Review of Cost of Service, the Long-Term Supply Cost Variance Deferral Account, and Island Industrial Rate Design

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Executive Summary

The Board of Commissioners of Public Utilities (the "Board") retained The Brattle Group, Inc. ("Brattle") to assist Board staff in its review of the 2026 General Rate Application ("Application") filed by Newfoundland and Labrador Hydro ("Hydro" or "NLH"). Board asked the Brattle Group to prepare an assessment on three areas of the application: cost of service, long term supply cost variance deferral account allocation methodology, and industrial customer rate design.

Two further matters emerged from Hydro's responses to information requests. The first is the treatment of transmission losses caused by exports, the second is that the Application assigns different prices to the same 2027 energy in different parts of the filing.

Our review identifies a common issue across these matters. *In several instances, the measure Hydro applies does not match the quantity the measure is intended to represent*. Holyrood fuel is classified as energy-related although Hydro states that the forecast production and fuel consumption are attributable to holding the units at minimum stable output for reliability. The capacity factor used to classify Holyrood's other costs counts the same minimum output as energy service. The Newfoundland Power hydraulic credit is based on a five-year average of observations that do not vary with the severity of the system peak. The proposed wind classification uses the marginal value of adding wind to a 2032 system to classify the embedded cost of existing wind resources in the 2027 Test Year. The common transmission-loss factor includes losses caused by Maritime Link exports, a small part of which arise on exports whose proceeds do not accrue to customers. And the deferral account values load variances at the seasonal second-block price but values the offsetting export revenue at an annual average price.

On Island Industrial rates, Hydro proposes to replace the existing demand charge and single energy rate with an hours-of-use ("HOU") rate: a lower demand charge, a first energy block priced to recover embedded costs, and a second block priced at seasonal marginal energy cost. Now that average and marginal energy costs have diverged, the HOU rate improves on the existing rate by sending a marginal-cost price signal that a single energy rate cannot. Three features weaken that signal. The $5.50/kW-month demand charge recovers about 31 percent of demand-related costs, leaving the rest in the first energy block. In winter, the second-block price exceeds the first-block price, so a customer that improves its load factor faces a higher average energy price rather than a lower one. Billing demand rests largely on Power on Order, the customer's contracted firm demand, which customers cannot readily change. We recommend that Hydro consider a higher demand charge, seasonal first-block prices, and a more responsive billing-demand definition, and that it

evaluate a three-part seasonal rate as an alternative. Whatever design the Board approves, the rates should be recalculated from the cost-of-service and deferral-account determinations the Board makes in this proceeding. A separate standby rate is not warranted while backup service is supplied on an interruptible basis but would be appropriate if customers with self-generation require firm backup capacity.

The principal recommendations are summarized below.

TABLE ES-1: RECOMMENDATIONS

Issue	Recommendation	Why
1- Cost of Service		
Holyrood fuel classification	Approve as modified: classify the minimum-output portion as demand-related for the Bridging Period.	Hydro states that the fuel is burned for reliability rather than to serve energy consumption.
Holyrood non-fuel classification	Approve as modified: compute the capacity factor on generation above minimum stable output, over all hours of the year.	The filed 11.16% energy share counts minimum output held for reliability as energy. The fuel recommendation classifies the same output as demand-related.
Holyrood energy-classified costs—allocator	Allocate energy-classified Holyrood costs on commitment-period energy rather than annual energy.	The plant operates seasonally and the monthly load data needed for this allocator are already on the record.
Holyrood unit-level classification	Treat Unit 3 separately from Units 1 and 2: functionalize its operating costs as transmission in the months it operates as a synchronous condenser (May through September) and classify its remaining costs as demand-related.	Unit 3 supports the transmission system from May through September and is held as peaking capacity from October through April. Order No. P.U. 37(2019) provides for transmission functionalization once the conversion is permanent.
Newfoundland Power hydraulic credit	Approve the move to demonstrated performance in principle but recompute the credit on the most recent complete five-year window and revisit it once performance under the new incentive is observable.	The 64 megawatt (“MW”) value is sensitive to the choice of window, and output at system peaks falls well short of tested capability.
Newfoundland Power thermal credit	Approve on an interim basis with a direction to evaluate the annual generation test results as performance data.	The current hydraulic and thermal components are held to different evidentiary standards.

Issue	Recommendation	Why
Newfoundland Power curtailable credit (Memorial University boilers)	Direct Hydro to reflect the tested curtailable capacity of the boilers in the compliance filing.	The Test Year counts the boilers' load as firm but gives no credit for their curtailability.
Wind purchase classification	Deny without prejudice; direct Hydro to provide the average ELCC of the existing fleet on the 2027 system.	The 43% figure is a planning value for a 2032 system; Hydro has not measured the existing resources on the Test Year system.
2- Long-Term Supply Cost Variance Deferral Account Allocation Methodology		
Deferral account framework	Approve in principle, subject to modifications described in this report.	A demand-and-energy framework is reasonable, but several implementation choices do not track the cost-of-service study or the stated valuation basis.
Deferral account component classification	Classify each component on the basis the Board approves for the corresponding Test Year cost or revenue; keep off-island purchases energy-related.	A variance corrects a Test Year amount and should be allocated on the same basis; the Test Year includes no off-island purchases.
Deferral account demand measure	Use the cost-of-service study's coincident-peak demand measure.	Hydro states that this would be consistent with the cost of service ; its stated reason for billing demand is data availability.
Deferral account carrying charges	Retain short-term borrowing costs or use a duration-matched rate.	Hydro identifies no risk in the deferral balance comparable to rate-base investment.
Deferral account load-variance valuation	Defer until Hydro values the load variance and the offsetting export revenue on the same price series.	The account values load variances at the second-block price but the offsetting export revenue at an annual average price.
Rural Rate Alteration	Retain within the account only as a separately identified subaccount.	The treatment is largely administrative, but it should remain transparent and traceable.
3- Island Industrial Rate Design		
Industrial rate recalculation	Recalculate the proposed Industrial rates following the Board's cost-of-service and Long-Term Supply Cost Variance Deferral Account ("LT SCVDA") determinations.	Changes to cost classifications, allocators, and marginal energy values affect the Industrial class revenue requirement and resulting rates.

Issue	Recommendation	Why
HOU demand charge	Increase the demand charge to recover demand-related costs rather than recovering a substantial portion through Block 1 energy charges.	Recovering demand-related costs through volumetric charges weakens cost reflectivity and dilutes incentives to manage peak demand.
HOU seasonal energy rates	Introduce seasonal Block 1 rates and reconsider the winter inclining-block structure.	Seasonal differentiation would better reflect system costs and could restore incentives to improve load factor during winter months.
HOU billing demand	Consider a more dynamic billing-demand definition that is less dependent on Power on Order and historical demand.	The current relatively fixed billing demand limits customers' ability to improve load factor and access lower Block 2 prices through changes in operating patterns.
Alternative industrial rate design	Evaluate a three-part seasonal rate with year-round NCP demand charges, winter CP demand charges, and seasonal energy charges.	Separately recovering connection costs, system peak-driven costs, and energy costs would improve cost reflectivity and provide more direct price signals.
Standby rates for self-generating customers	Do not introduce a separate standby rate under current interruptible backup-service arrangements; revisit if customers require firm backup capacity.	Interruptible service does not require Hydro to reserve additional firm generation capacity. A standby rate would be appropriate where firm backup obligations create costs not adequately recovered under existing rates.

The following report develops the evidence supporting these findings.

I. Assessment of Cost-of-Service Matters

The common theme across the principal cost-of-service issues is that Newfoundland and Labrador Hydro ("Hydro" or "NLH") uses measures that do not match the cost-causation question they are asked to answer. Five matters discussed below support that finding.

A. Classification of Holyrood Fuel Costs

Hydro proposes to continue treating all No. 6 fuel burned at Holyrood as energy-related. That treatment is conventional when fuel is consumed to produce energy in response to customer usage.[1] The 2027 Test Year record, however, describes a different operating role for Holyrood. Hydro states that the plant is required to remain available during the Bridging Period to support reliability, including backup for loss of the Labrador-Island Link.[2] Hydro describes the plant's current role as "primarily to provide system reliability and backup generation until new resources are commissioned,"[3] although another response states that Holyrood "continues to be operated primarily as a base load plant."[4] The Test Year production plan commits Holyrood only during the winter period and does not commit any unit from April 1 through October 15.[5] Since January 2025, Hydro's marginal cost of energy on the Island Interconnected System has been based on the market value of exports rather than the cost of Holyrood No. 6 fuel.[6]

Of 455.2 gigawatt hours ("GWh") of forecast Holyrood generation in 2027, 423.6 GWh is the minimum generation required to keep committed units online; 31.6 GWh is dispatched above that

1 See National Association of Regulatory Utility Commissioners, *Electric Utility Cost Allocation Manual* (January 1992) ("NARUC Manual"), pp. 35, 64. The NARUC Manual states that "[f]uel expense is almost always classified as energy-related," and it classifies variable production costs as energy-related because they "change with the amount of energy produced, delivered or purchased."

2 See CA-NLH-158, p. 1; PUB-NLH-102(c).

3 See NP-NLH-149.

4 See PUB-NLH-173.

5 See PUB-NLH-037(b); PUB-NLH-102(c); CA-NLH-159(a).

6 In Order No. P.U. 1(2025), the Board of Commissioners of Public Utilities (the "Board") approved a seasonal second-block wholesale energy rate of 9.698 cents/kWh from December through March and 3.354 cents/kWh from April through November, based on the opportunity cost of the market value of export sales, in place of a marginal cost of 18.165 cents/kWh based on Holyrood No. 6 fuel. See Order No. P.U. 1(2025), pp. 1–2, 4.

minimum.[7] Hydro further states that the forecast production and therefore the associated fuel consumption are "directly attributable to operating the units at minimum stable output for reliability purposes only."[8] Hydro's commitment schedule reproduces the 423.6 GWh: two units at 70 megawatts ("MW") from January 1 through February 28 and in December, one unit at 70 MW from March 1 to 14 and from October 16 through November 30, and one unit at 50 MW from March 15 to 31. Hydro attributes the dispatch above minimum to Holyrood's cost advantage over combustion turbines and to supply constraints elsewhere on the system, including the 700 MW limit assumed for the Labrador-Island Link in the production model.[9]

Those facts change the nature of cost-causation. The minimum-output fuel is not being burned because customers consume more energy; it is being burned to keep units synchronized and available for reliability. Hydro's earlier responses say the same. Hydro states that Holyrood is forecast to run at minimum generation levels "to provide capacity, not energy"; that winter Labrador-Island Link deliveries keep all Holyrood units at minimum output, so a 5 percent increase in demand would not require operating Holyrood above minimum; and that it manages fluctuations in Island energy consumption by adjusting export volumes.[10] Hydro relies on three grounds for retaining the energy classification: past practice in Newfoundland and Labrador, industry practice, and the limited allocation impact Hydro reports. The first two are legitimate regulatory considerations, and industry practice generally treats fuel as energy-related. They do not, however, resolve the tension between the classification and Hydro's own description of why the fuel is consumed. The materiality rationale does not hold on the record. Hydro states that its reference to a "likely small share" of fuel cost assumed that only the third unit's fuel would be reclassified.[11] Hydro's capacity-factor sensitivity reduces Island Industrial cost responsibility by approximately $2.37 million, and Hydro's recalculation with the minimum-commitment fuel classified as demand-related reduces the Island Industrial revenue requirement by $2,480,664, or 5.8 percent, with rate mitigation recalculated.[12]

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7 See PUB-NLH-168(b), (c). The minimum-output portion is 93.06 percent of the total. Hydro's footnote states the total as 455.6 GWh; the monthly figures in its Table 1 sum to 455.2 GWh.

8 See PUB-NLH-102(c).

9 See IIC-NLH-022(b); PUB-NLH-102(c); CA-NLH-159(a), (c); PUB-NLH-168(a), (c), Table 2; PUB-NLH-171(c). Hydro states that raising the Labrador-Island Link limit to 900 MW does not have a material impact on the forecast, but it has not quantified the effect. See IIC-NLH-034(e).

10 See CA-NLH-157(b); CA-NLH-160(c), (d); CA-NLH-168(b), (c). Hydro also states that shutting down a Holyrood unit one day earlier than planned can avoid more than $230,000 in fuel costs. See PUB-NLH-027, p. 4.

11 See PUB-NLH-169(a).

12 See IIC-NLH-022(c); CA-NLH-286; PUB-NLH-168(d), Attachment 1. The Island Industrial revenue requirement falls from $42,815,548 to $40,334,884.

