

CLOSING SUBMISSION OF SOLAR NOVA SCOTIA

IN THE MATTER OF *The Public Utilities Act*, RSNS 1989, c. 380, as amended

- and -

IN THE MATTER OF an Application by EfficiencyOne for approval of the 2027–2031 Demand Side Management Purchase Agreement between EfficiencyOne and Nova Scotia Power Incorporated, the establishment of a final agreement between the parties, and approval of a 2027–2031 Demand Side Management Resource Plan

NSEB Matter M12780

Filed: September 11, 2026

PART I: OVERVIEW

1. Solar Nova Scotia ("SNS") supports demand side management. For fifteen years, beginning with the creation of Canada's first dedicated DSM utility, Nova Scotia has been a national leader in this field, and the leadership delivered through EfficiencyOne ("E1") has produced significant benefits for customers and for the electricity system. SNS does not ask the Board to reduce DSM investment, to question its value, or to doubt E1's competence or good faith.
2. DSM in Nova Scotia is nonetheless at a critical juncture. The technologies, the economics, and the electricity system that shaped DSM over the past fifteen years are changing, and the Plan before the Board was built, in most respects, on the model that preceded those changes. Four conditions make that model difficult to sustain. Lower-cost efficiency opportunities are increasingly saturated, and unit costs are rising sharply as a result. A new generation of demand-side technologies, mature and commercially available, sits at the edge of the grid and behaves differently from the lighting measures that drove past savings. The electricity system itself is being transformed, with a coal-free grid targeted for 2030 and more than three gigawatts of new wind and solar expected by 2035, so that the province will require load flexibility, storage, and beneficial electricity demand it does not now have. And a growing share of Nova Scotia's remaining decarbonization opportunity lies in replacing fossil fuel use with clean electricity, not in reducing electricity consumption alone.
3. E1 describes itself as Canada's first energy efficiency utility. [E-24] That self-description is reflected in this Plan, which allocates approximately 89 percent of program investment to energy efficiency, 10 percent to demand response, and 1 percent to solar, and excludes strategic electrification entirely. [E-1, Appendix A, Table 8] SNS's central submission is that the time has come for E1 to become what the *Public Utilities Act* now contemplates: a demand side management utility, whose resource allocation, program design, and delivery model reflect the full range of demand-side opportunity available to the province, and not only the efficiency measures with which it began.

4. That transformation is not one E1 can make alone, and this submission does not fault E1 for not having made it. The record shows that the obstacles lie largely outside E1's control. Whether strategic electrification may be included in a DSM plan turns on a question of statutory interpretation that only the Board can settle. Whether E1 has any incentive to lower unit costs or to innovate in delivery depends on an accountability framework the Board sets through its approval. Whether strategic electrification can be allocated a share of the IRP's identified level depends on a load forecast and a resource plan prepared by others, in which the resource does not yet appear. Whether customer-sited batteries can participate depends on a compensation mechanism no DSM plan can create. In each case, E1 has acted rationally within the framework it was given. The framework is what needs to change, and the Board is the body positioned to change it.
5. SNS's submissions address three matters, each the subject of SNS's evidence, its information requests, and its cross-examination of E1's panel:
 - (a) **Strategic electrification** (Part II). The Plan excludes the resource on the basis of an interpretation of the *Public Utilities Act* that E1 adopted in good faith, did not test, and that sits uneasily with this Board's Benefit-Cost Analysis Test Decision and with E1's own earlier evidence. The analysis needed to assess the resource was not completed, and the planning framework upstream of the Plan does not yet account for it. SNS asks the Board to settle the interpretation, to direct that the analysis be done within the Plan period, and to note the gap in the load forecast and resource plan.
 - (b) **Unit costs and accountability** (Part III). The cost at which E1 acquires savings is rising steeply, and nothing in the Plan, in its design or its execution, gives E1 an incentive to change that. The delivery innovations that would lower costs are available on the record and not pursued. SNS asks for reporting, for unit cost to be brought within the Annual Adjustment Process, and for a funded obligation to pursue lower-cost delivery.
 - (c) **Demand response** (Part IV). The Plan's demand response target is small relative to both its investment and the IRP, and the reason is program design rather than resource availability. The lowest-cost demand response, acquired at the point new controllable load is installed, is not pursued. Customer-sited batteries face a barrier the DSM framework cannot remove alone. SNS asks for lower-cost acquisition pathways to be analyzed and designed, for a long-duration product to be defined, and for the battery barrier to be named on the record.
6. Part V consolidates the directions SNS requests. None seeks an increase in the approved investment envelope; where a direction requires reallocation, SNS asks that the reallocation and its effect on existing targets be identified. Each asks E1 to see, report, and act on something the record shows has not yet been addressed, and to do so within the Plan period rather than after it. Taken together, they are the steering the transformation requires.
7. SNS makes these submissions as an industry association whose members install solar and distributed energy resources in Nova Scotia. SNS's interest is not concealed. It is also not the basis of the submissions. The evidence relied upon below is substantially E1's own: its

filed responses, its testimony, and its Plan, supplemented by the evidence of Nova Scotia Power, Synapse, and SNS, and by public comments received at the hearing.

PART II: STRATEGIC ELECTRIFICATION

A. Where the Plan stands

8. Strategic electrification is not included as a resource in this Plan. E1 has allocated funding within Enabling Strategies for research, pilots, and coordination with NS Power and the system operator. [E-42, p. 2] E1's opening statement is candid that this was not an easy choice, and that "our commitment to that work has not changed." [E-42, p. 2] SNS takes E1 at its word on both points.
9. Schedule "A" provides that strategic electrification "may be introduced during the Plan period following Board approval, where innovation activities demonstrate a model that meets the applicable cost-effectiveness and regulatory (PUA) requirements." [E-42, Schedule "A", s. 5(a)]
10. SNS welcomes that provision as a signal of intent. Its difficulty is structural rather than a matter of good faith. It contains no budget, no target, no date, and no obligation to bring a measure forward, and innovation project selection will be finalized only after this Board's decision and "as priorities are assessed throughout the duration of the plan." [E-15, SNS IR-14(c)–(e); E-12, Board IR-53, p. 3] A commitment of that shape gives the Board, and the parties, no way to know whether the question will be revisited within the Plan period. SNS's submissions in this Part are directed at giving that intent a form the Board can rely on.

B. The interpretation question

11. E1's exclusion of strategic electrification rests on its reading of the *Public Utilities Act*: that a strategic electrification resource must satisfy the two statutory conditions "in isolation and without regard to other DSM resources," and that this applies "regardless of whether the strategic electrification resource passes the... modified-PAC test... or whether the overall DSM portfolio passes the... PAC test for DSM." [E-16, Synapse IR-07(a)]
12. This is a new statutory provision, applied for the first time in a plan application, and the question of how it interacts with the Board's Benefit-Cost Analysis Test Decision is a genuine one. E1 reached its reading in good faith. SNS submits, respectfully, that it is not the better reading, and that the Board is well placed to settle the question. Five features of the record bear on it.
13. **The words are E1's, not the statute's.** The phrase "in isolation and without regard to other DSM resources" appears in neither the Act nor the Decision. Asked in cross-examination where the words appear, E1's panel restated its understanding of the Decision rather than identifying a source. [Transcript, August 4, 2026 (SNS cross-examination)] That is not a criticism; it reflects that the phrase is E1's gloss on the provision rather than the provision itself.

