

M12661 – Nova Scotia Power (NSP) Application for an Above-the-Line Tariff Applicable to Port Hawkesbury Paper (PHP) – the Extra Large Industrial Dispatchable (ELID) Tariff

Opening Statement of Patrick Bowman¹

Nova Scotia Power Inc. (**NSP**) proposes a new tariff applicable to PHP, effective January 1, 2027. The proposed ELID is an “above-the-line” tariff, with Riders reflecting PHP’s unique load flexibility. Unlike the existing below-the-line ELIADC, an above-the-line tariff allocates asset-based system costs to PHP, not just variable or marginal costs.

It is common and appropriate regulatory practice for a tariff to credit a customer for the value created by adapting its load. However, the specific form of the ELID is, to my knowledge, unique in Canadian regulatory experience in the wide array of credits and benefits offered to PHP.

I conclude that NSP’s proposal does not reflect proper regulatory considerations for an above-the-line tariff. With the changes I recommend, I conclude that the ELID should be approved.

My recommendations are intended to align the ELID with a principled step-by-step design of an above-the-line tariff: establish a typical industrial load profile before application of the Riders, called the Customer Base Line (**CBL**); then apply the Dispatchable Rider (**DR**) to credit PHP for shaping its load in response to marginal system costs; and finally, apply the Interruptible Rider (**IR**) to credit any remaining capacity expected to be interruptible.

1) CUSTOMER BASE LINE (CBL):

As an above-the-line customer, the Cost-of-Service (**COS**) calculation should include all energy forecast to be sold to PHP from the integrated NSP system, net of Goose Harbour Lake wind, which is largely a pass-through, and all PHP capacity requirements, determined before application of the DR and IR.

NSP’s COS study does not reflect a proper CBL for PHP peak demand. Instead, it relies on PHP’s average historical experience under the ELIADC, where PHP was dispatched down during many peak hours. Those historical peaks are not representative of PHP’s underlying load and using those hours as the basis for future peak demand estimates effectively credits PHP a second time for past load shaping, for which it already received credit through the ELIADC.

Based on publicly available information, my assessment is that PHP’s CBL peak demand for COS purposes should be closer to 120 MW instead of the 65 MW proposed in the Application.²

If NSP has more detailed and reliable peak demand data supporting a more accurate CBL, I agree it should be used. Based on the evidence currently on the record, however, including PHP’s rebuttal that notes that absent a DR, PHP would operate at a high load factor throughout the year, 120 MW is

¹ I also note that in my response to PHP IR-1, I made a typographic error in the second bullet at the top of page 5, which should read “IR”, not “DR”.

² Confidential information generally accords with this value, as noted in N-10(c)(i) NSPI(Synapse) IR-24 Att. 1.

a reasonable representation of PHP's typical CBL as a high load factor customer before the DR or IR are applied.

Recommendation #1 is to set the CBL at 120 MW, absent an updated value from NSP

2) DISPATCHABLE RIDER (DR):

The DR credits PHP for shifting its load in response to marginal system costs. This is a substantial and unique benefit, particularly because it applies to approximately 800 GW.h of PHP consumption, even though almost 75% of that energy is forecast to come from PHP's own wind generation and is not purchased from NSP supplies.

I do not object to PHP receiving credit for its *bona fide* effect on the system relative to its CBL. However, NSP has not required sufficient practical controls over PHP's dispatch in exchange for this unique benefit.

Recommendation #2 is to increase the system operator's control of PHP's dispatch at peak times. Recommendation #6 is to require the Operating Procedures to be approved by the Board

I expect it will be difficult to properly establish the granular CBL with precision. This is needed to calculate the DR under NSP's proposal, which Bates White also noted. To avoid over-crediting PHP, some of the benefit-sharing aspects of the ELIADC mechanism should be retained to protect remaining customers.

The DR applies not only to the approximately 300 GW.h PHP is forecast to purchase from NSP supplies, but also to approximately 500 GW.h of its own wind generation. This added potential credit of the DR to PHP, unrelated to NSP supplies, further supports the principle of benefit sharing with other ratepayers.

Recommendation #3 is to retain some aspects of benefit sharing

3) INTERRUPTIBLE RIDER (IR):

The IR credits PHP for load expected to be interruptible at peak times, under system operator control, which brings generation planning benefits. At this stage, PHP's load should reflect the CBL modified by the DR load shaping.

As with Large Industrial IR (**LIIR**) customers, NSP should credit PHP only for load that is likely to be on the system at peak times. If a customer is expected to shape its load down at peak times, such that its load is already off the system, NSP need not compensate the customer for that reduction through the IR. The IR should only apply to additional interruptions the utility seeks to claim beyond customer load shaping. Similarly, if PHP is expected to shape its load away from peak times (for DR or any other reason), there should be no IR credit.

