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Request IR-1:

(a) Please identify the specific data sources, E1 filings, and information request responses that Brattle reviewed in preparing its evidence.

(b) Please confirm whether NSPI provided Brattle with any information, data, or analysis that is not part of the public record in this proceeding, including avoided cost inputs, load forecasts, capacity planning assumptions, or system modelling outputs. If so, please identify the information and provide a copy.

Response IR-1:

This IR response has been provided by The Brattle Group.

(a) Brattle reviewed public documents from the following proceedings:

- M12780 E1 2027-2031 DSM Plan Application
- M12282 E1 New Benefit Cost Analysis Test for Evaluating DSM Plans
- M12386 NS Power 10 Year System Outlook Report – 2025
- M12861 NS Power 2026 Load Forecast Report

All relevant materials are cited in Brattle's evidence.

(b) NS Power provided Brattle with the Company's submissions which were submitted to E1 during DSMAG engagement for the 2027-2031 DSM Plan. E1 set out in its response to NSEB IR-30 part (c) subsection (i) that DSMAG "submissions, comments, and positions taken by Members in DSMAG meetings or technical sessions are confidential and shall not be reproduced or made public, directly or indirectly, including in any future regulatory proceeding."[1] Accordingly, these submissions are not being provided at this time.

[1] E1(NSEB) IR-30, May 28, 2026, page 6.

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The only additional data provided by NS Power is summarized in Table 4 of the Brattle Evidence. However, as noted in the footnote to the table, the values provided are in alignment with those provided in response to NS Power Response to NSEB IR-4, Page 3 of 4, Exhibit N-2, M12783 – Regulation 3.6 – 2025 Net Metering Report, filed May 26, 2026.

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Request IR-2:

Reference: E-22, Page 3.

Preamble: Brattle states that the Preferred Plan allocates approximately $286.8 million (90% of total investment) to the EE portfolio, $29.1 million (9%) to DR, and $2.8 million (1%) to solar PV, which

> **"largely mimics the allocations in the 2023-2026 plan and indicates that the Plan largely maintains the existing DSM delivery model rather than materially rebalancing toward the resources that are likely to become more important in a winter-peaking, electrifying, and increasingly capacity-constrained system"**

And Reference: E-22, Page 7.

> **While the proposed budget may be directionally appropriate given the goal of limiting ratepayer impacts, its scope can be modified such that it reallocates funds from more expensive EE toward DR and SE where those resources have the potential to create higher system value.**

(a) Please provide Brattle's recommended allocation of DSM funding across EE, DR, and SE within the proposed five-year budget, including the recommended dollar amount, percentage share, and basis for each category, in keeping with its recommended expansion of DR and SE.

(b) If Brattle recommends reallocating funds from EE to DR or SE, please identify the EE program components or customer sectors that Brattle recommends reducing, the amount of each reduction, and the expected effect on energy savings and cost-effectiveness.

(c) Please confirm whether Brattle's reallocation recommendation is premised on maintaining the total portfolio at the Preferred Plan's $318.75 million budget, or

whether Brattle would support a different total spending level. If the latter, please provide the recommended total budget and its basis.

(d) Please confirm the PAC ratio Brattle would expect the expanded DR portfolio to achieve and explain how that estimate was developed. If Brattle cannot provide the calculation, please identify the information required to do so.

Response IR-2:

This IR response has been provided by The Brattle Group.

(a) Brattle does not have sufficient information to recommend a precise budget allocation across program categories. Its recommendation is directional and high level, with implementation falling squarely within the responsibilities of the program administrator.

(b) Please refer to part (a).

(c) Given the affordability focus in Nova Scotia, Brattle's reallocation recommendation was premised on maintaining the total portfolio at the Preferred Plan's $318.75 million budget.

(d) It is not possible to predict the PAC ratio ex ante, in the absence of E1 implementing the recommendations we put forth in our evidence. More specifically, we recommend that E1 prioritizes near-term residential DR measures with strong winter peak reduction potential, particularly smart thermostats and domestic hot water direct load control and adopt best practices from successful programs such as Ontario's Peak Perks program. Moreover, it will be instrumental for E1 to update its DR potential study, with emphasis on winter peak value, customer segments, event performance, attrition, device health, and locational value. Our expectation is that these two activities would allow E1 to create cost effective portfolio that builds upon its existing residential DR portfolio.

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Request IR-3:

Reference: E-22, page 5.

> **However, the fact that a program has social, environmental, or equity value does not mean it should be funded through DSM funding. DSM funding should be reserved for resources that directly and efficiently reduce Nova Scotia's energy and capacity supply obligations through demand-side measures or provide measurable system value in a manner consistent with the purpose of the DSM framework.**

(a) If Solar PV is removed from DSM funding and treated as an equity program funded through another mechanism, please identify who Brattle recommends should bear the cost.

(b) Please explain the funding and cost-allocation implications for MI and LI customers if Solar PV is removed from DSM funding.

Response IR-3:

This IR response has been provided by The Brattle Group.