14. **The reading was not tested.** E1 confirmed it did not seek clarification from government or from this Board before adopting it: "We believe that the board's decision was very clear of how they had written it out so we did not feel there was a need to seek further clarification." [Transcript, August 4, 2026 (SNS cross-examination); E-16, Synapse IR-07(b)] E1's confidence is understandable. But the reading determined whether an entire resource class would be available to ratepayers for five years, and the record now shows that other careful readers, including this Board's consultant and the counterparty utility, reached a different conclusion. That divergence is itself a reason for the Board to speak.
15. **The Board's invitation was not taken up.** The Order in M12282 expressly left it open to E1 to propose another approach for assessing strategic electrification. E1 confirmed it proposed none: "No, E1 agreed with the decision of the board... we did not believe that there was an alternative option to the modified PAC as proposed by the industrial group's consultant." [Transcript, August 4, 2026 (SNS cross-examination)] E1 had itself identified, in that proceeding, that the modified PAC presented a structural barrier for this resource. [M12282, E1 Closing Submissions] SNS notes this not to fault E1 for accepting the Board's direction, but because it means the question of whether a better approach exists remains open.
16. **The reading sits uneasily with the Decision and with E1's own earlier evidence.** At paragraph 168, the Board held that the requirement to evaluate DSM at the portfolio level "implies that, provided the overall portfolio passes the cost-effectiveness test, it is not a contravention of the statute if measures or programs themselves fail," and that justification "could be provided in a number of ways, including based on the factors the Board is required to consider under s. 6(2) of the *Energy and Regulatory Boards Act*." [M12282 Decision, para. 168] E1's reading leaves that paragraph without application to the one resource the Decision most directly addressed. And in its rebuttal evidence in M12282, E1 itself argued that portfolio-level evaluation allows measures that may not pass individually to be included in support of policy objectives, naming strategic electrification. [M12282, E-24, p. 5] SNS's reading is, in substance, the one E1 advanced a year ago.
17. **How the provisions operate together.** SNS anticipates E1's strongest response: that section 79A(b)(iv) of the Act defines strategic electrification as electrification "in a manner that reduces overall greenhouse gas emissions and electricity costs," that this is a condition of eligibility rather than a cost-effectiveness screen, and that eligibility must be established before portfolio-level screening under section 79H(2) is reached. On that reading, paragraph 168 never applies to a resource that has not first qualified. SNS submits that this is not the better reading, for three reasons. First, the definitional language describes the category of activity the Act contemplates; whether a particular program in fact reduces electricity costs is an empirical question, and the Act assigns the cost-effectiveness determination to the portfolio level. Second, the Board has already identified the modified PAC as the tool for measuring the electricity-cost condition; a failing result under that tool is a cost-effectiveness result of exactly the kind paragraph 168 contemplates being justified, and nothing in paragraphs 163 or 168 states that this one result is exempt from that framework. Third, E1's reading produces the outcome the Board's consultant identified as untenable: a resource excluded from every plan regardless of design, because the test cannot be passed at the resource level under current assumptions, and the justification

pathway is closed to it. SNS acknowledges that the Board, at paragraphs 128 to 136 and 162 to 168 of its Decision, preserved the requirement that strategic electrification reduce both emissions and electricity costs, and that policy considerations cannot override specific statutory requirements. SNS does not ask the Board to override the requirement. It asks the Board to hold that the requirement is assessed, like every other cost-effectiveness requirement in the Act, at the portfolio level with justification, and that integrated designs combining electrification with demand response and efficiency measures may be assessed on their combined electricity-cost effect. This is an interpretation SNS asks the Board to adopt; SNS does not suggest paragraph 168 has conclusively established it.

A favourable result under E1's own test was set aside. E1 confirmed that in earlier modelling rounds it evaluated strategic electrification under the Total Resource Cost test, the PAC, and the Nova Scotia Jurisdictional Cost Test, the test E1 itself proposed as appropriate for Nova Scotia, and that "those results were higher than what we saw in the PAC or the modified PAC." The Round 1 results are on the record at Synapse IR-02. [Transcript, August 4, 2026 (EAC cross-examination); E-16, Synapse IR-02] The Board's Order expressly permits E1 to use its proposed test "to provide more information about specific programs and measures." [M12282 Order, para. 3] E1 explained why it did not rely on that result: it regarded the analysis as "for informational purposes only," and while it agreed "we could use the results of those tests for justifying measures or programs in any other resource," it understood that "strategic electrification had to meet the legislative requirement first." [Transcript, August 4, 2026 (SNS cross-examination)] Asked by East Coast Environmental Law whether other approaches had been considered, E1 answered that it believed it had been "in compliance with what the board has directed us to do." [Transcript, August 4, 2026 (ECELAW cross-examination)]

18. Each of these steps follows logically from E1's reading of the statute. That is the point. The alternative approach, the justification pathway, and the favourable result under E1's own test were all available; each was set aside for the same reason. Resolve the interpretation, and the pathway the Board preserved in M12282 opens for this resource as it does for every other.
19. **The interpretation is the stated basis for exclusion.** E1's evidence is that strategic electrification "must meet the legislative requirement first... or else strategic electrification could not be included in a DSM plan." [Transcript, August 4, 2026 (SNS cross-examination)] No delivery-capability concern, no affordability concern, and no cost-effectiveness concern independent of the interpretation has been advanced as a reason for exclusion. If the Board resolves the interpretation as SNS submits it should, the stated basis for exclusion is answered, and what remains is the analytical work described in the next section.

C. The analysis is not yet complete

20. E1's modelling was conducted under time and data constraints that SNS acknowledges, and the panel was forthcoming about its scope. In cross-examination, E1 confirmed:
 - (a) No sensitivity analysis including federal funding was prepared: "No we did not." [Transcript, August 4, 2026 (SNS cross-examination)]

(b) No hourly modelling of peak impacts was performed. Zero peak impact was assumed; E1 stated it "would not have the data to support hourly modelling," and had indicated a willingness to pursue that analysis if NS Power's IRP data were made available. [Transcript, August 4, 2026 (SNS cross-examination)]

(c) No break-even program cost was calculated. Asked for one, E1 answered that under its Round 2 assumptions "even if our costs were zero it would not have passed," which speaks to those assumptions rather than to what a different design would produce. [Transcript, August 4, 2026 (SNS cross-examination)]

(d) E1 was unable to confirm at hearing whether a design targeted at end-of-life equipment replacement had been modelled ("subject to check but I believe we did"); its written evidence states that delivery models were considered only "indirectly." [Transcript, August 4, 2026 (SNS cross-examination); E-15, SNS IR-11(c)]

(e) E1 included a custom measure within its scenario but did not model a separate Energy Manager-led delivery pathway with its own acquisition-cost and participation assumptions. [Transcript, August 4, 2026 (SNS cross-examination)]

(f) No framework yet exists for comparing the value of the next dollar invested across DSM resources; E1 described that as "a hypothetical situation outside of what we have in our DSM plan." [Transcript, August 4, 2026 (SNS cross-examination)] SNS addresses the need for such a framework in Part III.

21. Asked whether E1 had demonstrated that every reasonably designed strategic electrification pathway would fail, or only that the designs it chose to model did, the panel answered fairly: "the conclusion relies on the measures that we would have modelled." [Transcript, August 4, 2026 (SNS cross-examination)] E1 added that its measure characterization drew on experience delivering government-funded electrification programs. SNS accepts that. The concession still means what it says: the record establishes what happened to the measures E1 tested, not what would happen to measures it did not.
22. The most significant gap is electric vehicles. E1 confirmed it "did not model electric vehicles," having "focused on building electrification measures to leverage existing partnerships, program infrastructure and expertise." [E-14, SBA IR-05(a)] That was a reasonable scoping choice for a first pass. But zero-emission vehicles are the subject of a legislated provincial target of 30 percent of new sales by 2030; Nova Scotia Power's load forecast anticipates more than 30,000 new electric vehicles during the Plan period; and the 2023 E3 report commissioned by Nova Scotia Power found that managed-charging light-duty vehicles deliver approximately \$3,400 in net present value per vehicle to ratepayers. [Environmental Goals and Climate Change Reduction Act, S.N.S. 2021, c. 20; E-24; E-15, SNS IR-11] A resource of that scale warrants analysis before it is set aside.
23. E1's evidence that the modelled scenarios would fail the modified PAC even with program costs reduced to zero is an important result, and SNS does not dispute it as far as it goes. [Transcript, August 4, 2026 (SNS cross-examination)] It establishes that under the load shapes, avoided cost assumptions, and design choices E1 selected, increased system costs exceeded increased revenues. Each of those inputs can be varied. A hybrid heating design

that avoids the winter peak, or a heat pump conversion targeted at end-of-life replacement, produces a different load shape and a different result. The record does not establish that either was assessed as a separately designed pathway with its own load shape and delivery assumptions. [E-15, SNS IR-11(c)]

