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Request IR-1:

Reference: Section 2.0 Marginal Cost Analysis, pages 11-14.

(a) Please provide the number of hours and percentage of hours for each of the years 2023, 2024 and 2025 year-to-date plus forecast that each generator class (e.g coal, natural gas, hydro, diesel, import, etc) was forecasted to be the marginal unit on the system in the PLEXOS model used in calculating NS Power's average annual marginal costs for the AARs. Please provide this information in tabular format disaggregated by generator type.

(b) For each of 2023, 2024 and 2025 to date and forecast to year-end, please provide the hours and percentage of hours of the year that each generation class was actually the marginal unit on the system. Please identify any material variances between forecast and actual, and provide explanations for variances exceeding 10%.

(c) For the 2026 forecast average annual marginal cost of $67.36/MWh calculation, please identify the % of hours in 2026 that each generation class is forecast to be the marginal unit on NS Power's system.

(d) Please confirm that Output-Based Pricing System (OBPS) compliance obligations are fully included in the marginal cost used in PLEXOS dispatch at their full economic value. If not fully included, please explain what costs are excluded and quantify the impact on marginal cost calculations.

Response IR-1:

(a) The table below provides the number of hours and percentage of hours for each fuel type forecast to be the marginal unit in the 2025 PLEXOS model for 2025. As a result of the

cyber incident, NS Power is currently only able to provide the requested information for 2025.

Fuel Type	2025	
	Hours	%
Solid Fuel	3,479	40
Liquid Fuel	1,361	16
Gaseous Fuel	3,225	37
Imports	44	1
Export	192	2
Biomass	459	5
Total	**8,760**	**100**

(b) Actual hourly marginal units are tracked by generating unit only and not by fuel type consumed, the actual hours for marginal units in 2023, 2024 and Q1 of 2025 is provided in the table below. Note Tuft's Cove 2 and 3 include both natural gas and Liquid Fuel types but they cannot be disaggregated due to data availability related to the cybersecurity incident. Actuals after Q1 2025 are also not available.

	2023 Total Hours	2023 (%)	2024 Total Hours	2024 (%)	Q1 2025 Total Hours	2025 (%)
Lingan 1	734	8.4	1,046	11.9	251	11.6
Lingan 2	146	1.7	272	3.1	170	7.9
Lingan 3	982	11.2	981	11.2	170	7.9
Lingan 4	971	11.1	599	6.8	195	9.0
Point Aconi 1	692	7.9	1,058	12.0	116	5.4
Point Tupper 2	482	5.5	849	9.7	450	20.8
Trenton 5	287	3.3	647	7.4	98	4.5
Trenton 6	1,102	12.6	1,446	16.5	172	8.0
Tufts Cove 1	413	4.7	660	7.5	25	1.2
Tufts Cove 2	719	8.2	234	2.7	167	7.7
Tufts Cove 3	1,412	16.1	623	7.1	160	7.4
Tufts Cove 4	670	7.6	252	2.9	51	2.4
Tufts Cove 5	16	0.2	71	0.8	28	1.3
Tufts Cove 6	0	0.0	-	0.0	-	0.0

	2023 Total Hours	2023 (%)	2024 Total Hours	2024 (%)	Q1 2025 Total Hours	2025 (%)
Burnside 1	55	0.6	15	0.2	50	2.3
Burnside 2	16	0.2	10	0.1	11	0.5
Burnside 3	20	0.2	9	0.1	8	0.4
Burnside 4	5	0.1	5	0.1	2	0.1
Tusket CT	15	0.2	3	0.0	8	0.4
VJ 1	5	0.1	2	0.0	25	1.2
VJ 2	18	0.2	2	0.0	3	0.1
Imports	0	0.0	-	0.0	-	0.0
Total	8,760	100.0%	8,784	100.0%	2,160	100.0

(c) The requested information is provided in the table below.

Fuel Type	2026	
	Hours	%
Solid Fuel	6441	74
Liquid Fuel	107	1
Gaseous Fuel	1417	16
Imports	0	0
Export	482	6
Biomass	313	4
Total	**8760**	**100.0**

(d) Confirmed, OBPS is included in the PLEXOS costs used for calculating hourly marginal costs. All variable operating costs for the marginal unit are included in the output marginal cost.

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Request IR-2:

Reference: Page 12, lines 7-9 and footnote 17.

> **The PLEXOS model used for the 2026 AAR forecast is the 2025 Q3 Fuel and Purchased Power Model.[17]**
>
> **17 - 2025 PLEXOS AAR F&PP model is based on the 2024 Q3 forecast F&PP model, with updated system assumptions, including commodity pricing update as of 2024-08-16.**

(a) In stating the above, is NS Power saying it ran its model in Q3 2025, but the system and pricing assumptions were as of August 2024? If not, please explain.

(b) If so, does NS Power have assumptions and pricing updates more current than last year?

(c) In forecasting new wind in 2026, what was the latest available information relied on by NS Power?

(d) Does NS Power agree that more current data is likely to lead to fewer mismatches between forecast and actual? If not, please explain.

(e) Why does NS Power not secure more recent data to make its assumptions and pricing updates closer in time to when it runs its model?

Response IR-2:

(a-e) Footnote 17 on page 12 of the Application was not updated from the 2025 AAR Application and is incorrect. The footnote should have instead been "2026 PLEXOS AAR F&PP model is based on the 2025 Q3 forecast F&PP model, with updated system assumptions, including commodity pricing update as of September 24, 2025."

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Request IR-3:

Preamble: Based on the principles of economic dispatch, and recognizing the influence of environmental legislation, REI expects that the highest variable cost generators would generally be: diesel combustion turbines (CTs); natural gas generation from Tufts Cove; and imports.

(a) Does NS Power agree? If not, please explain and identify the highest variable cost generators in order of merit, including the all-in variable cost per MWh for each generator inclusive of fuel, carbon costs, and OBPS compliance costs.

(b) Please provide, for the relevant PLEXOS model, the number of hours and percentage of total hours in which the three highest cost generators were forecast to be the marginal generator in 2024 and 2025 versus the actual number of hours and percentage they were the marginal cost generator. Please explain any material variances and their impact on marginal cost forecasting accuracy.

Response IR-3:

(a) NS Power agrees that generally diesel combustion turbines are often the highest variable cost generation available for dispatch. Natural gas-based generation and imported energy cost is highly dependent on the timing of the pricing, which varies according to seasonal, daily, and hourly market fluctuations. Typically, HFO generation at Tuft's Cove will be amongst the highest cost generation available to the system, usually, but not always, more expensive than natural gas.

(b) Due to the cyber event NS Power currently only has access to the 2025 AAR forecast and actual hourly marginal units for Q1 of 2025. A comparison is provided in the table below. The actual hours for solid fuel plants were 12 percent above forecast and Tuft's Cove actual

hours were 11 percent below forecast. This variance is driven by higher-than-expected natural gas prices making solid fuel generation more economic.

Fuel Type	Q1 2025 Forecasted		Q1 2025 Actuals	
	Hours	**%**	**Hours**	**%**
Solid Fuel Plant	1366	63	1622	75
Tuft's Cove	678	31	431	20
Diesel CT	26	1	107	5
Imports	14	1	0	0
Export	0	0	0	0
Biomass	76	4	0	0
Total	**2160**	**100**	**2160**	**100**

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Request IR-4:

Preamble: In response to the Board's Directive comparing monthly Forecast-to-Actual NB imports, in Section 2.3, page 14, NS Power indicated that forecast accuracy can be assessed via FAM reporting.

(a) Please identify specifically where (which schedules, tables, and line items) the relevant data can be found in the FAM filings to assess the accuracy of forecast marginal cost vs actual by generator class on a monthly basis. If such data is not currently reported in the FAM, please explain why not and what additional reporting would be required.

(b) For the purpose of assessing forecast accuracy, should "Actuals" be compared against "Forecast" or against "Budget"?

Response IR-4:

(a) The reporting included in the FAM provides actual costs against FAM budget costs to help FAM customers understand variances and drivers of any over and under recovery. AAR rates are not established in the same manner as FAM rates and there is separate proceeding related to AAR.

(b) Please refer to REI IR-5. AARs use a different forecast than those used in FAM reporting.

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Request IR-5:

Preamble: The Table below was compiled from the December FAM monthly reports (and October 2025 which is the YTD).

(a) Please confirm the accuracy of the data and identify the date of the "Forecast" and "Budget" each year.

(b) Please provide the missing information required to evaluate historical forecast accuracy regarding natural gas, diesel, import purchases, and Maritime Link.