(a) Section VI.B provides alternative mechanisms for funding programs with an equity basis,

> However, given the equity basis provided by E1, similar Solar PV programs could be supported through a non-DSM funding mechanism, such as a government-funded equity program, community energy program, distributed energy resource program, or other targeted clean-energy funding sources. That approach may better preserve the distinction between traditional DSM resources and in this case, energy equity benefits.[1]

[1] See 2027-2031 DSM Plan - Third-Party Expert Evidence Attachment 1 pg. 36 and 37 of 39.

Research by Efficiency Canada shows that reliance on government funding for equity-orientated programming is not without precedent. Efficiency Canada's 2025 Energy Efficiency Programs Report highlights the different sources of funding for programs aimed at furthering equity outcomes for underserved groups. The report notes that in 2024, ratepayer funding accounted for only slightly more programs than those funded by government.[2] It also highlighted the success of E1's HomeWarming program in increasing participation five-fold compared to 2023 levels through federal and provincial funding via the Oil to Heat Pump Affordability program (OHPA) and Home Heating Oil Transition Fund, in addition to ratepayer funding.[3] While not perfectly aligned with solar PV programs, there may be useful examples from other equity-based programming for E1 to draw from. Importantly, E1's own DSM plan highlights experience with leveraging Provincial or Federal funds to administer solar PV programs.[4] Therefore, using Provincial or Government assistance for equity-based programming would not be novel for E1.

(b) Please refer to part (a) for funding considerations. If such programs are funded through government (local/provincial/federal), there may be no direct cost allocation to specific customer classes but costs may be recovered through the tax base. To the extent that the tax base leads to a more progressive recovery than the recovery through electricity rates, that would lead to a lower burden on the LI and MI customers compared to the higher income customers. However, Brattle cannot comment on cost allocation and recovery specifics as that will depend on the specific funding mechanism that may be adopted.

[2] See Gaede, J., Nippard, A., Turner, K. 2026. The 2025 Energy Efficiency Programs Report. Efficiency Canada, Carleton University, Ottawa, ON, page 50.
[3] *Id., page 51.*
[4] See EfficiencyOne, *EfficiencyOne 2027–2031 DSM Resource Plan Application*, March 31, 2026, Appendix A, page 85 and 86 of 112.

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Request IR-4:

Reference: E-22, page 5.

Brattle states that "distributed solar PV systems already receive compensation through net metering, so by including them in the DSM funding, they are double compensated for ratepayer funds."

(a) Please provide the basis for Brattle's double-compensation assertion. In particular, please confirm whether participants in E1's proposed Solar PV program would receive both DSM incentives and net metering credits, and whether the PAC test calculation for the Solar PV program accounts for those credits.

(b) If the PAC test does not account for net metering credits, please provide the effect on the Solar PV program's PAC ratio if net metering revenues are removed as a PAC benefit.

(c) Would Brattle's double-compensation concern apply to any future expansion of the Solar PV program to customer classes beyond Mi'kmaw communities, and does this same concern apply to any other DSM measures that also receive provincial or federal support, such as heat pumps? Please explain.

Response IR-4:

This IR response has been provided by The Brattle Group.

(a) Confirmed. The double-compensation assertion refers to the fact that participants in E1's proposed solar PV program would receive both DSM incentives and net metering credits. First, participants will receive a financial incentive from E1 for solar installations on their premises. Second, customers would receive net metering credits for excess generation from their solar units at the retail rate. As a result, the costs credited to participating solar PV customers for their excess generation are transferred to the remainder of the customer base, including non-fuel and rider costs (including the DSM Cost Recovery Rider). Solar generation from participants in E1's proposed solar PV program would reduce the total energy that NS Power has to supply. However, given the lack of capacity value that solar PV provides in the Nova Scotia context, it does not help avoid any generation capacity related costs. Therefore, it also adds to the burden of fixed cost recovery that is spread across all residential customers.

It is our understanding that net metering credits are not directly accounted for in E1's cost-effectiveness calculations.

(b) To the extent net metering credits are not included in the PAC, the NSPM provides some support for treating net metering bill credits as a utility system cost.[1] If so, it may reduce the PAC ratio.

(c) Yes, Brattle's double-compensation concern would apply more broadly to any future expansion of the proposed Solar PV program beyond Mi'kmaw communities, because the concern is not specific to the customer group receiving the incentive; it arises from the fact that distributed solar PV already receives compensation through net metering and would also receive DSM-funded incentives if included in the Plan.

That said, this concern is distinguishable from DSM measures that may also receive provincial or federal support, such as heat pumps. For heat pumps, outside funding generally reduces the customer's incremental cost of adopting an efficiency or electrification measure, while the DSM incentive is intended to achieve energy savings, peak reduction, or other measurable DSM benefits that would not otherwise be achieved. By contrast, behind-the-meter solar PV is already compensated for its generation through the net-metering framework, and its inclusion in DSM funding would add a second

[1] See National Energy Screening Project, *National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources* (2026), Ch. 10, p. 10-14.

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ratepayer-funded support mechanism. Therefore, Brattle's concern is strongest for solar PV and should be evaluated separately from co-funded DSM measures such as heat pumps, where the relevant question is whether combined incentives are necessary, non-duplicative, and proportionate to incremental system benefits.