24. There is also a limitation in the test itself that Nova Scotia Power's expert identified: the modified PAC "creates a structural barrier for strategic electrification because the only benefit it captures is increased utility revenue from higher electricity sales, while it excludes many of the broader benefits that motivate electrification." [E-22, pp. 7–8] By its scope, it does not credit the customer's avoided fuel cost or other non-electric benefits. Avoided capacity and infrastructure costs are within its scope, but they can be captured only if the timing of load is modelled, which, as E1 confirmed, it was not. Brattle's recommendation is that "failed modified-PAC results should not be viewed as evidence that SE lacks value" [E-53; E-22, p. 37], and E1's own results under the Nova Scotia Jurisdictional Cost Test, which captures a broader set of benefits, were higher. NS Power's evidence adds that "it is very important to model the impact of SE measures on an hourly basis." [E-22, p. 23] None of this is a criticism of E1; it is a description of what the test can and cannot see without further work.
25. Electric vehicles illustrate the point most clearly, because they were not modelled at all. Managed charging adds load almost entirely in off-peak hours, where marginal cost is lowest and infrastructure is underused, and E1's own witness recalled the E3 report showing the managed scenario to be positive on a rate-impact basis. [Transcript, August 4, 2026 (SNS cross-examination)] But the same logic applies to building measures designed with equal care. SNS's submission is not that one measure class passes and another fails. It is that one design was tested under one set of assumptions, and that the designs most likely to succeed, in buildings and in transportation, remain to be run.

D. Why completing the analysis matters

26. **Strategic electrification is within E1's mandate, and E1 says so.** The 2023 amendment to the *Public Utilities Act* brought strategic electrification within the statutory definition of demand-side management. E1's opening statement acknowledges as much: "Strategic electrification is now part of our mandate." [E-42, p. 2] The question for this Board is how to help E1 discharge that mandate within the Plan period, rather than after it.
27. **Hourly analysis with NS Power is the key missing piece, and it is within reach.** Whether a measure reduces electricity costs depends heavily on when the new load arrives. Managed EV charging adds load in off-peak hours, where marginal cost is low and fixed costs are spread across more sales; unmanaged heating load adds it at the winter peak. Without hourly analysis, the modified PAC cannot distinguish between them. E1 stated at hearing that it lacked the data for hourly modelling but was willing to pursue it if NS Power's IRP data were made available. [Transcript, August 4, 2026 (SNS cross-examination)] E1's rebuttal evidence expresses doubt that hourly modelling would change its results [E-41, p. 28]; the way to find out is to do it. NS Power is a party to this proceeding, holds the hourly load and marginal cost data, and has itself recommended that E1 prioritize measures that

reduce or shift peak demand. [E-22] This is analysis the two utilities can do together, and SNS asks the Board to direct that it be done.

28. **The cost of deferral.** The technologies at issue (heat pumps, electric vehicles, managed charging, and hybrid heating) are mature and commercially available. Deferring program design to the next planning cycle carries three costs that fall on ratepayers rather than on E1.
29. First, the equipment decisions made between 2027 and 2031 are locked in. A furnace, water heater, or vehicle purchased during this period will be in service into the 2040s. The opportunity to influence those purchases at the point of replacement, the lowest-cost intervention available, closes with each one made.
30. Second, program capability is built by running programs. Delivery models, contractor networks, customer journeys, incentive structures, and evaluation methods are developed through implementation and refined through experience. A five-year deferral means Nova Scotia begins that learning in 2032, behind jurisdictions that began it in 2027.
31. Third, deferral is costly in precisely the terms the Plan prioritizes. Part III of this submission shows the portfolio's cost per kilowatt-hour rising steeply as low-cost measures saturate. Strategic electrification adds load rather than reducing it, and therefore generates utility revenue that partially offsets program cost from the first year. Its near-term rate profile is therefore likely to be more favourable than efficiency's, though comparative modelling would be required to establish the ranking. In a Plan constrained by near-term affordability, that is a reason to complete the analysis, not to defer it.
32. **Design determines the result.** SNS does not submit that any strategic electrification program will pass the modified PAC. It submits that whether one passes depends almost entirely on design, and that the determinants are well understood: targeting end-of-life equipment replacement so that the incentive covers only the incremental cost of the electric option; sizing rebates to close the customer's economic gap rather than to fund the whole measure; incorporating federal incentives that reduce the ratepayer contribution; managing the timing of new load so that it arrives off-peak; and delivering through channels, such as Energy Manager and integrated advisory support, with demonstrated lower acquisition costs. These are the designs to test next. [E-15, SNS IR-11(c), (d)] A well-designed program that passes is worth more to ratepayers than a poorly designed one that is funded anyway, which is why SNS asks for analysis before implementation, not implementation without it.
33. **Integration is the capability that waits with it.** Part III of this submission addresses program delivery and the case for integrated delivery across efficiency, demand response, distributed resources, and strategic electrification. Customer projects increasingly combine these resources: a heat pump conversion with a battery and managed charging, or a commercial retrofit with rooftop solar and demand response participation. E1 confirmed it offers no coordinated pathway for such projects today, while noting that improved collaboration across resources is contemplated in this Plan and that Energy Managers are one way to achieve it. [Transcript, August 4, 2026 (SNS cross-examination)] SNS agrees with both observations. But the integrated delivery model that all four resources will

eventually require cannot be developed while one of them is outside scope. Bringing strategic electrification in is what allows that work to begin.

E. The planning framework itself leaves the resource out

34. One further feature of the record deserves the Board's attention, because it explains why strategic electrification is at a disadvantage before any cost-effectiveness test is applied. E1's method for allocating resources within its fixed budget was proportionality to the IRP. Its witness described the approach under questioning from the Board: "we did make the decision to fix the budget and then... we still made sure that we were aligned with the IRP... the resources are still aligned consistently proportionately 65% for each of the resources." [Transcript, August 5, 2026 (Board questions)] E1's counsel put the same framework to Nova Scotia Power's expert, establishing that demand response at 29.3 MW is approximately two-thirds of the IRP's 44.3 MW benchmark, that efficiency peak savings at 85 MW are approximately 69 percent of the IRP's 123 MW, and that efficiency energy savings are 64 percent of the IRP target, and suggesting that the Plan is therefore "quite aligned with respect to its resource mix against the IRP." [Transcript, August 5, 2026 (E1 cross-examination of Dr. Sergici); E-16, Synapse IR-10, Table 2] SNS does not object to proportionality as a principle. It observes that a resource can only be allocated a share of its IRP-identified level if the IRP identifies a level for it.
35. Strategic electrification has none. It is not modelled in the Integrated Resource Plan as a demand-side resource. Nova Scotia Power's load forecast includes baseline electrification adoption, such as the electric vehicles referred to above, but it does not identify any incremental or controllable load attributable to a DSM program, because no such program exists. The reason is circular: because no program drives or shapes adoption, no program-attributable electrification load is forecast; because none is forecast, the IRP identifies no DSM contribution from it; because it identifies none, a plan allocating resources in proportion to IRP-identified levels allocates it nothing. Under that framework, strategic electrification is not excluded because it fails a test. It is excluded because the planning documents upstream of this Plan have not yet asked the question. The Board's consultant identified the same gap from the other direction, recommending that E1 be directed to model hourly impacts and to develop the resource rather than await its appearance in a forecast. [E-23]
36. SNS recognizes that the load forecast and the Integrated Resource Plan are prepared by Nova Scotia Power and the Independent Electricity System Operator, in proceedings other than this one. SNS asks the Board to note on this record that strategic electrification is not currently represented in either document as a demand-side resource, that this omission constrains what any DSM plan can allocate to it, and that its representation in future forecasts and resource plans would allow the resource to be assessed on the same footing as energy efficiency and demand response. A statement to that effect from this Board would be of assistance to the parties responsible for those documents.

