-2030 DSM Plan in developing the 2027-2031 DSM Plan. The 2026 DSM Extension estimated costs of $1.6 million for the DSM Plan includes only those activities that are planned in 2026 and are lower than the 2025 forecast of $2.6 million.

Request IR-07:

Reference: Page 5, lines 17-21.

The single change to the design objectives employed in the development of the 2026 DSM Extension, was to reduce the percentage investment range for low-income and equity to 15-20 percent (down from 17 to 22 percent under the 2023-2025 DSM Plan). This change was made to account for updated census data showing that the percentage of low-income Nova Scotians had reduced from 17.2 percent to 14.9 percent.

(a) Please provide a link to the Statistics Canada data on which E1 relies and how this relates to the investment level (include the calculation if applicable).

(b) Does E1 now accept that the most updated census data should be used when planning investments in low-income and equity programs? If not, please explain the rationale for the change in the 2026 Plan.

(c) If there are factors other than Statistics Canada data which informs the level of investment, please discuss and explain the weighting to be assigned to each factor.

Response IR-07:

(a) Please refer to EfficiencyOne's (E1) response in NSEB IR-11.

(b) Please refer to E1's response in NSEB IR-11.

(c) E1 did not use factors other than the Statistics Canada 2021 low-income prevalence factor (14.9%) to inform E1's design objective applied to the 2026 DSM Extension as related to the % investment in low-income and equity of total energy efficiency portfolio investment.

Request IR-08:

Preamble: At page 6, E1 states it was directed to "take notice of the concerns raised by the Industrial Group and be prepared to address them in its pending application".

(a) What does E1 understand to be the concerns which were raised by the Industrial Group?

(b) Please provide particular and specific examples how E1 has addressed each of the concerns raised by the Industrial Group.

(c) Does E1 believe the Industrial Group's concern with respect to rate class spending variances is limited to transparency in reporting? If not, please explain.

Response IR-08:

(a) EfficiencyOne (E1) understands the concern raised by the Industrial Group is about unanticipated cost impacts arising from variances in E1's planned DSM expenditures as compared to the actual DSM expenditures by customer class and that these variances could result in unexpected and significant impacts on customer classes where these costs have shifted by rate class. This matter is of particular importance to the Industrial Group as E1 transitions to a five-year DSM Plan. The next Plan will further extend the true-up mechanism. The Industrial Group indicated coordination is needed between E1 and NS Power to ensure that there are no significant impacts on customer classes at the end of the Supply Agreement.

(b) In response to the concerns raised in Matter 11912 – Nova Scotia Power Inc. Application for 2025 DSM Cost Recovery Rider (DCRR) and additional comments the Industrial Group

provided to E1 on rate class spending as part of E1's 2026-2030 DSM Plan Round 2 modelling, E1 has reviewed the causality of the issue and has developed the strategies provided below that can reasonably mitigate concerns raised by the Industrial Group.

Review of Causality of the Issue for Industrial Customers

1) The Impact of New Initiatives

Prior to 2019, expenditures for both the medium and large industrial rate classes were lower than what E1 had estimated in the DSM Plans for those years and as a result in 2019, E1 engaged Dunsky Energy Consulting to conduct a study as part of its ongoing efforts to enhance services for industrial customers. The objective was to help remove barriers for industrial customers to participate in E1's programs. As an outcome of the study, in 2020, E1 developed an industrial strategy in collaboration with several medium and large industrial customers. The objective of the strategy was for E1 to provide energy management support that would help facilitate a multi-year approach to energy planning and to improve industrial customers' ability to be more competitive. The specific actions implemented through this strategy included energy management support both onsite and roving; focus on relationship building through the Business Development managers; expansion of E1's Strategic Energy Management (SEM) program including performance-based incentives; and identifying capital projects that would be eligible for incentives through E1's for Custom program. The strategy was implemented in mid-2021 with three industrial customers and by 2023 this had increased to 15 industrial customers participating. In developing the rate class allocations for the 2023-2025 DSM Plan, E1's estimates, based upon the 2021 information, did not anticipate the popularity of the energy management program.

2) Increased Demand for Support from E1

E1 identified that after the lingering effects of the pandemic, there was an increased uptake in the Custom program to support large industrial projects. Customers initiated projects that had been postponed or not yet started because of the uncertainty caused by the pandemic. These projects are typically larger complex projects that often span multiple years.

3) Launch of Demand Response Programs

The 2023-2025 DSM Plan included a demand response program for the first time. As part of E1's implementation plan, the Business, Non-profit and Institutional (BNI) Aggregator was launched first and as part of the customer recruitment process, several medium industrial customers expressed interest in enrolling. This was not contemplated in the 2023-2025 DSM Plan rate class allocations where E1 relied on its third-party modeler for the development of assumptions. Because E1 had not delivered demand response programs before, there was no historical data available to rely upon.

4) Data Used for Rate Class Allocation

The 2023-2025 DSM Plan energy efficiency rate class allocations were largely developed using 2020 actuals, one year of historical data. E1 agrees that this approach may not have been as fulsome as was required.

E1 has used this causality review to inform strategies to demonstrate E1's responsiveness to the concerns raised by the Industrial Group.

Strategies

1) Improve the accuracy of the estimates used for the rate class allocation of expenditures in the DSM Plan

For the 2026 DSM Extension, E1 established the rate class allocation of expenditures by considering the following factors: reliance on three years of historical data to inform the rate class allocations for both energy efficiency and demand response (i.e., reflective of 2022, 2023, 2024 allocators); completed a review of customer commitments for projects within programs; and incorporated assumptions for any program changes that may impact specific rate classes (in 2026 there were no changes to programs offered to the Industrial Group, but this may apply in the future). E1 intends to review this methodology when preparing the rate class allocation of expenditures for the 2027-2031 DSM Plan to ensure this is informed by the best information available at the time. E1 understands the impact this has on the Balance Adjustment included in NS Power's DSM Cost Recovery Rider and is committed to managing these impacts to the extent possible.

2) <u>Provide enhanced reporting in the Quarterly and Annual Reports</u>

E1 understands the importance of transparency in reporting on rate class spending variances and is committed to enhancing the rate class spending reporting. In 2025, E1 enhanced its rate class reporting within its DSM reports. E1 will build on these enhancements in 2026 by providing year-end forecasts by customer rate class in the quarterly DSM reports to provide additional insights and more discussion on the casualty of variances. Additionally, in the Annual Progress Report, the reporting will be expanded to include an outlook on projected rate class expenditures for the entire Plan period and anticipated variances.

3) <u>Continue to Manage Program Expenditures</u>

E1 will continue to provide explanations for program spending variances compared to the DSM Plan that are greater than 25% in its Quarterly and Annual Progress Report. In the development of the DSM Plan program expenditures and energy savings are

informed by the best information at the time which includes evaluation insights, historical data, customer insights, and ensuring there is industry capacity to support achievability. There are several factors that may influence the implementation including: the level of participation in a program or program component; changes to savings in programs (e.g., changes to evaluated unitary savings, free-ridership levels, adjustment ratios, etc.); and changes to costs in programs (e.g., changes to delivery agent costs, marketing efforts, number of program full-time equivalents, etc.). As a result of these changes, retaining flexibility to shift funding between programs within the approved DSM investment is imperative for E1 to meet the approved performance targets for a DSM Plan. E1 will focus on the implications these shifts may have on rate class expenditures, particularly when the rate class spending is higher as compared to planned. An increase in rate class spending is driven by increased participation by the customers in the rate class, where these customers are receiving financial incentives and other energy management support, and the lifetime benefits associated with the programs.

While achieving board-imposed performance targets is a priority, E1 remains committed to considering rate class spending when reallocating funding between programs.

Program expenditures are managed through E1's annual budget process and quarterly forecasts within the approved DSM Plan investment. E1 does not support establishing caps on the industrial rate classes participation during a DSM Plan implementation given: consultation with all customers impacted would be required - not limited to the industrial group; it could harm customers who want to participate and who require E1's support for a project; there could be implications for future DSM Plan's ability to meet performance targets where customers may be less willing to participate if there is

uncertainty on whether the program would be curtailed on short notice; and there would be inequity created between customers in the rate classes with only a few having access.

