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September 30, 2019

The Board of Commissioners of Public Utilities
Prince Charles Building
120 Torbay Road, P.O. Box 21040
St. John's, NL A1A 5B2

Attention: Ms. Cheryl Blundon
Director Corporate Services & Board Secretary

Dear Ms. Blundon:

Re: Wholesale and Island Industrial Rate Design Review Update Report

At the time of Newfoundland and Labrador Hydro's ("Hydro") "Marginal Cost Update Report," submission to the Board of Commissioners of Public Utilities ("Board") in November 2018, Hydro committed to filing a status update with the Board in the third quarter of 2019 on the development of rate design proposals for Newfoundland Power and Island Industrial Customers. Please find enclosed the original and ten copies of Hydro's Wholesale and Island Industrial Rate Design Review Update Report.

Should you have any questions, please contact the undersigned.

Yours truly,

NEWFOUNDLAND AND LABRADOR HYDRO

SWalsh

Shirley A. Walsh
Senior Legal Counsel, Regulatory
SAW/las

Encl.

cc: Gerard M. Hayes, Newfoundland Power
Paul L. Coxworthy, Stewart McKelvey
Sheryl Nisenbaum, Praxair
Dennis M. Browne, Q.C., Browne Fitzgerald Morgan & Avis
Denis J. Fleming, Cox & Palmer

ecc: Dean A. Porter, Pool Althouse
Shawn Kinsella, Teck Resources Limited

Wholesale and Island Industrial Rate Design Review Update Report

September 30, 2019

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1.0 Background

On the Island Interconnected System, Newfoundland and Labrador Hydro ("Hydro") provides electricity service to Newfoundland Power Inc. ("Newfoundland Power") under the terms of the Utility Rate as provided in Hydro's Schedule of Rates, Rules and Regulations. Hydro also provides electricity service to five Industrial Customers on the Island ("Island Industrial Customers") under the terms of the Island Industrial Rate: Corner Brook Pulp and Paper Limited ("CBPP"); North Atlantic Refinery Limited ("NARL"); Teck Resources Limited ("Teck"); Vale Newfoundland and Labrador Limited ("Vale"); and Praxair Canada Inc. ("Praxair").[1]

In accordance with the 2013 General Rate Application ("GRA") Settlement Agreement, Hydro filed reports on Island Interconnected System marginal costs in late 2015 and early 2016 with the Board of Commissioners of Public Utilities ("Board"). The purpose of the reports was to provide the marginal cost methodology and marginal cost estimates for use in considering rate structure changes that may be required for the implementation of customer rates upon full commissioning of the Muskrat Falls Project. Marginal cost estimates are also useful in conservation and demand management evaluation, among other uses. Also in accordance with the 2013 GRA Settlement Agreement, Hydro filed a report in June 2016 prepared by Christensen Associates Energy Consulting entitled "Rate Design Review for Newfoundland Power and Island Industrial Customers." The report provided options to consider in modifying the rate designs of Newfoundland Power and Island industrial customers to reflect the expected change in system costs.

As a result of the delay in the commissioning of the Muskrat Falls Project, Hydro filed a Marginal Cost Update Report in November 2018. At the time of filing the Marginal Cost Update Report, Hydro committed to filing a status update with the Board in the third quarter 2019 on the development of rate design proposals for Newfoundland Power and Island Industrial Customers. [2]

[1] Teck Resources is in the process of closing operations at its mine site. As such, there is minimal load requirement for Teck reflected in the 2019 Test Year load forecast.

[2] Given that the retail rates for Hydro Rural customers on the Island Interconnected System are set to equal the rates of Newfoundland Power, Hydro is not conducting a rate design review for these customers.

Hydro is required to file its next GRA no later than September 30, 2020 to reflect supply from the Muskrat Falls Project.[3] Hydro plans to propose revised rate structures for Newfoundland Power and Island Industrial Customers in its next GRA. This report provides an update on the Wholesale and Island Industrial rate design review and the framework Hydro intends to use to develop the rate structure to be presented in its next GRA.

2.0 Rate Design Considerations

Hydro's rate design proposals presented in this report have given consideration to:

- Cost recovery;
- Customer rate stability;
- The pricing of electricity to promote efficiency; and
- Customer feedback.

