M12780

NOVA SCOTIA ENERGY BOARD

IN THE MATTER OF:	***The Public Utilities Act***
	– and –
IN THE MATTER OF:	**AN APPLICATION by EFFICIENYONE for approval of the 20272031 Demand-Side Management (DSM) 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 (DSM) Resource Plan**

RESPONSE TO INFORMATION REQUESTS

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Request IR-01:

Preamble: At pages 3–9 regarding the Mid-Course Adjustment (MCA), Mr. Love recommends (a) that the Board require explicit Board approval of any MCA, with a 30-day comment period for intervenors; (b) that unspent funding in early plan years may be carried forward and used in later years; and (c) that a material change in IRP-identified optimal savings levels should trigger an MCA.

(a) Please confirm whether, under your recommended framework, if E1 underspends in 2027 and 2028 and then seeks to spend those unspent funds in 2030 and 2031, the resulting total five-year expenditure would be permitted to exceed the Board-approved five-year budget of $318.75 million. If so, please confirm whether that excess would require a separate MCA filing.

(b) Does Mr. Love's recommended MCA process apply to: (i) spending reallocations; (ii) savings target changes; (iii) program design changes; (iv) rate-class impacts; (v) timing changes; or (vi) any other contemplated scenario?

(c) Mr. Love recommends that E1 consolidate its dedicated low-income program components into a single "Low Income Program" subject to the 20% MCA explanation threshold. He also recommends that the Board approve the IRP-aligned scenario at $464 million. If both recommendations were adopted, could E1 bring forward a mid-plan MCA to increase low-income program spending above the 20% threshold simply by providing an explanation, without full Board approval? Please clarify how the two recommendations interact.

Response IR-01:

(a) No. Carrying unspent early-year funding into later years does not, by itself, authorize E1 to exceed the Board-approved five-year budget. The recommendation is that the Board confirm the thresholds operate on a cumulative, five-year basis and that unspent funds in early years may be applied in later years so that planned investment and the associated savings are not lost — not that the five-year cap be raised. Any spending that would take cumulative program-level investment more than 20% away from the approved level over the plan term would require an MCA filing, and under the recommended framework every MCA filing requires explicit Board approval following a 30-day intervenor comment period. Carry-forward is a tool to keep the plan on its five-year trajectory; it is not a mechanism to overspend the approved budget.

(b) GEEG has three recommended triggers for an MCA. They are: (i) five-year spending for a program is projected to vary by 20% (ii) five-year spending for a rate-class is projected to vary by 15%; and (ii) the IRP-identified optimal DSM acquisition levels vary by 20% from the current plan targets.

(c) No. The two recommendations are not related. First, GEEG recommend a plan at the IRP-aligned scenario. Separately, GEEG recommend consolidating the dedicated low-income components (Affordable Single Family, Affordable Multifamily, Mi'kmaw New Home Construction, and Mi'kmaw Home Energy Efficiency Project) into a single "Low Income Program" so that this activity is tracked as one program and is subject to the program-level MCA threshold of 20%. Under the overarching recommendation that every MCA require explicit Board approval, if E1 filed an MCA to spend 20% more than an approved budget for the Low Income Program, it would require Board approval.

Request IR-02:

Reference: E-21, Page 7, lines 2–6.

> **"I recommend that E1 should file an MCA to address any material change to optimal DSM resource acquisition levels identified in the Evergreen IRP process. A material change would be cumulative DSM savings levels that are more than 20% away from currently approved levels over the current plan horizon."**

(a) Please confirm: (i) what "optimal DSM resource acquisition levels" means operationally — is this the IRP's Base profile or some other metric; and (ii) whether Mr. Love's recommended trigger would also apply when IRP findings indicate that currently approved savings levels are more than 20% above optimal (i.e., a trigger in either direction).

(b) Please elaborate on why Mr. Love views the 20% threshold as the appropriate trigger for an MCA.

(c) Do you recommend that the Board's approval of an MCA that proposes a budget increase be contingent on a finding that the incremental costs are justified on a rate-class-specific basis — specifically, that the net benefit to each ratepayer class that will bear incremental DCRR costs is positive?

(d) Please explain what you consider the minimum evidentiary threshold for Board approval of a MCA.

(e) How, if at all, would this differ for a budget-increasing MCA?

Response IR-02:

(a)

(i) An "optimal DSM resource acquisition level" is the level of DSM identified as economically optimal in a least-cost resource planning exercise. It is important that the DSM scenarios are used as an input to the planning process, and compared to other supply side resources and not simply the DSM figure that happens to be embedded in a load forecast or system outlook. This distinction matters because a system outlook takes the DSM level it is given as an input; it does not itself optimize the amount of DSM. NS Power's 2022 Evergreen IRP identifies 683.1 GWh of energy savings and 123.9 MW of demand savings over 2027–2031 as the optimal, least-cost level based on a review of multiple DSM scenarios. The IESO-NS 2026 10-Year System Outlook, by contrast, is expressly "not an integrated resource planning (IRP) exercise" but an annual resource-adequacy assessment built on a single pre-selected scenario — NS Power's Evergreen IRP scenario CE1-E1-R2 and the Province's 2030 Clean Power Plan. It does not optimize the DSM quantity: energy-efficiency savings enter only as a reduction embedded in the NS Power load forecast the Outlook adopts as its foundation, and the demand-response capacity it reflects is taken directly from E1's 2027–2031 DSM Plan Application (i.e., the Preferred Plan). Because the Outlook modeled no alternate DSM scenarios, the DSM level "baked in" is an inherited input, not an identified optimal level.

(ii) Yes. The recommended trigger is symmetric: it would apply where updated IRP findings show that the currently approved savings level is more than 20% away from the IRP-identified optimal level in either direction. The purpose is to keep the plan aligned with the least-cost level identified through integrated planning, whether that requires acquiring more DSM or less.

(b) The 20% threshold for IRP savings is meant to be similar to the program threshold. Ideally E1 would be able to adjust programs to meet an updated IRP scenario without filing an MCA if it is within the 20% band. Alternatively any IRP scenario that is different from the current plan could trigger an MCA, to ensure that the DSM plan is updated as soon as possible to meet Nova Scotia's needs.

(c) No. GEEG agrees with the Board's decision in M12282 that the Board must evaluate the cost-effectiveness of the plan at the portfolio level (para 166, at p. 65).

(d) GEEG does not recommend a fixed, prescriptive evidentiary standard, because the evidence required to support an MCA will vary with the circumstances of the particular adjustment. This is one of the benefits of the Board-approval steps GEEG recommends in the Evidence (Love Direct, p. 4, lines 15-21). Rather than specifying a set quantity of evidence in advance, opening each MCA to Board approval — with a minimum 30-day window for intervenor comment as described in the Evidence (Love Direct, p. 4, lines 18-21) — allows the Board and intervenors to identify, case by case, the evidence needed to make a proper decision on the specific modification proposed.