F. The portfolio absorbs the resource

37. The analysis E1 was not positioned to perform was performed by this Board's consultant. Synapse's evidence shows a modified PAC of 2.6 without strategic electrification and 2.3 with it, a difference Ms. Napoleon described as immaterial, noting that any result above 1.0 raises no cost-effectiveness concern. [E-23, p. 26; E-36, IR-5(b)]
38. The record therefore establishes that strategic electrification can be included while the portfolio remains comfortably cost-effective. What remains is the interpretation.

G. The weight of the record

39. On the proposition that strategic electrification should have a funded pathway during this Plan period rather than research alone, the record contains the following positions:
 - (a) **Nova Scotia Power / Brattle:** E1 should "develop a phased SE pathway with candidate measures that have stronger cost effectiveness potential and move beyond a research-only approach during the plan period," should prioritize "managed EV charging," and should "recognize that failed modified PAC results should not be viewed as evidence that SE lacks value." [E-22]
 - (b) **Synapse:** including strategic electrification is immaterial to portfolio cost-effectiveness; an offering for low- and moderate-income customers heating with oil should be developed. [E-23]
 - (c) **Affordable Energy Coalition:** supports "including substantial strategic electrification in the E1 contract, especially for low and modest income households." [E-58]
 - (d) **Ecology Action Centre:** "Strategic electrification must be part of Efficiency Nova Scotia's DSM work." [E-50]
 - (e) **Solar Nova Scotia:** the resource belongs in this Plan, not solely in research and development. [E-24; E-46]
40. These parties share no natural alignment of interest. They comprise the utility, this Board's consultant, anti-poverty advocates, environmental advocates, and the distributed energy industry. The Board does not resolve questions of statutory interpretation by counting parties, and SNS does not ask it to. But the breadth of agreement suggests the question is one on which the Board's guidance would be welcomed, by E1 as much as by anyone.

H. What SNS asks

41. SNS asks the Board to do three things, none of which requires a finding that E1 acted unreasonably.
42. First, to determine that, consistent with paragraph 168 of the Benefit-Cost Analysis Test Decision and the portfolio-level framework of the *Public Utilities Act*, a strategic electrification measure or program that does not individually pass the applicable cost-effectiveness test may be included in a DSM plan, with justification, where the overall

portfolio passes. That determination would give E1 the clarity it did not have when it prepared this Application.

43. Second, and independently of the first, to direct E1 to file, no later than December 31, 2027, an assessment of strategic electrification options for the Plan period, prepared in coordination with NS Power and addressing at minimum managed electric vehicle charging, hybrid heating systems, and high-efficiency electrification of fossil-fuel end uses at end-of-life equipment replacement. For each option, the assessment should provide modified PAC results, the break-even program cost at which the option would pass or, where no non-negative program cost produces a passing result, the quantified shortfall, results under the Nova Scotia Jurisdictional Cost Test as supplementary information, an assessment of available federal funding, and hourly peak-impact analysis using Nova Scotia Power's load data. Where E1 concludes an option should not proceed, it should explain why. Where E1 identifies an option that should proceed, it should file a program design for approval, funded by reallocation within the approved investment level through the Annual Adjustment Process established in Schedule "A", with the strategic electrification question addressed as a standing item at the Mid-Term Check-In, for implementation no later than program year 2029.
44. Third, to note in its decision that strategic electrification is not currently represented in Nova Scotia Power's load forecast or in the Integrated Resource Plan as a demand-side resource, that this constrains the allocation any DSM plan can make to it, and that its inclusion in future forecasts and resource plans would allow it to be assessed on the same basis as other demand-side resources.
45. None of these requests asks the Board to order expenditure on programs whose design has not been established, or to increase the approved investment envelope. Each asks only that the question be answered, with the analysis that would ordinarily accompany a plan application, on a timeline that keeps the answer within the Plan period. The mechanism for doing so, mid-plan introduction following Board approval with reallocation through the Annual Adjustment Process, is one E1 has already placed before the Board in Schedule "A." E1 has said its commitment to this work has not changed. These directions would give that commitment the structure it needs.

PART III: UNIT COSTS, ACCOUNTABILITY, AND DELIVERY INNOVATION

A. The trajectory

46. The cost at which E1 acquires savings is rising steeply, and the Plan projects that it will continue to rise. The following figures were put to E1 in cross-examination and confirmed. [Transcript, August 4, 2026 (SNS cross-examination)]

First-year savings acquisition cost	Base period	Comparison period	Change
Portfolio	\$0.37/kWh (2023–2025 actual)	\$0.59/kWh (2027–2031 Plan average)	+60%
Residential subtotal	\$0.35/kWh (2023 actual)	\$1.25/kWh (2031 Plan)	+257% (roughly 17% per year over eight years)
Home Energy Assessment	\$0.14/kWh (2023 actual)	\$3.10/kWh (2031 Plan)	over 2,000%

[E-2, Table 3; E-1, Appendix A, Tables 8 and 13; E-15, SNS IR-04]

47. The causes are largely structural, and SNS does not attribute them to mismanagement. Low-cost lighting measures have been baselined out of program eligibility. Federal co-delivery funding that lowered costs in 2023 has ended. The measures that remain are deeper, more capital-intensive, and more labour-intensive to deliver. E1's evidence on these points is credible and SNS accepts it.
48. The consequence, however, is the Board's concern. The IRP Reference Plan calls for 683.1 GWh of savings over the Plan period; E1 commits to 435.4 GWh, a shortfall of 247.7 GWh that widens every year. [E-16, Synapse IR-10, Table 2] As an illustrative sensitivity, holding energy efficiency program expenditure constant at the Plan level, the proposed investment would deliver approximately 694 GWh at the 2023–2025 actual unit cost of \$0.37/kWh ($435.4 \text{ GWh} \times \$0.59 \div \$0.37$), roughly the full IRP Reference Plan. SNS does not suggest that historical unit costs remain achievable; paragraph 45 explains why they changed. The illustration shows only that the shortfall against the IRP is a function of cost per kilowatt-hour at least as much as of budget, and that the cost trajectory therefore warrants scrutiny and analysis of alternative delivery. E1 did not accept the comparison, pointing to changes in portfolio composition and to Apex Analytics' benchmarking placing E1 "squarely in the middle of the range of comparable jurisdictions." [Transcript, August 4, 2026 (SNS cross-examination)] SNS returns to that answer below.

B. Nothing in the Plan creates unit cost discipline

49. Two questions were put to E1 on this point. First, whether any mechanism in the Plan, any target, reward, or consequence, gives E1 an incentive to reduce incentive levels or unit costs during the Plan period. E1's answer: "No, there is not." [Transcript, August 4, 2026 (SNS cross-examination)] Second, whether E1 adjusts incentive levels where demand for a program exceeds available funding. E1 confirmed it does not propose to. [Transcript, August 4, 2026 (SNS cross-examination)] The record shows those conditions already exist: E1 confirmed that Custom and Small Business Energy Solutions incentives were fully subscribed in 2026, and that it is common for those programs to be "fully subscribed years in advance." [Transcript, August 4, 2026 (SNS cross-examination)]
50. Where demand for a subsidy materially exceeds supply, the ordinary response is to reduce the subsidy until the two balance, delivering the same savings to more customers at lower cost per unit. Oversubscription is evidence that incentive levels exceed what the market

requires. The Plan's response to rising costs is nonetheless higher incentives: E1's evidence is that the Preferred Plan "focuses on reducing barriers to participation by providing higher incentives to customers." [E-15, SNS IR-07(e)]