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Request IR-5:

Reference: **E-22, Page 6.**

Preamble: **Brattle states that a 2026 ACEEE report reveals that in 2024 the average lifetime cost of energy efficiency was $0.032/kWh with a median of $0.029/kWh, whereas E1's Preferred Plan has a first-year unit cost of $0.66/kWh and a weighted-average lifetime unit cost of $0.05/kWh, implying "E1 spends almost twice as much funding compared to these other jurisdictions included in the ACEEE analysis to deliver a single kWh of efficiency."**

(a) **Please confirm whether Brattle's comparison of E1's lifetime unit cost to the ACEEE fleet average lifetime cost uses the same definition of "lifetime cost" and the same calculation basis. If not, please explain.**

(b) **Please confirm whether the ACEEE dataset used for this comparison is the same 2024 cross-sectional dataset of 42 US utilities cited by Mr. Love (Ex. E-21). If so, please confirm whether the dataset includes year-over-year trend data or is limited to a single-year snapshot.**

Response IR-5:

This IR response has been provided by The Brattle Group.

(a) It is our understanding that E1's lifetime unit cost is defined as the ratio of the total EE investment and the lifetime energy savings. ACEEE's median estimate is the observed median of the cost of energy efficiency among surveyed utilities. Based on the report, we understand that it is defined as the ratio of EE program spending to the projected lifetime energy savings.[1] Therefore, the definitions are equivalent.

(b) While the source cited in Mr. Love's testimony appears to be the same as that referenced in the Brattle Evidence, Appendix C from the cited ACEEE report notes 52 surveyed US utilities, not 42.

[1] See Mike Specian and Alex Aquino, *Faster and Cheaper: Demand-Side Solutions for Rapid Load Growth*, ACEEE, February 2026, Appendix C, p. 86.

Request IR-6:

Reference: E-22, page 8-9, Figure 1.

Preamble: Brattle has outlined the need for a stronger DR strategy, using the data contained in NSPI's 2025 System Outlook report. IESO-NS has recently filed its 2026 System Outlook, in Matter M12916.

(a) Please update Brattle's Figure 1 using the most recent data from the 2026 System Outlook and confirm whether the updated data changes Brattle's analysis or recommendations.

(b) Please confirm the data source and calculation underlying the 0.3% and 1.3% figures and provide Brattle's estimate of the maximum achievable DR penetration as a percentage of Nova Scotia peak load by 2031, including the supporting calculation.

Response IR-6:

This IR response has been provided by The Brattle Group.

(a) An updated Figure 1 which reflects the data from the IESO-NS 2026 10-Year System Outlook (10YSO) Report is provided on the next page.

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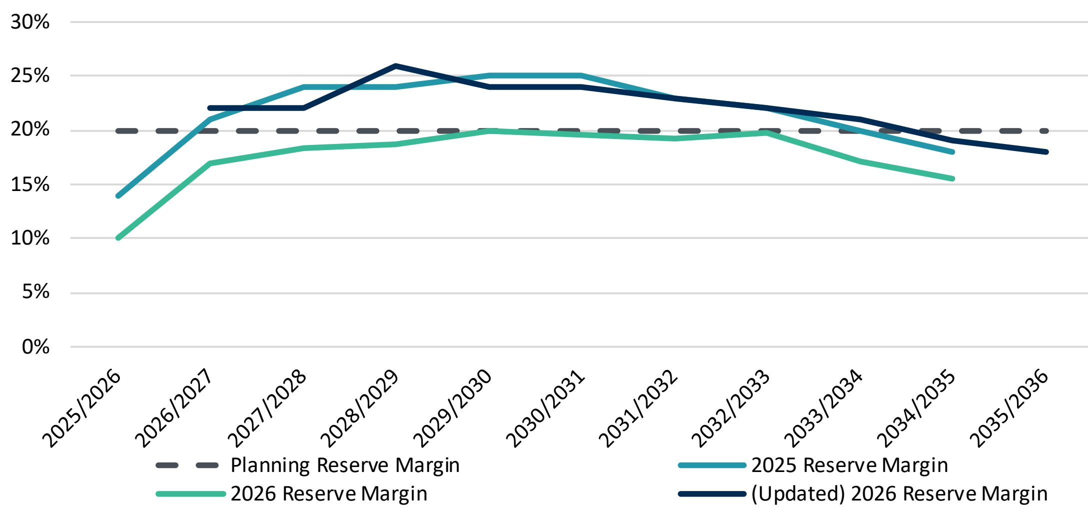

The IESO-NS 2026 10YSO improves the reserve margin, closer aligned with the 2025 reserve margin. The updated 2026 reserve margin is on average five percentage points higher than the initial 2026 reserve margin based on NS Power's 2025 10YSO Report. While the load forecast is relatively unchanged from the 2025 load forecast, capacity levels have improved due to changes to accreditation compared to 2025 and changes to the additions and retirements schedule, among others. Notwithstanding that these developments improve the reserve margin, with expected load growth, DR continues to have great option value and will be an important tool for quick response to load growth. These developments do not alter Brattle's recommendations.

(b) The data source for the underlying calculation is Nova Scotia Power's 2026 Load Forecast Report, Figure 68, p. 9.[1] The calculation is DR Peak Contribution/ System Peak. The 1.3 percent maximum potential DR penetration value is for 2036, not 2031.