(e) It would not differ in kind. A threshold trigger arising from an IRP-identified change in required savings would function in substantially the same way as a budget-increasing (or budget-decreasing) MCA, provided it is handled consistently with the recommendations in Section III of the Evidence (Love Direct, pp. 3-8), where GEEG addresses the mid-course adjustment process. GEEG specifically called out changes to the IRP recommended savings amounts separately not because an IRP-driven MCA would operate through a wholly different mechanism, but to make a distinct substantive point: the level of DSM in E1's plan should be driven by the optimal level identified through a current Potential Study and IRP process, rather than simply carried forward as a value fed into the System Outlook.

Request IR-03:

Reference: E-21, Pages 12 – 14.

Preamble: Mr. Love provides an analysis that includes reference to NSPI's most recent 10-year System Outlook from 2025, under Matter M12386, and outlines the projected peak load growth over the next ten years. Mr. Love's testimony relies on NSPI's 2025 10-Year System Outlook to establish the 73 MW gap between E1's Preferred Plan DSM peak reduction trajectory and the 234 MW of DSM that NSPI projected would be required by 2035. More recently, however, the IESO-NS released its 2026 10-Year System Outlook, on June 26, 2026, which supersedes NSPI's report and is the first to incorporate updated ELCC values from the 2026 E3 ELCC Study.

(a) Has Mr. Love had an opportunity to review the IESO-NS's recent 10-Year System Outlook from 2026, as filed in M12916? If so, please provide an update on his testimony as referenced above, and whether the outcomes in that report change anything else throughout his testimony?

(b) Please provide revised calculations, if any.

(c) Has Mr. Love had an opportunity to review the ELCC study from 2026? If so, please provide an update on his testimony as referenced above, and whether the outcomes in that report change anything else throughout his testimony?

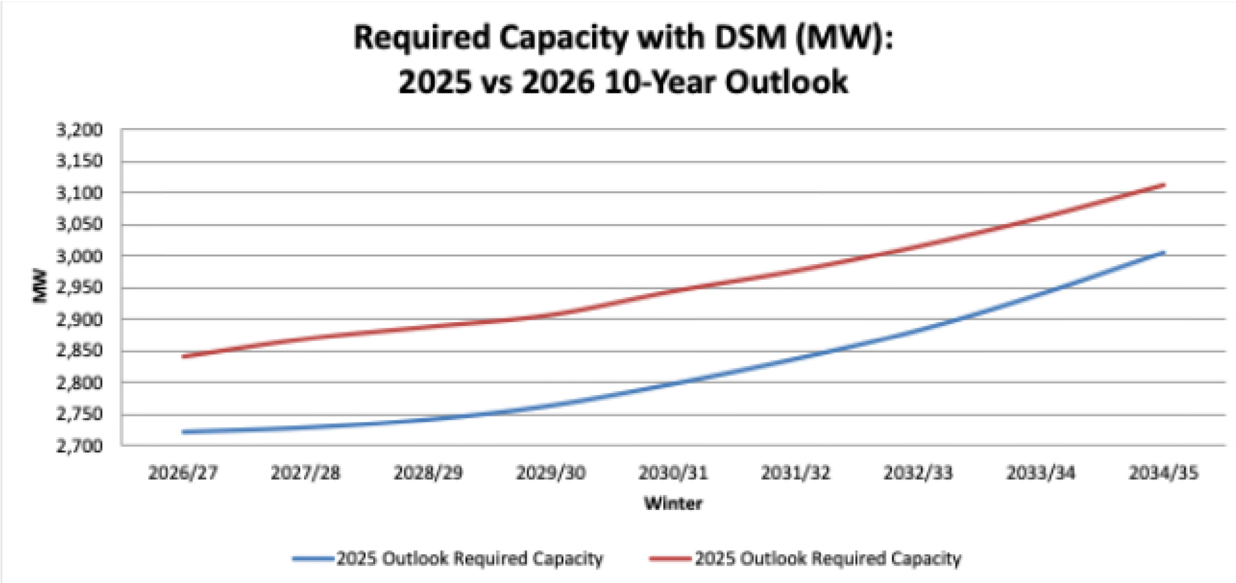
(d) Upon review of the updated 10-Year System Outlook, please confirm whether this changes Mr. Love's recommendation that the IRP Base level of 683 GWh should be the minimum target? Why or why not?

Response IR-03:

As a general comment, the Evidence was filed on June 23, 2026, three days before the IESO-NS 2026 10-Year System Outlook was released on June 26, 2026 in M12916. GEEG reviewed the 2026 Outlook, and the 2026 ELCC Study, in preparing these responses, and has incorporated that review into the answers in this response.

(a) Yes, Mr. Love has reviewed the IESO-NS 2026 10-Year System Outlook filed in M12916 ("2026 Outlook"). The 2026 Outlook uses Demand Response reductions for 2027 through 2031 from E1's plan, but it is not clear what scenario is used, or whether the non-DR portions of the plan were utilized. If it is presumed that the "Preferred Plan" scenario is used for all DSM assumptions, including DR, then that closes the discrepancy, or gap, in DSM forecasts, but does not eliminate the need for future firm capacity. In fact, the 2026 Outlook continues to show even greater firm capacity needs than the 2025 Outlook, as shown in the following figure.

Figure 1. Required Capacity for Nova Scotia (2025 vs. 2026 Outlook)



Between the 2025 Outlook and 2026 Outlook, required capacity has jumped an average of 133 MW, or 4.7%, per year for the next nine years. If DSM resources really did go from the IRP level in the 2025 Outlook to the Preferred Planning level in the 2026 Outlook, then the lower DSM projections would contribute at least 73 MW , or 68%, of the 107 MW jump in 2035. The 2026 Outlook not only shows higher capacity requirements, but also significant year-over-year load growth as shown Table 1 from the 2026 Outlook recreated below.