	A	B	C	D	E	F	G	H
1	(millions of dollars)							YTD
2		dec	dec	dec	dec	dec	dec	oct
3	**Natural Gas**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
4	Actual	92.4	110.5	117.6	147.2	160.1	148.2	98
5	Forecast					161	142.9	
6	Budget	19.6	52.5	42.9	47.1	144.1	109.2	146.8
7	Full Year Budget							176.4
8								
9	**Diesel**							
10	Actual	1.6	1.9	2.3	8.2	6.8	7.1	7
11	Forecast					11.1	4.1	
12	Budget	0	0.8	1.1	0.2	11.7	11.3	3.8
13	Full Year Budget							5.1
14								
15	**Import Purchases**							
16	Actual	50.2	49.9	50.3	-11.9	59.8	98.2	97
17	Forecast					58	86	
18	Budget	62.4	56.9	106.9	99.6	42.8	143.1	110.9
19	Full Year Budget							135.5
20								
21	**Martime Link**							
22	Actual	107	138.6	149.5	157.1	162.6	-324.9	156.7
23	Forecast					162.8	-336.5	
24	Budget	164	144.5	164.4	161.9	166.8	164.8	167.2
25	Full Year Budget							200.6

Response IR-5:

(a) NS Power did not prepare the referenced table; however, the data presented appears to be accurate. The monthly FAM reports are intended to compare actuals vs the current BCF/GRA forecast filed with the NSEB. This is considered the budget in the monthly FAM reports. As the BCF/GRA forecasts filed with the NSEB are typically for 2-3 years with assumptions from the year in which they are filed, actual market conditions can be materially different than the assumptions used in the BCF forecast. At the direction of the FAM SWG in 2023, as the result of a significant increase in commodity pricing, NS Power began comparing against the latest internal Fuel and Purchased Power forecast to provide a comparison to a more recent forecast in addition to comparing against the budget. As there was no BCF filed with the NSEB for 2025, the 2025 budget is based upon NS Power's internal forecast prepared in Q3 2024.

The dates used for budget and forecast is as of follows:

- 2019 Budget – 2019 BCF Refresh Forecast filed with the NSEB in 2016 with pricing assumptions from 2016.

- 2020-2022 Budget – 2020-2022 BCF Compliance Filing which was filed with the NSEB in Q4 2019 with pricing from Q3 2019.

- 2023-2024 Budget - 2022-2024 GRA Compliance Filing which was filed with the NSEB in Q1 2023 and pricing assumptions from July 2022.

- 2025 Budget – This is NS Power's internal forecast with pricing assumptions from Q3 2024. As there is no BCF forecast for 2025 filed with the NSEB this is the budget for 2025.

- 2023 Forecast – This is NS Power's internal forecast with pricing assumptions from Q3 2023 and with actuals from January to August 2023.

- 2024 Forecast – This is NS Power's internal forecast with pricing assumptions from Q3 2024 and with actuals from January to August 2024.

(b) Refer to response (a) above. There is no missing data as forecast is only applicable to 2023 and 2024.

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Request IR-6:

Preamble: It is understood that the PLEXOS model relies on monthly on-peak / off-peak pricing for imports, which may be reasonable in aggregate but may not reflect actual market pricing during periods of high system demand across interconnected power systems.

(a) Where the forecast marginal generator is an import, has NS Power assessed the accuracy of these forecasts on a monthly and annual basis? If yes, please provide the results of such assessments for the past three years. If no, please explain why NS Power has not undertaken such analysis given the materiality of import costs to marginal cost calculations.

(b) Over the last three years, for each year, please provide:

(i) The forecast number of hours in which NB imports and ML imports (disaggregated) were expected to be the marginal cost generator; and

(ii) The actual number of hours in which NB imports and ML imports (disaggregated) were the marginal cost generator.

Response IR-6:

Preamble: The pricing for imports used in the PLEXOS model are daily on- and off-peak, not monthly.

(a) In the 2026 AAR model results, imports are not forecast to be the marginal unit. Actual reported hourly marginal unit from 2023 to the end of Q1 2025 also shows imports were never the marginal unit.

(b) Please refer to REI IR-1.

Request IR-7:

(a) Please confirm that NS Power currently has the capability to produce reliable monthly marginal cost forecasts with accuracy comparable to or better than its annual forecasts. If not, what specific additional changes or resources would be required to enable it to do so, and what would be the associated costs and implementation timeline?

(b) Please provide an assessment of the operational and administrative impacts, including one-time or ongoing costs, to move from annual to monthly marginal cost updates for the AARs.

(c) Has NS Power analyzed or modeled results comparing the accuracy of annual versus monthly marginal cost pricing for the AAR tariffs? Is it able to do so?

(d) Does NS Power agree that monthly marginal cost pricing would improve price signals to market participants, including LRSs, and better reflect actual system conditions? If not, please explain in detail why annual pricing provides superior price signals despite monthly variations in fuel costs, import prices, and system conditions.

(e) Does NS Power agree that monthly marginal cost pricing would allow NS Power to recover costs more closely aligned with actual system conditions and fuel costs, thereby reducing cross-subsidization between bundled service customers and RtR market participants? If not, please explain why annual averaging does not create cross-subsidization risks and provide quantitative analysis supporting this position.

Response IR-7:

(a) Marginal cost forecasts prepared on a monthly basis, would not result in improvement in the accuracy of projected costs. Accuracy of marginal costs forecasts depends on accuracy

of key system assumptions, some of which, such as quantification of monthly air emissions, cannot be produced and updated in time to continuously execute monthly updates. Additionally, because marginal costs are calculated without PHP, removing PHP from the system forecast on a monthly basis would not be possible given the fact that fuel and import energy purchases were put in place to serve the total system demand. Further, as the Board previously determined,[1] the annually adjusted rates process was designed to establish rates for the entire year to provide price certainty to AAR customers; the process does not lend itself to quarterly applications. There is no regulatory framework under which monthly marginal costs could be produced, filed with NSEB, reviewed by the stakeholders, and approved. Accordingly, NS Power does not consider monthly marginal cost updates to be useful or practical.

(b) The requested study was not completed as a part of this filing.

(c) The requested study was not completed as a part of this filing. NS Power's position is that such an analysis would not be beneficial as the number of input changes in either monthly or annual forecasts versus actual marginal prices would not provide any further clarity into the benefit of one method over the other. For example, marginal costs produced monthly or annually would utilize the same shape for wind and hydro sites and this would not differ on a year ahead or monthly basis, meaning that the forecast would see the same amount of wind and hydro in each case. Another example is the distribution of forced outages which cannot be accurately adjusted on a monthly basis.

(d) NS Power does not agree that monthly marginal cost pricing would improve price signals under the AARs. As indicated by the Company in its 2024 AAR submission,[2] time- or season-differentiated pricing, or a monthly-based pricing as contemplated in this response, would be of a non-material consequence to both the FAM and AAR customers. Further, given the complementary nature of the AARs, many of which are taken in conjunction with

[1] M11989 – Board Decision, 319292, page 5. March 25, 2025.
[2] M11422 – 2024 AAR Application, Section 2.0.

other rates, such as the BUTU, EBS, or SS; the customer would either not have a financial incentive, or in case of energy balancing to non-dispatchable generation, even a physical ability to respond to pricing signals by shifting load.

(e) The monthly marginal cost pricing would result in a better alignment between cost recovery and cost causation; however, as demonstrated in the 2024 AAR submission, such a change would not produce a material cost effect on the FAM or AAR customers. Also, the AAR customers would lack ability to respond to monthly price signals as indicated in part (d).

Request IR-8:

Reference: Assumptions, page 11, Appendix A3 PCON; and Board-Directed Sensitivity Analyses, pages 12-13 and Appendix A6 PCON.

(a) NS Power has stated that higher SO2 emission limits have resulted in lower marginal costs. Please confirm the SO2 emissions associated with NS Power production in 2026, the applicable SO2 emission limits, and the remaining headroom under such limits.

(b) Please quantify the impact on marginal costs of the higher SO2 limits.

(c) Are the marginal costs for NS Power higher once SO2 limits are reached, and if so, by how much per MWh? Please provide the marginal cost curve showing the step change in costs as SO2 limits are approached and exceeded.

(d) With respect to the listed assumptions and Board-directed sensitivity analyses of commodity price volatility, unavailability of Muskrat surplus energy, and delays to wind, does NS Power agree that these are the three assumptions with the most risk of material variance from forecast? If not, please identify and rank the top five assumptions by risk of variance and potential impact on marginal costs, and explain why sensitivity analyses were not performed on all material risk factors.

(e) Please provide the surplus energy offered by Nalcor/NLH and accepted by NS Power in each year under the Energy Access Agreement historically, as compared to forecast.

(f) If the probability of zero Muskrat Surplus Energy being delivered is improbable, please quantify the probability distribution NS Power has assigned to various delivery scenarios. Would NS Power agree there is utility in running sensitivity analyses at

50%, 75%, 125% and 150% of forecasted Surplus Energy to better understand the range of potential impacts on forecasted marginal and average costs? If not, why not?

(g) Regarding the updated 2026 PHP CBL load, please confirm whether this reflects the Goose Harbour Lake wind farm.

(h) Please provide a sensitivity analysis showing the impact on marginal and average costs if PHP continues to receive service under the ELIADC through 2026 versus taking service under a to-be-filed successor tariff which may be above-the-line. Please quantify the potential revenue and cost impacts of each scenario.

(i) Does NS Power have any more up-to-date information regarding commercial operation dates of new wind generation than was included in the PLEXOS modeling? If yes, please provide the updated information and explain why it was not incorporated into the model. If no, when was the last update received and when is the next update expected?

(j) While NS Power conducts these sensitivity analyses, please confirm whether the results are incorporated into NS Power's marginal cost forecasts through probability-weighting or other methodologies, or whether they are simply informational. If they are not incorporated, please explain why NS Power does not use probabilistic forecasting methods to improve forecast accuracy.

