

1 **Q. Reference: Volume I, Sections 6.7.1 and 6.7.2**

2 Hydro proposes a first-block rate of 6.694¢/kWh after selecting the \$5.50/kW-month demand
3 charge and the 300-hour block boundary. The Application states that the first-block price is
4 intended to recover the remaining revenue requirement after the demand charge and second-
5 block rates have been determined.

6 **a)** Identify the amount of generation demand, transmission demand, energy-related fixed
7 costs, and any other costs recovered through the first-block rate.

8 **b)** Quantify any marginal energy costs recovered in the first-block rate.

9 **c)** Explain the economic basis for recovering demand-related costs through a volumetric
10 kWh charge whose revenues vary with energy consumption.

11 **d)** Quantify the change in Hydro's recovery of demand-related costs if Island Industrial
12 energy consumption differs from forecast by plus and minus 5 percent while customer
13 peak demands remain unchanged.

14 **e)** Explain how any resulting over- or under-recovery would be treated.

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17 **A. *Responses to a) to d) was provided by Christensen Associates Energy Consulting.***

18 **a)** Please refer to the table provided in part d) of this response, specifically the column labeled
19 "Base." The table identifies the portion of Block 1 revenue attributable to energy-related
20 and demand-related cost recovery. The demand-related components represent the total
21 amount of demand-related revenue requirement and does not treat separately the
22 demand-related generation and transmission cost components in the hours-of-use ("HOU")
23 rate design. One might assume that recovery of the demand components is proportional to
24 the shares of these components in required revenues. We have not acquired such
25 information from the cost-of-service study to make such a distinction.

- 1 **b)** Block 1 does not recover marginal energy costs. Rather, it is designed to recover the portion
2 of demand-related costs not recovered through the demand charge along with energy-
3 related financial costs. The energy-related component of the Block 1 revenue requirement is
4 calculated using a unit energy cost of \$0.03781/kWh, which reflects energy-related financial
5 costs and not marginal energy costs. Accordingly, no portion of Block 1 revenue is
6 attributable to the recovery of marginal energy costs.
- 7 **c)** Under the proposed HOU design, a portion of the demand-related costs is recovered
8 through a volumetric charge under the Block 1 energy price. The economic basis is that the
9 Block 1 billing determinant is directly tied to customer demand since a customer's Block 1
10 threshold is established based on hours of use (load factor). As a result, an increase in a
11 customer's peak demand increases the quantity of energy billed at the Block 1 rate. In this
12 way, customers that place increased demand on the system contribute more toward the
13 recovery of demand-related costs, even though a portion of those costs is recovered
14 through an energy charge rather than a standalone demand charge. More broadly, under
15 any rate structure, whenever the demand charge is set below the demand-related unit cost,
16 some demand-related costs must be recovered through energy charges. Accordingly, the
17 recovery of demand-related costs through volumetric rates is not unique to the proposed
18 HOU design.
- 19 **d)** The 2027 demand-related revenue requirement allocated to the Island Industrial class is
20 \$19,218,192, based on the billing data of Newfoundland and Labrador Hydro for this rate
21 application. This amount, and other data pertaining to the calculation of revenue
22 requirements, appear in the table on the next page in the column labeled "Base". Using
23 these data, it is possible to calculate how much of the demand-related revenue requirement
24 is recovered under the proposed rate design. \$6,025,800 is recovered through the demand
25 charge, while the remaining \$13,192,392 in demand-related costs are recovered through
26 the Block 1 energy charge. (Please refer to the rows labeled "Cost Recovery in DC (Demand
27 Charge)" and "Cost Recovery in EC (Energy Charge)".)

The product of unit costs and billing quantities in the Base column yields embedded costs.

The demand-related costs are split, for cost recovery purposes, as described above. By design, revenues match embedded costs, yielding the prices of the rate design.

The table below summarizes the impact of a 5% decrease and a 5% increase in energy consumption on the recovery of demand-related costs, while holding demand constant. Under such assumptions, the demand-related cost responsibility of the customer class remains unchanged. The third and fourth columns of table provide information paralleling the Base case for these scenarios. Total costs change with consumption, with all cost reductions taking place in the energy-related component, by assumption. Revenues change 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 and over-recovery in the event of increases. Under the assumption that demand costs are unaffected by the consumption changes, it requires a further assumption to conclude that full demand cost recovery occurs in Block 1 energy charge (in addition to the demand charge).

	Base	5% Reduction	5% Increase
Unit Costs			
Energy	\$0.0378		
Demand	\$17.54		
Billing Quantities			
Energy	613,371,340	582,702,773	644,039,907
Demand	1,095,600	1,095,600	1,095,600
Embedded Costs			
Energy	\$23,182,375	\$22,023,256	\$24,341,494
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	\$41,241,448	\$43,559,686
Revenues			
Energy: Block 1	\$21,845,846	\$21,801,803	\$21,887,297
Energy: Block 2	\$14,528,921	\$12,982,788	\$16,076,325
Demand	\$6,025,800	\$6,025,800	\$6,025,800
Total	\$42,400,567	\$40,810,392	\$43,989,423
Net Revenue	\$0	-\$431,057	\$429,737

The challenge for the utility is how to interpret the changes in revenues and costs. Are these recovery discrepancies a realistic reflection of the financial implications to the utility? An alternative, and perhaps more informative perspective, is to recognize that a change in energy consumption changes the utility's costs at Hydro's marginal cost, rather than the embedded cost rate. The table below reflects such a computation.

	Base	5% Reduction	5% Increase
Total Energy in kWh	613,371,340	582,702,773	644,039,907
Annual Marginal Cost	\$0.0511	\$0.0511	\$0.0511
Revenue	\$42,400,567	\$40,810,392	\$43,989,423
Cost	\$42,400,567	\$40,832,823	\$43,968,311
Net Revenues	\$0	-\$22,432	\$21,112

As shown above, changes in revenues are largely offset by corresponding changes in costs. Under a 5% reduction in energy consumption, revenues decline by approximately \$1.59 million relative to the base case, while costs decline by approximately \$1.57 million. Under a 5% increase in energy consumption, revenues increase by approximately \$1.59 million, while costs increase by approximately \$1.57 million. The resulting differences are small relative to the overall changes in revenues and costs.

In summary, this second table reveals that, under an HOU 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.

Please also refer to response to CA-NLH-292.

- e) The revenue variances resulting from a change in energy sales will be deferred in the Long-Term Supply Cost Variance Deferral Account ("SCVDA") – Load Variation component. The load variation is valued at the Block 2 price, as sales increase the calculated variance from test year sales results in a debit to revenue and an amount due to customers and a decrease in sales results in a credit to revenue and an amount due from customers. The variances are allocated to customer classes in the Long-Term SCVDA.