Table 1. Net System Requirement and System Peak Projections from 2026 Outlook

Year	System Peak (MW)		Net System Requirement (GWh)					
	System Peak (MW)	Growth (%)	Nova Scotia Power Net System Requirement (GWh)	Renewable - to-Retail Energy (GWh)	Municipality Energy (GWh)	Behind-the-Meter Solar (GWh)	IESO-NS Net System Requirement (GWh)	Growth (%)
2026	**2,484**	-	11,575	15	65	184	**11,838**	-
2027	**2,497**	0.5%	11,424	239	65	222	**11,951**	1.0%
2028	**2,526**	1.2%	11,525	286	67	264	**12,142**	1.6%
2029	**2,549**	0.9%	11,556	286	67	311	**12,220**	0.6%
2030	**2,563**	0.6%	11,568	286	67	362	**12,284**	0.5%
2031	**2,593**	1.2%	11,621	286	68	426	**12,400**	0.9%
2032	**2,620**	1.0%	11,689	286	70	491	**12,535**	1.1%
2033	**2,652**	1.2%	11,722	286	70	559	**12,637**	0.8%
2034	**2,689**	1.4%	11,815	286	70	631	**12,803**	1.3%
2035	**2,730**	1.5%	11,939	286	71	704	**13,000**	1.5%
2036	**2,765**	1.3%	12,097	286	72	769	**13,224**	1.7%

The 2026 Outlook does not change the general point of the Evidence, which is that there is a need for additional capacity resources to meet rising system load and peak load growth. A need that can be met with DSM resources. More specifically, the Planning Reserve Margin target is met through 2034 but falls below the 20% target in the final two years of the 2026 Outlook (19% in 2035 and 18% in 2036). This translates to a reserve deficit of 58 MW by 2036, which could be more than met by achieving IRP-level savings.

Finally, it is worth noting that energy efficiency enters only as a reduction within the NS Power load forecast in the 2025 Outlook and the IESO NS 2026 Outlook. The Outlook does not identify the least-cost level of DSM; it simply relies on what was provided in E1's Plan. The consequence is that the Outlook understates the DSM that a least-cost plan would acquire and, correspondingly, overstates the reliance on supply-side resources and the cost borne by ratepayers. This is the same concern that underlies the recommendation that the planning process should determine the optimal level of DSM, rather than accept the Preferred Plan level as a given. This is the same distinction drawn in the response to IG IR-02(a): the optimal DSM level is the least-cost quantity identified through the IRP process, not a value carried forward from a system outlook

(b) The specific 73 MW figure in my testimony was derived from NSP's 2025 10-Year System Outlook assumptions that used IRP-level DSM compared to the Preferred Scenario savings from E1's Plan filing. If the 2026 Outlook utilizes the "Preferred Plan" scenario there is no "gap" to show in DSM forecast assumptions. However, there is still significant new firm capacity resources required —even more than the 2025 Outlook, as discussed in the response to part a) of this question. Planners are struggling to fill the gap with expensive new generations and are being forced to delay the retirement of coal plan to maintain reserve margins. As the 2026 Outlook report concludes:

> *"The resource adequacy assessment shows minimal surplus capacity in the near-term, highlighting the importance of successfully implementing the projects listed in this report in order to maintain system adequacy while meeting legislated decarbonization targets." (p. 27)*

Investing in DSM at higher levels can go a long way towards mitigating the risk from these large supply-side projects and meeting Nova Scotia's growing electric energy needs.

(c) Yes, GEEG reviewed the 2026 Nova Scotia ELCC Study (E3, June 2026). It does not change the Evidence and is consistent with its recommendations. The ELCC Study finds that Nova Scotia's reliability risk remains concentrated in winter high-heating-demand periods, and that the firm-capacity contribution of energy-limited and dispatch-limited resources — onshore wind, storage, and demand response — exhibits declining marginal value as more of each is added to the system. In other words, each incremental MW of these supply-side and dispatch-limited resources contributes less firm capacity than the one before it. Energy efficiency is not one of the resources the ELCC Study included. Energy efficiency reduces load directly rather than adding a dispatchable resource, so it is therefore not subject to the same declining marginal-ELCC penalty. That distinction strengthens, rather than weakens, the case for acquiring cost-effective energy efficiency at higher levels: as the system leans more heavily on energy-limited resources to meet winter peak, the relative value of reducing the peak itself increases. Furthermore, the ELCC Study highlighted the need for a diverse portfolio of resources and found that demand response (DR) can also provide a "meaningful capacity value" ; both of which are benefits of a more comprehensive DSM plan.

(d) No. Review of the 2026 Outlook does not change the recommendation that the IRP-identified Base level (approximately 683 GWh) be treated as the minimum planning target. If anything, the 2026 Outlook underscores why the IRP scenario needs to be pursued now. By embedding demand response, and likely energy efficiency, at the Preferred Plan level it shows the reserve margin falling below target in the outer years. GEEG would, however, refine the recommendation to emphasize the planning process rather than a fixed number: IESO-NS should model higher levels of DSM in any potential studies and the Evergreen IRP process to determine the optimal level of DSM required, rather than carrying the Preferred Plan, or the previous IRP, level through as a given, and at a minimum should model the system savings and avoided costs associated with achieving higher DSM levels. The 683 GWh Base level remains the appropriate minimum target unless and until such modeling identifies a different least-cost level.

Request IR-04:

Reference: E-21, Page 25–26, lines 13–14 and 1–4.

"As described previously in my testimony, peak capacity needs are projected to grow, and current forecasts require more investment in DSM than the E1 Preferred Plan provides, which means that NS Power will need to acquire alternative sources of capacity, which will inevitably cost more than the DSM investment and leave customers on the hook to pay for these higher cost sources of energy."

Preamble: The 2026 System Outlook identifies that Trenton 5 and Lingan 2, previously scheduled for retirement in Winter 2027/2028, will now be required through Winter 2029/2030 pending the commissioning of fast-acting generation, and that 450 MW of fast-acting generation is required to meet the 20% Planning Reserve Margin target in 2029/2030.

(a) What assumptions did Mr. Love make in relation to the retirement of NSPI's generation assets, in reaching the conclusion that NSPI would need to acquire alternative sources of capacity?

(b) Please confirm how, if at all, this revised retirement and fast-acting generation schedule affects Mr. Love's assertion that planning below the IRP-identified DSM level forces NS Power to acquire higher-cost supply-side resources to cover the gap.

Response IR-04:

(a) The conclusion does not depend on the precise timing of any specific generation asset retirement. It rests on the more general and, in the 2026 Outlook, confirmed proposition that the system faces a growing firm-capacity requirement over the planning horizon — driven by load growth, coal phase-out obligations, and the transition to energy-limited resources — and that this requirement must be met either by reducing peak load through DSM or by acquiring supply-side capacity. Where cost-effective DSM is a least-cost resource, acquiring less of it than the least-cost level shifts the balance of the requirement onto more expensive supply-side resources. GEEG assumed that NS Power would meet its capacity requirement in a manner consistent with the resource additions and retirements reflected in the applicable system planning documents; GEEG did not assume any accelerated or unplanned retirement beyond what those documents show. Given that 2026 Outlook now anticipates keeping coal plants online longer than anticipated because fast-acting generation cannot be built quickly enough to meet resource needs - especially when a lower-DSM scenario than the IRP is baked into load forecasts - just shows how crucial these DSM resources are to meeting the Provinces' environmental goals and energy needs.