2.1 Cost Recovery and Customer Rate Stability

2.1.1 Cost of Service Methodology Review

On November 15, 2018, Hydro filed a "Cost of Service Methodology Review" application with the Board which proposed changes to the methodology to be used in preparation of the cost of service study which will include Muskrat Falls Project costs in test year revenue requirements. The Cost of Service Methodology Review proceeding is ongoing. Uncertainty will remain in class revenue requirements to be reflected in rates until the Board's decision the Cost of Service Methodology Review is released.

2.1.2 Relationship of Supply Costs to Customer Energy Usage

As the electrical system transitions from the use of base load thermal generation at the Holyrood Thermal Generating Station ("Holyrood TGS") to the purchase of energy generated by the Muskrat Falls Project, base load supply costs will no longer vary with changes in customer energy usage. This is a substantial change from the current relationship between energy sales and supply costs.

[3] Board Order No. P.U. 16(2019), p. 61/22-23.

The variable costs (i.e., fuel costs for the Holyrood TGS) will be replaced with fixed costs reflecting Hydro's payments under the Power Purchase Agreement with Muskrat Falls Corporation and the Transmission Funding Agreement with the Labrador-Island Link Operating Corporation. A reduction in customer energy usage will not impact the supply cost incurred by Hydro. A reduction in customer energy usage will only impact the amount of system energy available for export.

To ensure Hydro can recover its supply costs, Hydro will need to increase the level of cost recovery achieved in customer rates through higher fixed charges. This can be achieved through fixed monthly charges, energy blocking structures and increased demand charges.

2.1.3 Customer Rate Stability

The implementation of a new rate structure also requires consideration of the existing rate structure to enable evaluation of the customer impacts of proposed rate structure changes. Electricity costs often reflect a large portion of a customer's operating costs. Unless a transition period is considered, material increases in costs can be imposed on a customer solely as a result of a revised rate structure. The consideration of customer impacts through a transition plan increases the likelihood of gaining customer acceptance.

The overall embedded cost of serving customers is projected to increase materially with the commissioning of the Muskrat Falls Project. The Provincial Government ("Government") has committed to providing rate mitigation to limit the effects of the cost of the Muskrat Falls Project on customer rates. However, Government has not yet released its formal plan regarding the rate mitigation. As a result, there is material uncertainty in the amount and form of rate mitigation that will be provided to reduce the billing impacts on Newfoundland Power and Island Industrial Customers. This uncertainty has increased the challenge in presenting a proposed rate structure that will gain customer acceptance. For the purposes of this update, Hydro has assumed that the funds provided for rate mitigation will be deducted from the unmitigated costs on the monthly bills of Newfoundland Power and Island Industrial Customers.

Given the uncertainty regarding final customer rate impacts, Hydro's proposals in this report will focus on the proposed rate structure changes and will not yet deal with the projected billing impacts of including the costs of the Muskrat Falls Project.

2.2 Consideration of Marginal Costs

2.2.1 General

In November 2018, Hydro filed a Marginal Cost Study Update with the Board that provided the projected marginal generation and transmission costs for the period of 2021-2029. The results of the marginal cost study update reflected that once the Muskrat Falls Project is commissioned, Hydro will have excess energy available to supply projected growth in energy requirements but limited excess capacity available to serve growth in customer's demand requirements. As such, Hydro's marginal generation capacity costs are projected to be high during winter periods reflective of Hydro's internal marginal capacity costs (i.e., the cost of adding new peaking capacity to Hydro's system) and marginal energy costs are projected to be reduced (relative to No.6 fuel) based on the projected opportunity costs of exports. The marginal cost study update also shows marginal generation capacity cost variability throughout the day during the winter period. The low marginal energy cost and variability in marginal generation capacity costs by time of day is a material shift from the marginal costs that have existed prior to the commissioning of the Muskrat Falls Project.