51. The absence of a mechanism during the Plan period is only half of the difficulty. The other half is in how the Plan was designed. E1 selected its investment level as, in its words, "a judgment call," without formal economic analysis, and consulted the IRP afterward to allocate within that envelope rather than to determine it. [Transcript, August 5, 2026 (Board questions)] E1 then selected its savings target, 64 percent of the IRP Reference Plan, as a consequence of that choice. E1's opening statement describes the gap as "a direct and deliberate consequence" of the investment decision. [E-42, p. 3]
52. Where an applicant may determine both what it will spend and what proportion of the identified requirement it will undertake, and where cost-effectiveness is assessed only as a threshold the portfolio must clear, the incentives run in one direction. A plan proposing higher unit costs and a lower savings target is easier to deliver. It requires less participation to be recruited, less delivery capacity to be built, fewer contractor and partner relationships to be secured, and less innovation in how savings are acquired. It carries correspondingly less risk of missing the targets on which E1 is measured. A plan proposing lower unit costs and a higher target requires execution, and carries the risk that execution will fall short.
53. SNS does not suggest E1 designed this Plan to minimize its own delivery risk. SNS submits that nothing in the framework before the Board would reveal it if E1 had. The Plan is assessed on whether the portfolio passes a cost-effectiveness threshold. It is not assessed against what the same investment could deliver if delivered differently, and no such analysis was filed. The Board is asked to accept both the unit costs and the savings target as given, when they are the two variables most within the applicant's control.
54. That leaves two external disciplines on unit costs, and neither is adequate. The first is the portfolio-level PAC test, which confirms the portfolio is cost-effective but says nothing about whether it is as cost-effective as it could be. The second is benchmarking against comparable jurisdictions, which is the answer E1 gave when the arithmetic in paragraph 46 was put to it.
55. Benchmarking measures whether E1 resembles its peers. It does not measure whether the savings proposed could be acquired for less in Nova Scotia. And it sits uneasily with the premise of the Application. E1's opening statement rests on fifteen years of experience delivering DSM in this province, and E1 describes itself as Canada's first energy efficiency utility. [E-42, p. 1; E-24] SNS agrees that Nova Scotia has been a leader in this field. But an organization that positions itself as a leader cannot rely on the average performance of the organizations it leads as the measure of its own cost discipline. Leadership is a claim about being ahead of the peer group; benchmarking confirms only that one is within it. If the mid-range of comparable jurisdictions is the standard against which this Plan's unit costs are assessed, the Board should understand that it is being asked to approve costs measured against organizations Nova Scotia has historically outperformed.
56. The result is a framework in which the safest course for the administrator is to propose unit costs as high as the portfolio test will bear and targets as modest as the IRP will tolerate, and

in which a program with high approved costs and a modest target is reported as a success on exactly the same terms as the same savings acquired at half the cost. SNS does not say E1 has followed that course. SNS says the Board cannot tell, and that it should not have to guess.

C. The consequence: delivery innovation is not being pursued

57. An administrator accountable for savings volume within a fixed budget, and for nothing else, has one reliable path to meeting its targets as low-cost measures saturate: raise incentive levels. Higher incentives are certain, immediate, and low-risk. Redesigning delivery to acquire savings more cheaply is slower, carries execution risk, requires new capability, and yields E1 no benefit if it succeeds. The record shows that logic operating.
58. E1 agreed with each step of the following in cross-examination: that it is standard practice to bundle low-cost, quick-payback measures with costlier, longer-payback ones so that projects achieve acceptable economics; that as lighting and similar measures saturate, that strategy becomes less effective; that "there would not be an equivalent that would replace" lighting; and that the economics of deeper savings therefore become more challenging. [Transcript, August 4, 2026 (SNS cross-examination)] E1's response to that dynamic is higher incentives through the same delivery channels. What E1 has not done is treat the delivery model itself as the variable to be improved.
59. **Integrated delivery.** Customer projects increasingly combine energy efficiency, demand response, distributed resources and, if permitted, strategic electrification. Asked whether E1 offers any single, coordinated pathway for such projects, E1 answered: "Today we do not," adding that improved collaboration across resources is contemplated in the Plan and that Energy Managers are one way to achieve it. [Transcript, August 4, 2026 (SNS cross-examination)] SNS agrees with both observations, and notes that neither has yet been given a plan, a budget, or a date. Siloed delivery imposes administrative cost on E1, complexity on customers, and forgone value on projects, all of which are ultimately reflected in unit costs.
60. **The Energy Manager evidence.** The record contains direct evidence of what lowers unit costs. E1 confirmed that Energy Managers supported 94 percent of savings in the Custom Retrofit program, which serves existing buildings, in 2024 and 90 percent in 2025; that the Custom Incentives program as a whole, of which the Retrofit program is the largest component and which also includes new construction, delivers approximately half of this Plan's savings, "by design," at among the lowest and most stable unit costs in the portfolio; that customers with access to that non-financial support are the ones "realizing 95% of the customer savings"; and that such support is "very, very important, for sure." [Transcript, August 4, 2026 (SNS cross-examination); E-15, SNS IR-08(e)] E1 nonetheless confirmed it "considered shifting DSM spending from customer incentives toward additional staff roles" and determined the Plan should instead prioritize "maximizing the share of DSM investment that is directed to customer incentives and services." [E-15, SNS IR-09] Energy Manager costs are reported within DSM salaries and benefits, and E1 was unable to say what proportion of those roles is DSM-funded. [Transcript, August 4, 2026 (SNS cross-examination)]

61. SNS does not submit that E1 should expand its own Energy Manager complement. As Mr. Lutes observed, the private sector has matured and can deliver these services. [Transcript, August 4, 2026 (public comments)] SNS's submission is that the support model, meaning technical assistance, project development, funding navigation and implementation support, is associated with Custom Retrofit's stability and low unit cost, and that the evidence warrants testing that model in other programs, while acknowledging that project size and customer mix also contribute to Custom's results; that it addresses the non-financial barriers E1 itself identifies for small business customers, which higher rebates do not; and that it can be delivered through qualified private-sector providers. Asked which of those non-financial barriers a higher rebate addresses, E1 did not answer the question. [Transcript, August 4, 2026 (SNS cross-examination)]
62. The delivery capacity to do this already exists in the market. E1's Efficiency Preferred Partner network comprises the contractors, installers, and service providers who deliver most of the province's efficiency and distributed energy work, and who deal with customers at precisely the moments that matter for lower-cost delivery: equipment replacement, new construction, and project development. Mr. Lutes and Mr. Cook, both members of that network, spoke to its maturity and to its members' willingness to take on advisory and project-development roles. [Transcript, August 4, 2026 (public comments)] Any serious exploration of integrated or lower-cost delivery must begin with those partners, because they are the channel through which any redesigned program would reach customers. SNS submits that consultation with the Efficiency Preferred Partner network should be a required element of the delivery work sought in this Part, not an afterthought to it.
63. **Alternatives available but not pursued.** The pattern extends across the Plan. Where the record identifies a means of acquiring savings at lower cost per unit, it was available and not taken up:
 - (a) *External funding.* E1's 2023 Annual Progress Report attributes Home Energy Assessment's \$0.14/kWh unit cost, the lowest in its residential portfolio, to co-delivery of the federal Greener Homes program. [E-2, Section 3.2] E1 confirmed at hearing that the federal support "significantly accelerated adoption" and "brought down the overall cost for DSM." [Transcript, August 4, 2026 (SNS cross-examination)] E1 nonetheless "does not factor in impacts of external financial supports... unless E1 has a contract to deliver said supports over the longer-term," and did not factor the Clean Technology Investment Tax Credit or accelerated depreciation into program design, though both are in place with terms extending beyond this Plan. [E-15, SNS IR-07(c)]
 - (b) *End-of-life equipment replacement.* Targeting the point at which a customer must replace equipment in any event, so that the incentive covers only the incremental cost of the efficient or electric option, is the design with the lowest inherent unit cost. E1's evidence is that delivery models of this kind were considered "indirectly." [E-15, SNS IR-11(c)]
 - (c) *Demand response at the point of installation.* The Plan supports 121,039 smart thermostats, 68,539 installed at no charge, none required or encouraged to enrol in demand response; water heater incentives "could be made contingent on customers

enrolling," and are not; and no analysis has compared demand-response readiness at construction against later retrofit. [E-15, SNS IRs 01(e), 02(d), 06(c)] Part IV addresses these in detail.