(b) The revised retirement and fast-acting generation schedule reinforce the assertion that planning below the IRP-identified DSM level exposes customers to higher risk and higher cost supply-side alternatives for four reasons. First, DSM continues to remain a least cost resource as described in E1's Evidence. When resource planners substitute a more expensive resource for a less expensive one, ratepayers pay the difference. Second, the need for firm capacity is growing, not shrinking and DSM can meet that gap, as discussed in the response to IG IR-3(a).

Third, energy efficiency compares favorably to capacity-only resources such as fast-acting generation on durability and reliability. A combustion turbine or load-control resource provides capacity only, requires ongoing payments for as long as the capacity is needed, and is subject to forced outages: the 2026 ELCC Study assigns Trenton 5 a derate-adjusted forced outage rate of 12.6% and existing combustion turbines 10%. Energy efficiency reduces the firm peak directly, is not derated for forced outages, persists for the life of the installed measures without continued investment, and delivers energy savings that capacity resources do not.

Finally, the revised schedule demonstrates the risk and cost of relying on supply-side capacity -procurement. The 2025 10-Year System Outlook scheduled the first 300 MW of fast-acting combustion turbines for Winter 2027/2028, concurrent with the retirements of Trenton 5 and Lingan 2. One year later, the in-service date for all 450 MW of fast-acting generation has slipped to Winter 2029/2030, and IESO Nova Scotia finds that "Trenton 5 and Lingan 2 can only be retired once new fast-acting generation needed to replace the firm capacity they provide is in service and reliable operation of the new units has been established." The consequence is that 298 MW of coal-fired capacity will operate two additional winters. DSM does not carry this project-level schedule risk: savings accrue incrementally across thousands of installations, and a shortfall in one program does not leave a 300 MW hole in the reserve margin.

Request IR-05:

Reference: E-21, Page 17, lines 4-9.

> ***I respectfully recommend that the Board treat the IRP-identified Base level as the minimum planning target until an updated potential study is available, consistent with energy efficiency's status as a least-cost resource. Following this, I recommend that the Board direct E1 to utilize an overall savings target for the DSM portfolio that is aligned with the IRP-identified Base DSM level of approximately 683 GWh for 2027–2031 ("IRP-aligned scenario"), rather than the 435.4 GWh Preferred Plan; [sic]***

Reference: E-21, Page 23, lines 20-22.

The IRP scenario, as modeled by E1, costs $464M over five years vs. $318.75M for the Preferred Plan, an incremental cost of $145.25M, or approximately $29M per year. This incremental cost would deliver an additional 247.7 GWh of energy savings annually.

(a) Please confirm whether Mr. Love's recommendation that the Board direct E1 to utilize an IRP-aligned scenario assumes that:

(i) the IRP-identified Base DSM level remains an appropriate planning target for the 2027–2031 Plan period;

(ii) E1 can reasonably acquire the additional 247.7 GWh of energy savings during the 2027–2031 Plan period; and

(iii) E1 has, or can obtain, the internal, market, contractor, administrative, and participant capacity necessary to deliver those incremental savings.

(b) Has Mr. Love assessed the feasibility of achieving the incremental 247.7 GWh of energy savings, including consideration of contractor capacity, participant uptake, free-ridership/spillover, measure availability, administrative capacity, customer disruption, and timing constraints? If so, please provide that assessment. If not, please explain the basis for Mr. Love's conclusion that the IRP-aligned scenario is achievable during the Plan period.

(c) Please identify the program areas, sectors, and customer classes in which Mr. Love expects the additional $145.25 million DSM investment would be deployed in order to achieve IRP-aligned incremental savings.

(d) If the Board were to direct E1 to move toward the IRP-aligned scenario at a total investment of approximately $464 million, does Mr. Love recommend any limits, conditions, or reporting requirements regarding how the incremental $145.25 million should be allocated? Please explain.

Response IR-05:

(a) i) Confirmed, ii) Confirmed, iii) Confirmed

(b) GEEG has not independently done that analysis. However, the purpose of a potential study is to identify what is achievable and the past potential study identified this as both economic and achievable and E1's model showed it as well (see below). Furthermore, this represents savings of around 1.1% of sales, which is well within the range of other portfolios in North America. For example, in 2023 Maryland achieved 1.74%, Michigan 1.60%, New Jersey 1.47%, Vermont 1.43%, and Minnesota 1.35% of retail sales. Looking towards 2030, Illinois has a target of 2.05% savings as a percentage of sales per year from 2026 to 2030.

(c) E1 has currently modeled an IRP scenario which allocates funding between the rate classes and, presumably, programs. GEEG has not performed any additional analysis on how this allocation may be done.

(d) It should follow similar planning guidelines to the currently developed plan.

Request IR-06:

Reference: E-21, Page 23, lines 15–17.

> **"… However, customers are already paying a DCRR, and even the IRP level of DSM spending barely impacts the DCRR that customers are already paying."**

(a) Please quantify the assertion that the increase in investment "barely impacts" the DCRR. In the response, please provide by customer class: (i) the estimated DCRR impact of the Preferred Plan; (ii) the estimated DCRR impact of the IRP-aligned scenario; (iii) the incremental DCRR impact of moving from the Preferred Plan to the IRP-aligned scenario; (iv) the impact by customer class, including medium industrial and large industrial customers; and (v) all assumptions, calculations, and workpapers supporting the response.

(b) If Mr. Love has not calculated the DCRR impacts requested, please explain the basis for his conclusion that the incremental impact would be limited or immaterial.

(c) Please explain whether Mr. Love's conclusion that the IRP-aligned scenario would have only a limited impact on the DCRR depends on averaging costs across customer classes, or whether that conclusion holds for each customer class individually.

Response IR-06:

(a) The sentence should be corrected to state that the IRP level of DSM spending barely impacts the "bills" customers are already paying. Please refer to Exhibit TML-2 which shows the conclusion is expressed in terms of the impact on non-participant bills, which is the measure presented in the Evidence at Tables 2 and 3 and in Exhibit TML-2. On that basis, moving from the Preferred Plan to the IRP-aligned scenario increases average non-participant bills by 0.08% to 0.66% across rate classes over the full analysis period (2027–2046), and by 1.17% to 3.09% across rate classes when limited to the 2027–2031 plan years. For the two classes identified: the incremental increase relative to the Preferred Plan averages 1.17% for the Medium Industrial class and 2.83% for the Large Industrial class over 2027–2031 (5.83 and 14.13 percentage points cumulative over the five years, respectively). These figures are the IRP-scenario impact net of the Preferred Plan impact, and the annual breakout and source references are set out in the updated Exhibit TML-2.

(b) Please see the response to part (a)

(c) The conclusion does not depend on averaging across classes. Refer to Exhibit TML-2 which presents the incremental non-participant bill impact separately for each rate class, and the impact is limited for each class individually — the largest 2027–2031 class-average increase is 3.09% (General), and the two industrial classes at issue are lower, at 1.17% (Medium Industrial) and 2.83% (Large Industrial). The characterization that the incremental impact is limited holds on a class-by-class basis, not merely on a portfolio average.