Response IR-8:

(a) The annual regulatory SO_2 emission limit for 2026 is 45 kt. The 2026 AAR model results for the scenario including PHP load indicates an SO_2 emissions total of 39.3 kt for 2026 therefore the model dispatch is not constrained by the SO_2 air emissions environmental limit.

(b) To assess the impact of SO_2 Certificate of Variance (CoV), a scenario with the original SO_2 limits would have to be modeled, for comparison. Constructing a scenario with original SO_2 limits cannot be completed with accuracy because the pricing and availability for the required quantity of low-sulfur coal is unknown, as are fleet maximum capacity limits with alternative fuels. This scenario was not modeled as part of the 2026 AAR application. Qualitatively, other low SO_2 emitting fuels, such as, low-sulphur coal, natural gas or additional energy imports would have to be procured. Given that these would be less optimally priced as compared to the SO_2 emitting fuel, assuming all else equal, than it would be expected that marginal costs would rise as well.

(c) When SO_2 limits are expected to be a constraint on system dispatch in a given year, the issue is identified in advance through quarterly Fuel and Purchased Power forecasts. Fuel procurement and unit dispatch is optimized to minimize the cost impact over the entire year, therefore there is no step change in marginal costs over the year as SO_2 emissions in forecast approach the limit.

(d) All system assumptions can have a material impact on marginal costs of the system. For example, global conflicts can lead to disruption in fuel prices and supply similar to what was witnessed in 2022, fuel shipping disruptions due to potential new trade tariffs, natural gas supply disruptions, import energy disruption due to unforeseen plant outages in New Brunswick and Newfoundland and Labrador, meteorological events affecting wind farms and transmission towers, unplanned extended thermal plant outages beyond what is captured by the forced outage rates based on recent plant reliability performance, and several other system assumptions. Due to the uncertainty of the development of system sensitivity assumptions, NS Power does not believe additional sensitivity analysis would be productive. NS Power believes that the base case set of system assumptions is an accurate representation of the forecast marginal costs. NS Power does not propose any additional sensitivity analysis at this time.

(e) The table below shows the amount of offered energy from NLH including both surplus and bilateral energy. Due to the cyber incident, NS Power does not have access to forecasted volumes in 2022.

	NLH Offered GWh	NSP Accepted GWh	NSP Forecasted GWh
2022	[redacted]		
2023			
2024			
2025			

(f) Muskrat Falls, Labrador Island Link, and Maritime Link have been operating reliably in steady state for some time. NS Power believes that the probability of Maritime Link energy import deviation from forecast is now similar to the probability of energy delivery deviation from New Brunswick, or any other generating resource on the system. When forecasting Surplus energy, NS Power utilizes a combination of forecasts provided by NLH as well as historical and forward-looking information to provide the model with an amount which we believe will be available in the coming year. Due to the increased fleet flexibility as a result of SO_2 CoV, the cost impact of energy supply deviation from any resource is reduced, because NS Power has the ability to increase coal-based generation as a replacement energy and does not have to rely on the higher cost imported incremental natural gas and heavy fuel oil. NS Power does not believe that additional sensitivities focusing on one particular resource would increase the accuracy of marginal cost forecast.

(g) Generation from the Goose Harbour Lake Wind Farm is included in the forecast.

(h) NS Power produces marginal costs excluding PHP load and therefore, this sensitivity is a moot point. NS Power did not change the approach in the 2026 AAR filing due to the uncertainty in the timing of when, and if, PHP would take service on an Above-the-Line (ATL) rate. This process may change for 2027 AAR filing.

(i) Please refer to NSEB IR-7. For all other new Rate Based Procurement wind projects, NS Power assumes these are commercially operational January 2027 at the time this forecast was produced. NS Power generally receives quarterly updates from IPPs during construction. Assumptions used in this filing are accurate as of the date of responding to this information request.

(j) NS Power uses a deterministic forecast methodology in producing marginal costs forecast. This is methodology, covered under the FAM Plan of Administration, is used when setting BCF rates. The sensitivity analyses provided in this filing are for information purposes only. The model assumptions development is based on the approved methodology which is outlined in Appendix B of the FAM POA and which is applied to all Fuel and Purchased Power forecast models. The alternative methodology being discussed in this information request is not a part of any regulatory filing process. NS Power does not believe the comprehensive stochastic probabilistic approach would improve forecast accuracy, while increasing the risk of skewing marginal costs due to inherent imbalance of potential outcomes in a probabilistic analysis.

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Request IR-9:

(a) Please explain what financial and operational risks or benefits NS Power faces if it underestimates marginal costs in the AAR calculation versus the risks or benefits if it overestimates marginal costs.

(b) Please quantify these risks or benefits where possible and identify which customer classes bear the consequences of forecast errors in each scenario.

(c) With respect to the RtR market specifically, please explain whether there are any technical, operational, or regulatory impediments to calculating and updating marginal costs on a more frequent basis than annually (such as quarterly or monthly). If impediments exist, please identify and quantify them. If no impediments exist, please explain why NS Power has not proposed more frequent updates.

(d) If a true-up mechanism were implemented to reconcile forecast versus actual marginal costs, please explain how this would affect:

(i) the risks or benefits to NS Power identified in part (a) above;

(ii) the need for or benefit of more frequent marginal cost updates; and

(iii) the allocation of forecast risk between NS Power's bundled customers and RtR market participants.

Response IR-9:

(a-b) NS Power's earnings are not impacted by the over- or under-forecasting of annual average marginal fuel costs used for the pricing purposes of AARs. The implicit imbalances between the recovered forecasted and incurred actual marginal costs are flown into the

FAM. To the extent these costs are over-forecast the FAM customers see a reduction in their imbalance and the opposite happens if these costs are under forecasts. However, it's important not to lose a perspective on the materiality of this process on the FAM customers. As can be ascertained from Appendices D and E4, the load of the customers paying the forecasted average marginal cost of 67.36/MWh under the GRLF and Shore Power[1] in 2026 is 18 GWh, which represents 0.2 percent of the total FAM class load of 11.572 GWh forecasted for 2026. With the marginal cost of 67.36/MWh being significantly below the average base cost of fuel (BCF) of $81.44/MWh, a 10 percent variance of $6.736/MWh in the actual marginal cost from forecast, for example, would result in an imbalance of about $0.1 million or 0.01 percent of the total FAM cost budget of $913 million.

(c) Please refer to parts (a) and (b) of REI IR-7.

(d) In view of the low materiality of the fuel imbalance in recovery of the marginal fuel costs, discussed under parts (a) and (b), the true-up mechanism is not warranted at this time.

[1] Please note that NS Power does not forecast any service uptake in the RtR market under the EBS Tariff in the 2026.

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Request IR-10:

(a) Without commenting on the merits, please outline in detail the steps required to calculate and implement an annual true-up mechanism under which a credit or debit is calculated and applied to the applicable tariffs impacted by the Marginal Cost based on the difference between Actual versus Forecast Marginal Cost and Average Annual Cost. Please include the timing of calculations, the process for Board approval, and the mechanism for flow-through to customers.

(b) Please compare to the end of year calculation performed for the ELIADC.

Response IR-10:

(a) The steps involved would depend on the mechanism approved for the true up. An evaluation has not been undertaken to determine steps required to produce a reliable methodology for producing an annual true up.

NS Power has true up mechanisms on FAM, DSM, and Storm Riders, and each one operates differently. For the true up rider mechanisms currently in place there is a regulatory process and approval by the NSEB required for any changes to those Riders. The process would include the preparation and filing of an application by NS Power to the NSEB. The NSEB would subsequently issue a Board Order to direct the subsequent steps in the process for review by the NSEB and stakeholders.

(b) The Company has not designed a true up mechanism so is unable to compare to the ELIADC calculations.

Request IR-11:

Reference: Renewable to Retail Market Tariffs, page 31 states "Estimates for the current scope of work referenced remain in the range of $6.4 million" and cites to M11874, N-4, NS Power (NSUARB) IR-1.

(a) Attachments 1 and 2 to NSUARB IR-1 include actuals to the end of September 2024. Please refile Attachments 1 and 2 with updated actuals to November 30, 2025 and updated estimates to complete. Identify any material variances by cost category (above 10%) and provide a detailed explanation for each variance, including whether such variances indicate systemic estimating issues.

(b) This work was the subject of a capital work order CI C0053699 identified as a subsequent submittal in the 2023 ACE Plan. In what quarter does NS Power plan to file this Capital Work Order?

Response IR-11:

(a) Attachment 1, representing the current Capital Work Order, has been updated with costs to the end of October 2025 which is the most current data available. Variances in the 2025 costs from estimates in the previous version are due to the change in Commercial Operation Dates of the Licensed Retail Suppliers to Q3 2027. NS Power consequently adjusted implementation timelines for this project to align.

(b) This capital work order was filed on December 1, 2025 as part of the December 2025 package and has been assigned Matter number M12588.