Please also refer E1's response to IG IR–16 for more information on managing expenditures for the Custom and Business Energy Rebate programs for typically larger complex projects that often span multiple years.

(c) No. Please refer to part (b) of this IR response.

Request IR-09:

(a) Please explain the "enhanced discussion on variances" referenced on page 6-7.

(b) Please describe the specific steps being taken by E1 to manage inter-class reallocation of budgetary amounts, including a discussion of whether E1 is able to and has imposed caps on program components; has planned for and imposed caps on availability; yearly limits etc.? In responding, please discuss steps taken during the 2023-2025 Plan, if any, and going forward, in 2026.

Response IR-09:

(a) Please refer to EfficiencyOne's (E1) IR response to IG IR-08 part (b).

(b) Please refer to E1's IR response to IG IR-08 part (b).

Request IR-10:

Please provide particulars of all changes to the modelling inputs referenced on page 16 (including lines losses, avoided costs, discount rates, annual energy savings, peak demand savings, incremental costs, and incentives). For each change, please explain the rationale.

Response IR-10:

Overall, the 2026 DSM Extension modelling process remained consistent with the approach used to develop the approved 2023-2025 DSM Plan. The key global model inputs and assumptions applied to the 2026 DSM Extension and updated or changed from the 2023-2025 approved Plan for 2026 DSM Extension modelling including line losses, avoided costs, discount rates, annual energy savings, peak demand savings, incremental costs and incentives are described in Table 2 of Appendix A to the Application.[1]

The input data used to model 2025 savings in the 2023–2025 DSM Plan was developed in 2022, using current available information. Over the course of the three-year implementation period, EfficiencyOne made real-time adjustments informed by program delivery experience, internal performance tracking, independent evaluations, and evolving external factors such as market conditions, technology development, and updates to codes and standards. Internal process improvements were also made during this time frame, leading to updated naming conventions for many measures to allow for additional granularity and transparency.

Consistent with the approach used in the 2023–2025 Plan, the input data for the 2026 DSM - Extension was developed using a bottom-up approach which reflects the most up-to-date

[1] M12249, E1 2026 DSM Extension, Appendix A, Table 2: Key Global Model Input & Assumptions in 2026 DSM Extension Development, April 30, 2025, page 11-13.

information available at the time of model development. Because the 2026 model reflects a rebuild of input data using updated sources, the inputs do not directly correlate to that used in the 2023–2025 model. As such, it is not possible to provide a line-by-line reconciliation of input changes, particularly with respect to technical specifications at the individual measure level.

Request IR-11:

Reference: Page 23, Table 5: 2026 Program Savings and Investment.

(a) Please confirm that the residential energy efficiency programs cumulatively do not pass the total resource cost (TRC) test at 0.9.

(b) If E1 had as an objective that at the residential sector level, the programs should cumulatively pass the TRC tests, what would E1 do to achieve this?

(c) Please confirm that the demand response program does not pass the TRC test cumulatively with a total of 0.7.

(d) If E1 had as an objective to achieve at minimum a 1.0 TRC for the Demand Response program, how would it do so?

(e) Where the residential demand response cost far outweighs the benefits, why are these included as part of E1's plans?

Response IR-11:

(a) Confirmed. The residential energy efficiency programs cumulatively have a total resource cost (TRC) ratio of 0.9.

(b) An objective to cumulatively have a TRC ratio of 1.0 or greater at the sector or program level is not consistent with s. 79H of the *Public Utilities Act (PUA).* The legislative language clarifies that the Board must assess the aggregate of DSM programs rather than evaluating

them individually at the program level. Adoption of this legislative requirement was to allow for broader, more inclusive DSM planning for the benefit of electricity ratepayers. Forcing a program level cost effectiveness test screen would unduly and unnecessarily, restrict EfficiencyOne's (E1) ability to develop a balanced plan consistent with the Board approved balanced plan approach.

The 2026 DSM Extension cost effectiveness results under the TRC, applied in accordance with the PUA at the portfolio level, exceed the threshold ratio of 1.0, with a ratio of 1.6, thereby satisfying the statutory requirement of "cost-effective" under the *PUA*.

E1 uses the cost-effectiveness framework noted above to guide the development of its DSM Plan among other factors, including the concept of a balanced portfolio design; equitable allocation of investment and savings between residential and business sectors; and access to programs by all market sectors and rate classes by addressing barriers to participation. Combined, these considerations ensure that E1's DSM Plans are comprehensive, cost-effective, and beneficial to a wide range of customers while supporting broader environmental and regulatory goals.

Historically the dedicated low-income and equity program components do not individually have a TRC ratio of 1.0 or greater, which is a key driver for the cumulative TRC ratio for the residential energy efficiency programs being less than 1.0. However, as noted above, the DSM portfolio as a whole, has a TRC ratio of 1.6. Cost effectiveness testing at the portfolio level builds in needed flexibility to allow for greater access to energy efficiency programs for customers who may face barriers ensuring equity to all Nova Scotians in reducing energy bills through DSM offerings.

(c) Confirmed. The demand response (DR) programs cumulatively have a TRC ratio of 0.7.

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

(e) The residential DR program component was introduced in the 2023-2025 DSM Plan. Delivering programs in 2023-2025 has provided E1 valuable insights into the actual costs and capacity from DR in Nova Scotia, as well as challenges and opportunities. E1 recognizes that there have been early cost-effectiveness challenges presented by residential DR. E1 is exploring ways to improve cost-effectiveness of residential DR through the continued implementation of a modest residential DR offering. However, as noted above, the DSM portfolio as a whole, has a TRC ratio of 1.6.

While E1 is focused on improving cost-effectiveness of demand response over time, there are additional reasons to pursue DR in Nova Scotia including:

- The inclusion of the residential DR program component is consistent with E1's equity considerations, enabling participation from a broader customer base than to Business, Non-profit and Institutional (BNI) customers alone. When viewed in the context of the overall DSM portfolio, which remains cost effective, this program component currently plays a complementary role to the BNI program component.
- DR aligns with Nova Scotia's goals and policy objectives, including:
    - Nova Scotia's 2030 Clean Power Plan, which prescribes 150 MW of peak reduction from peak management, demand response, and energy efficiency investments.
    - DR can act as a flexible, clean capacity resource, reducing the need for expensive and carbon-intensive peaker plants. This aligns with provincial decarbonization goals including: phasing out coal by 2030; achieving 80% renewable energy by 2030; reaching net-zero emissions by 2050; and implementing the Green Choice Program.

- DR enhances grid reliability and peak demand management. DR plays a critical role in reducing peak demand, enabling NS Power to maintain system reliability, particularly during extreme weather events and periods of supply constraints. The ability of DR resources to ramp up or down quickly adds flexibility to the system. Example: Industrial DR pilot programs have successfully demonstrated peak demand reductions, alleviating stress on the grid during heatwaves and cold snaps.
- Aligns with best practices in other jurisdictions. Many leading jurisdictions, including California (CAISO), New York (NYISO), ISO New England, and Ontario, have successfully integrated DR into their capacity planning and market structures. Example: NYISO treats DR as a firm capacity resource in its forward capacity markets, positioning it alongside traditional generation assets. Notably, Ontario offered both programmatic and market-based DR while the province was in surplus. This allowed the market to mature, and today, now that Ontario is in a supply shortfall, market-based DR is heavily relied on.
- Capability building. Unlike more mature markets, Nova Scotia is still in the early stages of developing its DR framework. Continuing to support DR is essential for retaining the benefits of past investments and fostering long-term market development. The current DR program components are laying the foundation for future expansion, enabling the province to build expertise and operational experience in DR.

Request IR-12:

Reference: Page 24

(a) Please confirm that the two directives (e) and (f) were two recommendations of the Industrial Group in matter M10473.

(b) Please confirm that there is nothing explicit in these directives which limit compliance to multi-year plans. If not confirmed, please identify the specific wording from the Board on which E1 relies, that stated these directives only needed to be complied with when filing a multi-year plan.

(c) Has E1 turned its mind, on an individual basis, for each measure that fails cost-effectiveness testing? If so, please explain the process and how this is accounted for. If not, why not?