2.2.2 Marginal Cost Uncertainty

Also in November 2018, Hydro filed its "Reliability and Resource Adequacy Study" which proposes several changes to Hydro's planning criteria and assumptions including the adoption of a new interconnected system model, the transition from 2.8 LOLH to 0.1 LOLE as a planning criterion, and the return to the use of the P50 forecast as the base planning forecast.[4] The outcome of the proceeding related to the "Reliability and Resource Adequacy Study" will have significant impacts on Hydro's future system costs and marginal capacity costs. Hydro expects the proceeding to conclude in 2020 in advance of Hydro's next GRA. At the conclusion of the review of the "Reliability and Resource Adequacy Study," Hydro will need to update its projected marginal capacity costs.

The "Newfoundland and Labrador Conservation Potential Study (2020-2034)" prepared by Dunsky Energy Consulting, filed with the Board on August 12, 2019, raised uncertainty with respect to whether time of use rates or Critical Peak Pricing rates would be beneficial (Dunsky Energy Consulting refers to these rates as TOU and CPP). The report stated:

[4] Hydro currently uses a P90 forecast.

> "While TOU Rates, CPP and Equipment Control programs did not appear to offer additional DR potential, adjustments to the existing Industrial Curtailment programs, incorporating more aggressive EV adoption peak load impacts, or adding the Fuel Switching load curve impacts, all may alter conditions such that TOU Rates, CPP and/or Equipment Controls could become effective in the future: Changes to the utility load curve or to the constraints applied in other programs have significantly impacted the interactions among programs. For example, if the NL Utilities are able to negotiate Industrial Curtailment contracts with longer DR event durations, it may be possible that TOU Rates, CPP and Equipment Programs could offer additional potential as compared to the results presented herein."[5]

Hydro and Newfoundland Power have engaged Dunsky Energy consulting to conduct further review of the evaluation of the effectiveness of time of use and critical peak pricing rates. Additional information on the results of the Dunsky Energy Consulting analysis with respect to the potential benefits of time of use rates is expected in 2020.

Given the material uncertainty regarding the marginal generation capacity costs on the Island Interconnected System and the conditions in which time of use rates would be effective, Hydro is proposing not to implement time of use or critical peak pricing rate options for the Utility Rate and the Island Industrial Customer rates, at this in time. Therefore, the focus of the rate structure review in preparation for the filing of the next GRA will be to reflect the discontinuance of Holyrood TGS fuel as the basis for the marginal cost of energy on the Island Interconnected System.

2.2.3 Alignment of Marginal Revenues and Marginal Costs

Rate design also requires consideration of cost recovery when customer load varies from forecast. Aligning marginal energy rates with marginal energy costs minimizes the financial impact on the utility when a customer's energy requirement varies from forecast. Currently, there is a two-block energy rate in the Utility Rate structure; the second block rate is set to reflect the cost of No. 6 fuel based on the most recent test year cost of service study (on a cents per kWh basis). As a result, if Newfoundland Power's energy purchases vary from the test year forecast used in establishing the Utility Rate, the

[5] The "Newfoundland and Labrador Conservation Potential Study (2020-2034)," Dunsky Energy Consulting, filed with the Board on August 12, 2019, p. xii.

variance in Hydro's energy revenues will approximately equal the variance in Hydro's No. 6 fuel costs.[6] However, the Island Industrial Customer rate design is not structured in a similar manner.

The energy charge that applies to all kWh for Island Industrial Customers is set to equal the average embedded cost of energy in the most recently approved test year Cost of Service Study (i.e., 4.428 cents per kWh effective October 1, 2019). If energy sales to Island Industrial Customers vary from the test year forecast, Hydro's energy revenue varies by 4.428 cents per kWh. However, the marginal fuel cost change that results from the load variation (i.e., No. 6 fuel cost of 18.165 cents per kWh) is materially in excess of the marginal energy price of 4.428 cents per kWh. The RSP load variation component exists to address the difference between the marginal energy price and the marginal energy cost. Net savings or net costs resulting from load variations from Island Industrial Customers are recorded in the RSP for future disposition.[7]

The RSP load variation component has been a contentious issue in past GRAs. The Industrial Customers have proposed it be discontinued. Hydro believes the implementation of a revised rate structure in which the marginal energy price is established based on the marginal energy cost would strengthen the case for the elimination of the RSP load variation component.