Request IR-07:

Preamble: At pages 24–25 of Mr. Love's evidence (Tables 2 and 3), he presents the change in non-participant bills for the IRP-aligned scenario compared to E1's Preferred Plan. For the plan years 2027–2031, he shows incremental bill increases of 2.82% for the Large Industrial class and 1.17% for the Medium Industrial class. He characterizes these impacts as "minimal" and states they "do not represent any rate shock."

(a) Please provide the absolute dollar value of the incremental annual DCRR cost borne by the Large Industrial class and the Medium Industrial class under the IRP-aligned scenario compared to the Preferred Plan, for each year, 2027 to 2031, and in aggregate over the five-year term. Please confirm the source and methodology used to derive these figures.

(b) Mr. Love's bill-impact analysis compares the IRP-aligned scenario to a no-DSM counterfactual as the baseline (as stated in his evidence and footnote 48 to Table 2). Please confirm whether the percentage increases shown in Tables 2 and 3 represent the incremental cost of the IRP scenario over and above what industrial customers would pay under E1's Preferred Plan, or the incremental cost relative to a scenario with no DSM at all. If the latter, please recalculate the incremental bill impact relative to the Preferred Plan as the proper counterfactual.

Response IR-07:

(a) GEEG has not calculated the DCRR value. The percentages in Tables 2 and 3 are bill-impact percentages, not absolute-dollar DCRR charges.

(b) The percentage increases in Tables 2 and 3 represent the incremental cost of the IRP scenario over and above the Preferred Plan.

Request IR-08:

Reference: E-21, Section VII – Unit Costs.

Preamble: At pages 26–35 of the evidence, Mr. Love analyzes E1's rising unit acquisition costs, noting that the Preferred Plan projects a first-year EE unit cost of $0.66/kWh, up 35% from $0.49/kWh in the 2026 Plan, and that this figure is more than double the U.S. fleet average. He identifies four contributing factors: the end of federal Greener Homes funding, the LED lighting transition, inflationary pressures, and revised heat-pump evaluation results. Mr. Love states that E1 should be required to seek to redesign its programming to ensure greater cost-effectiveness.

(a) Where Mr. Love identifies the transition away from low-cost, high-volume lighting as a driving force of the cost increase, does Mr. Love view the loss of these savings as having been predictable at the time the 2023-2025 Plan was approved, or the 2026 Extension was approved? If so, should E1 have been planning for this? If not, why not?

(c) The benchmarking Mr. Love references is based on the ACEEE dataset for one year, which does not include any Canadian comparators. Has Mr. Love examined other Canadian jurisdictions? If so, which one(s), and please provide the quantitative figures. If not, why not?

(e) To the extent Mr. Love is of the view that US (or other Canadian jurisdictions) unit acquisition costs have also been increasing over recent years, how have other jurisdictions addressed the increase in unit cost prices?

(f) Given that Mr. Love considers E1's existing unit acquisition costs as materially above comparable jurisdictions, please explain how directing E1 to acquire substantially more savings — using the same program designs and delivery models that produced the elevated unit costs — would result in lower average unit costs for ratepayers rather than higher ones.

(g) Where E1's evidence characterizes the remaining achievable market as harder to reach and more expensive to serve, in Mr. Love's view, would the marginal cost per kWh of the additional IRP-scenario savings be higher or lower than the Preferred Plan average of $0.66/kWh? Please provide any analysis or evidence supporting the answer.

Response IR-08:

(a) Yes, the loss of low-cost lighting savings was predictable, and E1 should have been planning for it. The maturation of the residential lighting market and the resulting decline in claimable lighting savings have been well understood across the energy-efficiency industry for years. In the United States, this phase out was tied to the federal general-service-lamp efficiency standards and the transition to LEDs in 2020. In Canada, the Energy Efficiency Act and Energy Efficiency Regulations have been shifting the lighting baseline. The pending decline in lighting savings was identified in connection with the 2026 Extension and was, more broadly, a known industry trajectory. A prudent administrator anticipating the loss of its lowest-cost, highest-volume measure would have been developing replacement measures and cost-containment strategies in advance, rather than treating the resulting unit-cost increase as beyond its control.

(c) GEEG has not conducted a full unit-cost analysis of individual Canadian jurisdictions beyond the brief scan APEX Analytics provided in this Matter. A complete jurisdictional analysis is a substantial data-collection and normalization exercise. The ACEEE dataset reference in the Evidence already performs that work across a large number of U.S. program administrators spanning a range of market maturities, program designs, and delivery models, which is what makes it a sound benchmark for assessing where E1's costs sit relative to the broader fleet. The absence of Canadian comparators in that dataset does not undermine the benchmark, because the comparison is to a wide distribution of programs and program types rather than to one peer alone; E1's first-year cost is not remotely close to this benchmark but instead sits at roughly double the U.S. fleet average in that report.

(e) Other jurisdictions facing rising unit costs have responded principally through program-design and delivery changes rather than by accepting higher costs as fixed — for example, by recalibrating incentive levels toward the minimum necessary to secure participation, replacing mature low-cost measures (such as lighting) with new measure categories (such as heat pumps), tightening measure-eligibility and delivery models, and pursuing market-transformation and controls-based savings as commodity-lighting savings decline. These are the same categories of cost-containment recommended for E1 in Evidence, and they are the reason the recommendation is to redesign programming, not at spending more on the current design.

(f) As discussed in section g), the unit costs decrease overall between the preferred plan and the IRP. There are some efficiencies of scale that can be achieved by developing a larger DSM portfolio. In particular, fixed administration and setup costs will become a smaller portion of the acquisition cost, and variable non-incentive acquisition costs may be driven lower as program scale grows and marketing, outreach, and rebate processing can be done more efficiently. However, GEEG is not proposing that E1 acquire more savings using the same program designs and delivery models that produced the elevated unit costs. The recommendation is that E1 redesign its programming — including recalibrating incentive levels, revisiting heat-pump switchover assumptions, and replacing mature measures — to bring unit costs down, and then acquire savings at the IRP level. At the same time, even at the unit costs E1 has filed, cost-effective energy efficiency remains the least-cost resource: it passes the PAC test, and the IRP scenario yields approximately $200 million more in PAC net benefits than the Preferred Plan . The two recommendations are complementary — reduce unit costs through redesign, and acquire the least-cost resource at the IRP level — and pursuing the IRP level does not require accepting higher average unit costs.