[1] M12861, NS Power 2026 Load Forecast Report, May 15, 2026, page 9, Figure 68.

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Request IR-7:

Reference: **E-22, Page 9.**

Preamble: **Brattle references a 2026 Otter Tail Power study showing that winter-peaking utilities can achieve DR peak reduction capability of 28% of system peak (or 13% excluding large customer flexibility contracts).**

(a) **Please discuss Nova Scotia's system characteristics relative to Otter Tail Power's service territory in order to assess the usefulness of that figure as a meaningful benchmark for Nova Scotia's achievable DR potential.**

(b) **Please confirm whether the "large customer flexibility contracts" included in Otter Tail Power's 28% DR capability figure operate on the same basis as Nova Scotia's Large Industrial Interruptible Rider, specifically addressing whether those Otter Tail Power customers are contractually obligated to curtail on demand and are already compensated through their rate structure.**

(c) **If interruptible industrial load in Nova Scotia is removed from system peak for PRM calculations, please explain why Brattle considers the 28% figure, rather than the 13% figure, to be the appropriate benchmark.**

(d) **With respect to residential DR, please confirm whether the Otter Tail Power study's base case identifies 8 MW of additional incremental winter DR potential by 2041. If so, please explain how that finding supports Brattle's recommendation that E1 significantly expand residential DR, taking into account program maturity.**

Response IR-7:

This IR response has been provided by The Brattle Group.

(a) Please refer to E1 IR-9 part (a)

(b) Otter Tail Power customers are contractually obligated to reduce load to a firm service level. The customers are compensated through their rate structure.

(c) Both benchmarks are provided as achievable potential peak reductions and with the context of what they represent. The 13 percent figure is the more appropriate benchmark for comparing DR peak reduction capacity excluding interruptible loads.

(d) Yes, the identified 8 MW of DR potential is incremental to Otter Tail Power's existing DR levels. The study identifies meaningful incremental DR capability for a winter peaking utility that is already at the 98th percentile of existing peak reduction capability among comparable winter peaking utilities. Given the nascency of E1's residential DR program, there is much greater potential to derive meaningful grid value from expanding residential DR programs. Please refer to CA IR-5. Moreover, this argument is buttressed by the IESO-NS 2026 ELCC study, which shows that at lower levels of residential DR penetration, the estimated ELCC is greater than 90 percent. Please refer to IG IR-12.

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Request IR-8:

Reference: E-22, page 16.

> **A modified Plan should therefore require E1 to develop DR as a dispatchable system resource with clear performance, accreditation, and cost-effectiveness metrics. That should include a careful assessment of delivery models from other jurisdictions, including incentive levels, customer acquisition strategies, aggregator compensation structures, device-partner roles, and pay-for-performance mechanisms.**

(a) Please elaborate on the performance obligations, accreditation and cost-effectiveness metrics Brattle is recommending be included within the DR programming model. Is this based on experience, data, or judgement?

(b) Please identify any examples of comparable metrics from other jurisdictions that Brattle considered and recommends.

Response IR-8:

This IR response has been provided by The Brattle Group.

(a) Brattle's recommendation is based on a combination of experience and professional judgment regarding how demand response should be developed if it is intended to function as a dependable system resource rather than simply as a customer-facing DSM program. The recommended performance obligations would include, at a minimum, verified peak-load reduction during called events, customer/device availability, event participation and opt-out rates, attrition, device connectivity and operational performance, delivery cost per enrolled and verified kW, and the extent to which enrolled capacity is actually available during winter peak or reliability-risk hours. Accreditation metrics should translate enrolled DR capacity into dependable capacity based on measured event performance, availability, persistence, and expected performance during relevant winter system peak conditions.

Cost-effectiveness metrics should include transparent $/kW-year delivery costs, PAC results by segment and technology, incentive costs, acquisition costs, administrative costs, and verified load reduction, so that the Board and system planner can distinguish between nominal enrollment and dependable capacity value.

(b) Brattle has considered examples from other jurisdictions where DR is measured and reported as a dependable system resource. For example, Ontario IESO's Peak Perks program tracks event-level load impacts, total MW reductions, cost-effectiveness results, customer enrollment channels, opt-outs, and customer comfort impacts. PJM and ISO New England provide examples from wholesale-market contexts where DR resources are accredited and compensated based on their ability to provide capacity, subject to performance obligations and, in PJM's case, penalties for non-performance during required events. Con Edison's Brooklyn/Queens Demand Management program provides a distribution-planning example in which customer-side DR and other non-wires resources were procured and reported to regulators as part of a targeted effort to defer infrastructure investment. Hydro-Québec provides a particularly relevant winter-peaking example, because its winter DR events are called during the December - March period and publicly reported based on event timing and system need.

Brattle does not recommend that E1 adopt any one of these models directly. The appropriate metrics for Nova Scotia should reflect local system needs, especially winter peak reduction, resource adequacy, and customer affordability. However, these examples support Brattle's recommendation that E1's DR programming should include metrics such as verified event-level kW reduction, available and accredited capacity, opt-out and attrition rates, device connectivity and failure rates, cost per enrolled kW, cost per verified kW, incentive costs, aggregator or device-partner compensation, and annual performance reporting sufficient for NS Power, the IESO Nova Scotia, and the Board to assess whether DR can be relied upon as a dispatchable system resource.