Following the completion of the Muskrat Falls Project and the decommissioning of the Holyrood TGS, changes in energy sales will impact the amount of energy available for exports. Hydro is proposing to align the marginal energy price to customers to match the average unit value of exports (net of transmission tariffs) in the approved test year cost of service study. Under the proposed approach, as load varies from test year forecast, the change in revenue is aligned with the change in the value of exports. Hydro anticipates that a deferral account will be required to replace the RSP and provide recovery of cost variances from the test year forecast related to Muskrat Falls Project power purchase costs.[8] This deferral account can also deal with variances from the test year forecast export revenues.

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[6] Variances from the test year No. 6 fuel costs as a result of the variances in the price of fuel purchases are deferred to the Rate Stabilization Plan ("RSP") for future disposition.

[7] Balances in the RSP load variation component are allocated in the RSP by class based on 12-month rolling energy usage.

[8] Hydro filed a report with the Board in June 2016 entitled "Supply Cost Recovery Mechanism Review". This report evaluated whether a deferral account would need to be implemented to replace the RSP after the closure of the Holyrood TGS. The report concluded that the implementation of a deferral account would be required to permit Hydro to recover cost increases between test years resulting from changes in capital and operating costs related to the Muskrat Falls Project. The establishment of a deferral account provide recovery of Muskrat Falls cost variances would be consistent with OC 2013-343.

In the circumstance the Holyrood TGS No. 6 fuel is no longer on the margin to deal with load variances, the implementation of a two-block energy rate for Island Industrial Customers as currently exists for Newfoundland Power would eliminate the requirement for a deferral account to deal with earnings variances resulting from test year sales variations to customers.

3.0 Customer Engagement

Hydro has engaged Newfoundland Power and its Island Industrial Customers in the rate design review process. Hydro has met with Newfoundland Power, CBPP, NARL, Vale, and Praxair and discussed the requirement to change from the existing rate design.[9] All customers expressed concern with finalizing a new rate structure when there is still considerable uncertainty in the future costs to be recovered through customer rates.

Newfoundland Power indicated it is interested in a measured transition from the existing rate structure and believes the rate design change should initially focus on the removal of Holyrood TGS fuel as the marginal energy price. As additional marginal cost information becomes available and additional analysis is conducted on time of use pricing for the Island Interconnected System, other rate design changes can be further evaluated. Hydro agrees with Newfoundland Power with respect to the revisions required given the ongoing uncertainty with respect to marginal costs and the ongoing evaluation of time of use pricing for the Island Interconnected System.

NARL, Vale, and Praxair all indicated that they operate their facilities to be as efficient as possible in order to maximize output from their facilities. All three customers indicated minimal flexibility to deal with time of use rates but were open to further discussions as more information became available. CBPP is interested in ensuring it can operate its generation efficiently and in establishing mutually beneficial capacity assistance agreements. Hydro has reflected the feedback it received from Newfoundland Power and the Island Industrial Customers in its proposed framework for rate designs to be reflected in Hydro's next GRA.

[9] Hydro did not meet with Teck Resources to discuss new rate design proposals as the mine in the Province is no longer operational.

4.0 Wholesale Rate Structure

4.1 Existing Rate Structure

Hydro currently uses rates that can be characterized as a mixture of embedded cost pricing and marginal cost pricing.

The current structure of the Utility Rate consists of:

- A demand charge;
- A two-block energy charge, with the customer reaching the second block in all months; and
- A firming up charge to apply to purchases of secondary energy.

4.1.1 Demand Charge

The demand charge recovers a portion of the embedded demand-related costs. Historically, this rate has been negotiated between Hydro and Newfoundland Power giving consideration to estimated marginal capacity costs. In the Supplemental Settlement Agreement reached during Hydro's 2017 GRA proceeding,[10] the Parties agreed that the demand charge for the 2019 Test Year would be $5.00 per kW of Billing Demand.[11]

The Utility Rate includes two demand credits in the computation of Billing Demand, one for generation and one for curtailable load capability. These credits reflect the fact that Hydro can call on Newfoundland Power to use its generation and curtailable load to serve customer peak demand requirements.[12]

[10] Filed with the Board on July 16, 2018 and approved in Board Order No. P.U. 16(2019).