(d) Has E1 considered measure payback information when considering proposed incentive levels? If so, please explain the process of that consideration and how it has been accounted for. If not, why not.

(e) Please provide a list of measures in the 2023-2025 DSM Plan which failed cost-effectiveness testing (provide the TRC for each) and indicate whether each of these measures have been included in the proposed 2026 DSM Plan (include the 2026 TRC).

(f) Where there are measures which did not pass the 1.0 TRC, please provide E1's justification for continuing the measure in the 2026 Plan.

(g) Please provide a list of all measures in the 2023-2025 DSM Plan where the payback period was three years or less and identify which of each of these measures are proposed, to form part of the 2026 Plan.

(h) For those measures which are proposed to be included in 2026, please provide the incentive level for each, and indicate whether it has remained the same, gone up or gone down since the 2023-2025 Plan and why.

Response IR-12:

(a) The directives (e) and (f) made by the Nova Scotia and Utility Review Board to EfficiencyOne (E1) in their Decision on E1's 2023-2025 DSM Plan[1] align with two of the recommendations made by the Industrial Group (IG) in their Evidence[2]; however, the wording of the directives is not identical to the IG's recommendations.

(b) Directives (e) and (f) state that the information should be provided in "future resource plans" and "future applications", respectively.[3] E1 understood the 2026 DSM Extension to be a continuation of the approved 2023-2025 DSM Plan, as opposed to a stand-alone new resource plan. As such, E1's Application proposed that directives (e) and (f) from the 2023-2025 DSM Plan Decision be incorporated into the next DSM Resource Plan which E1 considered to be the five-year resource plan (2027-2031).

(c) Please refer to E1's responses to NSEB IR-17 and Synapse IR-11.

[1] M10473, E1 2023-2025 Demand Side Management (DSM) Resource Plan, Board Decision, page 65, Directives (e) and (f), November 8, 2022
[2] M10473
[3] M10473, E1 2023-2025 Demand Side Management (DSM) Resource Plan, Board Decision, page 65, Directives (e) and (f), November 8, 2022.

(d) Please refer to E1's responses to NSEB IR-17 and Synapse IR-11.

(e) Please refer to Attachment 1 of this IR response, filed electronically, for a list of measures which had a Total Resource Cost (TRC) test ratio of less than 1.0 in one or more of the three years modelled in the 2023-2025 DSM Plan. As set out in E1's response to IG IR-10, the naming conventions and groupings of measures have been updated since the 2023-2025 DSM Plan model to provide greater granularity and additional transparency. As a result, E1 is unable to reconcile the measures listed in Attachment 1 on a line-by-line basis with measures included in the 2026 DSM Extension model. Additionally, while prior DSM plan resource models serve as a point of reference for current plans, each new planning cycle incorporates updated data sources, assumptions, and methodologies to reflect current market conditions and best available information. As a result, the analysis carried out for the 2026 DSM Extension is effectively a new modelling exercise using new inputs. Key inputs into the TRC test, including discount rates, avoided costs, incremental costs, savings estimates, incentive levels, measure life, and net-to-gross-ratios have been updated since modelling was carried out for the 2023-2025 DSM Plan. Accordingly, prior cost effectiveness test results are not directly comparable to current test results.

Please refer to E1's response to NSEB IR-17 for a list of all measures in the 2026 DSM Extension with a TRC of less than 1.0, and the justification for the inclusion of the measure in the extension.

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

(g) Please refer to Attachment 2 of this IR response, filed electronically, for a list of all measures with a payback period of three years or less in at least one of the three years modelled in the 2023–2025 DSM Plan. As noted in part (e) above, E1 is unable to directly reconcile the

measures in Attachment 2 with those included in the 2026 DSM Extension model. However, E1 notes that the Affordable Single-Family Homes, Efficient Product Installation, and Mi'kmaw Home Energy Efficiency Project program components provide energy efficiency upgrades at no cost to the participant through a direct installation delivery approach. All measures delivered under these program components had a payback period of zero in each year of the 2023–2025 DSM Plan, and this remains the case in the 2026 DSM Extension.

For the remaining program components, as is the case with cost effectiveness testing, the simple payback calculation relies on updated model inputs, including incremental cost, incentive levels, and measure life. Accordingly, payback period results for measures modelled in the 2023-2025 DSM Plan are not directly comparable to the payback period results included in the 2026 DSM Extension.

Please refer to E1's response to Synapse IR-11 for a list of measures included in the 2026 DSM Extension with a payback period of three years or less as well as information about the other factors that E1 has considered in modelling the proposed incentive level.

(h) Please refer to part (g) of this IR response.

Request IR-13:

Reference: Appendix A, page 4, Table 1: Approved 2023 – 2025 Plan and 2023 and 2024 Results.

Please populate the table with 2025 Q1 and Q2 results and 2025 forecasted to year-end.

Response IR-13:

Table 1, below, has been populated with the 2025 Q1 results and the 2025 year-end forecast as reported in the 2025 Q1 Demand Side Management (DSM) report.[1] 2025 Q2 results are not currently available and will be reported in the 2025 Q2 DSM report to be filed on August 25, 2025. In preparing the response to this IR, EfficiencyOne (E1) identified that the Lifetime Benefits reported in Appendix A, page 4, Table 1 for 2023 and 2024 actuals were for energy efficiency only. E1 has updated the Lifetime Benefits for 2023 and 2024 actuals in the table below to now include both energy efficiency and demand response.

[1] M12290, E1 Q1 2025 DSM Report, May 26, 2025, page 6

Table 1: Approved 2023-2025 Plan with 2023 & 2024 Results and 2025 Q1 Results and 2025 Forecast

2023-2025	Year	Investment ($ million)	Lifetime Benefits ($ million)[a]	First-Year Energy Savings (GWh)	Lifetime Energy Savings (GWh)	Peak Demand Savings (MW)	Available Capacity (MW)	Low-Income & Equity (GWh)	Weighted Average Measure Life (years)
Plan as Approved	2023	53.1	172.6	120.7	1,502	26.9	3.0	5.3	12.4
	2024	57.5	179.7	142.6	1,540	25.6	10.0	5.3	10.8
	2025	62.5	192.6	149.5	1,639	26.3	17.9	5.3	11.0
	2023-2025	173.0	544.8	412.7	4,681	78.8	17.9	15.8	11.3
Results	2023	45.3	211.4	131.6	1,913	27.6	2.4	3.5	14.5
	2024	65.7	243.7	172.8	2,431	30.7	8.1	5.3	14.1
2025 Results and Year-end forecast	2025 Q1 results	15.4	54.7	41.1	500	5.0	0[b]	1.7	12.2[c]
	2025 year-end forecast	62.0	169.0	128.7	1,503	17.2	10.0	5.4	11.7
Results & forecast	2023-2025	173.0	624.1	433.1	5,847	75.5	10.0	14.2	13.4
% Progress (2023 & 2024 results and 2025 forecast)		100%	115%	105%	125%	96%	56%	90%	-

[a] Lifetime ratepayer benefits for 2023 actuals, 2024 actuals, 2025 Q1 actuals 2025 forecast are expressed as the net present value of the avoided costs, including energy, capacity, transmission, distribution, and carbon over the life of the program measures using the avoided costs from the 2023-2025 DSM Plan. A weighted average measure life for the portfolio is used as opposed to individual measure lives, the approach taken when lifetime benefits are calculated as part of the DSM Plan modelling.

[b] Available capacity results from the Demand Response program's 2024/2025 season (December 1 to February 28, 2025) are still being compiled and are expected to be reported in Q2.

[c] Weighted average measure life for Q1 2025 actuals was calculated by dividing the lifetime energy savings by the first year energy savings.

Request IR-14:

Reference: Appendix A, page 27.

In the 2025 DCRR matter, the Industrial Group raised concerns regarding DSM costs shifts and unexpected cost impacts between rate classes arising from variations in E1's planned and actual DSM program spending by customer class through mid-course adjustments. E1 notes that it is the actual spending by rate class that is reported to NS Power for purposes of collecting by rate class through the DSM Rate Rider and that the mid-course adjustment is not used for these purposes.