Cost Element	Month Number	Amount
530050 - 530050 Regular Labour	202302	$918
530050 - 530050 Regular Labour	202303	$1,322
530050 - 530050 Regular Labour	202304	$383
530050 - 530050 Regular Labour	202305	$1,549
530050 - 530050 Regular Labour	202306	$3,731
530050 - 530050 Regular Labour	202307	$2,616
530050 - 530050 Regular Labour	202308	$2,774
530050 - 530050 Regular Labour	202309	$4,516
530050 - 530050 Regular Labour	202310	$1,082
530050 - 530050 Regular Labour	202311	$2,444
530050 - 530050 Regular Labour	202312	$1,058
530050 - 530050 Regular Labour	202401	$533
530050 - 530050 Regular Labour	202402	$2,312
530050 - 530050 Regular Labour	202403	$820
530050 - 530050 Regular Labour	202404	$689
530050 - 530050 Regular Labour	202405	$4,121
530050 - 530050 Regular Labour	202406	$3,047
530050 - 530050 Regular Labour	202407	$1,354
530050 - 530050 Regular Labour	202408	$8,722
530050 - 530050 Regular Labour	202409	$3,302
530050 - 530050 Regular Labour	202410	$3,331
530050 - 530050 Regular Labour	202411	$3,009
530050 - 530050 Regular Labour	202412	$6,065
530050 - 530050 Regular Labour	202501	$4,438
530050 - 530050 Regular Labour	202502	$17,542
530050 - 530050 Regular Labour	202503	$17,683
530050 - 530050 Regular Labour	202504	$4,428
530050 - 530050 Regular Labour	202507	$8
530050 - 530050 Regular Labour	202509	-$783
Total Regular Labour		**$103,015**
530200 - 530200 Overtime Labour	202306	$318
530200 - 530200 Overtime Labour	202308	$316
530200 - 530200 Overtime Labour	202310	$316
530200 - 530200 Overtime Labour	202311	$38
530200 - 530200 Overtime Labour	202401	$21
530200 - 530200 Overtime Labour	202403	$23
530200 - 530200 Overtime Labour	202404	$23
530200 - 530200 Overtime Labour	202405	$481
530200 - 530200 Overtime Labour	202406	$458
530200 - 530200 Overtime Labour	202408	$584
530200 - 530200 Overtime Labour	202409	$386
530200 - 530200 Overtime Labour	202410	$91
530200 - 530200 Overtime Labour	202411	$130
530200 - 530200 Overtime Labour	202501	$343
530200 - 530200 Overtime Labour	202502	$157
530200 - 530200 Overtime Labour	202504	$1,615
530200 - 530200 Overtime Labour	202507	$175
530200 - 530200 Overtime Labour	202509	-$1,615
Total Overtime Labour		**$3,860**
530300 - 530300 Term Labour	202302	$31,561
530300 - 530300 Term Labour	202303	$7,284
530300 - 530300 Term Labour	202304	$4,461
530300 - 530300 Term Labour	202305	$4,992
530300 - 530300 Term Labour	202306	$4,672
530300 - 530300 Term Labour	202307	$4,109
530300 - 530300 Term Labour	202308	$6,369
530300 - 530300 Term Labour	202309	$2,114
530300 - 530300 Term Labour	202310	$5,074

Cost Element	Month Number	Amount
530300 - 530300 Term Labour	202311	$5,624
530300 - 530300 Term Labour	202312	$4,072
530300 - 530300 Term Labour	202401	$1,105
530300 - 530300 Term Labour	202402	$7,211
530300 - 530300 Term Labour	202403	$3,341
530300 - 530300 Term Labour	202404	$2,214
530300 - 530300 Term Labour	202405	$4,693
530300 - 530300 Term Labour	202406	$5,109
530300 - 530300 Term Labour	202407	$5,123
530300 - 530300 Term Labour	202408	$6,686
530300 - 530300 Term Labour	202409	$3,368
530300 - 530300 Term Labour	202410	$3,567
530300 - 530300 Term Labour	202411	$4,585
530300 - 530300 Term Labour	202412	$2,038
530300 - 530300 Term Labour	202501	$2,219
530300 - 530300 Term Labour	202502	$1,115
530300 - 530300 Term Labour	202503	$1,111
Total Term Labour		**$133,818**
530320 - 530320 Term Labour-Overtime	202302	$2,834
530320 - 530320 Term Labour-Overtime	202303	$1,362
530320 - 530320 Term Labour-Overtime	202304	$2,103
530320 - 530320 Term Labour-Overtime	202305	$2,021
530320 - 530320 Term Labour-Overtime	202306	$2,011
530320 - 530320 Term Labour-Overtime	202307	$1,721
530320 - 530320 Term Labour-Overtime	202308	$2,070
530320 - 530320 Term Labour-Overtime	202309	$2,158
530320 - 530320 Term Labour-Overtime	202311	$1,009
530320 - 530320 Term Labour-Overtime	202312	$1,013
530320 - 530320 Term Labour-Overtime	202403	$598
530320 - 530320 Term Labour-Overtime	202404	$990
530320 - 530320 Term Labour-Overtime	202405	$870
530320 - 530320 Term Labour-Overtime	202406	$767
530320 - 530320 Term Labour-Overtime	202407	$476
530320 - 530320 Term Labour-Overtime	202408	$295
530320 - 530320 Term Labour-Overtime	202409	$949
530320 - 530320 Term Labour-Overtime	202410	$911
530320 - 530320 Term Labour-Overtime	202501	$1,116
Total Term Labour Overtime		**$25,271**
531550 - 531550 Contracts	202411	$3,392
531550 - 531550 Contracts	202412	$3,731
531550 - 531550 Contracts	202501	-$3,562
531550 - 531550 Contracts	202508	$87,781
531550 - 531550 Contracts	202509	-$86,731
531550 - 531550 Contracts	202510	-$1,050
Total Contracts		**$3,562**
532500 - 532500 Consulting	202302	$55,977
532500 - 532500 Consulting	202303	$23,925
532500 - 532500 Consulting	202304	$30,167
532500 - 532500 Consulting	202305	$322,575
532500 - 532500 Consulting	202306	-$205,418
532500 - 532500 Consulting	202307	$133,653
532500 - 532500 Consulting	202308	-$17,290
532500 - 532500 Consulting	202309	$37,860
532500 - 532500 Consulting	202310	$49,313
532500 - 532500 Consulting	202311	$36,975
532500 - 532500 Consulting	202312	$48,825

Cost Element	Month Number	Amount
532500 - 532500 Consulting	202401	$67,593
532500 - 532500 Consulting	202402	$84,764
532500 - 532500 Consulting	202403	$65,525
532500 - 532500 Consulting	202404	$133,247
532500 - 532500 Consulting	202405	$94,935
532500 - 532500 Consulting	202406	$51,978
532500 - 532500 Consulting	202407	$239,071
532500 - 532500 Consulting	202408	$179,318
532500 - 532500 Consulting	202409	$566,837
532500 - 532500 Consulting	202410	$216,988
532500 - 532500 Consulting	202411	-$66,224
532500 - 532500 Consulting	202412	$309,827
532500 - 532500 Consulting	202501	$603,590
532500 - 532500 Consulting	202502	$250,148
532500 - 532500 Consulting	202503	$98,717
532500 - 532500 Consulting	202504	$211,726
532500 - 532500 Consulting	202505	$280,045
532500 - 532500 Consulting	202506	-$362,165
532500 - 532500 Consulting	202507	$5,561
532500 - 532500 Consulting	202508	-$93,343
532500 - 532500 Consulting	202509	$93,691
532500 - 532500 Consulting	202510	-$238,689
Total Consulting		**$3,309,700**
532850 - 532850 Application Software	202405	$6,461
Total Application Software		**$6,461**
535700 - 535700 Admin Overheads	202302	$27,903
535700 - 535700 Admin Overheads	202303	$7,645
535700 - 535700 Admin Overheads	202304	$4,853
535700 - 535700 Admin Overheads	202305	$6,217
535700 - 535700 Admin Overheads	202306	$7,876
535700 - 535700 Admin Overheads	202307	$6,244
535700 - 535700 Admin Overheads	202308	$8,508
535700 - 535700 Admin Overheads	202309	$6,346
535700 - 535700 Admin Overheads	202310	$5,197
535700 - 535700 Admin Overheads	202311	$7,072
535700 - 535700 Admin Overheads	202312	$4,640
535700 - 535700 Admin Overheads	202401	$953
535700 - 535700 Admin Overheads	202402	$5,503
535700 - 535700 Admin Overheads	202403	$2,584
535700 - 535700 Admin Overheads	202404	$1,971
535700 - 535700 Admin Overheads	202405	$5,484
535700 - 535700 Admin Overheads	202406	$5,067
535700 - 535700 Admin Overheads	202407	$3,880
535700 - 535700 Admin Overheads	202408	$9,157
535700 - 535700 Admin Overheads	202409	$4,240
535700 - 535700 Admin Overheads	202410	$4,275
535700 - 535700 Admin Overheads	202411	$4,426
535700 - 535700 Admin Overheads	202412	$4,683
535700 - 535700 Admin Overheads	202501	$4,183
535700 - 535700 Admin Overheads	202502	$10,609
535700 - 535700 Admin Overheads	202503	$10,643
535700 - 535700 Admin Overheads	202504	$2,965
535700 - 535700 Admin Overheads	202505	$0
535700 - 535700 Admin Overheads	202506	$0
535700 - 535700 Admin Overheads	202507	$54
535700 - 535700 Admin Overheads	202509	-$901
535700 - 535700 Admin Overheads	202510	$0
Total Admin Overheads		**$172,275**