Request IR-9:

Reference: E-22, Page 16.

> **E1 should undertake a new DR potential study that identifies and prioritizes resources based on winter peak value, including the relative potential of smart thermostats, domestic hot water control, BNI curtailment, and other controllable loads. That study would be instrumental for guiding expectations around customer segments, event performance, attrition, device health, locational value, and the costs required to turn enrolled devices into dependable capacity.**

(a) Please clarify whether Brattle's recommended DR potential study would focus primarily on improving the cost-effectiveness of Residential DR or would assess Residential and BNI DR on an equivalent basis.

(b) Based on Brattle's response to part (a), please explain how Brattle recommends allocating the cost of the DR potential study among customer classes, including MI and LI customers.

(c) When does Brattle suggest this DR potential study be completed, and what process does it recommend would follow thereafter?

(d) In Brattle's experience, have comparable jurisdictions completed similar DR potential studies as proposed? If so, please identify the jurisdictions and studies.

Response IR-9:

This IR response has been provided by The Brattle Group.

(a) A well-designed DR potential study helps identify which resources can provide dependable capacity, how much verified load reduction can reasonably be expected, how quickly programs can scale, what customer segments should be prioritized, and what it will cost to convert enrolled customers or devices into reliable dispatchable capacity. It can also help distinguish between nominal enrolled MW and accredited MW that can actually be relied upon in planning and operations. For E1, such a study would provide a stronger basis for deciding whether to prioritize smart thermostats, domestic hot water control, BNI curtailment, or other controllable loads; for determining appropriate incentive and aggregator compensation structures; and for establishing performance metrics that allow NS Power, IESO Nova Scotia, and the Board to evaluate DR as a system resource rather than simply as a DSM program. We understand that E1 has engaged a consultant to conduct an updated DSM potential study within the 2027-2031 DSM timeframe that will inform IESO-NS' IRP efforts as well as the DSM plan for the 2032-2036 term. While details on the status and progress for the updated DSM potential study remain scarce (refer to Brattle response to CA IR-04), it will be important for E1 to be mindful of the considerations above in its completion of the study.

(b) Please refer to IG IR-3. Brattle is unable to comment on specific cost allocation considerations for such DR potential studies as they are contingent on the entity that commissions such a study.

(c) From a DSM plan development perspective, the best time to undertake a DR potential study is early in the planning cycle, before the DSM portfolio is designed and budgets are allocated. Ideally, the study should be completed before the program administrator screens program options, sets participation targets, and proposes the resource mix. That allows the DR study to inform the plan rather than become a post-hoc justification for decisions that have already been made.

For a multi-year DSM plan, the practical sequence would be:

1. Update load forecasts, avoided costs, planning reserve margin needs, and winter peak risk;

2. Conduct the DR potential study using those system-planning inputs;
3. Use the study results to design programs, set MW targets, establish incentive levels, determine customer-segment priorities, and allocate budgets; and
4. Incorporate performance and accreditation metrics into the DSM filing.

For E1, that means a DR potential study should ideally be completed before the next full DSM plan is filed, and early enough that its findings can shape residential DR, BNI curtailment, water-heater control, smart thermostat, EV managed charging, and other controllable-load strategies. An alternative approach is to require the study as an early-plan compliance item. We understand that E1 has engaged a consultant to complete a DSM potential study to provide updated DSM potential projections to inform IESO Nova Scotia's 2026 Integrated Resource Plan (IRP). E1 expects that updates will be made to this study within the 2027-2031 DSM plan timeframe to inform the 2032–2036 DSM Plan and an anticipated future IRP process led by the IESO Nova Scotia during the 2027–2031 Plan period. The Board could require E1 to use the results of the 2026 DSM Potential Study to support a mid-cycle update, revised DR targets, or a reallocation of DSM funding. That would be better than waiting until the next DSM plan cycle, especially if system capacity conditions are tightening and winter peak value is becoming more important.

(d) Yes, several examples are available, particularly from Canadian and/or winter-peak-relevant systems:

- **Manitoba / Manitoba Hydro and Efficiency Manitoba.** Manitoba is a winter-peaking Canadian system with significant electric heating exposure. Efficiency Manitoba's 15-year DSM Market Potential Study was explicitly positioned as an input to DSM planning: the study flow moves from "market potential study" to target setting, preliminary plan, detailed program design, and final DSM plan for regulatory submission. The same study notes that it also assessed electric DR market potential for Manitoba Hydro, using common inputs and assumptions from the DSM market potential study. The study period covered 2023/24 through 2037/38 and included electricity savings measured in both kWh and winter kW.[1]

- **Prince Edward Island / efficiencyPEI.** PEI is part of the Maritime region and faces winter system-planning issues. efficiencyPEI's potential study covered both Maritime Electric and Summerside Electric customers and quantified both energy-efficiency savings and peak-load reductions from DR programs. The report states that the study was intended to inform province-wide energy-efficiency and peak-demand-reduction targets and to support program design strategies for future DSM planning periods. It also describes the study as including energy efficiency, DR, costs, and cost-effectiveness ratios over a 2021–2030 study period.[2]