(a) Does E1 understand that NSPI trues up load variances in the DSM rider (on a two-year lag) during the currency of a multi-year plan, i.e. intra-class true-up? If not, please explain E1's understanding.

(b) What, if any impact to E1's programming and spending does this have?

(c) Does E1 understand that at the end of a multi-year plan, mid-course adjustments i.e. program approved budget and spending are trued up in the DSM rider, in addition to the lagging load variance? If not, please explain.

(d) Where E1's overall budget is set, is this essentially an inter-class true-up?

(e) What, if any, impact to E1's programming and spending does this inter-class true-up have?

(f) What, if any, impact to E1's programming and spending would elimination of the end-of-plan period inter-class true-up have? Please explain

Response IR-14:

(a) EfficiencyOne (E1) provides the DSM Plan rate class expenditure information, that informs the DSM Rate Rider Application, to Nova Scotia Power Inc. (NS Power) each year. The total amount to be collected is aligned with the approved DSM Plan investment and the Supply Agreement. E1 understands that NS Power is responsible for calculating the DSM Rate Rider and therefore would be responsible for any true up that would be required at the rate class level related to collections.

(b) E1 understands that any load variances from NS Power's DSM Rate Rider calculations which may influence the amounts collected by rate class have no impact on E1's approved DSM investment.

(c) E1 understands that at the end of a multi-year DSM Plan, the actual expenditures by rate class as compared to those estimated in the DSM Plan are trued up. The mid-course adjustments do not impact the true up in the DSM rider.

(d) Yes, for DSM expenditures at the end of a DSM Plan, the true up is inter-class true up.

(e) Please refer to E1's response to IG IR-08 part (b).

(f) E1 cannot speculate on what the impact would be if the inter-class true up was eliminated. Any changes to the current approach may necessitate a full review of program development and spending as well as the possible limitations this could create.

Request IR-15:

Reference: Appendix A, page 27, Table 8: 2026 DSM Extension Rate Class Expenditures.

(a) Please provide a breakdown by program component of the proposed expenditures for each of the Large Industrial and Medium Industrial Classes in 2026 showing the forecast expenditures, cost, energy savings, and demand savings.

(b) Please provide a breakdown by program component of the actual expenditures for each of the Large Industrial and Medium Industrial Classes in 2023 and 2024, 2025 to date and forecasted showing the actual expenditures, energy savings, and demand savings.

Response IR-15:

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

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

LARGE INDUSTRIAL rate class	2023 Actual				2024 Actual				Q1 2025 Actual				2025 year-end forecast				2026 Plan application			
Program component	Expenditures $ (million)	Energy savings (GWh)	Demand savings (MW)	Available capacity (MW)	Expenditures ($ million)	Energy savings (GWh)	Demand savings (MW)	Available capacity (MW)	Expenditures $ (million)	Energy savings (GWh)	Demand savings (MW)	Available capacity (MW)	Expenditures $ (million)	Energy savings (GWh)	Demand savings (MW)	Available capacity (MW)	Expenditures $ (million)	Energy savings (GWh)	Demand savings (MW)	Available capacity (MW)
Business Energy Rebates	1.3	6.1	0.9	-	0.2	0.8	0.1	-	0.4	1.7	0.3	-	0.6	2.3	0.2	-	0.8	3.1	0.5	-
Custom	1.8	10.0	1.2	-	1.5	13.9	1.6	-	0.7	3.0	0.2	-	1.7	12.5	1.7	-	1.9	10.6	1.7	-
Strategic Energy Management	0.7	2.7	0.3	-	0.5	2.8	0.3	-	0.1	0	0.0	-	0.6	2.7	0.3	-	0.6	3.1	0.3	-
BNI Demand Response	0.0	-	-	0.0	0.0	-	-	0.0	0.0	-	-	No results yet	0.0	-	-	0.0	0.2	-	-	1.2
Enabling Strategies	0.2	-	-	-	0.2	-	-	-	0.1	-	-	-	0.3	-	-	-	0.4	-	-	-
Total	4.1	18.8	2.4	0.0	2.3	17.6	2.0	0.0	1.2	4.7	0.5	0.0	3.2	17.6	2.2	0.0	3.9	16.8	2.5	1.2

MEDIUM INDUSTRIAL rate class	2023 Actual				2024 Actual				Q1 2025 Actual				2025 year-end forecast				2026 Plan application			
Program component	Expenditures $ (million)	Energy savings (GWh)	Demand savings (MW)	Available capacity (MW)	Expenditures ($ million)	Energy savings (GWh)	Demand savings (MW)	Available capacity (MW)	Expenditures $ (million)	Energy savings (GWh)	Demand savings (MW)	Available capacity (MW)	Expenditures $ (million)	Energy savings (GWh)	Demand savings (MW)	Available capacity (MW)	Expenditures $ (million)	Energy savings (GWh)	Demand savings (MW)	Available capacity (MW)
Business Energy Rebates	0.7	2.8	0.5	-	0.1	0.5	0.1	-	0.2	0.9	0.1	-	0.3	1.0	0.1	-	0.3	1.2	0.2	-
Small Business Energy Solutions	0.0	0.0	0.0	-	0.1	0.1	0.0	-	0.0	0.0	0.0	-	0.0	0.0	0.0	-	0.0	0.0	0.0	-
Custom	0.4	1.9	0.5	-	0.1	1.1	0.1	-	0.0	0.1	0.0	-	0.4	2.5	0.4	-	0.4	2.2	0.4	-
Strategic Energy Management	0.2	0.7	0.1	-	0.4	1.4	0.2	-	0.1	0.0	0.0	-	0.3	0.7	0.1	-	0.3	0.7	0.1	-
BNI Demand Response	0.6	-	-	1.3	1.0	-	-	4.6	0.1	-	-	No results yet	1.7	-	-	5.1	1.2	-	-	5.9
Enabling Strategies	0.1	-	-	-	0.1	-	-	-	0.0	-	-	-	0.3	-	-	-	0.1	-	-	-
Total	2.0	5.4	1.0	1.3	1.9	3.0	0.4	4.6	0.4	1.0	0.1	0.0	2.9	4.3	0.6	5.1	2.4	4.1	0.7	5.9

Request IR-16:

Reference: Appendix A, page 28.

Each year, spending by rate class is influenced by the mix of participating customers or program activity, particularly in the BNI sector, where the exact timing of project completions can be difficult to predict. E1 understands the importance of reporting on rate class spending variances and is committed to enhancing the rate class spending reporting (refer to Section 10, Reporting). E1 will also continue to ensure that programs provide equity and access to all Nova Scotians so the benefits to those participating continue to be realized.

(a) While the exact timing of project completions can be difficult to predict, what steps has E1 taken to understand and manage project completions (and payout of incentives)?

(b) Does E1 agree that it is good business practices to proactively manage expenditures? If so, does E1 agree this extends to managing program expenditures?

(c) Please list all steps that could be taken by E1 to manage the timing of projects and payouts of incentives.

Response IR-16:

(a) EfficiencyOne's (E1) Custom and Business Energy Rebates programs provide financial support through incentives for customer projects that are often complex and extend over multiple years. E1's customer dedicated energy managers, roving energy managers, and business development managers work with customers to help identify projects and identify where E1 incentives are available. Final approval and direct management of the projects

are the customers' responsibility. E1's program staff, energy managers, and business development managers work with the customer to receive regular status updates on the project progress to inform them of the estimated completion dates. E1 has assigned customers to specific staff and promotes ongoing engagement including regular update meetings to track project progress. An internal project tracker has been developed and E1 staff have regular meetings to discuss each project's progress and the expected timing of the project completion. This informs E1's program forecast which includes the timing of incentive payments and the recognition of energy savings. These are updated regularly. This information is also used to inform E1's annual budget.

(b) Yes. E1 understands the importance of managing all expenditures including program expenditures within an approved budget.

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

Request IR-17:

Reference: Appendix A, page 42, Section 6. Demand Response.

Did E1 prepare final reports on the demand response pilots which identify the "valuable insights and learnings" referenced on page 42? If so, please provide copies.