Hydro offers two further grounds. It states that combustion turbine and diesel fuel are demand-related because those units are "dedicated capacity resources," while Holyrood "consumes fuel as a direct consequence of generating energy."[13] That distinction does not fit the minimum-output fuel. Hydro states that Holyrood's units have average recall times in excess of 24 hours and are unsuitable for standby operation after an unplanned Labrador-Island Link outage, so a unit held for reliability must stay synchronized and burn fuel at minimum output.[14] Hydro also states that the third unit contributes to the 10- and 30-minute operating reserves only if it is online, and that raising the output of units already online adds energy but no reserve capacity.[15] In the Test Year, Units 1 and 2 are synchronized in every committed hour and run at minimum output for 5,785 of their 6,168 committed unit-hours.[16] Hydro also states that when a generator's function changes materially, a utility could retain an existing method if the costs are not material or the change is transitional, and that Holyrood's planned transition arguably fits those criteria.[17] The recommendation below already confines the change to the Bridging Period.

Hydro's October 13, 2026 winter readiness report describes the same role. Hydro recommended that all three Holyrood units remain available through the Bridging Period "in accordance with capacity requirements" in its 2024 Resource Adequacy Plan, and states that the operational dependency on Holyrood "is directly linked to overall system reliability, until its capacity can be replaced by new sources of generation."[18] In setting minimum reservoir storage limits for the coming winter, Hydro assumes one unit online at its 70 MW minimum output and expects to support reservoir storage with Muskrat Falls energy rather than Holyrood energy.[19]

The most direct disposition is therefore to separate the minimum-output portion from the small amount dispatched above minimum. *We recommend classifying the minimum-commitment portion as demand-related for the Bridging Period and retaining energy classification for generation above that minimum. Holyrood also supplies energy in drought conditions: Hydro states that, in a severe drought, existing and committed resources could not meet the firm energy requirement without it. The Test Year forecast assumes average inflows and excludes drought injection, so the forecast fuel is minimum-output fuel; generation above minimum, including any drought injection, would remain*

[13] See PUB-NLH-170.

[14] See PUB-NLH-173.

[15] See CA-NLH-160(b).

[16] See PUB-NLH-171(d), Table 1. Unit 1 is committed for 4,008 hours, 3,767 of them at minimum; Unit 2 is committed for 2,160 hours, 2,018 of them at minimum.

[17] See PUB-NLH-169(c).

[18] See Newfoundland and Labrador Hydro, "2026–2027 Winter Readiness Planning Report," October 13, 2026, pp. 3, 5.

[19] See id., pp. 26–27.

energy-related under our recommendation.[20] *This approach follows the operating facts Hydro has placed on the record and is limited to the period in which Holyrood is retained principally for reliability*. Hydro's recalculation at PUB-NLH-168 applies this split, 93.06 percent demand and 6.94 percent energy, and can serve as the basis for the compliance filing. The same split should apply to the Holyrood fuel component of the Long-Term Supply Cost Variance Deferral Account ("LT SCVDA"), which Hydro proposes to classify as 100 percent energy-related; otherwise Test Year fuel costs and fuel variances would be classified on different bases.[21] Hydro's recalculation does not apply its own rule for redistributing mitigation. Hydro states that mitigation is classified on system load factor so that every class receives a proportionate share, yet in PUB-NLH-168 Island Industrial's revenue requirement falls by the full gross reduction of $2,480,664 and none of the additional $2,492,027 of mitigation reaches that class.[22][23] *The compliance Schedule F should apply Hydro's stated allocation rule consistently.*

B. Classification and Allocation of the Remaining Holyrood Costs

Hydro classifies Holyrood's non-fuel generation costs using a capacity-factor method. For the 2027 Test Year, the method produces an 11.16 percent energy share and an 88.84 percent demand share. The 11.16 percent figure is computed by dividing forecast generation by 466 MW of net capacity multiplied by all 8,760 hours of the year.[24] Holyrood is not committed all year. The 2027 schedule commits at least one unit on 167 days, or 4,008 hours, and leaves the plant idle for 198 days.[25]

The denominator is consequential. Using plant capacity only during hours in which at least one unit is committed produces a capacity factor of approximately 24.4 percent.[26] Measuring against

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[20] See CA-NLH-156(d); CA-NLH-158, p. 3; PUB-NLH-102(c).

[21] See PUB-NLH-084, Attachment 1.

[22] See PUB-NLH-167(c), (d); PUB-NLH-168(d), Attachment 1. The Island Industrial reduction equals the gross capacity-factor reduction of $2,368,173 in CA-NLH-286 scaled from an 88.84 percent to a 93.06 percent demand share. Hydro applies the rule in PUB-NLH-005 (Revision 1) and PUB-NLH-165.

[23] Under a system load factor classification, the share of a cost equal to the system load factor (average demand divided by peak demand) is classified as energy-related and the remainder as demand-related. See NARUC Manual, pp. 51–52.

[24] 466 MW over 8,760 hours gives 4,082 GWh of capacity-hours. Schedule F 4.3 shows forecast generation of 455,225,658 kWh, which against that denominator is 11.15 percent. The filed 11.16 percent results with 465.5 MW, the net capacity Hydro reports for the 2019 Test Year, or with the 455.6 GWh total stated in a footnote to PUB-NLH-168(b). See PUB-NLH-102(a); PUB-NLH-171(f).

[25] See Schedule F 4.3; PUB-NLH-037(b); CA-NLH-159(a); PUB-NLH-171(a), (d).

[26] 167 days of commitment is 4,008 hours. 466 MW over 4,008 hours gives 1,868 GWh of capacity-hours, and 455 GWh against that denominator is 24.4 percent.

committed unit-capacity hours produces approximately 47.5 percent, rising to about 49.7 percent when the reduced 50 MW commitment in the second half of March is reflected.[27] PUB-NLH-102(b) asked Hydro to reconcile the classifier with Holyrood's current reliability role, but the response describes how the method behaves as the capacity factor declines and does not address the minimum output held for reliability. In the first round, Hydro also declined to restate the classification under an operating-factor method, stating that the question did not contain sufficient information.[28] Hydro's consultant describes the method as using hours in service, which is not what Schedule F 4.3 does. Hydro now states that Exhibit 14 "should have more appropriately reflected the formula" in use, and that the Exhibit 14 formula yields 24.4 percent.[29] Hydro also states that its consultant was not asked to evaluate alternative classification approaches and has not reviewed the 2027 Test Year forecast since its July 30, 2025 memorandum.[30] Hydro states that the 8,760-hour formula is the one it has "consistently used."[31]

TABLE 1: HOLYROOD CAPACITY-FACTOR SENSITIVITY

Measure	Capacity factor	Energy / demand classification
All hours of the year (filed)	11.16%	11.16% / 88.84%
Hours at least one unit is committed	24.4%	24.4% / 75.6%
Committed unit-capacity hours	47.5%	47.5% / 52.5%
Committed unit-capacity hours, adjusted for March 50 MW commitment	49.7%	49.7% / 50.3%
All generation; Units 1 and 2 net capacity, all hours (estimated)	16.1%	16.1% / 83.9%
Generation above minimum; all hours of the year	0.8%	0.8% / 99.2%
Generation above minimum; Units 1 and 2 net capacity, all hours (estimated)	1.1%	1.1% / 98.9%

[27] A 47.5 percent capacity factor implies approximately 958 GWh of committed unit-capacity hours, which at the 155 MW average unit size is about 6,170 unit-hours, or 257 unit-days. That falls inside the range of 167 to 334 unit-days implied by a schedule that commits at least one unit and never more than two.

[28] See CA-NLH-153.

[29] See PUB-NLH-171(a).

[30] See PUB-NLH-172(d), (e).

[31] See PUB-NLH-171(a), (e).

The commitment-period denominators measure how intensively Holyrood runs once its units are online, not how much of the year the plant is needed for energy. A capacity factor serves as a classifier because it measures annual utilization: a plant that operates at high output through the year is an energy resource, and a plant that is idle for much of the year is held for capacity. That reasoning calls for an annual denominator, the convention the average-and-excess method follows in classifying production plant on the annual system load factor.[32] A seasonal denominator would also count as energy service the minimum output that Hydro attributes to reliability, raising the energy share to between 24 and 50 percent for a plant that, as Section I.A shows, is held principally for capacity.

The numerator, not the denominator, is the source of the mismatch. The filed calculation counts all 455.2 GWh of forecast generation as energy service, although 423.6 GWh is the minimum output required to keep committed units online for reliability, the same output Section I.A recommends classifying as demand-related for fuel.[33] Counting only the 31.6 GWh generated above minimum, against the same 8,760-hour denominator, gives an energy share of about 0.8 percent.[34] Treating Unit 3 separately would base the denominator on the net capacity of Units 1 and 2 alone. The record does not report net capacity by unit. In proportion to the units' nameplate ratings, two 170 MW units and one 150 MW unit, Units 1 and 2 account for about 323 MW of the 466 MW, and the energy share on generation above minimum would be about 1.1 percent.[35] Either measure applies to plant utilization the principle that governs Section I.A: output held at minimum for reliability is a capacity cost.

Holyrood's seasonal operating pattern bears instead on allocation. During the idle period (from April to mid-October), the plant produces no energy and is retained for availability. Actual operation has extended beyond that window: in 2026 one unit remained online through the spring, and in 2025 a unit ran in September and October to support reservoir storage during a drought. Hydro states that the Test Year plan reflects normal system conditions.[36] During the commitment period (winter

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[32] See NARUC Manual, pp. 49–51.

[33] See PUB-NLH-168(a), (c), Table 2.

[34] 466 MW over 8,760 hours gives 4,082 GWh of capacity-hours, and 31.6 GWh against that denominator is 0.77 percent. Applied to the $9.21 million of non-fuel cost that the filed 11.16 percent classifies as energy-related, the change would leave about $0.64 million energy-related and reclassify about $8.6 million as demand-related, before any separate treatment of Unit 3. See CA-NLH-155, Attachment 1.

[35] See Volume II, Exhibit 4, p. 6. 466 MW multiplied by 340/490 is 323 MW, which over 8,760 hours gives 2,833 GWh of capacity-hours; 31.6 GWh against that denominator is 1.1 percent. Counting all 455.2 GWh against the same denominator gives 16.1 percent, consistent with Hydro's statement that a two-unit capacity factor would be higher. See PUB-NLH-172(a).

[36] See CA-NLH-023; CA-NLH-158, p. 2; CA-NLH-161(a). Hydro burned 79,505 barrels of No. 6 fuel at Holyrood in April 2026, 18,440 barrels in May, and 1,326 barrels in June. See Newfoundland and Labrador Hydro, "Supply Cost Variance

Continued on next page

months), it is operated at minimum stable output for reliability, with only a small amount of dispatch above that floor. For the portion of Holyrood costs that remains energy-related, the relevant allocation question is therefore whether annual customer energy or energy consumed during the commitment period better tracks the period in which those costs are incurred.[37] Hydro states that Holyrood fuel and energy-classified fixed costs are part of its annual cost of service and should be recovered using annual energy, and that monthly energy would make allocations depend on the timing of dispatch and winter operating conditions.[38] A commitment-period allocator would be fixed from the Test Year production plan and would not vary with actual dispatch. The annual convention also predates the current operating pattern: the 2019 Test Year forecast had Holyrood generating in ten of twelve months, while the 2027 forecast has no generation from April through September.[39]

The monthly load forecast filed at PUB-NLH-052, Attachment 1 permits that comparison. The annual allocator is 84.84 percent Newfoundland Power, 8.65 percent Island Industrial, and 6.51 percent Rural Island Interconnected.[40] Using October through March instead produces 86.98 percent, 6.82 percent, and 6.20 percent respectively.[41] Applied to the $65.0 million No. 6 fuel pool for illustration, that change would move about $1.39 million of cost responsibility to Newfoundland Power and about $1.19 million off Island Industrial before rate mitigation.[42] If Holyrood fuel and non-fuel costs are reclassified as recommended above, the energy-classified Holyrood pool falls to about $5.2 million, and the seasonal allocator would move about $0.11 million to Newfoundland Power.[43] This effect is analytically distinct from the recommended fuel reclassification: the reclassification determines how much of Holyrood fuel is treated as demand- versus energy-related, while the seasonal allocator determines how any energy-related portion is distributed among customer classes. Each question should therefore be decided independently based on cost causation.

Deferral Account Report (Unaudited), Quarter Ended June 30, 2026," Attachment 2 to Hydro's Quarterly Summary for the Quarter Ended June 30, 2026 ("SCVDA Quarterly Report"), p. 7.

37 The NARUC Manual describes allocating fuel expense on time-differentiated energy, such as on-peak and off-peak kWh, as an alternative to total kWh, and describes methods that assign production costs to the periods in which units serve load. See NARUC Manual, pp. 59–61, 64.

38 See IIC-NLH-022(a).

39 See IIC-NLH-022(a), Table 1; PUB-NLH-168(b), Table 1.

40 See NP-NLH-120, Table 2.

41 Hydro's monthly fuel schedule shows No. 6 fuel burned only from January through March and from October through December. See PUB-NLH-168(b), Table 1.

42 The shifts are the allocator differences applied to the $65.0 million fuel pool. Newfoundland Power gains 2.14 percentage points, or $1.391 million; Island Industrial sheds 1.83 points, or $1.190 million; and Rural Island Interconnected sheds 0.31 points, or $0.201 million. The two reductions sum to the Newfoundland Power increase.