(d) *Enabling Strategies*. The Plan allocates \$29.1 million to Enabling Strategies, an amount equal to the entire demand response program. E1's response to SNS IR-14 lists the innovation projects completed in 2025: feasibility work on generator and hot-water demand response, duct sizing workshops, and heat pump water heater training. [E-15, SNS IR-14(a)] Each is directed at identifying new savings opportunities, which has value. None is directed at lowering the cost of delivering savings, and E1 has confirmed that project selection for the Plan period will be finalized only after this Board's decision. [E-12, Board IR-53, p. 3]

64. SNS submits that delivery innovation is the principal available response to rising unit costs, and that it is neither adequately funded nor adequately pursued in this Plan. As low-cost measures saturate, the cost of acquiring a kilowatt-hour is determined less by the measure than by how it is found, developed, financed, and installed. That is where the next gains are, and it is where the Plan is silent.

D. What SNS asks

65. SNS does not ask the Board to impose a unit cost performance target. The evidence does not establish an appropriate level for one, and a poorly calibrated target could distort program selection toward shallow measures. SNS asks for accountability, visibility, and a funded obligation to pursue the alternatives. None of the following directions seeks an increase in the approved investment envelope.
66. SNS respectfully requests that the Board direct E1 as follows:
- (a) **Unit cost reporting.** Report in each Annual and Quarterly Report first-year unit cost by program component and at the portfolio level against Plan forecast, with explanation of variances exceeding ten percent and the measures being taken to address them.
 - (b) **Unit cost within the Annual Adjustment Process.** Include unit cost among the metrics subject to the enhanced reporting, forward outlook, and variance signalling provided for in Schedule "A", so that cumulative unit cost performance is visible on the same basis as spending and savings.
 - (c) **Incentive level review.** Where a program is fully subscribed in advance of its funding period, review incentive levels annually and report through the Annual Adjustment Process on whether they remain the minimum necessary to achieve planned participation.
 - (d) **Integrated delivery plan.** File, no later than the Mid-Term Check-In, a plan for a coordinated pathway through which customers can access energy efficiency, demand response, distributed energy resource, and, if approved, strategic electrification support through a single process, including the role of Energy

Manager or advisory support and the timeline for implementation, developed in consultation with the Efficiency Preferred Partner network.

(e) Delivery innovation within Enabling Strategies. Dedicate an identified portion of Enabling Strategies funding to delivery-cost innovation, as distinct from measure and technology research, and report annually on projects undertaken, expenditures, and unit cost implications. Priority areas should include advisory and energy-navigator delivery models, including delivery through qualified private-sector providers; end-of-life equipment targeting on an incremental-cost basis; point-of-installation acquisition of demand response; and customer cost-sharing structures. Project selection and design should be undertaken in consultation with the Efficiency Preferred Partner network.

(f) External funding leverage. Pursue federal and other external co-delivery and co-funding arrangements as a program objective, and report annually on external funding leveraged, participant uptake of federal incentives, and the effect of both on program unit costs.

(g) Delivery model assessment. File, with the 2028 Annual Report, an assessment of alternative delivery models for any program whose unit cost exceeds Plan forecast by more than twenty-five percent, including at minimum Small Business Energy Solutions, prepared in consultation with the Efficiency Preferred Partner network.

(h) Filing requirements for future plans. Include in any future DSM plan application: a framework comparing the marginal value of investment across demand-side resources and an explanation of how the proposed allocation among them was determined; an analysis of the delivery approaches considered for each program, the unit cost associated with each, and the basis for the approach proposed; and an explanation of the relationship between the proposed savings target and the DSM contribution identified in the prevailing Integrated Resource Plan.

67. These directions ask E1 to see, report, and act upon the cost of what it delivers, and to treat the way savings are delivered as something capable of improvement. That is the discipline the Plan currently lacks, and it is the discipline that will determine whether the next plan can deliver more of the IRP's requirement than this one does.

PART IV: DEMAND RESPONSE

A. The target is small, and the reasons for it are program design rather than resource availability

68. Demand response receives approximately 10 percent of program investment in this Plan, \$29.1 million of \$289.7 million, and reaches 29.3 MW of capacity by 2031 against 44.3 MW identified in the IRP Reference Plan. [E-1, Appendix A, Table 8; E-16, Synapse IR-10, Table 2] Residential enrolment is held at 2026 levels; the growth that occurs is confined to the business, non-profit and institutional sector.

69. E1 characterizes this as an 80 percent increase in demand response impact, from 16.3 MW achieved in the 2026 season to 29.3 MW by 2031. [Transcript, August 4, 2026 (SNS cross-examination)] SNS does not dispute the arithmetic. It notes that the comparison runs from actual results to planned results, that the plan-on-plan growth is approximately 8 MW, and that a target reaching two-thirds of the IRP's identified level is not one the Board should regard as ambitious.
70. The Plan's own explanation for the constrained target is that Residential demand response "costs have scaled faster than evaluated benefits" and that E1 intends to optimize performance before scaling. [E-15, SNS IR-03; E-41] E1 has since clarified that Schedule "A" section 3(a), which provides that EcoShift enrolment "will continue," means maintaining the current level of participation, swapping out non-participating customers for participating ones, rather than adding capacity. [Transcript, August 4, 2026 (SBA cross-examination)] SNS accepts that clarification. It means that the Plan's demand response forecast is unchanged by Schedule "A", and that E1's strategy is to wait for the cost-effectiveness of its existing residential design to improve.
71. SNS's submission is that the difficulty lies in the design and the measures targeted, not in the resource. The current residential approach, which installs fully funded controllers and thermostats in existing homes and then works to keep customers engaged, is likely among the higher-cost ways to acquire demand response. It pays the full retrofit cost of every device, at a point in the equipment's life when the customer has no other reason to engage, and it then depends on sustained participation from customers who received the device without asking for it. Waiting for that model to become cost-effective is a reasonable response only if it is the sole model available. It is not.
72. The alternative begins with a different view of E1's role. Over the Plan period, Nova Scotia will add tens of thousands of heat pumps, electric water heaters, electric vehicles, and new dwellings, along with substantial commercial construction, to the grid. Every one of those is a new load, and most of them are controllable at the moment they are installed for a fraction of what it costs to retrofit control later. The most promising demand response program available to E1 is likely not one that revisits existing homes, but one that treats E1 as the steward of new load coming onto the system and ensures that load arrives controllable. The Plan does not take that view. New loads are not counted, not targeted, and not designed for. They are, on this record, ignored.

B. Lower-cost pathways exist and are not pursued

73. Potentially lower-cost demand response is available at the moment controllable equipment is being installed in any event: at new construction, at equipment replacement, and at the point of sale of devices DSM is already funding. At those moments, the incremental cost of demand-response capability is small, the customer is already making a decision, and no retrofit visit is required. The record establishes the scale of that opportunity and that the Plan does not pursue it:

(a) **Smart thermostats.** The Plan supports 121,039 smart thermostats, of which 68,539 are installed at no charge in customers' homes. E1 confirmed that participating customers are not encouraged to enrol these devices in demand

response, even where technically eligible. [E-15, SNS IR-01(e); Transcript, August 4, 2026 (SNS cross-examination)] E1's rebuttal describes these devices as "not stranded assets" because nothing prevents future enrolment. [E-41] Nothing in the Plan provides for it either.

(b) **Electric water heaters.** Between 50,000 and 100,000 residential electric water heaters, each approximately 3 kW of controllable load, are expected to be replaced during the Plan period. [E-24] E1 offers no incentive for these replacements and no program touches them; they are replaced without any involvement by E1. [E-15, SNS IR-02] E1 considered and did not adopt an incentive for integrated-control units, and confirmed that a water heater incentive "could be made contingent on customers enrolling in demand response programs." [E-15, SNS IR-02(c), (d)] The result is that the single largest population of controllable equipment being replaced during the Plan period passes through the market with no point of contact with the DSM program at all.

(c) **Heat pumps.** More than 100,000 heat pumps are expected to be installed during the Plan period. [E-24] The Plan contains no requirement, incentive, or target for demand-response controls at the time of installation.