Response IR-17:

EfficiencyOne (E1) did not produce a standalone final report on the Demand Response (DR) pilots, as these pilots were part of an ongoing program rather than discrete, time-bound projects. As such, the insights and learnings referenced on page 42 of Appendix A have been integrated directly into the design and operation of current DR offerings. Please refer to E1's response to Synapse IR-13.

Request IR-18:

(a) With respect to Table 20, page 43 and the residential demand response program components, please compare E1's offerings to NSPI's SmartGrid NS pilot.

(b) Please discuss how demand response (DR) events are determined and called (e.g., are there seasons, schedules, time frames for demand response, notification requirements, etc.).

(c) What is the upfront incentive to install batteries and what is the performance-based incentive to participate in DR events?

(d) If there is a document for customers outlining this program, please provide.

Response IR-18:

(a) NS Power's SmartGrid NS (SGNS) project was a pilot that has concluded, with a final report filed March 15, 2024.[1] The project's objectives were to gather data and learnings to determine whether distributed energy resources management system (DERMS) management of distributed energy resources (DERs) could deliver various customer and grid benefits. The project demonstrated that by leveraging the adoption of DERs through utility controlled DERMS, NS Power can better achieve its obligations to maintain reliability and system stability, to meet environmental targets, and to reduce upward pressure on rates.

[1] M09985, NS Power, CI C0010778 Smart Grid Nova Scotia Project Final Report, March 15, 2024.

E1 demand response (DR) programs are aimed at increasing DR capacity with the intent of meeting DR objectives set out in NS Power's Integrated Resource Plan (IRP) and the Province's 2030 Clean Power Plan. Please also refer to NS Power's SGNS Final Report section 10 - The Role of EfficiencyOne.

Table 1 compares E1's residential offerings to NS Power's Smart Grid NS residential offerings.

Table 1: E1 Residential Demand Response offerings as compared to NS Power Smart Grid

E1 Res DR (Eco Shift)	NS Power's Smart Grid NS Pilot
Smart thermostats - Utility control of smart thermostats (mini-split heat pumps, central heat pumps, and electric baseboards). - 7,004 participants (2026)	No equivalent offering
Water heaters - Utility control of electric water heaters through smart controllers. - 2,979 participants (2026)	No equivalent offering
Battery control - Active control of customer owned batteries for load shifting and dispatching to the grid. - 64 participants (2026)	Residential Batteries - Utility control of customer batteries to test various use cases. - 133 in-home batteries + 1 test battery - Utility owned assets
EV charging - Managed charging of electric vehicles either through EV supply equipment or on-board charging control (telematics). - 256 participants (2026)	EV Smart Charging - Utility managed charging of electric vehicles to test various use cases. - 100 in-home EV smart chargers (EV supply equipment) - 160 EVs enrolled in on-board charging control via telematics (ev.energy) - Utility owned EV smart chargers.
No equivalent offering	Bi-Directional Chargers - Installation of 2 bi-directional EV chargers & purchase of 4 compatible EVs

(b) DR program event constraints are established by E1, in collaboration with NS Power and E1's delivery providers. DR events are called by NS Power within the established program event constraints. DR events are called when day ahead system margin forecast is low and are expected to generally align with NS Power's Critical Peak Pricing (CPP) events.

E1 DR event constraints:

- Events may be called December through February; Monday through Friday (excluding holidays). Events may be morning or evening events.
- Events may be up to four hours.
- Maximum of 12 events per winter season (December – February).
- Customers receive day-ahead notifications (smart thermostats, EV/EV chargers and home batteries, Smart Synergy). No customer notifications for water heaters as these events typically go unnoticed by customers.
- Customers can opt out of events.

(c) Customers receive a $500 one-time incentive for enrolling a battery storage deceive. The enrollment incentive is intended to increase enrollment in demand response; it is not designed to incentivize the purchase and installation of a new battery system. Customers are also eligible for an annual incentive of $300 per kW based on their average performance across all events per season.

(d) Program documentation for Residential demand response ("Eco Shift") is available on Efficiency Nova Scotia's website: Eco Shift | Efficiency Nova Scotia

Request IR-19:

Reference: Appendix A, page 44, 6.1.2 BNI Demand Response.

(a) Please discuss and define "peak events", and how these are called, any limits in terms of days, seasons, hours etc. In providing your answer, please compare the BNI DR peak events with the Critical Peak Pricing program peak events.

(b) Who provides notice and how it is provided to customers.

(c) Who is eligible to enroll? Is there a document for customers that outlines the program? If so, please provide.

(d) What is the $/kW payment for BNI curtailment?

(e) Is there a penalty for failing to curtail when called on? If so, please explain.

(f) Who are "high potential customers"?

Response IR-19:

(a) Please refer to EfficiencyOne's (E1) response to IG IR-18 part (b).

(b) For BNI Curtailment, E1's service provider sends event notifications to customers via email. Notifications are sent to customers by 4 pm the day before an event. These communications protocols are reviewed with the customer in advance of the demand response (DR) season.

(c) Program documentation (including customer eligibility) for BNI Curtailment ("Smart Synergy") is available on Efficiency Nova Scotia's website: Smart Synergy | Efficiency Nova Scotia.

(d) BNI Curtailment customers receive an annual payment of $100/kW-yr based on the average curtailment across all events in the winter season.

(e) No, there is no penalty for failing to curtail.

(f) "High potential customers" refers to customers who are likely to be able to shift high amounts of capacity during peak periods (winter, morning and evening periods) and therefore are most likely to be successful in the program. E1 considers factors such as the customer's peak winter load; the type of business/operations; the variability in the customer's load profile; and whether the customer is operational during the required hours (winter mornings and evenings).

Request IR-20:

Reference: Appendix A, Page 45, Section 7. Enabling Strategies.

(a) Please expand Table 22 to include the investment for each year from 2023, 2024 and 2025 (separately) planned and actual and provide a breakdown of the investment by area of focus.

(b) Please identify which of these costs are directly assigned to specific customer classes (and which class).

Response IR-20:

(a) Tables 1, 2, and 3, below, show the breakdown of costs for each Enabling Strategies program by area of focus. For the 2023-2025 DSM Plan, these are provided as estimates only for each area of focus. Also, EfficiencyOne would note that for the 2023-2025 DSM Plan costs, some staff costs have shifted between the Enabling Strategies programs to reflect changes that were made during the implementation and, as such, these align with the 2023 and 2024 actuals and the 2025 forecast. The total 2023-2025 DSM Plan Enabling Strategies costs remain the same as approved.

Table 1: Enabling Strategies Education and Outreach

EfficiencyOne 2023-2025 DSM Plan
Enabling Strategies - Education & Outreach

Activities	2023 Plan	2023 Actual	2024 Plan	2024 Actual	2025 Plan	2025 Forecast	2026 Plan
Marketing							
Corporate Marketing , Website & Staff Costs	$ 651,000	$ 660,000	$ 701,000	$ 1,132,000	$ 751,000	$ 1,170,000	$ 638,000
Outreach							
Homeshow &Tradeshows, Sponsorships & Partnerships, Support for Diverse Communities	$ 105,000	$ 124,000	$ 105,000	$ 202,000	$ 105,000	$ 235,000	$ 654,000
Education							
Green Schools & EPP Support	$ 240,000	$ 207,000	$ 240,000	$ 255,000	$ 240,000	$ 258,000	$ 351,000
Total Education & Outreach	$ 996,000	$ 991,000	$ 1,046,000	$ 1,589,000	$ 1,096,000	$ 1,663,000	$ 1,643,000

Table 2: Enabling Strategies - Development & Research

Enabling Strategies - Development & Research

Activities	2023 Plan	2023 Actual	2024 Plan	2024 Actual	2025 Plan	2025 Forecast	2026 Plan
Information & Analytics							
Research & Data Analytics	$ 210,000	$ 230,000	$ 210,000	$ 95,000	$ 210,000	$ 220,000	$ 366,000
Engineering & Planning							
Consultants, Codes & Standards, Innovation & Staff Costs	$ 943,000	$ 569,000	$ 993,000	$ 746,000	$ 993,000	$ 1,397,000	$ 1,248,000
Market Transformation							
Consultants & Staff Costs	$ 297,000	$ 35,000	$ 297,000	$ 297,000	$ 297,000	$ 709,000	$ 740,000
Total Development & Research	$ 1,450,000	$ 834,000	$ 1,500,000	$ 1,138,000	$ 1,500,000	$ 2,326,000	$ 2,354,000