43 The filed energy-classified Holyrood revenue requirement is $74,224,568, of which $65,010,009 is No. 6 fuel. Under the recommended split, 6.94 percent of the fuel, or $4.51 million, remains energy-related; at a 0.77 percent energy share, about $0.64 million of the $9.21 million of energy-classified non-fuel cost remains energy-related, for a total of about $5.15 million, and 2.14 percentage points of that is about $0.11 million. See CA-NLH-155, Attachment 1.

The record also supports separate treatment of the third Holyrood unit. Exhibit 14 recommended separating the peaking unit for costing purposes, and Hydro states that only two units are required online during the peak winter period while the third remains offline but available.[44] The Test Year commitment schedule never commits more than two units. A unit that is retained for availability but does not generate in the Test Year is most naturally treated as a capacity resource.[45]

Hydro confirms that Unit 3 has no committed hours in the Test Year[46] but declined to classify it separately or to quantify the effect, stating that the units may rotate roles and that accelerated depreciation would make the costs differ depending on which unit is designated.[47] The passage from Exhibit 14 that Hydro quotes in support describes the separate treatment as feasible, using "the accounting fiction that one unit always plays the peaking role." Hydro also states that it does not operate a permanently designated peaking unit.[48] Assigning a fixed share of plant cost to the peaking role would avoid the rotation problem, because the designation need not follow a particular unit. Unit 3 returned from its annual maintenance outage on September 26, 2026, and Hydro expects it to be fully available as a generating unit this winter.[49]

Unit 3 also differs from Units 1 and 2 in function. From May through September, it operates in synchronous condenser mode, providing reactive power and voltage support to the transmission system rather than energy or generating capacity.[50] Because Unit 3 is the unit equipped to operate in that mode, its transmission role does not rotate among the units. Order No. P.U. 37(2019) provides for functionalizing Unit 3 as transmission once it is permanently converted to a synchronous condenser, and, in the long run, the unit is expected to operate in that mode year-round.[51] Until then, Unit 3 supports the transmission system for five months of the year and is held as peaking capacity for the other seven. Hydro's cost-of-service study does not reflect that division: it functionalizes all Holyrood plant and operating costs as production and classifies them on the plant capacity factor, so Unit 3's costs in its synchronous condenser months are classified and allocated in the same way as the costs of Units 1 and 2.[52] Separating Unit 3 also affects the classification of Units

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[44] The equivalent-peaker method classifies the cost of peaking capacity as demand-related and the additional cost of baseload and intermediate units as energy-related; under it, "all costs of actual peakers are classified as demand-related." See NARUC Manual, pp. 52–53.

[45] See Exhibit 14; PUB-NLH-102(c); CA-NLH-159(b). Hydro states that the only reason to bring the third unit online is to meet reserve requirements. See CA-NLH-160(b).

[46] See PUB-NLH-171(d), Table 1.

[47] See PUB-NLH-172(b), (c).

[48] See PUB-NLH-170.

[49] See Newfoundland and Labrador Hydro, "2026–2027 Winter Readiness Planning Report," October 13, 2026, pp. 4–5.

[50] Based on discussions with Board staff.

[51] See Volume I, § 6.2.2. The expectation of year-round operation is based on discussions with Board staff.

[52] See Schedule F 2.2A, line 11; Schedule F 2.4A, line 2; Schedule F 4.1, line 3.

1 and 2. Hydro states that a capacity factor computed on two units would be higher, with the costs of the third unit classified separately.[53]

We recommend classifying Holyrood's non-fuel costs for the 2027 Test Year on a capacity factor that counts only generation above minimum stable output, measured against net capacity over all 8,760 hours. We also recommend allocating the energy-classified portion of Holyrood costs using commitment-period energy and treating Unit 3 separately from Units 1 and 2. Unit 3's operating costs in the months it operates as a synchronous condenser should be functionalized as transmission, and its remaining costs should be classified as demand-related. Once Unit 3 operates as a synchronous condenser year-round, all of its costs should be functionalized as transmission, as Order No. P.U. 37(2019) provides. The capacity factor for Units 1 and 2 should then be computed on the net capacity of those two units, which Hydro should report in its compliance filing. Resolving the classification in this proceeding is important because Hydro's planning assumption is that steam generation at Holyrood may end by March 31, 2030; waiting until the next general rate application could leave it unresolved for much of the remaining life of the plant.[54] *The same classification should govern the Holyrood TGS Accelerated Depreciation Deferral Account when its balance is disposed of.*[55]

C. Newfoundland Power Generation Credit

Newfoundland Power owns generation that runs at the time of the system peak, which reduces the capacity Hydro must supply. Hydro proposes to replace the reserve-at-criteria calculation for Newfoundland Power's hydraulic generation credit with a 64 MW credit based on the average hydraulic output at the time of the system peak over 2020 through 2024.[56] The existing hydraulic credit of 83.5 MW was approved in Order No. P.U. 16(2019) and has not changed since the 2019 Test Year.[57] Including the thermal credit, the proposal reduces Newfoundland Power's total generation credit from 118.1 MW to 103.3 MW and increases Newfoundland Power's cost of service by

[53] See PUB-NLH-172(a).

[54] Hydro states that the March 31, 2030 date "is an assumption only." See NP-NLH-161. Hydro also states that it cannot provide an updated retirement date because retirement depends on the approval, construction, and commissioning of the 2025 Build Application projects. See PUB-NLH-082.

[55] Hydro does not propose disposition of that balance in this proceeding and states that Holyrood's role is relevant to the balances in the account. See Volume I, § 5.6.10; PUB-NLH-173.

[56] Reserve-at-criteria refers to the amount of generating capacity required, including reserves, to meet the utility's established reliability criterion. In this case, it is used to translate Newfoundland Power's generating capability into the amount of Hydro capacity that generation can effectively displace.

[57] The wholesale rate approved in Order No. P.U. 1(2025) retains a Generation Credit of 83,486 kW hydraulic and 34,568 kW thermal, a total of 118,054 kW. Under Hydro's proposal, the hydraulic credit would fall from 83.5 MW to 64 MW and the thermal credit would rise from 34.6 MW to 39.3 MW. See Order No. P.U. 1(2025), Schedule A, p. 1.

approximately $522,026 before the rural deficit allocation.[58] The thermal component would remain based on capability reduced by reserve-at-criteria, producing a 39.3 MW thermal credit.[59] The move from a capability-based hydraulic credit to demonstrated performance is defensible in principle. Our concern is with the data used to set the 64 MW value and with the continuing asymmetry between the hydraulic and thermal components.[60]

The five-year mean is not uniquely supported by the record. Hydro reports a median of 66 MW, a P80 value of 58 MW, a P90 value of 53 MW, a ten-year mean of 60 MW, and values of 59 MW and 58 MW during the top 5 percent and top 10 percent of demand hours.[61] Across rolling five-year windows, the average ranges from 56.0 MW to 65.5 MW. The selected 2020–2024 window is also the most volatile of the six rolling windows, with a sample standard deviation of 10.7 MW and a standard error of the mean of approximately 4.8 MW.[62] On that sample, 64 MW cannot be distinguished statistically from several of the alternative values on the record.[63] Each 10 MW change in the hydraulic credit changes Newfoundland Power's cost of service by about $0.3 million before the rural deficit allocation.[64] Hydro states that dispersion "is a practical consideration when assessing the reliability of the resulting generation credit," but considers the window representative.[65]

[58] See CA-NLH-136(a), (c); CA-NLH-138.

[59] Newfoundland Power's thermal capability of 44.5 MW divided by the reserve-at-criteria factor of 1.132350 gives 39.3 MW. See IIC-NLH-011(a).

[60] See Application, Exhibit 15; NP-NLH-099; NP-NLH-100.

[61] P80 and P90 denote the output levels exceeded in 80 percent and 90 percent of the observations, so a lower P-value is the more conservative credit. See PUB-NLH-108(b); CA-NLH-135(a); Application, Exhibit 15, pp. 2–3.

[62] The standard error is the sample standard deviation divided by the square root of the sample size: 10.7 MW over the square root of five gives 4.8 MW. A two-standard-error interval around the proposed 64 MW spans roughly 54 MW to 74 MW, which contains every alternative measure on the record except the P90 value of 53 MW.

[63] See PUB-NLH-108(b); CA-NLH-135.

[64] See PUB-NLH-108(d).

[65] See PUB-NLH-175(b).

TABLE 2: HYDRAULIC CREDIT—ALTERNATIVE MEASURES IN THE RECORD

Measure	Credit (MW)
Five-year mean (2020–2024), proposed	64
Median	66
P80	58
P90	53
Ten-year mean (2015–2024)	60
Top 5% of demand hours	59
Top 10% of demand hours	58

Hydro states that the proposed credit already excludes the four observations, all before 2020, for which no request to maximize all hydraulic generation was issued in support of system reserves; it treats requests limited to Avalon hydraulic generation as "often indicative" of transmission corridor limits rather than reserve needs.[66] The larger concern is that hydraulic output at the peak falls well short of the capability Newfoundland Power demonstrates in its annual generation tests. Hydraulic output in the tests conducted from December 2020 through February 2026 ranged from 79.4 MW to 90.1 MW, compared with the 64 MW average output at the system peak.[67][68] Newfoundland Power did not explain to Hydro why its reported available generation does not always match its actual generation when it is asked to maximize,[69] and Hydro did not assess the recovery characteristics of Newfoundland Power's run-of-river plants or set a threshold at which repeated requests before a peak would indicate reservoir depletion.[70] The shortfall was largest in 2024: on the three peak days, actual output was 26 MW to 36 MW less than the availability Newfoundland Power had reported.[71] Across the ten annual observations now available, hydraulic output at the system peak shows no discernible relationship to the level of the Island Interconnected System peak. That does not

[66] See PUB-NLH-174.

[67] See PUB-NLH-181, Table 1.

[68] The wholesale rate requires Newfoundland Power to demonstrate the Generation Credit by operating its generation at no less than the credit level for one hour, at a mutually agreed time between December 1 and March 31. See Order No. P.U. 1(2025), Schedule A, p. 1.

[69] See PUB-NLH-187.

[70] See PUB-NLH-186(b), (d).

[71] See PUB-NLH-108, Attachment 1.

establish that Newfoundland Power's hydraulic resources lack capacity value; it does show that the current sample is not a reliable measure of performance under system stress.[72]

Finally, the proposed hydraulic credit is calibrated on behavior recorded before Newfoundland Power had a formal incentive to maximize hydraulic production at system peaks. Hydro states that, if the proposed methodology is approved, it is a reasonable assumption that the winter of 2027–2028 will be the first opportunity for Newfoundland Power to maximize its hydraulic generation during periods of high demand when Hydro requests it.[73] Hydro also states that Newfoundland Power was aware during the 2020–2024 window of Hydro's intent to recommend a methodology change based on historical data.[74] Hydro recommends that the 64 MW value be reviewed on a recurrent basis and states that it recalculates the value annually, with any improvement captured in its next general rate application.[75] That timing supports a defined rule that rolls the five-year window forward as each year's data become available rather than a value fixed until the next application. *We recommend approving the move to demonstrated performance in principle but recomputing the hydraulic credit using the most recent complete five-year window, with the value revisited after performance under the new incentive becomes observable.* Hydro declines a performance-based thermal assessment because it has requested thermal generation from Newfoundland Power only a few times.[76] Hydro states, however, that the generation test results may be used, primarily for the thermal portion, in assessing the credit in the next general rate application.[77] Comparable data already exist in the annual generation tests: thermal output was less than the 39.3 MW thermal credit in six of the ten finalized tests since December 2015.[78] The asymmetry extends to cost allocation: only the hydraulic credit reduces Newfoundland Power's transmission coincident peak, a treatment the Board approved in Order No. P.U. 8(2007), and applying the thermal credit in the same way would lower Newfoundland Power's cost of service by $421,571, shifting $274,869 to Island Industrial and $146,702 to Rural Island Interconnected customers.[79] *The thermal credit can be retained on an interim basis with a direction to evaluate the test results as performance data and to propose*

[72] See CA-NLH-135(a), Table 1; PUB-NLH-108, Attachment 1.

[73] See NP-NLH-106; PUB-NLH-108(f).

[74] See PUB-NLH-175(a).

[75] See Application, Exhibit 15, § 2.4; PUB-NLH-175(b).

[76] See PUB-NLH-176. Hydro's request data show eight thermal requests from January 2020 through December 2025. See PUB-NLH-183.

[77] See PUB-NLH-178.

[78] See PUB-NLH-181, Table 1. The six results are 33.7 MW (December 2015), 36.1 MW (January 2017), 38.2 MW (December 2017), 38.1 MW (January 2019), 38.9 MW (December 2021), and 38.3 MW (February 2026). Hydro states that the December 2019 test was not finalized.

[79] See NP-NLH-174; PUB-NLH-109.

consistent treatment of the two components, including whether the transmission treatment approved in Order No. P.U. 8(2007) should continue.