(d) **Electric vehicles.** More than 30,000 electric vehicles are anticipated during the Plan period under Nova Scotia Power's load forecast. [E-24] The Plan contains no managed-charging measure and no enrolment target, and E1 confirmed it did not model electric vehicles. [E-14, SBA IR-05(a)]

(e) **New residential and commercial construction.** Nova Scotia recorded approximately 8,000 housing starts and approximately \$1.3 billion in non-residential construction in 2025. [E-24] E1 confirmed it has never conducted a formal analysis comparing the cost of building demand-response readiness into new construction against retrofitting after occupancy, while acknowledging that new construction is a "potentially cost-advantaged opportunity for DR integration." Its commitment is to "revisit this question during the Plan period." [E-15, SNS IR-06(c)] The new-construction program includes language encouraging demand-response readiness but no funding commitment and no target. [E-15, SNS IR-08(d)]

(f) **Backup generators.** Several hundred megawatts of backup-generator capacity is installed across the province, with tens of megawatts added annually. [E-24] The Plan forecasts approximately 6.6 MW through the Plan period, essentially flat. [E-1(iii), DR Technical Tables] E1 confirmed it does not view the opportunity as saturated, that the 6.6 MW figure is "an estimate" that "could" be exceeded, and that no potential study has been conducted on this technology in some time. [Transcript, August 4, 2026 (SNS cross-examination)] E1 also agreed that generators can sustain output well beyond the four-hour duration of its demand response events, and that longer-duration resources carry higher effective load carrying capability and therefore greater capacity value. [Transcript, August 4, 2026 (SNS cross-examination)] Asked in rebuttal why no long-duration resource is offered, E1 stated it "has not been requested to provide a long-duration DR resource," clarifying at the panel's request that Nova Scotia Power had not defined such an event. [E-41; Transcript, August 5, 2026 (Board questions)]

74. Each of these is a potentially lower-cost means of acquiring demand response than the retrofit model E1 is waiting to become cost-effective. Each was identified on the record. None is pursued in the Plan, and none has been compared against it.
75. Duration deserves separate emphasis, because it goes to how much a demand response resource is worth once acquired, not only what it costs. The capacity value of a resource is measured by its effective load carrying capability, the share of its nameplate that the system can rely on to meet peak. A resource that can sustain output across a full winter peak event earns a higher effective load carrying capability than one that can perform for four hours and stop. E1 agreed that backup generators can sustain output well beyond the four-hour duration of its events, and that longer-duration resources carry higher effective load carrying capability and therefore greater capacity value. [Transcript, August 4, 2026 (SNS cross-examination); E-24] The same is true of batteries sized for longer discharge and of hybrid heating systems that can shift load for the length of a cold spell. E1's demand response products are nonetheless designed around a four-hour event, and the capacity that the system operator will credit to them in the IRP is limited accordingly. The consequence for ratepayers is direct: the Plan pays to acquire resources capable of delivering more capacity value than the program design allows them to provide, and the difference is capacity the system must procure from somewhere else.

C. Customer-sited batteries face a constraint the DSM framework cannot remove alone

76. Batteries warrant separate treatment, because their difficulty is different in kind. E1 confirmed that zero batteries were enrolled in Smart Synergy in 2025, and that the Plan contains no technology-specific forecast for batteries through 2031. [E-15, SNS IR-10] E1 treats batteries and backup generators as technologically neutral for incentive purposes, viewing them as "equal economic value" to the program. [Transcript, August 5, 2026 (Board questions)] The pathway exists on paper. No battery has used it.
77. The reason emerged clearly at hearing. E1's evidence is that for larger capital investments such as batteries, a Smart Synergy incentive "may not be sufficient to drive investment without a broader business case," and that customer investment decisions in capital-intensive resources "may depend on economics that extend beyond the five-year approval period." [E-15, SNS IR-10(b)] Asked whether more capital-intensive demand response could be realized if performance incentives were guaranteed over a longer time frame than one to five years, E1 answered: "Yeah, we would agree with that." [Transcript, August 4, 2026 (SNS cross-examination)]
78. That is the concern. A battery is a fifteen-year asset. A DSM plan offers, at most, five years of incentive certainty, and any continuation depends on a future plan not yet filed. On E1's own evidence, that limited certainty may materially constrain customer investment in capital-intensive resources. SNS does not suggest that no program design could address it, or that it is the sole cause of zero enrolment; it submits that the record identifies it as a significant constraint that incentive levels alone are unlikely to overcome. What is required is a compensation mechanism for the capacity, energy, and flexibility value that customer-sited storage provides, on a term that matches the asset, of the kind Nova Scotia Power's

Distributed Energy Resource Integration Roadmap is intended to establish and that the system operator will need in order to count these resources in the IRP.

79. SNS recognizes that the establishment of such a mechanism may lie beyond what this Board can direct in a DSM proceeding. SNS asks the Board to do what it can: to find, on this record, that limited incentive certainty within the five-year DSM framework may materially constrain customer-sited battery participation; to direct a coordinated assessment of longer-term compensation and program-design options; and to encourage the Province, the Independent Electricity System Operator, and Nova Scotia Power to address longer-term compensation through the DER Integration Roadmap and the IRP process. A finding to that effect would give the parties responsible for the mechanism a clear statement of the need from the regulator best positioned to observe it.

D. Integration is the missing design principle

80. The pathways described above share a feature: each is a demand response opportunity that arises either inside a program E1 already runs or in an equipment-replacement market adjacent to one. The thermostats are Efficient Product Installation measures. Heat pumps are efficiency measures with controllable load. Water heaters are replaced in a market E1 does not currently serve but could. New construction is a program E1 delivers. Strategic electrification measures, if included, would be controllable loads by nature. In each case the demand response value is left on the table because the program that installs the equipment and the program that would control it are designed separately.
81. E1's own evidence points to the alternative. Asked whether it offers a coordinated pathway across resources, E1 answered "Today we do not," but identified Energy Managers as one way to achieve it. [Transcript, August 4, 2026 (SNS cross-examination)] Energy Managers already drive the Custom Retrofit program's savings and already identify curtailment opportunities in the customers they serve; Smart Synergy's growth depends on those same customer relationships. The integration exists in practice at the customer level and is absent in the Plan at the program level. Part III of this submission addresses integrated delivery generally; the point here is narrower. Demand response is the resource that most depends on integration, because its lowest-cost form is a feature added to something else.

E. What SNS asks

82. SNS respectfully requests that the Board direct E1 as follows:

(a) Lower-cost acquisition pathways. File, with the 2028 Annual Report, an analysis comparing the cost of acquiring demand response capability at the point of equipment installation or new construction against subsequent retrofit, addressing at minimum smart thermostats, electric water heaters, heat pumps, electric vehicle charging, and new residential and commercial construction, together with a program design for point-of-installation enrolment where the analysis supports it.

(b) Enrolment of DSM-funded controllable devices. Report in each Annual Report the number of DSM-supported controllable devices installed, the number enrolled in demand response, and the measures taken to encourage enrolment at the

point of sale or installation, and give preference, in DSM-funded measures, to controllable equipment that is demand-response capable where technically feasible.

(c) Long-duration and generator resources. In coordination with Nova Scotia Power and the system operator, define a long-duration demand response product and assess the generator capacity available to it, and report the results through the Mid-Term Check-In.

(d) Customer-sited batteries. Make a finding that limited incentive certainty within the five-year DSM framework may materially constrain customer-sited battery participation; direct E1, in coordination with Nova Scotia Power and the system operator, to assess longer-term compensation and program-design options and report through the Mid-Term Check-In; and encourage the Province, the system operator, and Nova Scotia Power to address longer-term compensation through the DER Integration Roadmap and the IRP process.

(e) Integrated demand response design. Include, in the integrated delivery plan requested in Part III, the treatment of demand response capability as a design feature of efficiency, new construction, and strategic electrification measures that install controllable load, rather than as a separately delivered program.