(g) E1's scenario modeling indicates that acquiring the additional IRP-level savings does not raise the cost of acquisition per unit of savings above the Preferred Plan level; on a whole-plan basis it lowers it. A direct like-for-like comparison of the two scenarios on an energy-efficiency-only basis is not possible on available record, because E1 did not file energy-efficiency-only investment figures for the IRP scenario that mirror those it filed for the Preferred Plan. E1 modelled the IRP savings level as a distinct "IRP scenario" and reported only its total DSM investment ($464 million) and its Program Administrator Cost Test (PAC) result (2.4). GEEG has therefore compared the two scenarios on the consistent basis that is available for both: total DSM investment relative to first-year energy-efficiency savings. This requires computing the ratio for the Preferred Plan from its filed investment and savings figures, because E1 did not present the comparison in this form. On that basis, the Preferred Plan reflects a total DSM investment of $318.75 million against 435.4 GWh of first-year energy-efficiency savings, while the IRP scenario reflects a total DSM investment of $464 million against 683.1 GWh of first-year energy-efficiency savings. That is approximately $0.73/kWh for the Preferred Plan and approximately $0.68/kWh for the IRP scenario, showing that the larger IRP scenario has lower costs per unit of first-year savings, not higher. These figures pair a total DSM investment (energy efficiency, demand response, solar-PV and enabling strategies) with an energy-efficiency-only savings quantity; because the same convention is applied to both scenarios, the comparison between them is consistent, though the ratio should not be read as a pure energy-efficiency unit cost.

Request IR-09:

Reference: Pages 32-34.

Preamble: Mr. Love notes that customer incentives account for approximately 71% of total plan costs under the Preferred Plan, up from the 66% in the 2026 Plan. Mr. Love criticizes the approach to compare to the small number of jurisdiction unit-cost benchmarks in Atlantic Canada, and recommends the Board direct:

> ***E1 to undertake measure-specific primary research (e.g., price-sensitivity or conjoint analysis) for high-value measures, consistent with the thresholds the CLEAResult methodology already contemplates, to confirm that incentive levels are set at the minimum necessary to secure participation. This research should then be used to inform updates to incentives no later than January 1, 2028.***

(a) In Mr. Love's experience, is it typical for customer incentives to make up 71% of total plan expenses? Please explain, with examples.

(b) Can Mr. Love provide an outline of best practices in the industry for setting incentive levels for DSM programming?

(c) Is Mr. Love aware of any other jurisdictions which have completed similar price-sensitivity or conjoint analyses? Where?

(d) What does Mr. Love expect a "fresh, ground-up incentive-design study" to involve in terms of scope, methodology, data collection, and cost?

(e) Has Mr. Love taken into consideration the cost, timing, and administrative burden of completing that research by January 1, 2028? If so, what assumptions have been made?

(f) If the study is completed by January 1, 2028, as recommended, does Mr. Love also recommend the study be filed with the Board and result in an MCA process? Please elaborate on what thresholds in relation to incentives would trigger an MCA.

(g) Given the noted concerns with the incentive amounts included currently within the proposed Plan, does Mr. Love consider it appropriate to have incentive reductions before the study is complete, and if so, on what evidentiary basis?

(h) Given the high unit costs and customer incentives, does Mr. Love agree it would be reasonable for the Board not to approve any increase in total DSM spending until such time as E1 completes primary research and reduces incentives to the minimum necessary to secure participation? Please explain why or why not.

Response IR-09:

(a) Yes. An incentive share of approximately 71% of total plan costs sits within the range Mr. Love has observed among leading North American program administrators, although it sits at the upper end of that range. Massachusetts provides the closest comparison: in 2025 the Mass Save Program Administrators spent 72% of their budget on customer incentives. Looking back to the timeframe of 2022-2025, Mass Save program administrators spent 73.7% of their budget on customer incentive. Other well-regarded administrators operate at materially lower incentive shares. Efficiency Vermont directed 48% of its 2023 expenditures to customer incentives, with technical assistance (15%) and other program delivery costs making up much of the balance. California takes a structural approach, capping non-incentive cost categories (10% administration, 6% marketing, 4% EM&V, and a 20% direct-implementation non-incentive target) rather than requiring a specific incentive share.

First, this comparison is not always exact, since the treatment of technical assistance, direct-install labor, evaluation, and administrator performance incentives varies. ACEEE's 2025 State Energy Efficiency Scorecard notes that program spending data "are rarely tracked in a comprehensive or standardized manner that would allow straightforward comparisons between states." This comparability problem is the same weakness identified with E1's reliance on a small set of Atlantic Canada unit-cost benchmarks. Second, an incentive share describes how an administrator spends its budget; it says nothing about whether the incentive level for any given measure is set at the minimum necessary to secure participation. The concern with the Preferred Plan is not the 71% figure in isolation; it is the absence of evidence that individual incentive levels, particularly the escalating out-year heat pump incentives, are set no higher than necessary.

(b) Yes. Best practices for setting incentives include:

- Setting incentives at the minimum level needed to secure participation.
- Differentiating incentive levels by measure, customer segment, and delivery channel, rather than applying uniform levels across dissimilar markets.
- Designing incentives to address identified market barriers by delivery channel and customer segment. For example, overcoming up-front equipment costs for time-of-sale rebates, providing cost assistance with design for custom retrofit projects, and covering a larger portion of costs for low-income customers who may be unable to pay any additional amount for efficiency measures.
- Keeping incentive structures simple and fi to the local market. For example, expressing incentives in terms that a customer will more easily understand, like percentage of project cost and not dollar per kWh.
- Revisiting incentive levels regularly as equipment costs, market adoption, and complementary funding (e.g., tax credits) evolve,

(c) Yes. These are techniques used by leadings jurisdictions to establish "willingness-to-pay" curve, or a measure of customer willingness to adopt different measures at different incentive levels. Recent examples include:

- Massachusetts. The Mass Save Program Administrators commissioned a Residential Heat Pump Invoice Cost Analysis (NMR Group with DNV, 2024) to inform incentive levels using actual installed-cost data, followed by the 2024/2025 Residential Heat Pump Pricing Study (finalized March 2026), which examines the effect of rebate levels on market prices — treating the shift from a $10,000 whole-home incentive to a $3,000-per-ton incentive as a natural experiment in price sensitivity.
- Illinois. Ameren Illinois commissioned a Heat Pump Research Study (Opinion Dynamics, September 2025) examining how incentives and tax credits influence adoption decisions.
- California. The 2025 Energy Savings Assistance Program Non-Energy Impacts Study applied formal willingness-to-pay and conjoint methods in a program-evaluation context.