Newfoundland Power's billing demand also reflects curtailable load. The Test Year includes the demand of new electric boilers at Memorial University of Newfoundland ("MUN"), about 25 MW and 110 GWh a year, but no curtailable credit for them, because the curtailable capacity had not been tested when the cost-of-service study was prepared.[80] Adding 21.7 MW of MUN capacity assistance to the existing 12 MW agreement would lower Newfoundland Power's mitigated cost by about $5.1 million and raise the cost of Rural Island Interconnected customers by a similar amount, most of which returns to Newfoundland Power through its share of the rural deficit; Island Industrial customers would be largely unaffected.[81] Hydro states that load supported by retained alternative supply, such as electric boilers with fuel-fired backup, is more likely to qualify as non-firm.[82] Counting the boilers as firm load while giving no credit for their curtailability overstates the capacity they cause Hydro to provide.[83] Hydro does not plan to revise the Application but states that the agreement could be addressed in its compliance application.[84]

We recommend that the Board direct Hydro to reflect the tested curtailable capacity of the MUN boilers in the compliance filing, on the same terms as the existing 12 MW curtailable credit, if testing is complete by then, and to file the test results.[85]

D. Wind Purchases

Hydro proposes to increase the demand-related share of purchases from the St. Lawrence and Fermeuse wind farms from 22 percent to 43 percent. The 43 percent value comes from the E3 reliability study filed as Exhibit 16. That study is informative for system planning, but the metric used in the Application does not directly answer the cost-classification question before the Board.

The E3 figure is the marginal effective load-carrying capability ("ELCC") of the first 50 MW increment of wind on a 2032 system, modeled on the output of the existing Fermeuse and St. Lawrence

[80] See PUB-NLH-188(a), (b) and Attachment 1. The only Newfoundland Power correspondence on the record dates from May 2022.

[81] See IIC-NLH-039(d) and Attachment 2. Before mitigation, the reduction to Newfoundland Power is about $8.7 million.

[82] See IIC-NLH-035(f).

[83] Peak-demand allocation methods allocate no production plant costs to interruptible (curtailable) customers. See NARUC Manual, p. 41.

[84] See IIC-NLH-039(c).

[85] The wholesale rate sets the terms of the Curtailable Credit: a one-hour curtailment test in December, a report by April 15 of the load curtailed in response to each of Hydro's requests, and adjustment of the credit to the average load actually curtailed. See Order No. P.U. 1(2025), Schedule A, pp. 1–2.

farms.[86] It is not the average ELCC of the existing 54 MW wind fleet on the 2027 Test Year system. The study's marginal ELCC declines with penetration: 43 percent at 50 MW, 38 percent at 100 MW, and 11 percent at 500 MW. Both existing purchase agreements expire in 2029, before the 2032 study year.[87] The existing farms are therefore not part of the 2032 system E3 modeled, and Hydro does not consider them in its long-term resource adequacy study.[88] The 43 percent figure is thus the value of the first 50 MW of wind on a system with no other wind. For a first increment, marginal and average values are close, so the difference that matters most is the system against which the wind is measured. Asked for the average ELCC of the existing 54 MW, Hydro interpolated the E3 curve between 50 MW and 100 MW and reported 42.97 percent, or 23.20 MW. That figure reapplies the 2032 curve rather than measuring the existing resources on the Test Year system, and Hydro states that the study "would not typically be used for near-term analysis."[89]

The system vintage also matters. E3 selected 2032 because aging thermal units were expected to have retired by then, whereas Holyrood remains in the 2027 Test Year system. Capacity value depends on the system against which a resource is measured. Hydro's own overview of the E3 study states, in comparing it with the prior study, that "the disparity in study year alone makes this current study not directly comparable due to shifts in loads and resources."[90] Hydro states that the 2032 study is an appropriate basis because the wind capacity studied "is similar to that of the existing wind farms," but it does not address the difference between the systems against which the resources are measured.[91] Wind would be the only resource in the cost-of-service study classified with a capacity value study.[92] For Newfoundland Power's hydraulic generation, by contrast, Hydro treats actual output during peak-demand events as "a more reliable measure than reported availability" and considers an ELCC-based measure outside the scope of the credit calculation.[93] The existing 22 percent classification rests on that kind of evidence. The Board approved it in 2019 on the basis of Hydro's ELCC study of wind availability during peak periods, and the Brattle review in that proceeding found it "not an unreasonable estimate" based on wind output during the top 25 hours

[86] Effective load-carrying capability measures the quantity of perfectly reliable capacity a resource displaces at a fixed reliability standard. Marginal ELCC is measured on the next increment added to a given system; average ELCC is the reliable capacity the whole installed fleet displaces, as a share of its nameplate. Where marginal ELCC falls with penetration, the marginal value of an increment added to an existing fleet is less than the fleet's average value. See PUB-NLH-103(a); CA-NLH-151(c).

[87] The St. Lawrence agreement expires May 31, 2029, and the Fermeuse agreement expires June 30, 2029. See PUB-NLH-166(c).

[88] See Application, Exhibit 16, Attachment 1, p. 20; CA-NLH-148; CA-NLH-151(b).

[89] See Exhibit 16; PUB-NLH-103(a); PUB-NLH-162.

[90] See Application, Exhibit 16, ELCC Overview, p. 7; CA-NLH-159(b).

[91] See PUB-NLH-163(a).

[92] See PUB-NLH-163(b).

[93] See PUB-NLH-164.

of each year from 2013 to 2017.[94] Hydro's 2018 study measured the existing 54 MW at approximately 12 MW, or 22 percent, which is the average-ELCC measure we recommend; Hydro states that neither that study nor the 2025 study retains the model files needed to reconstruct its result.[95] Hydro's updated peak-hour data point higher. Across the ten highest-load hours of each year from 2017 through 2025, the two farms' combined output averaged 28.5 MW, or 53 percent of installed capacity, although it was 1.2 MW and 3.7 MW at the 2017 and 2023 annual peaks. Average output in peak hours is not an ELCC, which depends on output in the hours of greatest loss-of-load risk; the data support measuring the existing farms on the Test Year system rather than adopting either figure.[96] Both purchase agreements pay for energy only; neither provides for a capacity or availability payment,[97] so any demand classification of the purchases depends entirely on the capacity the wind farms displace.

These concerns do not imply that ELCC is an inappropriate classifier in principle. They imply that the ELCC used for ratemaking should match the ratemaking question: the average contribution of the existing resources, evaluated on the relevant Test Year system. The immediate dollars are comparatively small. CA-NLH-146 shows that moving from 22/78 to 43/57 increases Newfoundland Power's cost of service by $128,499 and decreases Island Industrial's by $120,885 and Rural Island Interconnected customers' by $7,613 before deficit allocation and mitigation; after the rural deficit is reallocated, Newfoundland Power's net increase is $121,616.[98] With rate mitigation recalculated, reverting to 22/78 leaves Newfoundland Power's revenue requirement unchanged and raises Island Industrial's by $129,786, because Island Industrial also gives up its share of the mitigation that the reversion releases.[99] While these numbers are relatively small, the methodological issue nevertheless matters because Hydro proposes to carry the same classification into the LT SCVDA and because the difference could become more material if the wind portfolio grows.

We recommend retaining the existing 22 percent demand / 78 percent energy classification for the 2027 Test Year and directing Hydro to file, by a specified date, the average ELCC of the existing wind fleet computed on the Test Year system. Hydro computed that measure for the same farms in its 2018 study and intends to update the ELCC study before each Resource Adequacy Plan filing.[100] *The*

[94] See PUB-NLH-166(h); Order No. P.U. 37(2019).

[95] See CA-NLH-144.

[96] See CA-NLH-150, Tables 2 and 3.

[97] See PUB-NLH-166(a); CA-NLH-148.

[98] The two reductions sum to $128,498, one dollar below the Newfoundland Power increase, which is rounding in the filed schedules. See CA-NLH-146, Attachment 1.

[99] See PUB-NLH-165, Table 1.

[100] See CA-NLH-144; PUB-NLH-103(c).

proposed change can then be reconsidered using a measure that is aligned with the embedded costs being classified.

E. Export-Related Transmission Losses

Hydro's responses raise a further cost-allocation question, smaller in amount than it first appears. Forecast Island Interconnected System transmission losses are 327.3 GWh in 2027, of which 207 GWh is associated with energy exported from Soldiers Pond to Bottom Brook for delivery over the Maritime Link. Hydro states that export-related losses are variable and, valuing the 207 GWh at its 2027 average export value of 3.998 cents/kWh, estimates them at $8,275,860.[101,102]

The loss model does not separately remove export-related losses before calculating the common transmission-loss factor. Hydro states that the full 327.3 GWh is used to calculate one factor applied to Newfoundland Power, Island Industrial, and Rural Island Interconnected load, and that the production energy allocated to domestic classes therefore includes the additional energy needed to supply export-related losses. The same response states that no portion of the losses is directly borne by domestic load. Hydro has since stated that the second statement means only that the losses are not directly assigned to a class: the losses reduce the energy available to monetize, and Hydro allocates the resulting value in the same manner as net export revenue, on system load factor.[103,104]

The question for the Board is therefore not which domestic class bears the losses. PUB-NLH-106(b) allocates approximately $7.18 million of the $8.28 million to Newfoundland Power, $0.565 million to Island Industrial, and $0.529 million to Rural Island Interconnected, the same proportions used for the export credit.[105] Because the common loss factor applies equally to the three classes and the export credit is allocated on system load factor, the treatment changes class shares only slightly; Hydro's illustration of a 100 GWh reduction in losses shifts about $90,000 among classes.[106] The question is whether Island Interconnected customers should bear losses caused by export flows whose proceeds do not accrue to them. Approximately 40 percent of 2027 Maritime Link deliveries are made under the Energy and Capacity Agreement, and the rest are market exports of Muskrat Falls excess energy; the energy dispatched for export comprises 985.46 GWh of Nova Scotia Block

[101] See PUB-NLH-106(a), (b). The remaining 120.3 GWh of the 327.3 GWh forecast is domestic loss.

[102] See PUB-NLH-106.

[103] See CA-NLH-314(a); PUB-NLH-106(b), (c).

[104] See PUB-NLH-106(a), (c).

[105] The three allocations sum to approximately $8.27 million, consistent with the $8,275,860 total after rounding of the Newfoundland Power figure.

[106] See CA-NLH-314(c).

energy and 1,553.07 GWh of Residual Block energy.[107] Of the $83.0 million of 2027 Residual Block export revenue, customers receive the $38.1 million of monetized NLH Deferred Energy,[108] while the remaining $44.9 million accrues to Hydro's non-regulated operations as a dividend, which Hydro states may be used for rate mitigation.[109] The $18.3 million point-to-point transmission rate that Nalcor Energy Marketing pays to export Muskrat Falls energy over Hydro's transmission system to the Maritime Link is included in Hydro's transmission rate revenue; the record does not state whether that rate compensates for Island transmission losses.[110]

The amount at issue is also smaller than the 207 GWh figure suggests. Total Island losses rise by 120 GWh from the 2019 Test Year, because the east–west export flow also offsets part of the traditional west–east flow to the Avalon Peninsula; Hydro's model run without exports isolates the export effect on the 2027 system.[111] Hydro reports that eliminating Maritime Link exports would reduce total Island losses by 41 percent, or about 134 GWh, worth approximately $5.4 million at 3.998 cents/kWh.[112] Limiting Maritime Link exports to Energy and Capacity Agreement deliveries, a 63 percent reduction in those exports, would reduce losses by 39 percent, so nearly all of the incremental losses are associated with market exports rather than with Nova Scotia Block deliveries, although Hydro states that losses do not vary linearly with exports.[113] Hydro states that no costs to which clause 3(a) of Order in Council OC2013-343 applies are included in its cost of service.[114] Whether lost monetization caused by losses on exports made for the benefit of Muskrat Falls Corporation falls within that clause is a legal question for the Board.

These amounts are small relative to the $797.7 million Test Year revenue requirement, and with Newfoundland Power on the capped rate path through 2030 they do not change near-term rates. *We recommend that Hydro report, in its next general rate application, the Island transmission losses attributable to Maritime Link flows, apportioned among Nova Scotia Block deliveries, monetized NLH Deferred Energy, and other Residual Block exports, and state whether the point-to-point transmission rate paid for Maritime Link exports compensates for those losses.*

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[107] See CA-NLH-314(a).

[108] See IIC-NLH-015(g), Table 3.

[109] See NP-NLH-150; IIC-NLH-015(g); NP-NLH-067.

[110] See CA-NLH-082(a).

[111] See Volume II, Exhibit 4, p. 3; Volume I, Schedule A-I. Schedule A-I reports losses of 206.9 GWh in the 2019 Test Year and 327.3 GWh in the 2027 Test Year.

[112] 41 percent of 327.3 GWh is 134.2 GWh; at $39.98/MWh, 134.2 GWh is $5.37 million. See CA-NLH-314(a); PUB-NLH-036(d).