[11] Billing demand is determined based on the weather-adjusted native peak less credits for Newfoundland Power's generation and curtailment capability. The weather-adjusted native peak has a minimum billing demand set at 99% of the test year native load. Because the weather adjustment is determined after the conclusion of the winter season, the billing demand for the remainder of the year is trued-up to recover the difference between the billing demands applied during the winter season and the weather-normalized billing demand established at the conclusion of the winter season.

[12] The provision of the generation and curtailable credits in the Utility Rate is consistent with the treatment of these credits in the cost of service study used in determining the test year revenue requirement.

4.1.2 Energy Charge

The existing energy blocking structure in the Utility Rate provides for reliable recovery of costs allocated to Newfoundland Power, combined with the provision of a marginal cost-based price that reflects the cost of additional usage based on the test year cost of No. 6 fuel at the Holyrood TGS.

The energy blocking structure has been set at a level allowing Newfoundland Power to see the marginal energy price in all months. The second block has been priced to reflect the average annual test year cost of fuel at the Holyrood TGS. The first block price is set to recover the remaining revenue requirement.

4.1.3 Firming Up Charge for Secondary Energy

Newfoundland Power has a contract with CBPP that it enables Newfoundland Power to purchase excess energy generated by CBPP. Savings from these purchases are provided to Newfoundland Power customers through transfers to the Newfoundland Power Rate Stabilization Account.

Hydro purchases the secondary energy sales from CBPP and applies a firming up charge to determine the price to be paid by Newfoundland Power.[13] When Newfoundland Power purchases secondary energy from CBPP, the firm energy billed by Hydro to Newfoundland Power is reduced in the month in which it is provided. However, since Hydro must provide the firm energy requirements in the absence of secondary energy, Hydro applies a firming up charge to the secondary energy purchases by Newfoundland Power. The firming up charge ensures that the capacity costs Hydro incurs to provide firm energy are recovered regardless of whether the energy is supplied by Hydro or CBPP.[14]

Under the current rate structure, secondary energy purchases are beneficial to Newfoundland Power's customers as the cost of the secondary energy, including the firming up charge, is materially less than the second block energy rate which is priced at the test year cost of fuel at the Holyrood TGS. This may not be the case subsequent to the commissioning of the Muskrat Falls Project.

[13] Hydro purchases secondary energy from CBPP only if the purchase does not result in spilled energy by Hydro.
[14] The firming up energy charge is computed by applying the revenue requirement assigned to gas turbines and transmission assets to Newfoundland Power's peak transmission demand for the test year and divided by its forecast load to express on a cents per kWh basis.

4.2 Proposed Rate Design Framework

Hydro and Newfoundland Power agreed on a rate design framework which outlines the approach Hydro proposes for use in developing the Utility Rate structure to be put forward in its next GRA. A copy of the proposed rate design framework is provided as Appendix A. The proposed framework for each rate design component is described in the following sections.

4.2.1 Demand Charge

No change is proposed to the process for determination of the demand charge or the process for the calculation of the Billing Demand.

4.2.2 Energy Charge

Hydro proposes to maintain the two-block energy rate structure, with the sizing of the first block of energy to be determined in consultation with Newfoundland Power prior to the filing of Hydro’s next GRA. Hydro proposes to continue to signal the marginal cost of energy through the second block energy rate; however, instead of being set based on the cost of No. 6 fuel consumed at Holyrood TGS, Hydro proposes the second block rate be based on Hydro’s test year average unit value of exports (net of transmission tariffs). The first block energy rate would continue to be calculated based on the approved test year revenue requirement which is not recovered through the demand charge and second block energy charge.

4.2.3 Firming Up Charge for Secondary Energy

As the second block energy charge will be based on Hydro’s test year average unit value of exports (net of transmission tariffs), it is unlikely that secondary energy purchases from CBPP will continue to be beneficial for Newfoundland Power’s customers. As such, Newfoundland Power must determine if it will continue its agreement with CBPP for the purchase of secondary energy. If Newfoundland Power terminates the agreement, the Utility Rate will no longer require a firming up charge.