- **Puget Sound Energy.** Puget Sound Energy is a winter peaking system in the US. Its 2023 Conservation Potential and Demand Response Assessment estimated winter and summer DR potential by program type, including water-heater controls, HVAC controls, bring-your-own-thermostat, EV charging control, commercial and industrial curtailment, and critical peak pricing; the study estimated 439 MW of winter DR potential by 2050, about 7.05 percent of PSE's forecasted winter peak.[3]

[1] https://efficiencymb.ca/wp-content/uploads/Efficiency-Manitoba-15-year-Market-Potential-Study.pdf
[2] PEI-Potential-Study-Final-Report-Volume-I-.pdf
[3] PSE Conservation and Demand Response Assessment, Appendix E. 2023 Electric Progress Report.

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Request IR-10:

Reference: E-22, Page 16.

> **Finally, E1 should be required to report DR performance in a way that allows the resource to be used in system planning and operations. That means annual accreditation and performance reporting after each peak season, opt-outs, attrition, device failures, customer compensation, delivery costs, and verified peak reduction. Without a comprehensive performance evaluation, DR will continue to sit in an uncomfortable middle ground counted as a promising future resource but not managed with the rigor needed for NS Power or the Board to rely on it.**

(a) Please describe Brattle's recommended DR reporting requirements, including reporting cadence, required content, and the forum in which the reporting should be provided.

(b) Please describe the comprehensive performance evaluation framework Brattle recommends for DR (if different than in its response to IR-8) and identify whether the recommendation is based on specific data, professional judgment, or both.

Response IR-10:

This IR response has been provided by The Brattle Group.

(a-b) Please refer to IG IR-8 and IG IR-9.

Request IR-11:

Preamble: **NSPI is both the entity that pays E1 for DSM under the purchase agreement and the entity that benefits directly when DR and SE reduce its capacity requirements.**

Please confirm whether Brattle considered the relationship between NSPI's interest in DSM spending that may reduce capacity costs and ratepayers' interest in cost-effective EE programs. If so, please explain how that consideration was reflected in Brattle's analysis. If not, please explain why not.

Response IR-11:

This IR response has been provided by The Brattle Group.

The relationship between the two organizations is not relevant to Brattle's assessment. Brattle evaluated E1's proposed DSM Plan based on whether it maximizes utility system benefits from the expenditure of ratepayer-funded DSM dollars.

Request IR-12:

Preamble: **IESO-NS has recently published an updated ELCC Study, from E3: https://ieso-ns.ca/wp-content/uploads/2026/06/2026-Nova-Scotia-ELCC-Study-Report.pdf**

(a) Please confirm whether Brattle assumed a static ELCC in its evidence and whether Brattle considered the BESS additions, as confirmed and outlined in the 2026 ELCC Study, when forming its conclusions regarding expanded DR programming.

(b) Please confirm whether the 2026 ELCC Study changes any of Brattle's conclusions or recommendations.

(c) Please confirm whether Brattle's Smart Synergy cost-effectiveness analysis accounts for declining DR ELCC as BESS penetration rises. If not, please provide the resulting PAC ratio or identify the information required to calculate it.

Response IR-12:

This IR response has been provided by The Brattle Group.

(a) Brattle did not review the recent 2026 ELCC study in preparation of its evidence. The Brattle Evidence was filed on June 23, 2026, and the final ELCC study was published on the IESO-NS website on June 24, 2026.

(b) While we haven't reviewed E3's analysis in depth, the ELCC study shows that marginal ELCC for residential DR reduces from 92 percent to 64 percent when it goes from 20MW to 30MW DR capacity.[1] E1's residential DR program exhibits a capacity of just 3.8MW,

[1] See Energy+Environmental Economics, Nova Scotia Effective Load Carrying Capability Study, June 2026, Table D-8, page 62.

so it is still nascent relative to the incremental levels assumed in the ELCC study. Even with increasing participation, residential DR will have an ELCC of >90 percent until it hits 10 MW. At levels above that, it can still offer meaningful capacity reduction potential. Therefore, this study does not change our conclusions about residential DR and its inclusion. If anything, it provides support for increasing residential DR contribution from existing DSM portfolio levels.

(c) We have not developed a cost-effectiveness analysis for the Smart Synergy program. However, such an analysis would require the marginal ELCC values for increasing levels of BNI DR penetration and the corresponding estimates for marginal generation capacity. Without in depth analysis of the assumptions in the ELCC analysis, it is not possible to draw definitive conclusions about potential PAC ratio for the BNI DR program.

Request IR-13:

Reference: E-22, page 20.

> **For instance, an EV managed charging program, or electric water heating program which can shift the load to off-peak hours, could improve grid utilization and defer expensive incremental grid investment. Integrating flexibility into the design of SE programs is particularly relevant because E1's own application recognizes that demand response and flexible demand side resources will become increasingly important as the electricity system evolves in response to electrification, environmental compliance, and changing market conditions.**

(a) Please confirm whether Brattle is aware of any existing or proposed E1 managed EV charging program within the DSM Plan's DR programming.

(b) In Brattle's opinion, could the savings from a managed EV charging program be captured within a DR program? If not, please explain why not.