[113] See PUB-NLH-036(d). 39 percent of 327.3 GWh is 127.6 GWh, compared with 134.2 GWh with no Maritime Link exports.

[114] See CA-NLH-314(b).

II. Assessment of Long-Term Supply Cost Variance Deferral Account

Hydro proposes a new deferral account to record differences between forecast and actual supply costs, and to share each difference among classes using a mix of demand and energy measures. The account would classify supply-cost variances between demand and energy using the approved cost-of-service classifications and allocate those amounts among Newfoundland Power, Island Industrial, and Rural Island Interconnected. We consider the basic demand-and-energy framework defensible, but several implementation choices require modification because they either depart from the cost-of-service study or do not match the stated cause or valuation of the variance.[115]

Finding 1: Each component of the account should be classified on the basis the Board approves for the corresponding Test Year cost or revenue.

Hydro proposes to classify each component of the LT SCVDA on the same basis as the corresponding cost or revenue in the Test Year cost-of-service study, so that amounts recovered in base rates and their later true-up are allocated consistently. PUB-NLH-088 asked Hydro why five components (the load variation, on-island and off-island purchases, net revenues from exports, wind purchases, and greenhouse gas credit revenue) are not classified as 100 percent energy-related, and Hydro answered with that principle.[116] We agree with the principle, which is also the basis for our recommendation in Section I.A that the Holyrood fuel component follow the minimum-output split. A variance corrects a Test Year amount. Classifying the correction differently from the amount it corrects would shift costs among classes whenever actual results depart from forecast, even if no class's cost responsibility had changed. *We therefore do not recommend classifying these components as 100 percent energy-related*.

Applied to those components, the principle has four consequences. First, the load variation and its export offset should carry the same classification; otherwise an offset that is exact in total would still leave a net amount for each class. Hydro classifies both on system load factor, and we agree.[117] That classification does not resolve the difference in valuation addressed in Finding 3. Second, on-island purchases other than wind, net revenues from exports, and greenhouse gas credit revenue follow

[115] See Application, Section 5.7; Exhibit 10; PUB-NLH-085.

[116] See PUB-NLH-088.

[117] See PUB-NLH-088(a), (c).

the classifications in the Test Year cost-of-service study and in Order Nos. P.U. 37(2019) and P.U. 14(2026), and we agree with Hydro's treatment of them.[118] Third, the wind component should follow the classification the Board approves for wind purchases in this proceeding. Under our recommendation in Section I.D, that classification is 22 percent demand and 78 percent energy, rather than the 43 percent and 57 percent Hydro proposes.[119] Fourth, off-island purchases should remain energy-related, the classification approved in the 2019 cost-of-service study. Hydro proposes system load factor because these purchases support firm capacity when they back up Muskrat Falls deliveries over the Labrador-Island Link. Hydro's stated rationale concerns backup over the Labrador-Island Link; it does not address purchases over the Maritime Link, and the 2027 Test Year includes no off-island purchases against which to test it.[120] *If Hydro considers a different classification warranted, it should propose one, with supporting evidence, in its next cost-of-service study*.

Finding 2: The proposed demand allocator does not align with the cost-of-service measure of demand.

The proposed demand allocator is not the coincident-peak allocator used in the cost-of-service study. Hydro proposes to use readily available billing-demand measures that are constructed differently across the three classes.[121] Hydro confirms that the allocator uses current-year billing demand for Newfoundland Power and Island Industrial and maximum peak demand for Rural Island Interconnected customers "instead of the coincident peak," and that class cost responsibility will differ to the extent the measures differ.[122] When asked about the alternative, Hydro stated that using a current-year coincident-peak allocator "would be consistent with the Cost of Service." Hydro chose billing demand because it is "readily available information that is easily verifiable," and it states that a demand-and-energy approach should not add substantially to the administrative burden if the demand allocators are readily available and verifiable. The strongest argument for the proposed billing-demand measure is that it captures changes between test years. That objective can

[118] See PUB-NLH-088(b), (c), (e).

[119] See PUB-NLH-088(d).

[120] See PUB-NLH-088(b). Hydro's schedule of LT SCVDA components records off-island purchases over the Maritime Link and the Labrador-Island Link on separate lines, with no amount in either for the Test Year. See PUB-NLH-084, Attachment 1. The 2019 classification is consistent with the convention that purchased-power energy charges are energy-related and demand charges are demand-related. See NARUC Manual, pp. 21, 35.

[121] A coincident-peak allocator measures each class's demand at the hour of the system peak, so it apportions costs caused by that peak. A billing-demand measure records each customer's own maximum demand, which need not fall at the system peak and is defined differently in each class's rate. Each peak-demand method in the NARUC Manual allocates demand-related production costs on class contributions to one or more system peaks; none uses billing demand. See NARUC Manual, pp. 41, 45–47.

[122] See CA-NLH-334; CA-NLH-335.

also be met by updating the cost-of-service demand measure with current-year determinants. *We therefore recommend using the cost-of-service coincident-peak measure*.[123]

Finding 3: The proposed account values load variances and the offsetting export revenue at different prices.

The account values firm load variances at the second-block energy rate. For Island Industrial, that rate is 8.889 cents/kWh from December through March and 3.285 cents/kWh from April through November, a load-weighted average of $51.12/MWh.[124] The offsetting change in export revenue is valued at an annual average price: the $39.98/MWh average export value Hydro uses to value export-related losses,[125] or the $39.88/MWh figure Hydro uses in its sensitivities.[126] Under the Muskrat Falls Power Purchase Agreement, the value of monetized NLH Deferred Energy is set by contract as the energy monetized multiplied by the Annual Average Sales Price, and Hydro confirms that load variances change regulated export revenue only when load is below the Base Block Energy.[127] Hydro's illustration of a 10 percent reduction in Island Industrial load records a load variation of $3,135,690 but an export revenue gain of only $1,144,599, because it values the gain at $39.88/MWh and counts as exported only the reduction in second-block sales.[128] Hydro's forecast monthly export prices span a much wider range. These are not interchangeable measures, particularly in winter, when the second-block price is 8.889 cents/kWh.[129]

[123] See PUB-NLH-086(a); PUB-NLH-087.

[124] See Application, Vol. III (Revision 1), Exhibit 10, § 8.0; PUB-NLH-130(e); CA-NLH-290, n. 5. Volume I instead describes the Island Industrial load variation as calculated using the average embedded cost of energy. See Application, Vol. I, ch. 5, § 5.7.5, p. 5.26. The existing SCVDA values the Island Industrial load variation at a single rate of 4.428 cents/kWh and the Newfoundland Power load variation at the seasonal wholesale second-block rates of 9.698 and 3.354 cents/kWh. See SCVDA Quarterly Report, pp. 11–12.

[125] See PUB-NLH-106(b).

[126] See CA-NLH-290, n. 3.

[127] See CA-NLH-042; IIC-NLH-021(a).

[128] See CA-NLH-290, Table 2.

[129] See PUB-NLH-088(a); IIC-NLH-003(a), Table 1.

TABLE 3: 2027 ENERGY VALUES USED IN THE RECORD

Valuation	2027 value
Average export value used to value export-related losses	$39.98/MWh
Average monetized-export value used in PUB-NLH-005 and CA-NLH-290 sensitivities	$39.88/MWh
Forecast monthly Salisbury export prices, including path charges	$23–$127/MWh (CAD), varying by month
Island Industrial second-block price used for load variances, load-weighted	$51.12/MWh; $88.89 winter; $32.85 non-winter

When load falls, the account recovers the lost revenue from customers at the seasonal second-block price but credits the resulting export gain at an annual average price; customers bear the difference through the account. Hydro's own premise is that the two variations "would offset each other based on volume if prices were consistent with the test year," and that supplying second-block load or exporting the energy "yields the same marginal value."[130] The Board approved the seasonal second block on the same premise, finding that it "would better align the variations in Hydro's energy revenues with its variations in export sales that result from variances in energy sales to Newfoundland Power."[131] Hydro's illustration does not produce that offset. In winter, the two prices differ by about 4.9 cents/kWh.[132] *We recommend approving the load-variation component only after Hydro states which price governs both sides of the variance and either values the load variance on the same basis as the export offset, which the Muskrat Falls Power Purchase Agreement fixes at the Annual Average Sales Price, or explains why customers should bear the difference. Hydro should also correct the description in Volume I. The separate $39.98/MWh and $39.88/MWh figures should also be reconciled.*[133]

Finding 4: The proposed carrying-charge rate is not aligned with the risk characteristics of the LT SCVDA balance.

Hydro proposes to accrue carrying charges at its approved 4.88 percent weighted average cost of capital rather than at short-term borrowing costs. Hydro's strongest argument is consistency with

[130] See PUB-NLH-056(d); CA-NLH-180(c).

[131] See Order No. P.U. 1(2025), p. 4.

[132] 8.889 cents/kWh less 3.998 cents/kWh is 4.891 cents/kWh. See PUB-NLH-106(b).

[133] Hydro describes $39.88/MWh as the average 2027 monetized export value and $39.98/MWh as the average value of exports in the 2027 Test Year. See CA-NLH-290, n. 3; PUB-NLH-106(b).

other regulatory balances and the fact that a long-lived account may remain outstanding for more than a year. Hydro's Application, however, states that LT SCVDA balances are "not expected to be material and fast-growing" and that the account will operate like the Rate Stabilization Plan, "where balances in the account are collected annually."[134] Hydro now describes the account as a standing mechanism similar to the Rate Stabilization Plan, which used the weighted average cost of capital, and states that the forecast annual extinguishment of customer-funded balances reflects the current management of rates rather than the design of the account.[135] Asked whether the balance carries prudence, forecast, or non-recovery risk comparable to rate-base investment, however, Hydro identified none, stating that its proposal "is not based on a quantified prudence, forecast, or non-recovery risk comparable to the risks associated with capital investments included in rate base."[136] A regulatory receivable or payable that is substantially lower-risk than rate-base investment should not automatically earn the same return as rate base. Hydro forecasts a short-term borrowing rate of 3.39 percent for 2027, falling to 2.69 percent by 2030, and estimates that financing a $100 million balance for a full year at the weighted average cost of capital instead of the 2027 short-term rate adds approximately $1.5 million to the revenue requirement.[137] For the $45.8 million balance Hydro describes as a reasonable annual expectation, accrued through 2027 and settled in March 2028, the weighted average cost of capital adds $292,259 compared with short-term rates; in 2023 the short-term rate applied to the SCVDA, 5.72 percent, exceeded the approved 5.43 percent weighted average cost of capital.[138] The Board adopted short-term borrowing costs for the existing SCVDA in Order No. P.U. 33(2021) because Hydro planned to finance the balance with short-term debt in the near term, and it later approved the weighted average cost of capital for the Electrification Cost Deferral Account in Order No. P.U. 33(2023). Hydro still uses short-term borrowing to manage timing differences between rate-mitigation receipts and supply-cost payments. The existing SCVDA accrues carrying charges at 3.35 percent, Hydro's 2025 short-term cost of borrowing, compared with the 4.88 percent weighted average cost of capital Hydro proposes for the LT SCVDA.[139] *We recommend retaining short-term borrowing costs for the LT SCVDA or using a rate matched to the expected duration of the balance.*[140]

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[134] See Application, Vol. I, ch. 5, § 5.7.6, p. 5.28.

[135] See CA-NLH-325(a).

[136] See PUB-NLH-093(b); CA-NLH-211(b).

[137] See PUB-NLH-142(e).

[138] See CA-NLH-191(c); CA-NLH-326, Attachment 1; PUB-NLH-093(a).

[139] Hydro's 2025 short-term borrowing costs were $14.5 million on a weighted average short-term debt balance of $431.3 million. The 2025 rate applies from January through November 2026 and is trued up to the actual 2026 rate in December. See SCVDA Quarterly Report, pp. 1, 15.

[140] See PUB-NLH-093(a), (c); CA-NLH-325(a); CA-NLH-063.

Hydro agrees that the Rural Rate Alteration is not a supply-cost variance and proposes to retain it in the LT SCVDA for administrative continuity. The Labrador Interconnected share is written off to Hydro's net income, and no portion is allocated to Island Industrial.[141] Hydro did not propose a treatment or disposition of the Rural Rate Alteration Account in this Application and will submit a proposal no later than February 2027.[142] *We do not see a need to create a separate mechanism solely for this item, but it should be reported as a separately identified subaccount so that a non-supply-cost item remains transparent within a supply-cost variance account*.[143] Hydro's quarterly SCVDA report shows the Rural Rate Alteration in a separate Utility Customer Balance; in the first half of 2026 the alteration totaled $12.9 million, of which $12.4 million was allocated to Newfoundland Power.[144]

Other design features warrant monitoring but are not necessary to the principal recommendation. One component of the account already has a ±$500,000 deadband, reflecting the principle that some cost-control incentive should remain.[145] Rate-mitigation funding shortfalls would accumulate in the account rather than immediately change rates.[146] Hydro estimates that, after the transfer of the Rural Rate Alteration balance approved in Order No. P.U. 15(2026), approximately $46 million of additional mitigation is required in 2027 to extinguish the existing SCVDA, for a total of about $251 million.[147] And the existing SCVDA will be extinguished rather than simply transferred.[148] These features reinforce the need for transparent reporting, but the central issues for this proceeding are the classification of the account's components, the demand allocator, the valuation of load variances, carrying charges, the Rural Rate Alteration, and the treatment of export-related losses.