Table 3: Enabling Strategies - Regulatory Affairs

EfficiencyOne 2023-2025 DSM Plan
Enabling Strategies - Regulatory Affairs

Activities	2023 Plan	2023 Actual	2024 Plan	2024 Actual	2025 Plan	2025 Forecast	2026 Plan
DSM Planning							
E1 Costs: DSM Consultants, Professional Fees & Staff Costs	$ 897,000	$ 526,000	$ 1,392,000	$ 2,439,000	$ 1,242,000	$ 2,193,000	$ 1,420,000
Flow Through Costs: NSEB Counsel & Consultants, CA & Consultants, SBA & Consultants	-	-	150,000	260,000	350,000	450,000	150,000
	$ 897,000	$ 526,000	$ 1,542,000	$ 2,699,000	$ 1,592,000	$ 2,643,000	$ 1,570,000
Regular DSM Matters							
E1 Costs: DSM Consultants, Professional Fees & Staff Costs	$ 347,000	$ 306,000	$ 347,000	$ 349,000	$ 347,000	$ 279,000	$ 360,000
Flow Through Costs: NSEB Counsel & Consultants, CA & Consultants, SBA & Consultants	20,000	20,000	25,000	18,000	25,000	25,000	43,000
Regulatory Assessment	40,000	47,000	40,000	77,000	40,000	107,000	107,000
	$ 407,000	$ 373,000	$ 412,000	$ 444,000	$ 412,000	$ 411,000	$ 510,000
Support Independent Energy System Operator's Integrated Resource Plan							
E1 Costs: DSM Consultants, Professional Fees & Staff Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ 920,000
	$ -	$ -	$ -	$ -	$ -	$ -	$ 920,000
Total Other (Regulatory) Costs	$ 1,304,000	$ 899,000	$ 1,954,000	$ 3,143,000	$ 2,004,000	$ 3,054,000	$ 3,000,000

(b) Industrial classes (Small, Medium, and Large) are excluded from the Education and Outreach portion of Enabling Strategies costs as the activities are primarily focused on residential and non-industrial BNI customers.

Request IR-21:

Reference: In Appendix A, page 51 it refers to increased rebates in the spring and fall campaigns for LED lighting.

(a) What percentage of the cost of the product(s) was covered by the incentive in each of these campaigns?

(b) Please explain the "LED baseline changes in 2025" and why increased rebates were required.

(c) Did E1 have data or information that suggested that consumers would not purchase LEDs absent higher incentives? If so, please provide.

Response IR-21:

(a) The 2024 spring and fall campaigns provided rebates of up to 70% and 80% off the package prices, respectively.

(b) As part of the 2022 independent third-party evaluation[1], the evaluator determined that residential LED lamps and fixtures would become the baseline starting in 2025. This determination was based on indications that the market was rapidly moving away from compact fluorescent lamps. The sales of non-A type LED had been increasing since 2019, reflecting the market maturity of this product.

[1] M11071, Exhibit 2, E1 2022 DSM Programs Evaluation Reports, Measure Assessment, Appendix II, March 31, 2023, page 205.

Rebates were raised and promoted during 2024 spring and fall campaigns to increase customer awareness that this would be the final year that rebates would be offered on these product categories. As part of the 2024 program evaluation, customers were surveyed after purchasing rebate eligible LED products to determine the impact of E1's rebates on their decision making. The evaluator measured free-ridership on LED lamps and LED fixtures in 2024 to be 15% and 8%, respectively[2] versus 27% and 14%[3] in the previous survey conducted in 2022, emphasizing that customers would not have purchased these products at full price or would not have purchased the same number of these products without these higher rebates. In the 2022 seasonal campaigns, E1 provided rebates of up to 65% off the package price, compared to 70-80% off the package price in 2024.

In the survey completed in 2022 by the evaluator, E1 asked about participant satisfaction with Business Energy Rebates (BER) rebates, the response was 8.8 on a 10-point scale.[4] When further probed about why they were not more satisfied with the rebate amounts, three of eight responded that the rebate was too small or expected a higher rebate.[5]

(c) Please see part (b) of this IR response.

[2] M12186, Exhibit 2, E1 2024 DSM Programs Evaluation Reports, Efficient Product Rebates Program Report, March 31, 2025, page 31-32.
[3] M11071, Exhibit 2, E1 2022 DSM Programs Evaluation Reports, Efficient Product Rebates Program Report, March 31, 2023, page 41.
[4] M11071, Exhibit 2, E1 2022 DSM Programs Evaluation Reports, Efficient Product Rebates Program Report, Appendix II, Question G3, March 31, 2023, page 27.
[5] M11071, Exhibit 2, E1 2022 DSM Programs Evaluation Reports, Efficient Product Rebates Program Report, Appendix II, Question G4B, March 31, 2023, page 28.

Request IR-22:

Reference: Appendix A, Attachment 3 – 2026 DSM Extension Energy Efficiency Technical Tables.

Preamble: In Section 1.6 of EfficiencyOne 2026 DSM Extension Evidence, page 7 of 25, states that; "Consistent with the concept of an extension to the existing Board approved DSM Plan, there are no new programs contemplated under the 2026 DSM Extension".

This Excel file compares to Appendix A, Attachment 4 excel file (Measure Level Technical Tables for 2023 – 2025) from M104173 with Appendix A, Attachment 3 excel file in this matter (Measure Level Technical Tables for 2026).

(a) For Attachment 3 – please provide a working excel file that calculates values within cells – especially for ratios (TRC Ratio, PAC Ratio, Net-to-Gross Ratio, etc.).

i) Please specify the values used in the TRC Costs (column AD), Total TRC Net Resource Benefits (column AE) and PAC Costs (column AG).

(b) Please align 2026 measures with the 2023 – 2025 tables such that individual measures can be compared – as of now the measure names for 2026 do not reconcile to the 2023 – 2025 measures.

(c) Please provide an excel file that specifically compares per unit incentives and per unit direct installation costs proposed in the 2026 plan to 2023 – 2025 levels by measure.

(d) Where 2026 incentive and/or direct installation costs have increased compared to the 2025 plan levels, please explain the justification for each increase.

(e) Please confirm that the "gross per unit one-time incremental measure cost" provided in Column J is the total cost to both administrators and participants. If not confirmed, please provide a column that includes a total participant and administrator investment on a per unit basis by measure.

(f) Please compare the proposed unit DSM Administrator Cost (per unit incentive + direct installation cost) to total measure cost on a per unit basis (both administrator and participant upfront cost) for each measure.

Response IR-22:

(a) Appendix A, Attachment 3 to the 2026 DSM Extension Application is an output of the ProCESS™ model. Calculations are done within the ProCESS™ model, not in Excel, and as a result EfficiencyOne (E1) is unable to provide a version of Attachment 3 with formulas intact.

However, E1 has updated Appendix A, Attachment 3 – 2026 DSM Extension Measure-level Energy Efficiency Technical Tables to include annotations which describes the source and calculation of the measure-level technical table fields. The updated Attachment 3 has been provided as Attachment 1 to this IR response, filed electronically.

Net-To-Gross Ratio (NTGR) is an input to the model. These inputs were primarily developed using the NTGR ratios from the 2023 DSM Evaluation reports. The evaluator calculates NTGR using established free-ridership and spillover levels, using the following calculation:

NTGR = (1 – % Free-ridership + % Spillover)

(b) Please refer to E1's response to IG IR-10.

(c) Please refer to part (b) of this IR response. E1 is unable to provide a line-by-line measure level comparison of per unit incentives and per unit direct installation costs.