Cost Element	Month Number	Amount
535705 - 535705 Contractor Admin Overhea	202411	$518
535705 - 535705 Contractor Admin Overhea	202412	$570
535705 - 535705 Contractor Admin Overhea	202501	-$515
535705 - 535705 Contractor Admin Overhea	202504	$0
535705 - 535705 Contractor Admin Overhea	202505	$0
535705 - 535705 Contractor Admin Overhea	202506	$0
535705 - 535705 Contractor Admin Overhea	202508	$12,695
535705 - 535705 Contractor Admin Overhea	202509	-$12,543
535705 - 535705 Contractor Admin Overhea	202510	-$152
Total Contractor Admin Overhead		**$573**
605050 - 605050 AFUDC Interest	202302	$645
605050 - 605050 AFUDC Interest	202303	$872
605050 - 605050 AFUDC Interest	202304	$1,100
605050 - 605050 AFUDC Interest	202305	$2,924
605050 - 605050 AFUDC Interest	202306	$1,924
605050 - 605050 AFUDC Interest	202307	$2,771
605050 - 605050 AFUDC Interest	202308	$2,792
605050 - 605050 AFUDC Interest	202309	$3,088
605050 - 605050 AFUDC Interest	202310	$3,420
605050 - 605050 AFUDC Interest	202311	$3,713
605050 - 605050 AFUDC Interest	202312	$4,037
605050 - 605050 AFUDC Interest	202401	$4,524
605050 - 605050 AFUDC Interest	202402	$5,069
605050 - 605050 AFUDC Interest	202403	$5,464
605050 - 605050 AFUDC Interest	202404	$6,455
605050 - 605050 AFUDC Interest	202405	$7,123
605050 - 605050 AFUDC Interest	202406	$7,505
605050 - 605050 AFUDC Interest	202407	$9,020
605050 - 605050 AFUDC Interest	202408	$10,167
605050 - 605050 AFUDC Interest	202409	$13,411
605050 - 605050 AFUDC Interest	202410	$14,695
605050 - 605050 AFUDC Interest	202411	$14,414
605050 - 605050 AFUDC Interest	202412	$16,246
605050 - 605050 AFUDC Interest	202501	$20,110
605050 - 605050 AFUDC Interest	202502	$21,676
605050 - 605050 AFUDC Interest	202503	$22,394
605050 - 605050 AFUDC Interest	202504	$23,514
605050 - 605050 AFUDC Interest	202505	$24,917
605050 - 605050 AFUDC Interest	202506	$24,508
605050 - 605050 AFUDC Interest	202507	$25,298
605050 - 605050 AFUDC Interest	202508	$25,333
605050 - 605050 AFUDC Interest	202509	$25,279
605050 - 605050 AFUDC Interest	202510	$24,166
Total AFUDC Interest		**$378,574**
Total		**$4,137,109**

RtR Set Up Projects	Actuals			Estimates to Complete		Totals
	2023	2024	2025 (end Oct)	2025 Nov-Dec	2026	
Labour	$ 122,016	$ 94,397	$ 49,552	$ -	$ 179,511	**$ 445,476**
Contracts		$ 7,124	$ (3,562)	$ -	$ -	**$ 3,562**
Consulting	$ 516,561	$ 1,943,858	$ 849,281	$ -	$ 490,711	**$ 3,800,411**
Software	$ -	$ 6,461	$ -	$ -		**$ 6,461**
Overheads	$ 92,502	$ 53,309	$ 27,037	$ -	$ -	**$ 172,848**
Interest	$ 27,286	$ 114,093	$ 237,195	$ 48,163	$ 232,899	**$ 659,636**
Contingency					$ 224,545	**$ 224,545**
Total	**$ 758,365**	**$ 2,219,241**	**$ 1,159,504**	**$ 48,163**	**$ 1,127,666**	**$ 5,312,938**

REI IR-11 Attachment 2 has been filed electronically.

Request IR-12:

Reference: Appendix F2, F3 and F4.

(a) For each cross-referenced document from the GRA, please provide the assigned NSEB exhibit number.

(b) Please provide a pdf version of each cross-referenced document and relevant tab from the cross-referenced document.

(c) Please explain why NS Power refused access to confidential information in this matter upon undertaking by REI when it granted such access in respect of the 2024 AARs under similar confidentiality undertakings. What specifically changed in NS Power's assessment of confidentiality risks or REI's status? If NS Power is willing to provide access subject to more limited redactions, please specify what information would be disclosed and what redactions would remain, with justification for each category of redacted information.

Response IR-12:

(a-b) Please refer to the table below.

2026 AAR Appendix	Cross-reference Provided in 2026 AAR Appendix	M12451 NSEB Exhibit No.	Refer to
F2	2026 COSS – Exhibit 5, page 1, Energy	N-17(C)-(i)	Attachment 1
	2026 COSS – Exhibit 5, cell E48		
	2026 COSS – Exhibit 9A, line 11, column 3, divided by a transmission loss factor of 1.03	N-17(C)-(i)	Partially Confidential Attachment 2
	2026 COSS – Exhibit 9A Annual, cell D24		
F3	2026 COSS – Exhibit 5, page 1, column 2	N-17(C)-(i)	Attachment 1
	2026 COSS – Exhibit 6, page 6, column 1	N-17(C)-(i)	Attachment 3
	2026 COSS – Exhibit 9A, column 10	N-17(C)-(i)	Partially Confidential Attachment 2
	2026-2027 GRA SR-01 Attachment 11, Revenue requirement in tab "Anc Serv - Fig 6-8" and "Anc Serv - Fig 6-10".[1]	N-17-(i)	Attachment 4
F4	Not applicable – no cross-references	n/a	n/a

(c) NS Power has granted access to REI counsel in this matter.

[1] 2026 AAR Appendix F3 reference to "2026-2027 GRA DE-03 to DE-04 Appendix L Attachment 3" should have referred to 2026-2027 GRA SR-01 Attachment 11.

NOVA SCOTIA POWER INC.

CLASSIFICATION OF OPERATING EXPENSES

FOR THE YEAR ENDING DECEMBER 31, 2026

(IN THOUSANDS OF DOLLARS)

		(1) TOTAL COMPANY	(2) DEMAND EXPENSES	(3) ENERGY EXPENSES	(4) CUSTOMER EXPENSES
	GENERATION FUNCTION				
(1)	FUEL	434,033	$0	$434,033	-
(2)	PURCHASES - OTHER THAN BIOMASS AND WIND	18,420	$8,334	$10,086	-
(3)	PURCHASES - BIOMASS	20,238	$5,365	$14,874	-
(4)	MARITIME LINK	199,839	$90,413	$109,426	
(5)	PURCHASES - WIND ERIS	33,315	15,071.5	18,243.4	-
(6)	PURCHASES - WIND NRIS	111,168	50,290.1	60,877.4	
(7)	IMPORTS	94,391	0	94,390.8	-
(8)	BUTU CAPACITY CREDIT	302	302	0	
(8)	OPER. & MAINT. - STEAM	111,342	50,384	60,957	-
(9)	OPER. & MAINT. - HYDRO	3,544	1,604	1,940	-
(10)	OPER. & MAINT. - WIND	15,773	7,138	8,635	-
(11)	OPER. & MAINT. - BIOMASS	12,703	5,748	6,955	-
(12)	OPER. & MAINT. - LM6000	1,214	549	665	-
(13)	OPER. & MAINT. - OTHER CT's	2,999	2,999	0	-
(14)	OPER. & MAINT. - GENERATION BATTERIES	0	0	0	-
(15)	OPER. & MAINT. - RADIAL TO GENERATION TRANS.	2,753	1,246	1,507	-
(16)	DSM				
(17)	FCR DEFERRAL	0	0	0	-
(18)	REG. AFFAIRS - ADVOCACY EXPENSE	1,363.8	617	747	-
(18)	GRANTS IN LIEU OF TAXES	22,178	10,036	12,142	-
(19)	**Depreciation:**				
(20)	STEAM	46,717	21,140	25,577	-
(21)	HYDRO	16,146	7,306	8,839	-
(22)	WIND	12,949	5,860	7,089	-
(23)	LM6000	6,832	3,092	3,741	-
(24)	GAS TURBINE - OTHER	2,805	1,269	1,536	-
(25)	GENERATION BATTERIES	8,352	3,779	4,572	-
(26)	RADIAL TO GENERATION TRANS.	2,820	1,276	1,544	-
(27)	GENERAL PROPERTY	17,217	7,791	9,426	-
(28)					
(29)	INTEREST NET OF AFUDC	62,759	24,753	38,007	-
(30)	PREFERRED DIVIDENDS	0	0	0	-
(31)	CORPORATE TAXES	-4,353	-1,717	-2,636	-
(32)	NON-OPERATING REVENUE:				
(33)	EXPORT SALES	0	0	0	-
(34)	STEAM AND ASH SALES	-5,018	-1,295	-3,723	-
(35)	OTHER REVENUE	-3,357	-866	-2,490	-
(36)	RETURN (PROFIT/LOSS)	89,090	35,138	53,952	-
(37)					
(38)	**TOTAL GENERATION**	**$1,338,533.946**	**$357,621.467**	**$980,912.479**	**-**

NOVA SCOTIA POWER INC.