LIIR credits are adjusted to reflect this likelihood consideration, and PHP should be treated no different.

According to the historical ELIADC data, PHP was dispatched down whenever an interruption occurred under the IR at peak times. If this is also expected to be the case in future, there would be little to no IR credit available to PHP.

Recommendation #4 is to conclude there is likely little to no credit due under the IR.

I take note of NSP's reply evidence³ which indicates that PHP's load at 3 CP times will not necessarily be always dispatched down, and NSP would therefore need to include some PHP load in generation system planning absent the IR. If a proper CBL for PHP indicates expected material load (above 8 MW) at 3 CP, after application of the DR, then PHP should receive IR credit for that capacity. I had already acknowledged this in response to PHP IR-1⁴. For example, this would apply if the past average 3 CP load of 57 MW, after responding to the ADC, remains representative of future peak period load expectations under the DR. In this case, PHP would not receive IR credit for all 120 MW (which NSP appears to suggest)⁵, but only for the portion expected to be online (for example, 57 MW).

4) PRIORITY IR:

NSP also proposes a further 10% IR credit for "Priority" interruptibility, meaning PHP would be interrupted before other customers.

I do not find this appropriate for three reasons:

1. PHP is rarely interruptible in practice under the IR because it would have already been dispatched down under the DR.
2. PHP is not priority interruptible compared to some LIIR customers, who do not participate in the Telemetry and Control option. Note this is contrary to Brubaker's rebuttal evidence⁶ claiming that PHP is the first customer to be interrupted on the system.
3. Labelling of PHP as priority interruptible does not create any new interruptible load (MW) or value to the system.

Recommendation #5 is to eliminate the priority interruptible credit.

PHP has rejected the NSP version of the ELID, and instead proposes an 8 MW peak load, a 100% Revenue-to-Cost ratio, and an added ancillary services related credit. These proposals are not appropriate and should be rejected.

Recommendation #7 is to reject the PHP proposals.

I also note issues raised by Synapse⁷ suggesting that some of the above ratemaking principles should be abandoned simply to arrive at a rate PHP will accept. That would be inconsistent with

³ Exhibit N-38.

⁴ Exhibit N-28, page 3.

⁵ Exhibit N-38, page 14.

⁶ Exhibit N-36, page 12.

⁷ Exhibit N-21, page 14.

good ratemaking practice, and would provide a concession unavailable to other regulated customers.

As I set out in Information Request responses, if the full suite of measures above were adopted to the fullest extent (for example, if PHP received no IR at all, but captured the full estimated benefit of the DR), their total costs would be on the order of \$48.5 million for 2027. It could be less, for example, if NSP calculates a CBL for PHP that has a viable IR load such as 57 MW, then the annual bill would be reduced by nearly \$6 million. As a coarse measure of reasonableness, the entire LI class has costs of about \$72.9 million even though PHP's peak load is larger by roughly 50% than the LI class, and PHP's energy usage is lower by roughly 50%. For reference, before IR, the cost of demand is about 30% of the cost basis for LI and energy cost is about 70%.

In their rebuttal evidence, NSP appears to dismiss my concerns over complexity of the DR in practice, and the creation of a CBL for year-end allocation purposes (sec 2.2.3⁸) which NSP indicates is not significantly more complicated than under the ELIADC. I believe NSP mis-states aspects of my concerns, which do not only relate to future practice (ELID) versus past practice (ELIADC), but to future practice where only 300 GW.h are purchased under ELID but 800 GW.h are theoretically compensable under the DR, a complexity driven by the new wind.

Brubaker's rebuttal (page 4⁹) indicates I have proposed discriminatory rate making by suggesting PHP peak load for COS purposes use average demand while other classes use anticipated 3 CP demand. This is not correct. I propose that PHP use the expected 3 CP peak demand, based on a high load factor load prior to DR, which PHP's own witnesses confirm should be assumed if there were no DR. My concern is that the NSP proposal is discriminatory towards PHP by double-crediting dispatchability. The 65 MW peak is discriminatory as it reflects a load lower than PHP would operate absent DR. No other customer class gets credited to reduce their load at system peaks (through ADC), and then additionally claims a COS credit because their peak was lower.

Further, Brubaker routinely appears to suggest that the DR (former ADC) is about energy, not capacity, and that it is optional for PHP to respond. Yet the effect of Brubaker's 8 MW 3 CP proposal is to credit PHP for firm capacity effects of the DR/ADC, as if PHP can be expected to be relied upon in future as a capacity resource (for both generation and transmission purposes). If the DR/ADC is only energy, and not required participation, then there should be no capacity benefit applied. Hence the 120 MW flat load assumption I have proposed.

⁸ Exhibit N-38.

⁹ Exhibit N-36.