83. None of these directions seeks an increase in the approved investment envelope. Each asks E1 to look for demand response where it is cheapest, to count what it is already funding, and to say clearly what it cannot do alone so that others can.

PART V: RECOMMENDED DIRECTIONS

84. SNS respectfully requests that the Board approve the 2027–2031 DSM Resource Plan and Purchase Agreement subject to the following directions. Each is set out with its supporting reasoning in the Part indicated. Together they are designed to do what E1 cannot do unilaterally: to settle the question of law that determines the Plan's scope, to establish the accountability that the Plan lacks, to open the planning framework to a resource it does not yet see, and to name the barrier that others must remove. They ask E1 to become a full demand side management utility, and they give the Board the means to steer it there.

Strategic electrification (Part II)

85. **Direction 1: Interpretation.** That the Board determine that, consistent with paragraph 168 of the Benefit-Cost Analysis Test Decision and the portfolio-level framework of the *Public Utilities Act*, a strategic electrification measure or program that does not individually pass the applicable cost-effectiveness test may be included in a DSM plan, with justification, where the overall portfolio passes.
86. **Direction 2: Assessment and filing.** That E1 file, no later than December 31, 2027, an assessment of strategic electrification options for the Plan period, prepared in coordination with Nova Scotia Power and addressing at minimum managed electric vehicle charging, hybrid heating systems, and high-efficiency electrification of fossil-fuel end uses at end-of-life equipment replacement; that the assessment provide for each option modified PAC

results, the break-even program cost at which the option would pass, results under the Nova Scotia Jurisdictional Cost Test as supplementary information, an assessment of available federal funding, and hourly peak-impact analysis using Nova Scotia Power's load data; that where E1 concludes an option should not proceed, it explain why, and where no non-negative program cost produces a passing result, quantify the shortfall; that where an option should proceed, E1 file a program design for approval, funded by reallocation within the approved investment level through the Annual Adjustment Process, identifying the proposed reallocation and its effect on existing targets, for implementation no later than program year 2029; and that strategic electrification be a standing item at the Mid-Term Check-In.

87. **Direction 3: Planning framework.** That the Board note in its decision that strategic electrification is not currently represented in Nova Scotia Power's load forecast or in the Integrated Resource Plan as a demand-side resource, that this constrains the allocation any DSM plan can make to it, and that its inclusion in future forecasts and resource plans would allow it to be assessed on the same basis as other demand-side resources.

Unit costs and accountability (Part III)

88. **Direction 4: Unit cost reporting.** That E1 report in each Annual and Quarterly Report first-year unit cost by program component and at the portfolio level, calculated as program expenditure divided by evaluated first-year net energy savings consistent with E1's existing Annual Progress Report methodology, against Plan forecast for the same period, with explanation of variances exceeding ten percent and the measures being taken to address them. The ten percent threshold corresponds to the level at which E1's Annual Progress Reports already flag program status variances.
89. **Direction 5: Annual Adjustment Process.** That unit cost be included among the metrics subject to the enhanced reporting, forward outlook, and variance signalling provided for in Schedule "A".
90. **Direction 6: Incentive level review.** That where a program is fully subscribed in advance of its funding period, E1 review incentive levels annually and report through the Annual Adjustment Process on whether they remain the minimum necessary to achieve planned participation.
91. **Direction 7: Integrated delivery plan.** That E1 file, no later than the Mid-Term Check-In, a plan for a coordinated pathway through which customers can access energy efficiency, demand response, distributed energy resource, and, if approved, strategic electrification support through a single process, including the role of Energy Manager or advisory support and a timeline for implementation, developed in consultation with the Efficiency Preferred Partner network; and that the plan treat demand response capability as a design feature of efficiency, new construction, and strategic electrification measures that install controllable load.
92. **Direction 8: Delivery innovation.** That E1 dedicate an identified portion of Enabling Strategies funding to delivery-cost innovation, as distinct from measure and technology research, and report annually on projects undertaken, expenditures, and unit cost implications, with priority to advisory and energy-navigator delivery models including

delivery through qualified private-sector providers, end-of-life equipment targeting, point-of-installation acquisition of demand response, and customer cost-sharing structures, and with project selection and design undertaken in consultation with the Efficiency Preferred Partner network.

93. **Direction 9: External funding.** That E1 pursue federal and other external co-delivery and co-funding arrangements as a program objective, and report annually on external funding leveraged, participant uptake of federal incentives, and the effect of both on program unit costs.
94. **Direction 10: Delivery model assessment.** That E1 file, with the 2028 Annual Progress Report due April 1, 2029, an assessment of alternative delivery models for any program whose cumulative unit cost exceeds Plan forecast by more than twenty-five percent, including at minimum Small Business Energy Solutions, prepared in consultation with the Efficiency Preferred Partner network, for consideration at the Mid-Term Check-In. The twenty-five percent threshold corresponds to the variance level at which E1's Annual Progress Reports require management discussion.
95. **Direction 11: Future plan filings.** That E1 include in any future DSM plan application a framework comparing the marginal value of investment across demand-side resources and an explanation of how the proposed allocation among them was determined; an analysis of the delivery approaches considered for each program, the unit cost of each, and the basis for the approach proposed; and an explanation of the relationship between the proposed savings target and the DSM contribution identified in the prevailing Integrated Resource Plan.

Demand response (Part IV)

96. **Direction 12: Lower-cost acquisition.** That E1 file, with the 2028 Annual Progress Report due April 1, 2029, for consideration at the Mid-Term Check-In, an analysis comparing the cost of acquiring dependable demand response capacity, including enrolment and continuing participation costs, at the point of equipment installation or new construction against subsequent retrofit, addressing at minimum smart thermostats, electric water heaters, heat pumps, electric vehicle charging, and new residential and commercial construction, together with a program design for point-of-installation enrolment where the analysis supports it; and that E1 report annually the number of DSM-supported controllable devices installed, the number enrolled in demand response, and the measures taken to encourage enrolment, with preference given, in DSM-funded measures, to controllable equipment that is demand-response capable where technically feasible.
97. **Direction 13: Long-duration resources.** That E1, in coordination with Nova Scotia Power and the system operator, define a long-duration demand response product and assess the generator and storage capacity available to it, and report the results through the Mid-Term Check-In.
98. **Direction 14: Customer-sited batteries.** That the Board find that limited incentive certainty within the five-year DSM framework may materially constrain customer-sited battery participation; that E1, in coordination with Nova Scotia Power and the system operator, assess longer-term compensation and program-design options and report through

the Mid-Term Check-In; and that the Board encourage the Province, the system operator, and Nova Scotia Power to address longer-term compensation through the DER Integration Roadmap and the Integrated Resource Plan process.

PART VI: CONCLUSION

99. The Board is not asked to choose between affordability and demand side management, or between this Plan and no plan. It is asked to approve a Plan that E1 has built with care within the constraints it set for itself, and to attach to that approval the directions that would allow DSM in Nova Scotia to reach the resources, the delivery models, and the cost discipline that the next five years will require.
100. E1 was created to lead Canada in demand-side innovation, and for fifteen years it did. The resources that will define the next fifteen are different from those that defined the last: they add load as often as they reduce it, they are controllable at the point of installation, and they are owned by customers who need certainty beyond a single planning cycle. An energy efficiency utility was the right institution for the first era. A demand side management utility is what the second requires, and the *Public Utilities Act*, as amended, already describes it.
101. E1 cannot make that transition on its own, and nothing SNS asks requires a finding that it should have. The interpretation question is a genuine one, and the Board is the right body to settle it. The accountability framework is the Board's to set. The planning documents upstream of this Plan are prepared by others, and a statement from the Board is what they will hear. In each case, E1 has said the work matters. These directions would give that work a form the Board can rely on, and give E1 the steering it needs to become the utility the province now asks it to be.
102. Solar Nova Scotia thanks the Board for its consideration.

ALL OF WHICH IS RESPECTFULLY SUBMITTED this 11th day of September, 2026.

David Brushett, P.Eng.

Chair, Solar Nova Scotia