CLASSIFICATION OF OPERATING EXPENSES

FOR THE YEAR ENDING DECEMBER 31, 2026

(IN THOUSANDS OF DOLLARS)

		(1) TOTAL COMPANY	(2) DEMAND EXPENSES	(3) ENERGY EXPENSES	(4) CUSTOMER EXPENSES
	TRANSMISSION FUNCTION				
(1)	**Transmission - HV (not aplicable as a separate item)**				
(2)	O&M - HV Before Storm Expense	0	0	0	-
(3)	O&M - HV Storm Expense	0	0	0	-
(4)	REG. AFFAIRS - ADVOCACY EXPENSE	0	0	0	-
(5)	GRANTS IN LIEU OF TAXES	0	0	0	-
(6)	**Depreciation:**				
(7)	TRANSMISSION	0	0	0	-
(8)	GENERAL PROPERTY	0	0	0	-
(9)					
(10)	INTEREST NET OF AFUDC	0	0	0	-
(11)	PREFERRED DIVIDENDS	0	0	0	-
(12)	CORPORATE TAXES	-0	-0	0	-
(13)	**Non-Operating Revenue:**				
(14)	OTHER REVENUE	-0	-0	0	-
(15)	RETURN (PROFIT/LOSS)	0	0	0	-
(16)					
(17)	**TOTAL - HV**	**0.0**	**0**	**0**	**-**
(18)					
(19)	**Transmission - EHV and HV combined**				
(20)					
(21)	O&M - EHV Before Storm Expense	36,836	36,836	0	-
(22)	O&M - EHV Storm Expense	265	265	0	-
(23)	REG. AFFAIRS - ADVOCACY EXPENSE	134	134	0	-
(24)	GRANTS IN LIEU OF TAXES	9,171	9,171	0	-
(25)	**Depreciation:**				
(26)	TRANSMISSION	25,986	25,986	0	-
(27)	GENERAL PROPERTY	10,577	10,577	0	-
(28)					
(29)	INTEREST NET OF AFUDC	24,044	24,044	0	-
(30)	PREFERRED DIVIDENDS	0	0	0	-
(31)	CORPORATE TAXES	-1,668	-1,668	0	-
(32)	**Non-Operating Revenue:**				
(33)	OTHER REVENUE	-281	-281	0	-
(34)	FCR DEFERRAL	0	0	0	-
(35)	RETURN (PROFIT/LOSS)	34,131	34,131	0	-
(36)					
(37)	**TOTAL - EHV and HV Combined**	**139,195**	**139,195**	**0**	**-**
(38)					
(39)	**TOTAL TRANSMISSION**	**$139,194.860**	**$139,194.86**	**$0**	**-**

EXHIBIT 5
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NOVA SCOTIA POWER INC.

CLASSIFICATION OF OPERATING EXPENSES

FOR THE YEAR ENDING DECEMBER 31, 2026

(IN THOUSANDS OF DOLLARS)

		(1) TOTAL COMPANY	(2) DEMAND EXPENSES	(3) ENERGY EXPENSES	(4) CUSTOMER EXPENSES
	DISTRIBUTION FUNCTION				
(1)	**Before Streetlights:**				
(2)	SUBSTATIONS	$2,076	$2,076	$0	-
(3)	OVERHEAD LINES Before Storm Expense	$57,697	$13,044	$0	44,652.9
(4)	OVERHEAD LINES Storm Expense	25,920	8,696	0	17,223.4
(5)	UNDERGROUND LINES	813	211	0	601.9
(6)	LINE TRANSFORMERS	0	0	0	-
(7)	METERS	1,670	0	0	1,670.3
(8)	COMMUNICATIONS	0	0	0	-
(9)	REG. AFFAIRS - ADVOCACY EXPENSE	311	81	0	230.0
(9)	GRANTS IN LIEU OF TAXES	17,077	9,524	0	7,553.0
(10)	**Depreciation:**				
(11)	DISTRIBUTION - Land	0	-	0	-
(12)	DISTRIBUTION - Easements	2,996	1,501	0	1,494.9
(13)	DISTRIBUTION - Other	1,328	666	0	662.7
(14)	DISTRIBUTION - Substations	8,862	8,862	0	-
(15)	DISTRIBUTION - Poles and Fixtures	20,480	5,325	0	15,154.9
(16)	DISTRIBUTION - OH Lines	11,920	6,282	0	5,638.0
(17)	DISTRIBUTION -UG Lines	2,886	655	0	2,231.0
(18)	DISTRIBUTION -Line Transformers	27,743	27,743	0	-
(19)	DISTRIBUTION -Services	4,054	-	0	4,053.8
(20)	DISTRIBUTION -Meters	7,941	-	0	7,941.4
(21)	GENERAL PROPERTY	25,968	15,046	0	10,922.1
(22)					
(23)	INTEREST NET OF AFUDC	45,412	25,327	0	20,085.4
(24)	PREFERRED DIVIDENDS	0	0	0	-
(25)	CORPORATE TAXES	-3,150	-1,757	0	(1,393.1)
(26)	RETURN (PROFIT/LOSS)	64,464	35,952	0	28,512.2
(27)					
(28)	**Streetlights:**				
(29)	MAINTENACE	813	813	0	-
(30)	GRANTS IN LIEU OF TAXES	327	327	0	-
(31)	DEPRECIATION	4,481	4,481	0	-
(32)	INTEREST NET OF AFUDC	871	871	0	-
(33)	PREFERRED DIVIDENDS	0	0	0	-
(34)	CORPORATE TAXES	-60	-60	0	-
(35)	RETURN (PROFIT/LOSS)	1,236	1,236	0	-
(36)	**Subtotal**	7,668	7,668	0	-
(37)					
(38)	POLE SERVICES	-16,364	-5,490	0	(10,874.0)
(39)	OTHER REVENUE	-716	-346	0	(370.2)
(41)	**TOTAL DISTRIBUTION**	**$317,055.555**	**$161,065.07**	**$0**	**155,990.5**

EXHIBIT 5
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NOVA SCOTIA POWER INC.

CLASSIFICATION OF OPERATING EXPENSES

FOR THE YEAR ENDING DECEMBER 31, 2026

(IN THOUSANDS OF DOLLARS)

		(1) TOTAL COMPANY	(2) DEMAND EXPENSES	(3) ENERGY EXPENSES	(4) CUSTOMER EXPENSES
	RETAIL FUNCTION				
(1)	CUSTOMER EXPERIENCE AND SOLUTIONS	8,639	0	0	8,638.5
(2)	CALL CENTRE	13,495	0	0	13,495.3
(3)	BILLING SERVICES & PAYMENTS	3,800	0	0	3,800.1
(4)	METER SERVICES - INSPECTORS	0	0	0	-
(5)	METER DATA SERVICES	730	0	0	729.7
(6)	METER SERVICES - FIELD	2,365	0	0	2,365.3
(7)	ELECT. WIRING INSPECT. - FIELD	7,627	0	0	7,627.0
(8)	REVENUE OPS ADMIN	0	0	0	-
(9)	CREDIT SERVICES	0	0	0	-
(10)	BAD DEBT EXPENSE	4,969	0	0	4,968.6
(11)	MARKETING & SALES	0	0	0	-
(12)	REG. AFFAIRS - ADVOCACY EXPENSE	28	0	0	28.2
(12)	COGS	0	0	0	-
(13)	GRANTS IN LIEU OF TAXES	426	0	0	426.5
(14)	**Depreciation:**				
(15)	DISTRIBUTION	0	0	0	-
(16)	GENERAL PROPERTY	6,251	0	0	6,250.7
(17)	INTEREST NET OF AFUDC	5,115	0	0	5,115.0
(18)					
(19)	PREFERRED DIVIDENDS	0	0	0	-
(20)	CORPORATE TAXES	-355	0	0	(354.8)
(21)	**Non-Operating Revenue:**				
(22)	LATE PAYMENT CHARGE	(5,743.1)	0	0	(5,743.1)
(23)	CONNECTION CHARGES AND METER REMOVAL	(3,494.1)	0	0	(3,494.1)
(24)	NSF	(158.5)	0	0	(158.5)
(25)	RETAIL SALES	(1,490.5)	0	0	(1,490.5)
(26)	WIRING INSPECTIONS	(7,253.5)	0	0	(7,253.5)
(27)	AMI OPT OUT CHARGE	(830.9)	0	0	(830.9)
(28)	OTHER REVENUE	(141.7)	0	0	(141.7)
(29)	RETURN (PROFIT/LOSS)	7,261.2	0	0	7,261.2
(31)	**TOTAL RETAIL**	**$41,239.3**	**$0.0**	**$0.0**	**$41,239.3**
(33)					
(34)	**TOTAL NET EXPENSES**	**$1,836,023.6**	**$657,881.4**	**$980,912.5**	**$197,229.7**

EXHIBIT 5
Page 5 of 5

NOVA SCOTIA POWER INC.
CLASSIFICATION OF OPERATING EXPENSES
FOR THE YEAR ENDING DECEMBER 31, 2026
(IN THOUSANDS OF DOLLARS)