Overall, we recommend approving the demand-and-energy framework in principle, classifying each component on the basis the Board approves for the corresponding Test Year cost or revenue, using the cost-of-service coincident-peak allocator for demand, retaining duration- and risk-matched carrying charges, separately reporting the *Rural Rate Alteration, and deferring the load-variance valuation until Hydro values both sides of the variance on the same price series. The treatment of*

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[141] See PUB-NLH-091.

[142] See NP-NLH-156.

[143] See PUB-NLH-091.

[144] See SCVDA Quarterly Report, pp. 4, 13.

[145] A deadband is a band of variance absorbed by the utility rather than passed through, so that the utility keeps an incentive to control the cost within that range. See CA-NLH-208; NP-NLH-102. In the existing SCVDA, the deadband applies to the Other Island Interconnected System supply cost variance, which combines the variations in thermal generation, off-island purchases, on-island purchases, and Corner Brook Pulp and Paper firm energy. See SCVDA Quarterly Report, p. 8.

[146] See PUB-NLH-105(c); PUB-NLH-092(b).

[147] See PUB-NLH-142(b). Hydro records the $45.0 million transfer from the Utility Customer Balance in May 2026. See SCVDA Quarterly Report, p. 4.

[148] See CA-NLH-336; PUB-NLH-094(b).

export-related losses should be resolved now because it affects both the cost-of-service study and the deferral account.

III. Assessment of Proposed Island Industrial Rates

Finding 1: The proposed Island Industrial rates must be recalculated to reflect the Board's cost-of-service and marginal-cost determinations.

The Board's cost-allocation decisions will change the proposed Island Industrial rates. Hydro proposes a new hours-of-use ("HOU") rate for Island Industrial customers. We review the merits of that structure separately, but the proposed rate cannot be evaluated in isolation from the cost-of-service and marginal-cost findings in this report. The rate design uses the Island Industrial class revenue requirement and marginal energy costs as direct inputs. If those inputs change, the resulting rates must change as well.

The first connection is the class cost split. Reclassifying Holyrood fuel, changing the classification or allocator for Holyrood non-fuel costs, or changing the wind classification changes the Island Industrial class cost of service. Those changes operate through different mechanisms and can have different magnitudes. For example, a more demand-related treatment of Holyrood fuel lowers Island Industrial's gross allocated cost because its share of coincident demand is lower than its share of annual energy. Hydro's recalculation of the minimum-commitment reclassification reduces the Island Industrial revenue requirement by $2,480,664.[149] Separately, allocating Holyrood's energy-classified costs based on commitment-period rather than annual energy also reduces Island Industrial's share, because Island Industrial accounts for a smaller share of energy consumption during the period when Holyrood operates. The wind classification has a substantially smaller effect. Whatever combination the Board ultimately approves, the class revenue requirement used to design the industrial rates should be recomputed from the approved cost-of-service study rather than carried forward from the filing.

The second connection is the marginal energy price. Hydro's proposed second-block prices are based on seasonal marginal energy costs. IIC-NLH-003(b), Table 2 reports weighted-average marginal energy costs of 8.889 cents/kWh in winter and 3.285 cents/kWh outside winter, which are the

[149] See PUB-NLH-168(d), Attachment 1.

proposed second-block prices.[150] The same seasonal prices value load variances in the LT SCVDA, while the offsetting export revenue is valued at an annual average price of $39.98/MWh or $39.88/MWh. The Board should avoid approving one price as the relevant marginal value for industrial rate design while allowing a materially different price to perform the same conceptual role in the deferral account without reconciliation.

The third connection is the treatment of export prices over time. The proposed industrial second block is priced using forecast export values, while differences between forecast and actual export-related values can flow through the LT SCVDA. Hydro states that this does not create double counting within the 2027 Test Year design as filed.[151] The remaining issue is sequence. Hydro is to file its methodology for updating the wholesale rate between test years by November 30, 2026, separately from the LT SCVDA allocation decision in this proceeding.[152][153] Because both mechanisms can expose the same customers to changes in export value, they should be coordinated so that the reset rule and the deferral account assign the same risk consistently.

The Board should first determine the cost-of-service classifications and allocators that govern Island Industrial's revenue requirement. It should then ensure that the marginal energy values used in the rate design are reconciled with the values used in the deferral account. The proposed industrial rate levels can then be recalculated using those approved inputs. This sequencing does not prejudge whether the hours-of-use structure itself should be approved; it ensures that any approved structure is built on the cost responsibility and marginal-cost determinations the Board adopts.

Accordingly, any final Island Industrial rate schedules should be filed after the cost-of-service and LT SCVDA decisions are incorporated. If the Board changes the Holyrood or wind classifications, the Holyrood energy allocator, or the marginal-cost basis relevant to the second block, Hydro should show the resulting change in the class revenue requirement and the recalculated rate elements rather than relying on the prices in the original Application.

[150] Hydro states that "No adjustments to these marginal costs are made." See CA-NLH-180(a).

[151] See PUB-NLH-056(d).

[152] See PUB-NLH-056(c).

[153] Order No. P.U. 1(2025) directed Hydro to file a methodology for updating the wholesale rate no later than its next general rate application or April 15, 2026. Order No. P.U. 13(2026) extended that deadline to November 30, 2026, after Hydro stated that the later filing would allow it to develop a framework applied consistently to the wholesale rate and to the proposed Island Industrial rate structure, including its marginal rate component. See Order No. P.U. 1(2025), p. 4; Order No. P.U. 13(2026), p. 2.

Finding 2: The proposed HOU rate improves marginal-cost price signals over the status quo, but several design refinements could strengthen cost reflectivity and incentives for efficient system utilization.

Hydro has proposed a material redesign of the Island Industrial Customer rate, with implementation proposed for July 1, 2027. The existing demand-plus-single-energy-rate structure would be replaced by an hours-of-use ("HOU") design with a lower demand charge, a revenue-recovery-oriented first energy block, and a seasonal second energy block intended to reflect Hydro's marginal opportunity cost of energy.[154]

Hydro has a reasonable basis for moving away from a single embedded-cost volumetric rate because average and marginal energy costs have diverged materially with the interconnection of Muskrat Falls, and the proposed HOU design improves efficiency by separating embedded-cost recovery from marginal-cost pricing. However, several aspects of the proposed implementation merit further consideration. The 300-HOU threshold appears to be driven primarily by bill impact and Block 2 access considerations rather than a demonstrated relationship to underlying system costs. Additionally, recovering a substantial share of embedded demand related costs through the volumetric Block 1 rather than a cost-based demand charge weakens the direct relationship between cost causation and the billing determinant used for recovery. Finally, based on the Christensen Associates Energy Consulting ("CA Energy") report, the current billing demand for the HOU rate combines Power on Order, current metered demand, and demand from previous billing periods. Therefore, billing demand is "sticky" and difficult to vary from month to month. This implies that customers' incentives to improve load factor will be muted, which undermines one of the primary premises of the HOU rate, as stated by Hydro. On the flip side, if the billing demand varies month to month, the inclining block structure can create an unintended consequence in winter months in which customers are incentivized to increase billing demand because doing so shifts consumption from the higher-priced Block 2 into the lower-priced Block 1. While the current definition of billing demand based on Power-on-Order limits this incentive in practice, this still raises the question of whether the proposed HOU rate provides the clearest and most cost-reflective means of achieving Hydro's objectives.

Below, we discuss Hydro's existing rate for Industrial Customers, its proposed HOU rates, and our assessment of the proposed rates.

[154] Newfoundland and Labrador Hydro (Hydro), 2026 General Rate Application, Volume I, Chapter 6, Section 6.7, pp. 6.17-6.25; Christensen Associates Energy Consulting (CA Energy), Pricing for a Revised Island Industrial Rate for Newfoundland and Labrador Hydro, May 11, 2026, Exhibit 17.

A. Hydro's Existing Rate Design for Industrial Customers

Hydro's existing rate is a flat volumetric energy rate with a demand charge and other specific customer charges. This design is intended to recover Hydro's embedded energy and delivery costs. Volumetric costs are recovered through a rate component that varies with volumetric consumption and demand-based costs are designed to be recovered primarily through a rate component that varies with a demand-based billing determinant. Both rate components reflect the average costs incurred by the system to serve. The billing demand used to charge industrial customers is based on Power on Order, which is the contracted, or firm, demand for each customer. There are currently six industrial customers that take service under this rate.

Under the existing rate, customers can consume energy beyond their contracted demand but only if there is available system headroom, which is referred to as "non-firm" service option. This additional energy consumption is charged at a marginal energy rate based on energy import costs to reflect underlying costs to procure this energy without the need to build the delivery system to accommodate this non-firm load.

This rate design, a volumetric energy rate with a demand charge, is quite common for large industrial customers. Price signals they provide for customers are straightforward and easy to understand. Customers can reduce the demand portion of their bill by reducing their maximum demand and can reduce the volumetric portion of their bill by reducing their volumetric load. Additionally, the current demand charge recovers around 61% of demand-driven costs, the rest of which is recovered from energy charges.[155]

One of the biggest weaknesses of this rate structure is that it is designed around the average energy cost. Hydro's unique generation portfolio, low-cost hydro paired with high cost imports and gas peakers, creates a system cost profile where average energy cost is not close to the marginal energy cost. This is a relatively recent occurrence because of the completion of the new 824 MW Muskrat Falls plant. This plant, along with new transmission links to the Island of Newfoundland, the Maritime provinces, and the northeastern United States, has increased embedded system costs driven by the additional capital investment. But it has also reduced marginal energy costs to reflect wider access to energy supply and external power markets. This means that a volumetric energy price that reflects the average embedded system costs does not create a price signal that aligns with the cost of serving an incremental load: in winter months, where peaker plants are operational to serve marginal load, the rate is too low and in months where all energy is served through low-cost hydro, the rate is too

[155] Current demand charge is $10.73/kW-month and Hydro's 2027 Test Year Cost of Service Study estimates demand related costs are $17.54/kW-month. Newfoundland and Labrador Hydro, 2026 General Rate Application, ch. 6, § 6.7.1, p. 6.20.

high. This creates price signals that may not reflect the cost of incremental consumption and leads to suboptimal consumption decisions.

B. Hydro's Proposed Rate Design for Industrial Customers

Hydro is proposing to move their industrial customer base to a new rate with a lower demand charge, a volumetric hours-of-use charge, and any other customer charges are kept as-is. See Table 4.

Structurally, the hours of use charge functions as a block rate: customers pay a per-kWh price for the first block and a different price for all usage beyond that block. Rather than a fixed kWh-based threshold applied to each customer, each customer's usage billed in the first block is based on their billing demand and the hours-of-use threshold established in the rate. For example, under the 300 hours-of-use threshold proposed by Hydro, a customer that uses 10,000 kWh in a month and has a billing demand of 25 kilowatts ("kW") would have 7,500 kWh (25 kW * 300 hours-of-use) billed under Block 1 and the remainder of their usage billed under Block 2. Any customer whose volumetric usage is less than 300x of their billing demand (i.e., the hours-of-use threshold) would have all their consumption billed under Block 1.

TABLE 4: HYDRO'S EXISTING AND PROPOSED RATE DESIGN

Rate component	Existing	Proposed
Demand charge	$10.73/kW-month	$5.50/kW-month
Firm energy	4.428 cents/kWh	Replaced by two-block energy rate
Block 1 Energy	-	6.694 cents/kWh
Block 2 - Winter (Dec.-Mar.)	-	8.889 cents/kWh
Block 2 - Non-winter (Apr.-Nov.)	-	3.285 cents/kWh
HOU block boundary	-	300 hours of use

An hours-of-use design is typically used to incentivize high load factors and better utilization of the system particularly when the second block rate is lower than the first block. Customers are incentivized to reduce their peak demand to shift as much of their volumetric energy as possible into a block of usage with a lower volumetric rate. Hours-of-use rates, as with any declining block rate, have weaker price signals to reduce volumetric consumption because average costs per kWh decrease as customers use more energy.