4.2.4 Rate Mitigation Adjustment

Assuming Government provides rate mitigation to limit rate increases resulting from the Muskrat Falls Project, Hydro plans to explicitly identify rate mitigation funds as a separate adjustment on the monthly bill. As Newfoundland Power is the only customer on the Utility Rate, Hydro anticipates identifying the billing adjustment as an explicit monthly adjustment expressed on a dollar amount per month basis.

5.0 Island Industrial Customer Rate Structure

5.1 Existing Rate Structure

The existing rate structure for Hydro's Island Industrial Customers includes:

- Monthly demand charges based on test year embedded costs, applied to the customers' annual declaration of Power on Order;[15]
- An average embedded cost energy rate based on test year costs, applied to all firm energy;
- A non-firm rate based on the marginal fuel rate at the time the non-firm energy is required; and
- Specifically assigned charges to recover the costs related to specifically assigned assets, computed separately for each customer tor which transmission assets are specifically assigned.

5.1.1 Demand Charge

The customer pays a demand charge in each billing period based on their firm power[16] requirements. The demand charge is determined based on the average monthly embedded demand cost from the test year cost of service study.

Customers can also avail of interruptible demand. The available interruptible demand in the Island Industrial Customers service contract is defined as follows:

> "Provided the Amount of Power on Order is equal to or greater than 20,000 kW, the amount of Interruptible Demand and Energy available shall be the greater of 10% of the Amount of Power on Order and 5,000 kW. If the Amount of Power on Order is less than 20,000 kW, the Amount of Interruptible Demand and Energy available shall be 25% of the Amount of Power on Order."

[15] Set no later than October 1 of the current calendar year for the following calendar year.
[16] Firm power equals the customer Power on Order at the beginning of each year.

There is no demand charge for interruptible demand. If customers' demand requirements exceed their Power on Order plus their interruptible demand, a new billing demand is established based on the new peak demand less its interruptible demand.

5.1.2 Energy Charge

The customer pays a monthly firm energy charge for firm power consumed up to the demand level of Power on Order. There is no blocking structure for the energy rate.

Consumption in excess of Power on Order is billed at the applicable non-firm rate. The non-firm energy price is based on the fuel cost of the thermal energy source which is at the margin at the time of consumption, serving as a representation of marginal cost. The non-firm price depends on the generation unit deemed to be at the margin, of which there are three types: Holyrood TGS, gas turbines, and diesel.

The industrial rate for CBPP currently reflects a pilot project which permits CBPP to exceed its firm demand without incurring a charge for non-firm energy. This pilot project is discussed in further detail in section 5.1.4.

5.1.3 Capacity Assistance

Hydro currently has a contract for capacity assistance with CBPP (100.4 MW).[17] The contract stipulates rules on frequency and duration of interruption and payment terms. Interruptions cannot exceed 100 hours per winter, no more than two calls per day, and normally have durations between three and six hours. Hydro provides annual reports to the Board advising as to the use of the contracts during the preceding winter season.

5.1.4 CBPP Pilot Agreement

Under the pilot agreement initiated in 2009[18], CBPP's generation no longer needs to follow its load in order to minimize the demand billed by Hydro. The pilot agreement allows CBPP to exceed its firm demand level without having to pay for interruptible energy. Through the pilot agreement, CBPP has

[17] Capacity assistance was tested and verified at 100.4 MW for the Winter 2018-2019 period.
[18] Approved in Board Order No. P.U. 17(2009).

been able to manage its hydraulic resources more efficiently and from a system perspective has reduced the requirement for the use of Holyrood TGS generation in supplying customer requirements. In addition, Hydro can call on CBPP to maximize its generation and provide additional hydraulic energy to the grid (to the extent that it is available at the time of the request).

In the "Cost of Service Methodology Application," Hydro requested the Board's approval to discontinue the CBPP generation demand credit. Hydro believes that the benefits to all customers arising from the fuel cost savings that supported the pilot project implementation are not expected to continue upon commissioning of the Muskrat Falls Project. It is Hydro's position that a revised agreement may be appropriate to reflect the future benefits of enabling Hydro to call on CBPP to maximize its generation.

5.1.5 Specifically Assigned Charges

The Island Industrial Customer rate includes a customer-specific charge (specifically assigned charge) designed to recover the costs of transmission and terminal facilities specific to providing service to each customer. Specifically assigned charges include operating and maintenance costs, return on debt and equity, and depreciation. For customers who make contributions in aid of construction ("CIAC") for the assets, the specifically assigned charge is based on the estimated operating and maintenance cost for the specifically assigned asset.