(1)	***INTERMEDIATE CLASSIFICATION***				
(2)					
(3)	THERMAL O&M	$111,342			
(4)	HYDRO O&M	$3,544			
(5)	WIND O&M	$15,773			
(6)	BIOMASS O&M	$12,703			
(7)	LM6000 O&M	$1,214			
(8)	OTHER CT's O&M	$2,999			
(9)	GENERATION BATTERIES	$0			
(10)	RADIAL TO GENERATION TRANS.	$2,753			
(11)					
(12)	NET THERMAL O&M	$150,328			
(13)					
(14)	THERMAL O&M	$0	Intermediate Classification Factor		
(15)	HYDRO O&M	0	Was:	16%	
(16)	WIND O&M	0	Now:	0%	
(17)					
(18)	BIOMASS O&M	0			
(19)					
(20)	LM6000 O&M	0			
(21)					
(22)					
(23)	OTHER CT's O&M	0			
(24)					
(25)	THERMAL VARIABLE O&M	$0			
(26)					
(27)	THERMAL O&M	$111,342			
(28)					
(29)	HYDRO O&M	3,544			
(30)	WIND O&M	15,773			
(31)	BIOMASS O&M	12,703			
(32)	LM6000 O&M	1,214			
(33)	OTHER CT's O&M	2,999			
	GENERATION BATTERIES	0			
	RADIAL TO GENERATION TRANS.	2,753			
(34)					
(35)	NET THERMAL O&M D&E SPLIT	$150,328			
(36)					
(37)	THERMAL O&M DMD. ALLOC. %	45.25%			
(38)	THERMAL O&M ENG. ALLOC. %	54.75%			
(39)					
(40)	BIOMASS DEMAND ALLOC %	45.25%			
(41)					
(42)	BIOMASS ENERGY ALLOC %	54.75%			
(43)					
(44)		NRIS		ERIS	
(45)	WIND O&M DMD. ALLOC. %	45.25%		45.25%	
(46)	WIND O&M ENG. ALLOC. %	54.75%		54.75%	
(47)					
(48)					
(49)	OTHER CT's O&M DMD. ALLOC. %	100.00%			
(50)					
(51)	POLE & WIRE DMD/CUST SPLIT	26.00%			
(52)					
(53)		**DEMAND**		**ENERGY**	**CUSTOMER**
(54)					
(55)	GEN. PROP. ALLOC. - GEN.	7,791		9,426	0
(56)	GEN. PROP. ALLOC. - TRANS. < 138 kV	0		0	0
(57)	GEN. PROP. ALLOC. - TRANS. > 69 kV	10,577		0	0
(58)	GEN. PROP. ALLOC. - DIST.	15,046		0	10,922
(59)	GEN. PROP. ALLOC. - RETAIL	0		0	6,251
(60)					
(61)	TOTAL	33,414		9,426	17,173

EXHIBIT 9A

NOVA SCOTIA POWER INC.

SALES, GENERATION AND DEMAND ANALYSIS

FOR THE YEAR ENDING DECEMBER 31, 2026

	(1) MWH SALES	(2) ENERGY LINE LOSSES	(3) ENERGY REQUIREMENT	(4) CLASS NON-COINCIDENT DMD. (KW)	(5) SYSTEM COINCIDENT FACTOR	(6) SYSTEM COINCIDENT DMD. (KW)	(7) DEMAND LINE LOSSES	(8) SYSTEM COIN. PEAK DMD. (KW)	(9) SYSTEM COINCIDENT L/D FACTOR	(10) 3CP kW	(11) 3CP % Contribution
(1) DOMESTIC	5,213,777	8.3%	5,644,779	1,567,908	83.9%	1,315,928	14.1%	1,501,844	42.91%	4,353,838	64.2%
(2) SMALL GENERAL	353,434	8.2%	382,310	87,055	78.7%	68,512	12.4%	76,999	56.68%	222,264	3.3%
(3) GENERAL	2,219,406	7.8%	2,393,511	470,705	82.7%	389,273	11.1%	432,607	63.16%	1,206,116	17.8%
(4) GENERAL LARGE	358,568	5.0%	376,587	62,748	70.3%	44,117	6.8%	47,132	91.21%	137,482	2.0%
(5) SMALL INDUSTRIAL	255,142	7.7%	274,652	51,659	70.4%	36,368	14.0%	41,444	75.65%	123,550	1.8%
(6) MEDIUM INDUSTRIAL	438,585	6.7%	467,931	69,240	81.6%	56,500	10.9%	62,638	85.28%	158,818	2.3%
(7) LARGE INDUSTRIAL	697,603	3.5%	722,194	104,169	74.7%	77,775	5.7%	82,192	100.30%	246,525	3.6%
(8) PHP	810,547	2.4%	829,996	199,370	32.6%	65,000	4.3%	67,790	139.77%	203,227	3.0%
(9) MUNICIPAL	124,528	3.2%	128,550	32,826	93.1%	30,554	4.3%	31,866	46.05%	93,931	1.4%
(10) UNMETERED	77,000	8.2%	83,275	21,371	51.0%	10,903	14.1%	12,443	76.40%	31,520	0.5%
(11) SUB-TOTAL	10,548,590	7.2%	11,303,785	2,667,050	78.6%	2,094,930	12.5%	2,356,954	54.74804%	6,777,270	100.0%
(12) SHORE POWER											
(13) GEN.REPL./LOAD FOLL.											
(14) ELIADC											
(15) BUTU											
(16) REAL TIME PRICING											
(17) EBS/SS											
(18) SUB-TOTAL	155,071	0	159,281	94,296	2	53,819	0	56,516	1	178,670	
(19) TOTAL Bfr EXPORT	10,703,661	7.1%	11,463,067	2,761,346	77.8%	2,148,748	12.3%	2,413,470	54.22%	6,955,940	
(20) EXPORT SALES	0		0		0.0%		0.0%	0	0.00%	0	
(21) TOTAL	10,703,661	7.1%	11,463,067	2,761,346	77.8%	2,148,748	12.3%	2,413,470	54.22%	6,955,940	
(22) LG, LIR, MUNIS SUBTOTAL	1,180,700	4.0%	1,227,331	199,743	76.3%	152,446	5.7%	161,189	86.9%	477,938	
VOLTAGE SERVICE-BASED ANALYSIS BY LARGE CUSTOMER RATE CLASSES											
EHV TRANSMISSION SERVICE											
(23) EHV - LIR	217,318	3.1%	224,039	33,243	56.0%	18,609	3.1%	19,185	129.3%	60,987	
HV TRANSMISSION SERVICE											
(24) LARGE INDUSTRIAL	149,381	4.2%	155,636	24,113	83.9%	20,237	4.2%	21,084	80.9%	55,214	
(25) MUNICIPAL	67,563	4.2%	70,392	17,910	92.2%	16,512	4.2%	17,203	44.8%	51,011	
(26) SUBTOTAL	216,944	4.2%	226,029	42,022	87.4%	36,748	4.2%	38,287	64.7%	106,225	
DISTRIBUTION BULK POWER SUBSTATION (>2MVA)											
(27) LARGE INDUSTRIAL	32,210	4.45%	33,643	8,310	56.9%	4,728	4.45%	4,938	74.5%	15,952	
(28) MUNICIPAL	0	0.00%	-	0	0.0%	0	0.00%	-	0.0%	0	
(29) SUBTOTAL	32,210	4.45%	33,643	8,310	56.9%	4,728	4.45%	4,938	74.5%	15,952	
DISTRIBUTION PRIMARY (BFR BULK POWER SUBST.)											
(30) LIR	298,694	5.9%	316,227	50,776	67.4%	34,201	4.4%	35,722	95.5%	111,062	
(31) MUNICIPAL	55,511	4.2%	57,849	14,918	94.1%	14,043	4.2%	14,634	43.3%	45,013	
(32) LARGE GENERAL	358,568	4.8%	376,587	62,748	70.3%	44,117	4.8%	47,132	86.8%	137,482	
(33) SUBTOTAL	712,774	5.3%	750,664	128,441	71.9%	92,361	5.6%	97,488	83.5%	293,557	
DISTRIBUTION TOTAL	744,984	5.3%	784,306	136,751	71.0%	97,089	5.5%	102,426	83.0%	309,509	
(34)EHV, HV, DISTR. BPS, DISTR. PRIMARY FEEDER	1,179,245	4.7%	1,234,374	212,017	71.9%	152,446	4.9%	159,898	88.1%	476,721	
(35) LG, LIR, MUNICIPAL SUBTOTAL	1,180,700	4.0%	1,227,331	199,743	76.3%	152,446	5.7%	161,189	86.9%	477,938	
(36) VARIANCE	(1,454.1)	0.0	7,043.7	12,273.9	(0.0)	0.0	(0.0)	(1,290.9)	0.0	(1,217.1)	

EXHIBIT 6
PAGE 1 OF 6

NOVA SCOTIA POWER INC.