(d) Please refer to part (c) of this IR response. The DSM model is a forecast, based on information at a point in time. Incentive levels during implementation may vary from the levels included in the model as E1 adapts to changing product prices, market response to incentives, and evaluation results. Current incentive levels differ from what was modelled in the 2023-2025 DSM Plan and inputs used to evaluate incentive levels, such as incremental costs, have been reviewed and updated. For that reason, current incentive levels (as of the time of DSM Extension preparation) and measure level-inputs were used as a starting point for the 2026 DSM Extension analysis. Incentive levels were reviewed and adjusted on a measure-by-measure basis to align with expectations for 2026 and with the thresholds set out in E1's incentive setting methodology.

Changes made to incentives during implementation are done using E1's incentive setting methodology. Consistent with the Board's directive in the 2023-2025 DSM Plan decision[1], E1 identifies any instances where the per unit incentive amount for a measure by more has been adjusted by more than 10% from the amount included in its resource plan and provides an explanation for the variance in its quarterly reports.

Consistent with the approach used for incentive-level input development, E1 used current direct installation costs as a starting point for the direct installation measures. These costs

[1] M10473, 2023-2025 Demand Side Management Resource Plan, NSUARB Decision, September 6, 2022, page 65.

were updated, as required, based on current contract information and expectations for implementation of these measures in 2026.

(e) The Gross Per Unit One-Time Incremental Cost reflects the cost difference between implementing an efficient measure instead of the baseline or standard measure. It does not include any program administrator costs. It is calculated as follows:

Gross Per Unit One Time Incremental Cost = (Efficient Equipment Cost + Efficient Labour Cost) – (Baseline Equipment Cost + Baseline Labour Cost)

Please refer to column N in Attachment 1 to this IR response, filed electronically. The 2026 DSM Extension Measure-level Energy Efficiency Technical Tables have been updated to include the Per Unit DSM Customer Cost. This reflects the incremental cost for the customer to implement the efficient measure (compared to the baseline alternative), after incentives. It is calculated as follows:

Per Unit DSM Customer Cost = Gross Per Unit One Time Incremental Cost – Per Unit Incentive

The Per Unit DSM Administrator Cost (Incentive + Direct Installation Cost) is provided in the 2026 DSM Extension Measure-level Energy Efficiency Technical Tables. Please refer to Column M in Attachment 1.

(f) Please refer to column O in Attachment 1 to this IR response. The 2026 DSM Extension Measure-level Energy Efficiency Technical Tables have been updated to include the Total Per Unit DSM Cost. It is calculated as follows:

Total Per Unit DSM Cost = Per Unit DSM Customer Cost + Per Unit DSM Administrator Cost

Request IR-23:

Reference: Appendix A, Attachment 4 – 2026 DSM Extension Demand Response Technical Tables, '19b. BC Ratios Cost Categories' tab & 'BCA by Cost Category' tab

(a) Please provide a version of the table provided in Tab 19b, aligning with E1's 2026 proposed plan, that includes annual costs and annual avoided costs by year, and split each DR option by rate class.

(b) For the tab "BCA by Cost Category", please provide an excel file that calculates the TRC, PAC, PCT, RIM and SCT ratios for each DR sub-option based on the costs provided in each row (including the formulas in the calculation columns).

i) For the Societal Cost Test values, please explain what societal costs and benefits have been included.

Response IR-23:

(a) The 2026 Extension Demand Response Technical Tables workbook is an output of Guidehouse's proprietary DRSim modelling software. The requested data is not available as the DRSim model is not configured to output the '19b. BC Ratios Cost categories' tab & 'BCA by Cost Category' tab with rate class information.

(b) The Guidehouse DRSim software is pre-built with the traditional cost-effectiveness tests, including the PAC, TRC, PCT, RIM and SCT tests. EfficiencyOne (E1) utilizes the TRC and PAC results from the DRSim software and has validated these tests to ensure the correct costs and benefits are included, as applied in Nova Scotia. Although the results of the PCT, RIM

and SCT tests have also been pre-built within the model, and can be viewed within various BC Ratios tabs, E1 does not utilize these tests, and has not validated the inputs or results for these tests, therefore the results of these tests should not be relied upon.

The requested cost-effectiveness results are not performed within the excel workbook referenced; rather they are performed by Guidehouse's proprietary DRSim model and the excel workbook contains the results of that analysis. While E1 is unable to add the requested excel formulas to the workbooks, E1 has provided the general formulas used for the TRC and PAC tests in demand response below. E1 can also confirm that the results of the PAC and TRC results by year can be found in Appendix A, Attachment 4 – 2026 DSM Extension Demand Response Technical Tables, '19c. BC Ratios by Year' using the available pivot table dropdown functionality.

<u>Description of TRC and PAC costs and benefits as applied within DRSim model</u>:

- The TRC test (as utilized in Nova Scotia) is a ratio of the utility benefits divided by the utility costs + customer costs.
- The PAC test is a ratio of the utility benefits divided by the utility costs.

In both the TRC and PAC test upfront (one-time) costs are levelized over ten years (the expected life of demand response programs), based on Guidehouse's recommendation.

Table 1, below, describes the benefits and costs included in the TRC and PAC as applied in Guidehouse's DRSim model.

Table 1: Summary of benefits and costs used for the TRC and PAC tests as applied in the DRSim model for demand response

	TRC	PAC
Benefits	• Avoided generation capacity costs • Avoided T&D capacity costs • Avoided energy purchases*	• Avoided generation capacity costs • Avoided T&D capacity costs • Avoided energy purchases*

	TRC	PAC
Costs	Program Delivery Costs: • Program Admin • Program Development • Program Delivery • Marketing & Recruitment • Technology Enablement Customer Costs: • O&M Cost* • Participant Cost*	Program Delivery Costs: • Program Admin • Program Development • Program Delivery • Marketing & Recruitment • Technology Enablement • Customer Incentives

*Benefit/cost stream is zero.

i) The Societal Cost Test is not currently considered a relevant test within the Nova Scotia regulatory context and therefore has not been configured or validated by E1. Because no societal costs or benefits inputs have been added in the model, the test reflects shown under “SCT” simply reflect the “TRC” results.

Request IR-24:

Reference: E1 Evidence, Section 3.2: Updates to Avoided Cost Calculation, pages 15 & 16 of 25 & Appendix A - Attachment 1: Tables 2 – 4, pages 4 – 6 of 8.

(a) In Attachment 1, Table 2 & 3 states that the actual avoided costs of energy are used for the years 2026 to 2055. As these are forecast years, please explain what is meant by the term "actual".

(b) Please provide the comparable annual avoided costs of energy for the forecast years 2026 – 2055 as used in the 2023 – 2025 DSM Plan (for Tables 2 & 3).

(c) Per Tables 2 and 3 of Attachment 1, please explain qualitatively the sustained and meaningful drop in avoided costs after 2029.

Response IR-24:

(a) Tables 2 and 3 in Attachment 1 of Appendix A provide the avoided costs EfficiencyOne (E1) used for modelling the 2026 DSM Extension that were provided by NS Power on August 23, 2024. 'Actual' is used to represent the modelled results rather than a levelized or smoothed result which has been modified in some way.

(b) E1 notes there are no accurate comparable avoided costs of energy for the 2023-2025 DSM Plan and 2026 DSM Extension given that the avoided costs of carbon were embedded in the avoided costs of energy used in the 2026 DSM Extension (developed by NS Power from the 2022 Evergreen Integrated Resource Plan) and excluded from the avoided costs of energy used in the 2023-2025 (developed by NS Power from the 2020 Integrated Resource

Plan). The annual avoided costs of energy for 2026-2055 from the 2020 Integrated Resource Plan avoided costs (which was the source used for the 2023-2025 DSM Plan), has been provided in the table below for years 2026-2045[1] (the avoided costs for the 2023-2025 DSM Plan as provided by NS Power were for 2023-2045). E1 is unable to provide the comparable time varying avoided costs in Table 2 as these were not provided by NS Power for the 2023-2025 DSM Plan.

Year	Actual Annual AVC Energy ($/MWh)
2026	$83
2027	$85
2028	$76
2029	$76
2030	$89
2031	$85
2032	$85
2033	$85
2034	$84
2035	$85
2036	$91
2037	$94
2038	$91
2039	$88
2040	$87
2041	$96
2042	$98
2043	$101
2044	$103
2045	$102

[1] M10473, E1 2023-2025 DSM Resource Plan, Appendix A, Attachment 2: Avoided Costs Brief, March 11, 2022.