There are a few key components unique to Hydro's hours-of-use rate design:

- Hydro is proposing a flat energy charge for Block 1 that generally aligns with average embedded system costs and a seasonally variable energy charge for Block 2 that aligns with the marginal cost to provide energy. The demand charge is designed to cover only 31 percent of the demand related costs while the remaining 69% of the demand related costs for industrial customers will be recovered under the Block 1 volumetric component.[156]
- Rate levels are established by first setting the demand charge to $5.50/kW-month to align with the demand charge applied to Newfoundland Power. Then, Block 2 rates are set using seasonal marginal energy costs based on the opportunity cost of exporting energy. Finally, Block 1 rates are set to recover the remaining revenue requirement.[157]
- Block 1's threshold is designed so that most customers in most months have volumetric usage that spills into Block 2. This helps to ensure they are exposed to the marginal cost of electricity set in Block 2.
- Customer billing demand is based on the Power on Order. This results in consistent cost recovery and ensures fixed delivery costs continue to be recovered even if a customer has a low demand in a given month. However, this also implies that the incentives for customer to reduce their demand, and benefit from the HOU rate by quickly accessing the Block 2 prices is also limited.
- The non-firm component of the existing rate is carried over so that customers can still procure non-firm energy at marginal rates beyond their contract demand levels if there is available system capacity.
- The hours of use rate has a number of benefits, particularly compared to the existing rate that it would replace consisting of a flat volumetric energy charge plus a demand charge. More specifically:
- Hydro has a large divergence between the cost it must recover from customers on average and the opportunity cost of additional volumetric consumption. A single, static volumetric rate cannot simultaneously recover embedded costs and provide the correct marginal price signal, whereas the HOU structure can improve upon. The hours-of-use design bifurcates the recovery of revenue into two buckets to ensure cost recovery and provide marginal price signals at the same time. The marginal cost design of the new rate encourages better use of the electricity system by exposing customers to a higher cost for energy when underlying costs are high and vice versa. In particular, the seasonal design of the marginal rate provides a key temporal seasonal signal for customers in a system that is winter peaking.

[156] Newfoundland and Labrador Hydro, 2026 General Rate Application, ch. 6, § 6.7.1, p. 6.20.

[157] Newfoundland and Labrador Hydro, 2026 General Rate Application, ch. 6, §§ 6.7.1–6.7.3, pp. 6.20–6.21

- Overall, the revenue requirement recovered across all industrial customers does not change so there are no cost-shifts onto other customer classes, namely Newfoundland Power and Rural Island Interconnected customers. There are, however, intra-class cost shifts designed to better align customer bills with the costs each customer imposes on the system. ; Christensen Associates Energy Consulting ("CA") finds in their report prepared for Hydro that both the current and proposed HOU rates recover revenues from individual customers that are broadly consistent with their allocated cost to serve, with all customer revenue-to-cost ratios between approximately 0.90 and 1.05.[158] A revenue-to-cost ratio of 1.0 indicates that revenues collected from a customer exactly equal its allocated cost to serve, a ratio below 1.0 indicates under-recovery, and a ratio above 1.0 indicates over-recovery.
- Based on CA analysis, no customer experiences large annual bill changes greater than 5% because of the new proposed rate design[159]. Compared to the existing rate, CA estimates that the proposed rate will result in winter bills increasing 24.7% and non-winter bills decreasing by 12.1% creating seasonal bill volatility.[160]
- If customers respond to price signals as intended, lower marginal rates during Block 2 non-winter hours may lead to increased usage and can improve utilization of the system ultimately helping to reduce costs overall.

While HOU improves upon the existing rate design in several dimensions, it is not entirely consistent with cost-reflectivity, a foundational rate design principle. Below, we reproduce the well-established rate design principles[161] we will use to evaluate the HOU rates for Island Industrial Customers:

- **Cost-causation/Cost reflectivity**: Rates should reflect the costs customers cause the utility to incur and should fairly apportion the cost of service among customers and classes. This is usually the foundational principle.
- **Revenue sufficiency**: The overall rate structure should provide the utility a reasonable opportunity to recover its authorized revenue requirement and maintain financial viability.
- **Equity**: Similarly situated customers should be treated consistently, costs should be allocated fairly among customer classes, and rates should avoid inappropriate cross-subsidization or undue discrimination.

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[158] Christensen Associates, Pricing for a Revised Island Industrial Rate (May 11, 2026), p. 19, Table 10

[159] Christensen Associates, Pricing for a Revised Island Industrial Rate (May 11, 2026), pp. 18–19, Table 9

[160] Christensen Associates, Pricing for a Revised Island Industrial Rate (May 11, 2026), pp. 18–19, Table 11

[161] Ryan Hledik, Sanem Sergici, Sai Shetty, and Peter Cappers, Deliberate Design: Creating Electricity Rates with Purpose (January 2025), https://www.brattle.com/wp-content/uploads/2025/01/Deliberate-Design-January-2025.pdf.

- **Simplicity**: Customers should be able to understand the rate and respond to it, and the rate should be practical for the utility to administer.
- **Bill Stability/Gradualism**: Ensure that bills do not fluctuate materially during bill transitions

Assessment with respect to the cost-reflectivity principle

The hours-of-use rate combines volumetric and demand-based cost recovery in a volumetric rate component. This makes it harder to target volumetric reductions or peak demand reductions individually as needed by the system. Hydro alleviates this in part by designing the threshold to be low enough so that most customers in most months would shift some of their usage into Block 2.

The HOU rate sets the demand charge at $5.5/kW-month, almost one third of the actual cost of service implied levels. By recovering some of the demand related costs through volumetric Block 1 energy price, the efficiency of the price signals gets diluted and the relationship between cost causation and customer price signal becomes less direct. This makes it harder for customers to understand how peak and volumetric reductions directly translate into bill savings. Moreover, a billing demand based on Power on Order, which remains relatively stable across the year, undermines the incentives to improve load factors and active management of the customer demand.

There is no intra-day temporal rate component. This means that a customer whose usage peaks in overnight hours will pay the same as a customer whose usage peaks during the system peak despite very different impacts on system costs. This does not align with cost causation principles, nor does it incentivize customers to reduce their consumption during periods of high energy costs.
There are a few other design elements of Hydro's hours-of-use rate that undermines its cost-reflectivity:

DETERMINATION OF THE BLOCK 1 THRESHOLD

The 300 hours-of-use Block 1 threshold is established because it results in most customers experiencing usage spilling over into Block 2 most of the time. This is an important goal, but there is no discussion around why a smaller number of hours-of-use couldn't be used instead. A smaller number would allow all customers in all months to move into Block 2.

Additionally, the threshold at which customers move from embedded system costs to marginal energy costs has no relationship with the underlying energy supply and may not align with the energy costs Hydro pays to serve that energy. If low-cost hydro energy is plentiful and customers are moved onto a rate that reflects an export opportunity cost too quickly, this will not result in an economically efficient level of energy consumption.

LACK OF SEASONALITY IN BLOCK 1 RATE

CA report notes that seasonal Block 1 rates are not a commonly accepted approach to recover demand related costs and does not recommend Hydro implement one.[162] However, establishing seasonally varying Block 1 rates would reflect each season's contribution to system capacity needs and is more cost reflective. We have seen examples of this in other jurisdictions. For instance, Evergy Missouri Metro's General Service rates and Arizona Public Service General Service rates all have hours use designs with seasonally varied rates for all blocks including Block 1.[163] While this would create greater seasonal bill swings, it would further improve cost reflectivity, especially when utility costs have a significant seasonal component. Hydro's 2024 Marginal Cost of Service Study shows strong seasonality in capacity costs: winter accounts for 95 percent of annual marginal capacity cost. More importantly, using a single annual cost produces an average embedded cost for Block 1 that is below the marginal cost in winter months, as discussed below. This is the most concerning aspect of the current design.

WINTER INCLINING BLOCK RATES

The proposed rate has a declining block rate structure in the non-winter months, meaning that the Block 2 rate is lower than Block 1 rate. This incentivizes improved load factor to "move load" as quickly as possible into the second block with a lower rate. This is how a typical hours-of-use rate functions.

In the winter months, however, the opposite is true. Block 2 rate is greater than the Block 1 rate, following an inclining block rate structure. In this case, improved load factor and moving more of the load into the second block will not be beneficial for the customers. This implies that this inclining block structure reduces a customer's incentives to better utilize the system because there is no benefit to having more volumetric load charged under Block 2.

HYDRO'S PROPOSED BILLING DEMAND DILUTES THE LOAD FACTOR PRICE SIGNAL THAT IS CENTRAL TO AN HOURS-OF-USE DESIGN

Hydro uses a combination of values to determine billed demand under the current rate including metered demand, Power on Order for the current year, and Power on Order for the prior year. This is

[162] Christensen Associates, Pricing for a Revised Island Industrial Rate (May 11, 2026), p. 5; Newfoundland and Labrador Hydro, 2026 General Rate Application, ch. 6, p. 6.21.

[163] Evergy Missouri Metro, P.S.C. MO. No. 7 – Electric Tariff, available at: https://www.evergy.com/-/media/documents/billing/missouri/detailed_tariffs_mo/mo-metro-rate.pdf and Arizona Public Service (APS), Rates, Schedules and Adjustors – Business, accessed October 5, 2026, available at: https://www.aps.com/en/Utility/Regulatory-and-Legal/Rates-Schedules-and-Adjustors#Business

a relatively stable metric for billing demand and we understand that Hydro proposes to use the same billing demand for the HOU rate.

One of the key benefits to an hours-of-use rate is to incentivize lower peak demand through the use of declining block rates that shift faster with higher load factor. However, under the proposed hours-of-use rate, if a customer's billing demand is defined similar to that of the existing rate, it would make the movements from Block 1 to Block 2 more difficult and undermines one of the key price signals an hours-of-use rate depends on to encourage better system utilization. In other words, "stickiness" of the billing demand will mute incentives to improve load factor and will make it harder to take advantage of the Block 2 marginal prices.

WINTER DEFINITION MAY NEED TO BE REVISED

Hydro's monthly load-weighted marginal costs place March closer to the non-winter months than to the rest of the winter: $127.69/MWh in January, $100.62 in February, $87.17 in December, and $43.44 in March, compared with $47.55 in July and $44.67 in November.[164] Hydro includes March because system peaks can occur then; its table lists March peaks in five winters since 1985–86, the most recent in 2014–15.[165] This implies that March carries capacity risk, and the risk belongs in a capacity charge, not in the energy price. While we understand Hydro kept December–March definition for consistency with the Newfoundland Power rate, we recommend a re-evaluation for both rates.

Assessment with respect to other rate design principles

Above, we have analyzed the proposed HOU rate with respect to the cost-reflectivity principle. It is also important to evaluate it with respect to other principles to ensure that there are no major implications for these other principles:

REVENUE SUFFICIENCY

The HOU structure appears capable of being designed to recover the Island Industrial class's approved revenue requirement because Block 1 is intended to recover remainder of the embedded costs, after Block 2 recovers marginal energy costs and demand charge recovers a fraction of the demand related costs. Another important consideration is that the final rates be recalculated after the Board resolves the underlying cost-of-service classifications and allocators as discussed earlier in our report, because changes to those inputs change the class revenue requirement that the rate must recover.

[164] See PUB-NLH-132(b).

[165] See IIC-NLH-028(a).

EQUITY

The HOU rate can improve equity if it better aligns customer charges with cost causation, particularly by distinguishing between embedded-cost recovery and the marginal cost of incremental energy use. However, equity depends on the accuracy of the underlying class cost allocation and on whether the Block 1 threshold and billing-demand rules avoid creating advantages or disadvantages unrelated to actual cost responsibility. We have suggested several considerations for cost-causation; addressing those cost-causation related considerations will also help improve equity in this proposed rate design.

SIMPLICITY

The HOU design is more complex than the existing rate because customers must understand multiple blocks, seasonal prices, and the interaction between billing demand and the 300-hour Block 1 threshold. That complexity is manageable for sophisticated industrial customers, but the rate should define the billing-demand determinant and block calculations very clearly to avoid ambiguity.

BILL STABILITY

The HOU rate may reduce bill stability relative to a flatter structure because winter Block 2 prices are materially higher than non-winter prices, making bills more sensitive to seasonal usage patterns. At the same time, tying Block 1 to billing demand can moderate some volatility, although the precise effect depends on how Power on Order, measured demand, and any demand ratchets interact with the block calculation.

C. Recommendations

Our assessment is that the HOU rate generally achieves its intended objectives; however, several refinements could improve cost reflectivity and provide more efficient price signals. We offer four recommendations: three involve modifications to the proposed HOU rate, while the third presents an alternative rate design that would achieve the underlying objectives through a different approach.

Adjust the hours-of-use rate with a larger demand charge

First step is to create a demand charge that fully recovers all demand-related costs. This design alleviates issues with an hours-of-use rate design in which the demand-related costs are recovered through a volumetric energy charge. The demand charge can be based on contract demand or could be designed around coincident peak demand (i.e., a time block during the day that aligns with the system peak) to provide a stronger price signal for customers to reduce peak demand during these periods of high system load. Removing all demand-related costs from the hours-of-use component

still preserves the bifurcated price signal associated with embedded energy costs and marginal energy costs. Additional analysis is important to evaluate the impacts on customer bills.

