

1 Q. **Reference: PUB-NLH-061; Island Industrial rate design**

2 Please quantify the amount of fixed or demand-related 2027 costs recovered from Island
3 Industrial Customers through the proposed demand charge and through Block 1 energy charges,
4 respectively, and quantify the reduction in recovery of those fixed or demand-related costs
5 resulting from a 10% and 25% reduction in Island Industrial energy requirements with billing
6 demand unchanged.

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9 A. *This response was provided by Christensen Associates Energy Consulting.*

10 The 2027 demand-related revenue requirement allocated to the Island Industrial class is
11 \$19,218,192, based on the billing data of Newfoundland and Labrador Hydro (“Hydro”) for this
12 general rate application. This amount, and other data pertaining to the calculation of revenue
13 requirements, appear in the table on the next page in the column labeled “Base”. Using this
14 data, it is possible to calculate how much of the demand-related revenue requirement is
15 recovered under the proposed rate design. \$6,025,800 is recovered through the demand
16 charge, while the remaining \$13,192,392 in demand-related costs are recovered through the
17 Block 1 energy charge. (Please see the rows labeled “Cost Recovery in DC (Demand Charge)” and
18 “Cost Recovery in EC (Energy Charge)”.) Note that the Block 1 energy costs to be recovered are
19 the energy-related unit costs applied to the full energy consumption less the revenues from
20 Block 2 energy.

21 The product of unit costs and billing quantities in the Base column yields embedded costs. The
22 demand-related costs are split, for cost recovery purposes, as described above. By design,
23 revenues match embedded costs, yielding the prices of the rate design.

24 Because demand is assumed not to change despite reductions in energy consumption of 10%
25 and 25%, the demand-related revenue requirement remains constant in these scenarios. The
26 third and fourth columns of table provide information paralleling the Base case for these

scenarios. Total costs decline as consumption declines, with all cost reductions taking place in the energy-related component, by assumption. Revenues decline by more than embedded costs, leading to an *apparent* conclusion that the rate would result in under-recovery of revenues in the event of consumption declines. Under the assumption that demand costs are unaffected by the consumption reduction, it requires a further assumption to conclude that full demand cost recovery occurs in Block 1 energy charge (in addition to the demand charge), and the entire revenue shortfall can be seen as under-recovery of energy-related charges. From the utility's perspective, though, all that matters is the extent of the under-recovery, as there are no cost allocation implications to be drawn from the outcome.

	Base	10% Reduction	25% Reduction
Unit Costs			
Energy	\$0.0378		
Demand	\$17.54		
Billing Quantities			
Energy	613,371,340	552,034,206	460,028,505
Demand	1,095,600	1,095,600	1,095,600
Embedded Costs			
Energy	\$23,182,375	\$20,864,138	\$17,386,781
Demand	\$19,218,192	\$19,218,192	\$19,218,192
Cost Recovery in DC	\$6,025,800	\$6,025,800	\$6,025,800
Cost Recovery in EC	\$13,192,392	\$13,192,392	\$13,192,392
Total	\$42,400,567	\$40,082,330	\$36,604,973
Revenues			
Energy: Block 1	\$21,845,846	\$21,753,146	\$21,566,906
Energy: Block 2	\$14,528,921	\$11,439,006	\$6,860,442
Demand	\$6,025,800	\$6,025,800	\$6,025,800
Total	\$42,400,567	\$39,217,953	\$34,453,148
Net Revenue	\$0	-\$864,377	-\$2,151,825

The challenge for the utility is how to interpret the changes in revenues and costs. Are these shortfalls a realistic reflection of the financial implications to the utility? An alternative, and perhaps more informative perspective, is to recognize that the reduction in energy consumption reduces the utility's costs at Hydro's marginal cost, rather than the embedded cost rate. The table below reflects such a computation. Revenues decline according to the rate's energy prices: Block 2 energy reduction decreases billings according to the seasonal price of Block 2 energy; Block 1 energy reduction decreases billings according to the (annual) price of Block 1 energy. Energy-related costs decline at the season's marginal energy cost. Net revenue reductions are

modest as a result. Revenues and costs decline identically when Block 2 energy is reduced (assuming that actual marginal cost equals forecasted). Revenues and costs decline differentially when Block 1 consumption is reduced, with the difference being the difference between the Block 1 price and the seasonal marginal cost. Net revenues decline in non-winter months, when the Block 1 price exceeds marginal cost and increase in winter months, when the Block 1 price is less than marginal cost (i.e., revenues decline less than costs).

	Base (\$)	10% Reduction (\$)	25% Reduction (\$)
Total Energy in kWh	613,371,340	552,034,206	460,028,505
Annual Marginal Cost	0.0511	0.0511	0.0511
Revenue	42,400,567	39,217,953	34,453,148
Cost	42,400,567	39,265,080	34,561,849
Net Revenues	0	(47,127)	(108,701)

As shown above, reductions in revenues are largely offset by corresponding reductions in costs. Under a 10% reduction in energy consumption, revenues decline by approximately \$3.18 million relative to the base case, while costs decline by approximately \$3.14 million. Under a 25% reduction in energy consumption, revenues decline by approximately \$7.95 million, while costs decline by approximately \$7.84 million. The resulting differences are small relative to the overall reduction in revenues and costs.

In summary, this second table reveals that, under an Hours of Use design, net revenue impacts of even large class-wide load changes are likely to be relatively small, reflecting the match between Block 2 price and marginal cost. Focusing on the effect on embedded costs can thus be somewhat misleading. In addition, attempting to assign revenue reductions to cost categories depends upon assumptions which can be unavoidably arbitrary.

See also, response to PUB-NLH-130, part (d).