Please refer to Attachment 2 of E1's response to Synapse IR-05 for a side-by-side view of the avoided costs used in the 2023-2025 DSM Plan and the 2026 DSM Extension.

(c) The following response has been provided by NS Power.

Prior to 2030 there are multiple factors contributing to the higher costs in the No DSM, No Energy Efficiency (No EE) scenario which lead to the higher annual avoided costs in this period. These are:

- Increased thermal generation in years 2026 and 2027 to serve the higher load in the No DSM, No EE scenario.

- The Reliability Intertie is economically added in the No DSM, No EE scenario prior to 2030 but is not built in this period in the Base Case scenario. The cost of the Reliability Intertie is attributed 90% to energy.

- Due to the higher load in the No DSM, No EE scenario more wind and solar generation is built during this period in order to meet the 80% renewable energy standard in 2030.

The fluctuations in annual avoided cost values across the whole data series are mainly attributed to the difference in capital investment timing between the two scenarios which has a degree of uncertainty. To remove this variability from the data set the Equivalent Escalating Avoided Cost of Energy series, which smooths the results across the assessment period, was created, and has been used in previous proceedings.

Request IR-25:

Reference: Appendix B, Attachment 1 –2026 Summary Results.

Please provide an updated excel file that layers in the total rate impacts from the 2023 – 2025 DSM Plan with the rate impacts from the 2026 DSM Plan for each rate class by year.

Response IR-25:

As set out in Appendix B to the 2026 DSM Extension Application, EfficiencyOne's (E1) 2026 DSM Extension Rate and Bill Impact Analysis (RBIA) provides a broad trend-based picture of the rate and bill impacts of proposed DSM activities to be carried out during the 2026 period, looking forward until 2041, when the modelled impacts of 2026 measures expire. In the case of the 2026 Application, while it is not a stand-alone DSM Plan Application but rather a one-year extension to the 2023-2025 DSM Plan, E1 conducted a rate and bill impact analysis to provide insight on the one-year extension which included the 2026 DSM Extension investment only. E1 did not conduct a 2023-2026 RBIA as part of the 2026 DSM Extension development.

Please refer to Table 1 in Appendix B to the Application which presents the average rate impacts over the 2026 DSM Extension period compared to the rate impacts from the 2023-2025 Plan RBIA.[1]

[1] M11249, E1 2026 DSM Extension, Appendix B, Table 1, April 30, 2025, page 10.

Request IR-26:

Reference: Appendix B, page 13 of 24, and pages 15-16 of 24.

On page 13 of Appendix B, E1 states that:

> **When examining non-participant bill impacts, it is important to note the broad reach of E1's point-of-sale rebate program components, Instant Savings and the Instant Rebates portion of Business Energy Rebates (BER-IR). These offerings provide discounts on products that can be installed in every home and business; *in larger classes it is assumed that each customer does participate every year, either directly or indirectly through contractors that perform work in their facilities*. The result is that there are likely very few actual non-participants in the General, Large General, Medium Industrial, Large Industrial and Municipal classes. *[emphasis added]***

(a) For each of the industrial rate classes, please provide the number and percentage of customers who have participated in EE and DR programs in each of the 2023 – 2025 Plan years so far. Please provide on a per program component basis if possible.

(b) Please provide the distribution of industrial customers for each rate class anticipated to participate in the 2026 DSM Plan (i.e. participants vs. non-participants).

(c) Based on the answer to the above, how is the average bill increase calculated for non-participant bills for each industrial rate class (0.3% increase for small industrial, 0.1% increase for medium industrials, and 0.1% increase for large industrials).

Response IR-26:

(a) Please refer to Table 1 and 2, below. Table 1 sets out the number of industrial class customers who have participated in energy efficiency programs in 2023-2025 (as of May 31, 2025) by rate class and program component and Table 2 sets out the number of industrial class customers who have participated in Business, Non-profit and Institutional (BNI) Demand Response in 2023-2024, where rate class participation information is tracked. EfficiencyOne (E1) notes that rate class participation data is unavailable for Business Energy Rebates-Instant Rebates (BER-IS) and therefore has not been included in Table 1 below. Participation data for Demand Response for 2025 is not yet available. For the purposes of this analysis, "Customer participation" has been defined as each unique electricity customer account number participating in a program component in a given year (the same participant may be counted in multiple program components, and in multiple years)

Table 1: Industrial Rate Class Unique Customers Participating in Energy Efficiency in 2023-2025 by Rate Class and Program Component

Program Component	Rate Class	2023		2024		2025	
		Participating Customers	% of Total Rate Class Customers	Participating Customers	% of Total Rate Class Customers	Participating Customers	% of Total Rate Class Customers
Business Energy Rebates – Application Rebates	Small Industrial (21)	13	1%	13	1%	8	0%
	Medium Industrial (22)	7	4%	6	3%	5	3%
	Large Industrial (23, 25)	6	17%	4	13%	2	6%
Custom	Small Industrial (21)	11	1%	8	0%	1	0%
	Medium Industrial (22)	13	7%	12	7%	2	1%
	Large Industrial (23, 25)	8	22%	9	28%	5	16%
Strategic Energy Management	Small Industrial (21)	0	0%	0	0%	0	0%
	Medium Industrial (22)	3	2%	6	3%	6	3%
	Large Industrial (23, 25)	5	14%	6	19%	6	19%
Efficient Product Installation	Small Industrial (21)	1	0%	0	0%	0	0%
	Medium Industrial (22)	0	0%	0	0%	0	0%
	Large Industrial (23, 25)	0	0%	0	0%	0	0%
Small Business Energy Solutions	Small Industrial (21)	12	1%	11	1%	5	0%
	Medium Industrial (22)	0	0%	1	1%	0	0%
	Large Industrial (23, 25)	0	0%	0	0%	0	0%

Table 2: Industrial Rate Class Unique Customers Participating in Demand Response 2023-2024 by Rate Class

Rate Class	2023		2024	
	Participating Customers	Percent of Total Rate Class Customers	Participating Customers	Percent of Total Rate Class Customers
Small Industrial (21)	0	0.0%	3	0.1%
Medium Industrial (22)	3	1.6%	19	10.4%
Large Industrial (23, 25)	0	0.0%	0	0.0%

(b) The distribution of industrial customers for each rate class anticipated to participate in the 2026 DSM Plan (i.e. participants vs. non-participants) is provided in Table 3, below. Unlike Table 1 above which provides only tracked participation results, anticipated rate class participation for both tracked and untracked participants is provided in Table 3.

Table 3: Estimated Rate Class Participation for Tracked and Untracked Participations in 2026 RBIA

Rate Class	Total Rate Class Customers	Total participants	2026 RBIA Forecast Participants			Non-Participants
			EE - tracked	EE - untracked	DR	
Small Industrial	2079	435	35	400	20	1644
Medium Industrial	183	183	29	183	37	0
Large Industrial	32	32	32	32	13	0

As stated on page 13 of Appendix A, the RBIA participation forecasting methodology assumes each customer in larger classes participates in DSM every year, either directly or indirectly through contractors. As a result, there are no non-participants forecast for the Medium Industrial and Large Industrial classes in the 2026 DSM Extension RBIA.

(c) The average bill impact calculated for non-participants in the DSM scenario is not dependent on the distribution of industrial customers for each rate class anticipated to participate in the 2026 DSM Extension provided above in part (b). In the bill impact calculation for non-participants in the DSM scenario, non-participants are assumed to use the same amount of energy as they do in the no-DSM scenario (i.e., no energy or demand savings from DSM). The calculation factors in the rate impacts of the 2026 DSM investment, assuming zero customer energy or demand savings. Therefore, non-participant bill impacts

are driven only by the rate class rate impacts, as calculated within NS Power's rate model in Appendix B, Attachment 5.[1] The average rate impacts, as modelled in the DSM scenario in the RBIA, are a 0.3% increase for small industrial, 0.1% increase for medium industrial, and 0.1% increase for large industrial.

[1] M12249, E1 2026 DSM Extension, Appendix B, Attachment 5, April 30, 2025.