The Parties agreed in the 2017 GRA Supplemental Settlement Agreement[19] that the indexed cost approach shall continue to be used in allocating operating and maintenance costs in the determination of specifically assigned charges pending the development of a reasonable alternative. Hydro has agreed to report, in the next GRA, on Hydro's experience in tracking actual operating and maintenance expenses and the resulting figures.

5.2 Proposed Rate Design Framework

Similar to the rate design framework proposed for Newfoundland Power, Hydro plans to limit its proposed changes to the Island Industrial rate structure to those necessary as a result of No. 6 fuel at the Holyrood TGS no longer reflecting the marginal energy cost on the Island Interconnected System. To

[19] Approved in Board Order No. P.U. 16(2019).

reflect this change, Hydro is proposing to implement an energy blocking structure in which the marginal price is based on Hydro's test year average unit value of exports (net of transmission tariffs) . This change also requires a change to the non-firm energy rate. The proposed framework for each rate design component is described in the following sections.

5.2.1 Demand Charge

Hydro proposes to maintain the embedded cost based demand charge and continue to base it on the customers' annual forecast Power on Order. For any rate mitigation that is provided by Government and determined to be demand-related through a cost of service allocation,[20] Hydro anticipates that a demand charge mitigation credit will apply to determine the net demand charge. Hydro proposes to continue to have no demand charge for interruptible demand.

Hydro notes that the CBBP Power on Order has further decreased to 4 MW. If CBPP discontinues its request for a Power on Order but requires Hydro to be available for backup, Hydro may also be required to develop an Island Industrial stand-by rate for inclusion in its next GRA filing.

5.2.2 Energy Charge

Hydro proposes to introduce a two block energy charge, similar to that of the Utility Rate. However, for the Industrial Customer class, the first block size for each month is proposed to be computed separately for each customer based on each customer's Power on Order multiplied by a specified number of hours. For example, the use of peak demand for 365 hours a month by a customer equals an approximate 50% load factor. A customer with 10 MW of Power on Order would have a first block size of 3.65 GWh in this example. More analysis is required to finalize the load factor to be reflected in the calculation of the first block size.

All kWh usage in excess of the first block would be priced at Hydro's test year average unit value of exports (net of transmission tariffs). The first block energy rate would therefore be based on the approved test year revenue requirement which is not recovered through the demand charge and the second block energy charge. For any rate mitigation that is provided by Government and determined to

[20] Hydro is assuming the test year cost of service study will be used to allocate rate mitigation funds among customer classes and between demand-related and energy-related costs.

be energy-related through a cost of service allocation, Hydro anticipates that an energy charge mitigation credit will apply to determine the net energy charge.

Under the proposed rate structure, customers that manage their demand effectively and achieve a high load factor will increase their amount of energy use billed on the lower cost second block energy rate. Customers with lower load factors will have a lower percentage of energy use billed on the lower cost second block energy rate and a higher percentage of their energy use billed on the higher first block energy price. Hydro believes this approach is fair for all customers as it provides equal opportunity for customers to access the lower priced second block energy rate regardless of whether they have a higher or lower Power on Order.

Pricing the second block energy rate at Hydro's test year average unit value of exports (net of transmission tariffs) makes it revenue-neutral for Hydro to sell to an Island Industrial Customer or to export the energy. This would eliminate the need for the RSP load variation component as variations in energy consumption by Island Industrial Customers will be offset by increases or decreases in export sales.

Hydro proposes to provide non-firm energy to customers based on either the net export value of sales or the fuel cost of the thermal energy source, whichever is at the margin at the time the customers are accessing interruptible demand.[21]

5.2.3 Capacity Assistance

Hydro proposes to continue to work with its Island Industrial Customers to identify and optimize opportunities to avail of capacity assistance and curtailments to assist with peak demand management and system optimization.