Response IR-13:

This IR response has been provided by The Brattle Group.

(a) Based on our review of E1's Plan, we are not aware of any included managed EV charging programs in the 2027-2031 Preferred Plan. E1 has previously offered EV charging through its Eco Shift Program; however, EVs and EV chargers were removed from Eco Shift effective April 9, 2026.[1]

(b) Yes. Managed EV charging programs are typically implemented to help alleviate distribution system peaks driven by EV charging load. To the extent they are successful, avoided distribution benefits will be calculated within the PAC framework and can benefit

[1] Changes to the Eco Shift Program

customers in the form of lower long-term rates. To the extent distribution peaks align with broader system peak, they can result in incremental generation and transmission savings as well. Therefore, such savings may reasonably be incorporated within a DR portfolio. The point the evidence makes is that any strategic electrification program design should incorporate flexibility to ensure that the benefits of electrification materialize.

Request IR-14:

Reference: E-22, page 20.

> **E1 should be required to develop a more targeted building electrification program focused on measures with the best chance of meeting Nova Scotia's statutory criteria of reducing costs by incorporating more directly controllable electric load, displacement of high-emitting fossil fuels, and integration with weatherization and building controls, and even prioritizing electrification in parts of the grid with headroom for distribution capacity….**
>
> **… However, the Board should also not allow SE to remain a research-only activity for the full 2027–2031 plan term. At a minimum, the evidence supports requiring E1 to develop a phase-in pathway that identifies more effective candidate measures including integrated flexibility and load control features while continuing to refine its data gathering process for the purposes of cost-effectiveness calculations.**

(a) Has Brattle identified any specific SE program design, incorporating the recommended flexibility features, modelled and assessed as likely to pass the modified PAC test in Nova Scotia? If yes, please provide the analysis. If no, please confirm that the recommendation to redesign SE programs is a general one.

(b) In Brattle's experience, what strategic electrification programs have been considered or implemented in comparable jurisdictions?

(c) Please explain how the recommended "phase-in" pathway produces a different outcome than E1's current Enabling Strategies approach.

(d) Please explain how long Brattle expects the recommended analysis and program development to take, whether the changes could be (or should be) addressed through a Mid-Course Adjustment, and how Brattle recommends implementing any new program within the Plan.

(e) If E1 is unable to develop a strategic electrification portfolio that is cost-effective under the approved modified PAC test, please explain the basis on which Brattle recommends increased investment in SE programming.

Response IR-14:

This IR response has been provided by The Brattle Group.

(a) Brattle has not designed an alternative SE portfolio to the Preferred Plan. Brattle's recommendation points to important design features as a general guidance for developing a portfolio with a better chance to clear the cost-effectiveness threshold.

(b) In Brattle's experience, comparable jurisdictions have considered or implemented strategic or beneficial electrification programs focused primarily on building electrification, transportation electrification, and managed load flexibility. In Canada, Newfoundland Power and Newfoundland and Labrador Hydro's 2021–2025 Electrification, Conservation and Demand Management Plan introduced customer electrification programs alongside traditional CDM, including EV and charger incentives, with charger incentives designed to support load-management capability. Newfoundland and Labrador Hydro's public materials also describe EV rebates, smart-charger support, DC fast-charging infrastructure, customer education, and pilots to shift EV charging to off-peak periods to reduce peak impacts. Ontario's IESO is another relevant example: its 2025–2036 eDSM Framework includes beneficial electrification measures intended to improve affordability, expand customer choice, and reduce emissions while minimizing electricity-system impacts, with initial emphasis on residential customers heating with non-regulated fuels such as heating oil.

Other jurisdictions provide useful examples of how electrification programs can be paired with flexibility and cost-control features. Efficiency Maine's Beneficial Electrification Plan focuses on heat pumps and EVs that meet Maine's statutory beneficial-electrification criteria, which is relevant to Nova Scotia because Maine is a cold-climate, winter-peaking jurisdiction with substantial delivered-fuel heating.[1] BC Hydro's Electrification Plan includes incentives, energy studies, fleet-electrification advisory services, infrastructure assessment funding, and pilot/infrastructure funding for medium- and heavy-duty fleet electrification, while emphasizing fuel switching from fossil fuels to clean electricity. In Massachusetts, utility and policy work has considered active load-management measures such as grid-enabled hybrid heat pumps, HVAC flexibility, water-heater flexibility, EV managed charging, vehicle-to-grid, behind-the-meter storage, and industrial demand response. These examples support Brattle's view that SE programs should be designed around measures that reduce emissions while managing incremental electric load, particularly through controls, managed charging, weatherization, hybrid or controllable heating, and targeting of deployment to avoid adverse peak or distribution impacts.

(c) E1's enabling strategies approach does not indicate any plans to introduce new SE measures within the existing timeframe. The phase-in proposed by Brattle recommends that E1 identify stronger candidate measures, improve data collection and cost-effectiveness modeling, and redesign programs to better align electrification with system planning needs within the current term.