(d) GEEG recommends that E1 repeat the comprehensive incentive-setting exercise that CLEAResult performed for the 2016–2018 Plan period. That methodology, filed on this record as Attachment 1 to E1's Response to NSEB IR-19, identifies price sensitivity research and conjoint analysis as the two comprehensive methods for setting incentives and recommends they be applied to measures with annual incentive expenditure exceeding $400,000 over two or more years. To translate this to the current 5-year Plan, this threshold could be updated to $1,000,000 or more over five years. At a minimum this should cover building envelope, air source heat pumps, mini-split heat pumps, heat pump water heaters, smart thermostats, new construction, small business measures, and custom business projects. Under E1's own methodology, updated primary customer research — including installed-cost data, price-sensitivity or conjoint analysis, and contractor input — is the appropriate tool for setting these incentive levels. E1 last conducted price-sensitivity research in 2014, and the CLEAResult methodology has not been repeated for the 2027–2031 Plan. GEEG has not prepared a cost estimate for such a study.

(e) GEEG has not prepared a cost estimate or project plan. However, the CLEAResult methodology has been executed once before by E1, and the comparable studies cited in part (c) were scoped, fielded, and reported within normal evaluation cycles of roughly twelve to eighteen months. If E1 commissions the work promptly following a Board decision in this matter, a January 1, 2028 completion date could be achievable for some of the highest impact measures, and additional measure research could be scheduled based on portfolio impacts.

(f) The resulting report should be filed with the Board. The recommendations from the report should be used to inform future incentive levels that E1 can set in their programs. If modifying incentive levels to conform with the report findings results in projected costs that vary from an approved plan enough to trigger an MCA, then an MCA would be appropriate. The study itself does not require a separate MCA trigger; the existing spending thresholds capture any material consequence of its findings.

(g) Yes, in one specific respect. the Evidence recommended a reduction in out-year incentive levels for heat pump measures. Specifically, that the Board direct E1 to hold incentives for mini-split and centrally ducted heat pumps at $500 and $900 respectively in the Instant Savings and HEA programs, rather than allowing them to escalate to $900 and $1,500 by 2031. The evidentiary basis is E1's filing itself: E1 has not provided evidence supporting incentive increases beyond the

2027 levels it proposes, and it simultaneously projects a decline in participation in the final year of the plan when incentives reach their highest level. Holding incentives at the 2027 levels pending the results of primary research declines to approve unsupported escalation. This not a recommendation for across-the-board incentive reductions in advance of the study.

(h) No. The record demonstrates that additional DSM is needed now, and pausing DSM investment to await further study would put Nova Scotia further behind. Incentive-setting is not a problem that must be solved perfectly before any investment proceeds; the appropriate course is to move forward and adjust incentive levels as better information becomes available. As stated above, a substantial portion of the concern relates to the escalation of incentive levels in the out years of the plan — a concern the Board can address through the targeted measures recommended in parts (d), (f), and (g) without withholding approval of needed DSM investment.

Request IR-10:

Reference: E-21, pages 47 and 48, lines 21–22 and 1–7.

Q. IN THE DSMAG MEETINGS E1 WAS ASKED TO EXTEND SMART SYNERGY ELIGIBILITY TO LARGE INDUSTRIAL INTERRUPTIBLE ("LII") CUSTOMERS FOR THE INTERRUPTIBLE PORTION OF THEIR LOAD. DO YOU SUPPORT THIS PROPOSAL? A. No. While E1 has not committed to this, it instead states it "may be appropriate" and that it is "committed to further discussions to fully assess the incremental value and appropriateness of such participation." I recommend the Board direct that LII customers not be made eligible for Smart Synergy on their interruptible load, because doing so would be paying twice for the same demand reduction.

(a) Does Mr. Love agree that, per E1's own characterization, the question of incremental value of LII eligibility for Smart Synergy has not yet been fully assessed?

(b) Would it be reasonable for the Board not to foreclose LII eligibility before E1 has completed the assessment and further discussions it has itself committed to undertake?

Response IR-10:

(a) Based on the resources already cited, additional assessment is not necessary, which is why recommendation referenced above was made. This recommendation does not turn on the outcome of any assessments that E1 may feel is necessary. The more fundamental point, which E1 has already confirmed, is that NS Power "does not plan firm capacity requirements on the basis of interruptible load above the customer's contracted firm demand ," and for that reason E1 has not treated that interruptible load as eligible incremental demand response capacity. Because the system does not plan around that above-firm load as firm capacity, paying a Smart Synergy incentive to reduce it would procure no capacity the system was relying on. On that basis, the question of eligibility is answered regardless of any further incremental-value study.

(b) The position, as set out at pages 47–50 of the Evidence — including the Northeast Power Coordinating Council's reliability direction against counting the same load reduction in more than one program — is that the Board should confirm that LII customers are not eligible for Smart Synergy on their interruptible load. As the franchise holder, E1 remains free to further assess whether there is any genuinely incremental, additional-to-tariff value in LII participation; nothing in the recommendation prevents E1 from doing so. But from the record before the Board, the double-counting concern is clear and the eligibility question is answered. It should be noted that the operational details of the LII–Smart Synergy interaction are matters within NS Power's knowledge, and IG may wish to direct questions on the specifics of NS Power's interruptible-load planning to NS Power.

Request IR-11:

Preamble: Smart Synergy is described on E1's website as open to businesses willing and able to reduce energy use during high-demand events, through manual shutdown or automation, in four-hour morning or evening blocks. The current general eligibility rule states: "Businesses must not be participating in and/or receiving incentives from an existing demand response or demand reduction program." Participant eligibility is further limited to customers on Rate Codes 10, 11, 12, 21, 22, and 23. Rate Code 25, the Large Industrial Interruptible Rider, is not listed.

(a) The current Smart Synergy eligibility rules exclude LII customers on two independent grounds: (i) the general rule prohibiting participation by customers in an "existing demand response or demand reduction program"; and (ii) the omission of Rate Code 25 from the list of eligible rate codes. (i) Please confirm that these are E1-designed program rules, and not constraints imposed by legislation, regulation, tariff, or technical system limitation.

(b) Please confirm (or explain otherwise): (i) LII customers participate in the interruptible program by offering up to their full contracted load as a reliability product, available for interruption on 10 minutes' notice; (ii) LII customers at times voluntarily reduce load in advance of a potential interruption event; (iii) these voluntary pre-event reductions reduce system load and provide reliability value; and (iv) voluntary pre-event load reductions by LII customers are functionally equivalent to the load reductions Smart Synergy is designed to incentivize — and if not confirmed, please explain the material operational distinction and how it justifies ineligibility.

Response IR-11:

By way of introduction, it is noted that IR-11 does not refer to the Evidence filed by Mr. Love. Nonetheless, the following response is provided.

(a) The Smart Synergy eligibility rules are set out in E1's program-eligibility requirements filed in this proceeding, which is governed by the Public Utilities Act and conducted under the Energy Board's supervision of the franchise holder's demand-side management activities: the Board has general supervision over those activities under s. 79G(1), and under s. 79H(1) is responsible for determining the cost-effective demand-side management that must be undertaken. The eligibility of Large Industrial Interruptible customers for Smart Synergy is therefore not a matter of unfettered discretion to be changed at will, but a program-design question that falls to be resolved within that statutory and regulatory framework and subject to Board approval.