5.2.4 CBPP Pilot Agreement

Hydro believes CBPP should have the opportunity to manage its generation as efficiently as possible and, to that end, proposes to work with CBPP to develop a proposal to achieve this objective. Hydro is

[21] The marginal energy cost estimate is increased by 10% in computing the non-firm energy rate to reflect an administrative and variable operating and maintenance charge.

engaged with CBPP on discussions with respect to the future value of CBPP providing available capacity to the system upon Hydro's request. Hydro will provide a further update to the Board on this matter as discussions proceed.

5.2.5 Specifically Assigned Charges

As noted earlier, Hydro will report on its experience in tracking actual operating and maintenance expenses related to specifically assigned assets in the next GRA.

6.0 Conclusion

Hydro's proposed rates designs for use in preparation the next GRA will reflect the discontinuance of Holyrood TGS No. 6 fuel as the basis for the marginal cost of energy on the Island Interconnected system. Specifically, the proposed rate structures provide for the following:

- Change in firm and non-firm rates to provide updated marginal energy cost signals to customers.
    - This is reflected in Newfoundland Power's second block energy price, which will be based on Hydro's test year average unit value of exports (net of transmission tariffs) in place of the No. 6 fuel cost, as well as in the addition of a second energy block to the Island Industrial Customer rates that will also have the same pricing basis as the second block energy price to Newfoundland Power.
    - The proposed alignment of marginal energy price with the marginal energy cost will eliminate the requirement for a load variation component and provide Hydro the opportunity to recover supply cost variability that results from customer energy use variability.
- Better alignment of rate structure between Newfoundland Power and Island Industrial Customers.

Given the uncertainty regarding the marginal capacity costs on the Island Interconnected System and the conditions in which time of use rates would be effective, Hydro is proposing not to implement time of use or critical peak pricing rate options at this time for the Utility Rate and the Island Industrial Customer rate. Hydro and Newfoundland Power have engaged Dunsky Consulting to conduct further review in the evaluation of the effectiveness of time of use and critical peak pricing rates for the Island

Interconnected System. Additional information from Dunsky Energy Consulting on the potential benefits of time of use rates is expected in 2020.

Hydro has not yet completed its discussions with the Industrial Customers with respect to the proposed rate structure changes, capacity assistance agreements, and the pilot agreement with CBPP. Hydro will reflect the results of these discussions in the proposed rate structures included in the next GRA filing and any other applications that will be required to reflect changes in these agreements.

Appendix A

Proposed Rate Design Framework

newfoundland labrador hydro
a nalcor energy company

Proposed Rate Design Framework – Wholesale Rate to Newfoundland Power

The proposed rate design framework is intended to guide the development of the Utility Rate charged by Newfoundland and Labrador Hydro ("Hydro") to Newfoundland Power Inc. ("Newfoundland Power") following Hydro's first General Rate Application to address recovery of Muskrat Falls Project costs ("Hydro's Next GRA"). The appropriateness of the framework remains subject to (i) Hydro's post-Muskrat Falls revenue requirement (inclusive of any rate mitigation) to be allocated to Newfoundland Power, and (ii) any unforeseen matters that may arise prior to Board of Commissioners of Public Utilities approval.

1. Demand charge will be negotiated between Hydro and Newfoundland Power. The demand charge will be applied to Newfoundland Power's annual weather adjusted native peak on a monthly basis.

2. The sizing and pricing of Newfoundland Power's first block energy component, which may vary monthly or seasonally, will be determined in consultation with Newfoundland Power.

3. First block energy rate will be computed based on approved test year revenue requirement not recovered through the demand charge and the end-block energy charge.

4. The second block firm energy rate will be in consideration of Hydro's marginal cost of energy, which is assumed to be Hydro's test year average unit value of exports (net of transmission tariffs) reflected in the cost of service study.[22]

5. Continuation of application of Generation and Curtailable Credits in determination of billing demand, as provided for in the current rate structure. The amount of the Generation Credit will be reviewed in Hydro's next GRA.

6. Newfoundland Power agrees to terminate its agreement with Deer Lake Power for secondary energy purchases subject to sufficient evidence from Hydro demonstrating that Newfoundland Power's customers would not be disadvantaged.

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[22] Hydro has assumed that the value of exports (on a ¢/kWh basis) would be equal to that reflected in the test year cost of service study and variances from this value between test years would be captured through a deferral account.