Create a seasonally varying Block 1 rate

This refinement may help to reduce the inclining block structure observed in winter months for Block 2 rate (relative to Block 1 rate) because a larger share of embedded costs are driven by winter system use. As was evidenced by Hydro's 2024 Marginal Cost of Service study, there is strong seasonality in Hydro capacity costs, with winter accounting for 95% of the annual capacity costs. CA report notes that seasonal Block 1 rates are not a commonly accepted approach to recover demand related costs and do not propose implementing one here.[166] However, establishing seasonally varying Block 1 rates would reflect each season's contribution to system capacity needs, is more cost reflective, and we have seen examples of this in other jurisdictions. It would create greater seasonal bill swings, but when utility costs vary meaningfully between season as is the case for Hydro, creating a similar signal within industrial rates is not unrealistic.

These two refinements would improve the cost reflectivity of the HOU rate and mitigate some of the unintended consequences discussed above, including the reduced incentive to improve load factor during the winter months. With these refinements, the volumetric energy charges would recover only energy-related costs, while the demand charge would recover demand-related costs, providing more economically efficient price signals. Introducing seasonality into the Block 1 energy rate would further improve alignment with seasonal cost differences and could result in the winter Block 2 rate being lower than the winter Block 1 rate, thereby restoring an incentive to improve load factor.

The resulting rate design would place greater emphasis on the demand charge, which would operate independently of the volumetric energy charges, while preserving the distinction between embedded lower-cost energy and marginal higher-cost energy. One potential drawback is greater seasonal variation in customer bills. This effect could be managed through advanced communication with customers so that they understand and can plan for the expected pattern of higher winter and lower non-winter bills.

Revisit the design of the billing demand in the HOU rate

Under the proposed HOU rate, billing demand is largely determined by the customer's Power on Order, which is relatively fixed and difficult for customers to influence in the near term. While this approach provides Hydro with greater revenue stability and predictability, it also weakens the incentives the HOU rate is intended to create for customers to improve their load factors and benefit

[166] Christensen Associates, Pricing for a Revised Island Industrial Rate (May 11, 2026), pp. 5, 18

from the lower marginal energy prices in Block 2, particularly during non-winter months. Because the Block 1 energy threshold is directly tied to billing demand, customers have limited ability to influence the allocation of their energy consumption between the two blocks through changes in their operating patterns. Moreover, the use of a relatively fixed billing-demand determinant may limit the extent to which customers can realize bill savings from reducing their peak demand, thereby weakening incentives for more efficient utilization of the system.

If one of Hydro's primary objectives in introducing the HOU rate is to encourage higher load factors and more efficient use of existing capacity, Hydro should consider adopting a more dynamic and less persistent ("sticky") billing-demand definition that more closely reflects customers' actual demand. Such an approach would strengthen the relationship between customers' operating decisions and their electricity bills, providing more actionable price signals. However, any modification should balance these efficiency benefits against the potential for increased revenue volatility and the need to ensure adequate recovery of demand-related costs.

Design a seasonal volumetric rate with a two-part demand charge

We understand that Hydro intends to achieve two key goals with the proposed HOU rate: 1) expose industrial customers to the marginal energy prices which are drastically different between winter and non-winter seasons, and 2) do this in a way to incentivize improved load factor/utilization of the system.

As we discussed above, while the proposed HOU represents an improvement over Hydro's current rate design, it is still not entirely cost reflective. We propose the Board consider an alternative rate design, which is more cost reflective than the proposed HOU, and addresses the incentive problems discussed above. This rate is a seasonal volumetric rate with a two part demand charge: a coincident peak demand charge which would be effective only in the winter months, and a non-coincident demand charge which would be effective in all months. This three-part seasonal rate separates embedded demand-cost recovery from volumetric energy pricing, applies marginal-cost pricing to winter energy when system costs are highest, and sets the non-winter energy charge to recover the remaining class revenue requirement. More specifically:

- **A non-coincident peak (NCP) demand charges** recovers customer-specific transmission connection costs and is applicable year around.
- **A coincident peak (CP) demand charge** recovers system peak-driven generation/transmission costs.
- **Winter energy** is priced at marginal energy cost, preserving the strongest efficiency feature of Hydro's HOU proposal.

- **Non-winter energy** is then set residually so that the rate as a whole recovers the remaining embedded revenue requirement after accounting for revenue recovered through the demand charges and winter energy charge.

This approach preserves a strong marginal price signal precisely in the season when incremental consumption is most costly, while avoiding the HOU rate's use of a block threshold to separate embedded and marginal energy. It also eliminates the winter distortion discussed above, because customers would no longer be able to move usage between a lower-priced Block 1 and higher-priced Block 2 by changing the billing-demand determinant.

Hydro indicates that it did not pursue a coincident-peak charge because customers may have limited visibility into when the system peak will occur, and because billing demand would be set after the peak occurs.[167] However, Hydro can mitigate this concern by defining a fixed peak window in winter months during which each customer's maximum demand would set its coincident-peak billing demand. Customers can try to reduce their maximum demand within this peak window, and do not need to know exactly when the system peak occurs.

IV. Premise of Standby Rates

Standby rates are designed for customers with on-site generation whose relationship with the grid differs materially from that of a conventional full-requirements customer. A customer may normally supply all or part of its own requirements and therefore purchase relatively little energy from the utility, while still relying on the utility to maintain sufficient capability to serve the customer's load when its generation is unavailable because of planned maintenance or an unplanned outage. The central rate-design challenge is that low routine grid consumption does not necessarily imply a correspondingly low cost of providing reliable service. The utility may still need generation and transmission capability available to serve the customer's potentially significant demand when self-generation is unavailable. The standby-rates therefore distinguish between the customer's reservation of utility capability and its actual use of the system.

A well-designed standby rate seeks to ensure that these customers pay the costs associated with maintaining grid service for them without discouraging economically efficient self-generation. This follows the broader principle of cost causation: rates should recover costs through the billing

[167] See PUB-NLH-128(c).

determinants that cause those costs. This could be achieved by recovering capacity costs through demand charges and energy costs through volumetric charges. Customers with self-generation may impose capacity costs despite lower energy purchases, and rates should recover those costs while limiting cost shifts to other customers.

This is different from Hydro's proposed HOU rate or the three-part seasonal rate considered elsewhere in this report. Those are alternative ways of designing rates for ordinary Island Industrial service. *A standby rate would instead apply only to an industrial customer whose self-generation materially changes how it relies on Hydro's system and who satisfies defined eligibility requirements.*

<u>Finding:</u> A separate standby rate is not warranted under Hydro's current interruptible backup-service arrangements but may be appropriate for industrial customers with self-generation that require firm backup capacity.

A. When a Standby Rate Would Apply

For purposes of Hydro's Island Industrial customers, we would distinguish two potentially eligible circumstances.

A **standby customer** would normally meet essentially all of its electricity requirements with on-site generation and rely on Hydro principally when that generation is unavailable because of scheduled maintenance or an unexpected outage. The customer therefore purchases relatively little energy from Hydro during normal operation but requires Hydro to stand ready to serve potentially a large portion of its load when its generating equipment is unavailable. This corresponds directly to the standby-service definition in the materials provided.

A **partial-requirements or supplementary customer** would use its own generation to meet a portion of its load on an ongoing basis and normally purchase the balance from Hydro. When its generator becomes unavailable, its purchases from Hydro increase to replace the lost self-generation. Although such a customer is more regularly connected to and supplied by Hydro, the relevant standby requirement is the additional capacity Hydro must be capable of providing when the customer's generator is unavailable. Standby and supplementary customers can impose similar capacity requirements on the grid and therefore can appropriately be subject to similar rate structures.

Accordingly, the relevant eligibility criterion should be the customer's reliance on material on-site generation as part of its normal supply arrangement, rather than simply ownership of a generator. Emergency generators used only when normal utility service fails should not qualify, because they do not reduce the capacity Hydro must normally provide to the customer.

Hydro reports that Corner Brook Pulp and Paper used Generation Outage Power once in ten years and that service is supplied at interruptible rates.[168] Interruptible service drives no generation investment because it is excluded from the system peak used for planning; therefore this customer did not introduce additional capacity costs for the Hydro system.[169] We agree with the CA Energy, who expressed the view that a standby charge is not necessarily warranted here where capacity beyond Power on Order is supplied on an interruptible basis and the rate recovers the associated costs.[170]

B. Potential Standby Rate Design for Hydro

If and when a standby rate is merited for Hydro's industrial customers, a potential Hydro standby rate could retain the underlying rate design otherwise applicable to Island Industrial customers but add rate components that separately recognize the capacity Hydro must reserve and the customer's actual use of Hydro's system when self-generation is unavailable. The structure could have three principal elements.

Generation and Transmission Reservation charge. An eligible customer would pay a year-round $/kW-month charge for the amount of capacity Hydro must stand ready to supply when the customer's generation is unavailable. For a customer whose generation normally supplies its entire load, the reservation quantity could be based on the customer's expected maximum demand during an outage or maintenance event. For a partial-requirements customer, the relevant reservation quantity could generally correspond to the capacity supplied by its self-generation, and therefore the incremental demand that could return to Hydro when that generation is unavailable. This could be structured as observed maximum demand for a self-sufficient standby customer and generator size for a partial-requirements customer. The reservation charge could recover the generation and transmission capacity costs attributable to Hydro maintaining reliable backup service. Any customer-specific transmission connection costs could instead be addressed through the transmission component of Hydro's rate, depending on how those costs are classified in Hydro's cost-of-service study.

As-used demand charge. When the customer actually takes service from Hydro, an additional demand charge could apply to measured demand. This component would recover demand-related costs associated with the customer's actual use of shared system facilities rather than the mere reservation of capacity. Generation and transmission as-used demand charge recovers generation

[168] See PUB-NLH-135(b).

[169] See IIC-NLH-035(a); Volume I, § 6.7.6.

[170] See PUB-NLH-136(a).

and transmission demand costs not recovered through the reservation charge and applies the charge to measured demand during a defined peak window. For Hydro, the billing determinant should ultimately be aligned with the generation and transmission cost drivers identified in Hydro's cost-of-service study.

As-used energy charge. Energy actually supplied by Hydro would also be subject to a volumetric charge. Consistent with the broader industrial rate-design work, that charge could reflect the seasonal and marginal cost of supplying energy, particularly given the significant difference between winter and non-winter marginal energy costs identified in Hydro's Application.

The resulting framework would therefore be relatively straightforward: a reservation charge for the generation and transmission capability Hydro must maintain for the customer, an as-used demand charge reflecting the customer's actual use of capacity when taking service, and a seasonal as-used energy charge for electricity actually supplied. This structure would not replace the HOU or three-part seasonal rate for ordinary industrial customers. Rather, it would provide a separate cost-reflective framework for the subset of customers whose self-generation materially reduces their normal purchases from Hydro while leaving Hydro with an obligation to stand ready to serve them.

V. Conclusion

The cost-of-service record identifies several places where the measure used in the Application does not match the cost or reliability quantity being measured. Because the proposed Island Industrial rate is built from the class cost allocation and marginal energy costs, the Board’s decisions on those inputs must be reflected in the final rate design.

For the 2027 Test Year, the Board can resolve several matters on the existing record: the minimum-output treatment of Holyrood fuel and non-fuel costs, the commitment-period allocation of Holyrood energy-classified costs, separate treatment of Holyrood Unit 3 (transmission functionalization of its operating costs in the months it operates as a synchronous condenser), the classification of LT SCVDA components, use of the cost-of-service coincident-peak allocator in the LT SCVDA, and the carrying-charge principle. Other matters require a focused additional filing rather than a new methodology exercise, principally the average ELCC of the existing wind fleet on the Test Year system, and the reconciliation of the energy prices used in the LT SCVDA. The compliance filing should also reflect the tested curtailable capacity of the MUN boilers and apply Hydro’s stated mitigation rule consistently. Hydro should report, in its next general rate application, the transmission losses attributable to Maritime Link flows by export category.

We conclude that Hydro's proposed HOU rate represents a meaningful improvement over the existing Island Industrial rate design by introducing seasonal marginal energy price signals while preserving the recovery of embedded costs. However, several features of the proposed design could be refined to improve cost reflectivity and encourage more efficient utilization of the system. In particular, recovering a substantial portion of demand-related costs through volumetric energy charges weakens the relationship between cost causation and customer price signals, while the winter inclining-block structure and relatively inflexible billing-demand definition undermine the incentive to improve load factor. We recommend that Hydro consider increasing the demand charge to recover a greater share of demand-related costs, introducing seasonal Block 1 energy prices, and revisiting the billing-demand definition. We also recommend consideration of an alternative three-part seasonal rate that separately recovers customer-specific transmission connection costs, system peak-driven costs, and energy costs. This alternative could provide more direct and economically efficient price signals while maintaining revenue sufficiency.

We also considered the applicability of standby rates for Island Industrial customers with on-site generation. We find that a separate standby rate is not warranted under current arrangements, where backup power is provided on an interruptible basis without requiring Hydro to maintain additional firm capacity. However, if customers require firm backup service in the future, a standby rate with reservation and as-used charges could ensure appropriate cost recovery while avoiding cost shifts to other customers.