(d) As part of the proposed enabling strategies, E1 has committed to providing annual progress reports on its research activities. Among the four focus areas outlined, two stand out: (1) market research and technology assessment to identify emerging strategic electrification opportunities with improved economics; and (4) ongoing evaluation of how changes to avoided costs, particularly capacity values may improve cost-effectiveness of strategic electrification in future plan periods. Therefore, E1's own plans indicate there may be opportunities for further refinement of the SE portfolio within this DSM term. The key point is that SE should not remain a research-only activity for the entire 2027–2031 period; the Plan should include a defined pathway from analysis to pilot or phased deployment.

[1] https://www.efficiencymaine.com/docs/EMT_Beneficial-Electrification_Planning_Report_01_2025.pdf

Brattle believes this issue could appropriately be addressed through a Mid-Course Adjustment if the Board determines that the current record is not sufficient to approve full-scale SE programming now. A reasonable implementation approach would be to require E1 to complete the recommended SE analysis early in the Plan period, file the results with proposed program designs, and seek approval through a Mid-Course Adjustment or similar Board-approved update mechanism. New programs should be implemented first on a targeted or phased basis, focusing on measures most likely to satisfy Nova Scotia's statutory criteria, such as controllable or flexible building electrification, electrification paired with weatherization and controls, managed EV charging, or measures targeted to customers currently using high-emitting fuels and to areas of the grid with available capacity. This approach could allow E1 to refine cost-effectiveness assumptions, test customer uptake and operational performance, and establish measurement and reporting protocols before committing ratepayer funds to broader deployment.

(e) Brattle is not recommending that E1 increase ratepayer-funded deployment of SE measures that fail the Board-approved modified PAC test. Rather, Brattle's recommendation is that E1 should increase the level of program-development effort directed to SE so that potentially cost-effective measures are not prematurely excluded based on incomplete program design, insufficient data, or screening assumptions that do not fully reflect flexibility and load-control value. In other words, the recommended investment is in analysis, pilots, data development, hourly modeling, customer targeting, and program design -not in broad deployment of uneconomic SE measures.

The basis for this recommendation is that SE may be able to satisfy Nova Scotia's statutory criteria if it is designed more strategically. For example, measures that displace high-emitting fuels, are paired with weatherization or building controls, avoid incremental winter peak impacts, shift load to lower-cost hours, or target areas of the distribution system with available capacity may perform better under the modified PAC framework than generic building electrification measures. Brattle also recognizes that the modified PAC test creates a structural barrier because it captures increased electricity revenues but does not fully capture broader non-electric fuel savings, emissions benefits, or customer benefits. However, unless the applicable test is changed, Brattle's recommendation is not to override the modified PAC result; it is to require E1 to do the work necessary to determine whether a narrower, better-targeted, flexible SE portfolio can be developed that passes the approved test.

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Request IR-15:

Reference: E-22, Page 3.

> **Demand Response should play a larger and more disciplined role in the 2027–2031 DSM portfolio. DR provides system value because it can reduce load during the hours when the system is most stressed and when avoided capacity is most valuable. DR involves voluntary short-term reductions in electricity consumption triggered by grid reliability conditions or high prices. This response avoids the need to dispatch less efficient and more expensive generation during high-demand periods, as well as reduces the need to build peaking capacity when it can be aggregated into a sizable, dispatchable portfolio. These principles are directly relevant to Nova Scotia, where peak demand, winter reliability, and flexible load management are becoming increasingly important.**

(a) Please confirm whether the system-level benefits of DR, including avoided peaking capacity investment, improved planning reserve margin, and operational flexibility during high-stress hours, accrue exclusively to the customer class enrolled in the DR program, or whether they accrue to all ratepayers on the NSPI system regardless of class.

(b) If the system-level benefits of DR accrue to all ratepayers, does Brattle agree that cost allocation of DR program costs should be reviewed?

(c) Does Brattle agree that it would be reasonable for this review to be done during the next 5-year plan within the DSMAG, before investment grows beyond its current "relatively modest" levels?

(d) In other jurisdictions where DR is treated as a capacity resource and procured through competitive or utility-administered capacity markets, please confirm that the costs of DR procurement are typically allocated as part of the overall capacity supply obligation and spread across all ratepayers in proportion to their contribution to

system peak demand rather than allocated exclusively to the class enrolled in the program. If not, please explain.

Response IR-15:

This IR response has been provided by The Brattle Group.

(a) DR programs that provide marginal generation capacity benefits, improved planning reserve margin and operational flexibility would provide benefits to all customer classes and would not necessarily be limited to participant customers.

(b) Brattle has not conducted a regulatory review of how DSM plan costs are allocated to different customer classes, therefore is not able to opine on this question.

(c) Please refer to part (b).

(d) The precise allocation method differs by jurisdiction, so Brattle would not state the proposition as a universal rule without qualification. Some program-specific costs, pilots, or utility-administered DSM costs may be recovered through DSM riders or other regulatory mechanisms, and the allocation may vary by customer class depending on the applicable tariff. However, where DR is procured and accredited as a capacity resource for system reliability, the general principle is that the costs and benefits are system capacity costs and benefits. In that context, it is reasonable for those costs to be recovered broadly from load, typically through load-serving entities or customers in proportion to capacity responsibility, coincident peak contribution, or another regulator-approved allocator, rather than being allocated exclusively to the enrolled participating class.