(b) (i) Confirmed

(ii) Neither confirmed nor denied as the Consumer Advocate has no visibility into the operations of LII customers, or their interactions with NSPI. However, it is possible that LII customers could voluntarily reduce load in advance of potential interruption events. The reason for an LII customer voluntarily reducing some load, would be to avoid a full interruption call, which would be costlier and more difficult to recover from. The fact is that the LII customers is already contracted to do the full reduction, if so called. This means that any voluntary reduction is only voluntary in the sense that the LII is using their voluntary discretion to help to avoid a larger non-voluntary action. If the customer was not on the interruptible rate, there would be no reason for them to voluntarily reduce load.

(iii) Confirmed. As explained in b(ii), this load benefit was, essentially, already contractor for by the LII being on the interruptible rate.

(iv) Not confirmed. The distinction is not the physical act of reducing load but whether the reduction is one the system plans around and pays for. The LII customers have already been paid to reduce their load when needed. From a planning perspective that load reduction has already been accounted for. NS Power has confirmed it does not plan firm capacity on the basis of LII above-firm load. Paying a second Smart Synergy incentive of roughly $100 per kW for reducing that same above-firm load would compensate the customer twice for a reduction the system has already secured and paid for under the tariff, while procuring no incremental capacity the system was relying on. That is the double-counting the Evidence identifies, and it is the material distinction that justifies ineligibility.

Request IR-12:

(a) Please confirm that PJM, ISO-NE, Efficiency Maine, and CAISO operate demand response frameworks in which interruptible or standby capacity commitments and voluntary performance-based demand response are treated as separate products with separate compensation rules, using baseline or firm service level methodologies to measure only incremental reductions. If not confirmed, please explain.

(b) On the basis that Smart Synergy incentives would apply only to incremental reductions above the customer's operating baseline, and that no Smart Synergy payment would be made for MW that are simultaneously dispatched down or held in reserve under the LII tariff, does Mr. Love agree that the two programs are operationally complementary rather than duplicative? If not, please identify the specific interval or MW overlap that would give rise to double compensation.

Response IR-12:

By way of introduction, it is noted that IR-12 does not refer to the Evidence filed by Mr. Love. Nonetheless, the following response is provided.

(a) GEEG has not completed detailed research into interruptible tariffs in the jurisdictions mentioned. It is generally correct that organized-market demand response frameworks distinguish between firm capacity-type commitments and voluntary, performance-based demand response, and that they use baseline or firm-service-level methodologies to credit only reductions below an established reference level. The core principle underlying those methodologies is the same one that drives the recommendation: a customer should be credited only for reductions that are incremental to what it is already committed to provide, and the same MW should not be counted or paid twice. That is precisely the concern here — the Northeast Power Coordinating Council's reserve directory expressly provides that a Balancing Authority "shall not count" reserve from loads already counted in other demand response programs.

(b) In principle, a demand response program that pays only for reductions incremental to a properly set baseline — and that excludes any MW simultaneously dispatched or held in reserve under the interruptible tariff — would avoid paying twice for the same MW. In California, there is at least one example of an "incremental only" process. Customers in Southern California Edison's Emergency Load Reduction Program can only be compensated for the reductions below the pre-committed Firm Service Level in the CAISO Base Interruptible Program. The concern is that no such methodology exists here. E1 has confirmed it "has not yet developed a finalized methodology" for isolating incremental voluntary curtailment separate from the LII tariff obligation, and that doing so "may present a technical challenge". More fundamentally, NS Power has confirmed it does not plan firm capacity on the basis of LII above-firm load, so there is no firm capacity for an incremental Smart Synergy payment to procure. Until a workable incremental-only baseline methodology is demonstrated — and until the system actually plans around the load in question — the programs are not shown to be complementary in practice, and the risk is double compensation for a reduction the tariff already secures. The overlap arises wherever a Smart Synergy "event" reduction coincides with load the customer is already obligated to make interruptible under the LIIR, since that above-firm load is already committed and compensated under the tariff.

Request IR-13:

(a) Please confirm that under Nova Scotia's current beneficiary-pays DSM cost allocation model, all Large Industrial customers (both firm and interruptible) currently bear a share of Smart Synergy program costs.

(b) Does Mr. Love agree that, under the beneficiary-pays principle, a customer class that is ineligible to receive benefits from a program should not bear the cost of that program?

(c) If LII customers are confirmed ineligible for Smart Synergy, does Mr. Love support removing their current share of Smart Synergy program costs from the LII cost allocation? If not, please provide the policy or regulatory basis for requiring an ineligible customer class to fund a program.

(d) If E1 declines both to extend eligibility and to adjust the cost allocation, please explain how this outcome is consistent with the beneficiary-pays principle and with the Board's direction on DSM cost allocation.

Response IR-13:

By way of introduction, it is noted that IR-13 does not refer to the Evidence filed by Mr. Love. Nonetheless, the following response is provided.

(a) Confirmed. However, the premise of the question overlooks that the Large Industrial Interruptible Rider is a customer election, not an immutable class attribute. A Large Industrial customer can choose to take service on a non-interruptible basis and participate in Smart Synergy, or to take the LIIR; the two are alternatives. A customer is therefore not permanently foreclosed from Smart Synergy's benefits by class membership — it has chosen the interruptible tariff, under which it is already compensated for the reduction at issue.

(b) The beneficiary-pays principle aligns cost responsibility with the benefits a class receives, and as a general proposition a class that receives no benefit from a program should not bear its costs. That general principle, however, does not lead to the exemption the question implies, for the reason given in part (a): LII status is an election. A customer that has chosen the interruptible tariff is not a class categorically excluded from Smart Synergy's benefits; it has selected an alternative arrangement under which it is separately compensated. Its ineligibility for a second payment on the same load flows from avoiding double payment, not from a denial of benefits it could not otherwise access.

(c) GEEG does not support carving LII customers out of Smart Synergy cost responsibility. The apparent objective of that argument is to relieve LII load of DSM cost responsibility by pairing an ineligibility finding with a cost-allocation exemption. That result is not warranted, because LII status is a customer election rather than a categorical exclusion from benefit: a Large Industrial customer can access Smart Synergy by electing non-interruptible service, and its ineligibility on interruptible load exists only to prevent paying twice for a reduction already compensated under the LIIR. This is similar to a residential electric customer that uses propane for water heating, but still pays for E1s programs that provide incentives for an electric heat pump water heater. If the customer wants to switch to electric water heating at some point, they can take advantage of E1's HPWH incentive, but until then E1 is not compensating the customer for saving electricity by using propane.

(d) see responses to part a), b), and c)