ALLOCATION OF OPERATING EXPENSES

FOR THE YEAR ENDING DECEMBER 31, 2026

(IN THOUSANDS OF DOLLARS)

		(1) TOTAL COMPANY	(2) DOMESTIC	(3) SMALL GENERAL	(4) GENERAL	(5) GENERAL LARGE	(6) SMALL INDUSTRIAL	(7) MEDIUM INDUSTRIAL	(8) LARGE INDUSTRIAL	(9) PHP	(10) MUNICIPAL	(11) UNMETERED	(12) ALLOCATION FACTOR
	DEMAND CLASSIFICATION												
	GENERATION												
(1)	FUEL	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	See BCF File
(2)	PURCHASES - OTHER THAN BIOMASS AND WIND	8,334	5,353.41	273.29	1,483.02	169.05	151.92	195.28	303.12	249.89	115.77	38.76	See BCF File
(3)	PURCHASES - BIOMASS	5,365	3,446.16	175.93	954.67	108.82	97.79	125.71	195.13	160.86	74.53	24.95	See BCF File
(4)	MARITIME LINK	90,413	58,081.04	2,965.04	16,089.83	1,834.04	1,648.18	2,118.66	3,288.69	2,711.09	1,256.04	420.48	See BCF File
(5)	PURCHASES - WIND ERIS	15,071	9,681.86	494.26	2,682.11	305.73	274.74	353.17	548.21	451.93	209.38	70.09	See BCF File
(6)	PURCHASES - WIND NRIS	50,290	32,306.16	1,649.23	8,949.57	1,020.14	916.76	1,178.45	1,829.26	1,507.98	698.64	233.88	See BCF File
(7)	IMPORTS	0	0	0	0	0	0	0	0	0	0	0	See BCF File
(8)	BUTU CAPACITY CREDIT	302	193.84	9.90	53.70	6.12	5.50	7.07	10.98	9.05	4.19	1.40	See BCF File
(9)	OPER. & MAINT. - STEAM	50,384	32,368	1,652	8,967	1,022	919	1,181	1,833	1,511	698	234	D-3A
(10)	OPER. & MAINT. - HYDRO	1,604	1,030	53	285	33	29	38	58	48	22	7	D-3A
(11)	OPER. & MAINT. - WIND	7,138	4,585	234	1,270	145	130	167	260	214	99	33	D-3A
(12)	OPER. & MAINT. - BIOMASS	5,748	3,693	189	1,023	117	105	135	209	172	80	27	D-3A
(13)	OPER. & MAINT. - LM6000	549	353	18	98	11	10	13	20	16	8	3	D-3A
(14)	OPER. & MAINT. - OTHER CT's	2,999	1,927	98	534	61	55	70	109	90	42	14	D-3A
(15)	OPER. & MAINT. - GENERATION BATTERIES	0	0	0	0	0	0	0	0	0	0	0	D-3A
(16)	OPER. & MAINT. - RADIAL TO GENERATION TRANS	1,246	800	41	222	25	23	29	45	37	17	6	D-3A
(17)	DSM	0											See DSM Allocation
(18)	FCR DEFERRAL	0	0	0	0	0	0	0	0	0	0	0	P-14
(19)	REG. AFFAIRS - ADVOCACY EXPENSE	617	300	47	243	0	27	0	0	0	0	0	R-2
(19)	GRANTS IN LIEU	10,036	6,447	329	1,786	204	183	235	365	301	139	47	P-7
(20)	DEPRECIATION	51,514	33,093	1,689	9,168	1,045	939	1,207	1,874	1,545	714	240	EXH 6D
(21)	INTEREST NET OF AFUDC	24,753	15,902	812	4,405	502	451	580	900	742	343	115	P-14
(22)	PREFERRED DIVIDENDS	0	0	0	0	0	0	0	0	0	0	0	P-14
(23)	CORPORATE TAXES	-1,717	-1,103	-56	-306	-35	-31	-40	-62	-51	-24	-8	P-14
(24)	**Non-Operating Revenue:**												
(25)	STEAM AND ASH SALES	-1,295	-832	-43	-231	-26	-24	-30	-47	-39	-18	-6	O-8
(26)	OTHER REVENUE	-866	-556	-28	-155	-18	-16	-20	-31	-26	-12	-4	O-8
(27)	RETURN (PROFIT/LOSS)	35,138	22,573	1,152	6,253	713	641	823	1,278	1,054	487	163	P-14
(28)	INTERR. RIDER DMD ADJ.	-11,165	0	0	0	0	0	0	-11,165	0	0	0	DIRECT
(29)	ALLOC. OF INTERR. DMD. ADJ.	11,165	7,173	366	1,987	226	204	262	406	335	155	52	D-4
(30)	PHP DEMAND ADJ.	-6,338	0	0	0	0	0	0	0	-6,338	0	0	DIRECT
(31)	ALLOC. OF PHP DMD. ADJ.	6,338	4,072	208	1,128	129	116	149	231	190	88	29	D-4
(32)	PHP PRIORITY DMD ADJ.	-634	0	0	0	0	0	0	0	-634	0	0	DIRECT
(33)	ALLOC. OF PHP PRI. DMD. ADJ.	634	407	21	113	13	12	15	23	19	9	3	D-3B
(34)													
(35)	**TOTAL GENERATION**	357,621.467	241,294	12,350	67,003	7,610	6,866	8,791	2,481	4,277	5,205	1,745	
(36)													
(37)	**TRANSMISSION**	357,621	0										
(38)													
(39)	**Transmission - HV (not aplicable as a separate item)**												
(40)	OPERATING & MAINT. (Before Storm Expense)	0	0	0	0	0	0	0	0	0	0	0	D-3B
(41)	OPERATING & MAINT. (Storm Expense)	0	0	0	0	0	0	0	0	0	0	0	D-3B
(42)	REG. AFFAIRS - ADVOCACY EXPENSE	0	0	0	0	0	0	0	0	0	0	0	R-2
(42)	GRANTS IN LIEU	0	0	0	0	0	0	0	0	0	0	0	P-8A
(43)	DEPRECIATION	0	0	0	0	0	0	0	0	0	0	0	EXH 6D
(44)	INTEREST NET OF AFUDC	0	0	0	0	0	0	0	0	0	0	0	P-15A
(45)	PREFERRED DIVIDENDS	0	0	0	0	0	0	0	0	0	0	0	P-15A
(46)	CORPORATE TAXES	-0	-0	-0	-0	-0	-0	-0	-0		-0	-0	P-15A
(47)	**Non-Operating Revenue:**												
(48)	OTHER REVENUE	-0	-0	-0	-0	-0	-0	-0	-0	-0	-0	-0	O-9A
(49)	RETURN (PROFIT/LOSS)	0	0	0	0	0	0	0	0	0	0	0	P-15A
(50)													
(51)	**TOTAL - HV**	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	

EXHIBIT 6
PAGE 2 OF 6

NOVA SCOTIA POWER INC.

ALLOCATION OF OPERATING EXPENSES

FOR THE YEAR ENDING DECEMBER 31, 2026

(IN THOUSANDS OF DOLLARS)

DEMAND CLASSIFICATION

		(1) TOTAL COMPANY	(2) DOMESTIC	(3) SMALL GENERAL	(4) GENERAL	(5) GENERAL LARGE	(6) SMALL INDUSTRIAL	(7) MEDIUM INDUSTRIAL	(8) LARGE INDUSTRIAL	(9) PHP	(9) MUNICIPAL	(10) UNMETERED	(11) ALLOCATION FACTOR
(1)	**Transmission - EHV and HV combined**												
(2)	OPERATING & MAINT. (Before Storm Expense)	36,836	23,664	1,208	6,556	747	672	863	1,340	1,105	511	171	D-3A
(3)	OPERATING & MAINT. (Storm Expense)	265	170	9	47	5	5	6	10	8	4	1	D-3A
(4)	REG. AFFAIRS - ADVOCACY EXPENSE	134	65	10	53	0	6	0	0	0	0	0	R-2
(4)	GRANTS IN LIEU	9,171	5,892	301	1,632	186	167	215	334	275	127	43	P-8B
(5)	DEPRECIATION	36,562	23,488	1,199	6,507	742	667	857	1,330	1,096	507	170	EXH 6D
(6)	INTEREST NET OF AFUDC	24,044	15,446	789	4,279	488	438	563	875	721	333	112	P-15B
(7)	PREFERRED DIVIDENDS	0	0	0	0	0	0	0	0	0	0	0	P-15B
(8)	CORPORATE TAXES	-1,668	-1,071	-55	-297	-34	-30	-39	-61	-50	-23	-8	P-15B
(9)	**Non-Operating Revenue:**												
(10)	FCR DEFERRAL	0	0	0	0	0	0	0	0	0	0	0	P-15B
(11)	OTHER REVENUE	-281	-181	-9	-50	-6	-5	-7	-10	-8	-4	-1	O-9B
(12)	RETURN (PROFIT/LOSS)	34,131	21,927	1,119	6,074	692	622	800	1,242	1,023	473	159	P-15B
(13)													
(14)	**TOTAL - EHV**	139,195	89,400	4,571	24,801	2,821	2,541	3,259	5,058	4,170	1,927	647	
(15)													
(16)	**TOTAL TRANSMISSION**	139,194.86	89,400	4,571	24,801	2,821	2,541	3,259	5,058	4,170	1,927	647	
(17)													
(18)	**DISTRIBUTION**												
(19)	**Before Streetlights:**												
(20)	OPERATING & MAINT.	24,028	16,170	888	4,710	435	520	622	359	0	103	220	EXH 6A
(21)	REG. AFFAIRS - ADVOCACY EXPENSE	81	39	6	32	0	4	0	0	0	0	0	R-2
(21)	GRANTS IN LIEU	9,524	6,513	359	1,882	113	209	234	99	0	27	89	P-9
(22)	DEPRECIATION	66,079	45,192	2,489	13,057	784	1,447	1,621	688	0	186	616	EXH 6D
(23)	INTEREST NET OF AFUDC	25,327	17,311	953	5,002	302	554	621	265	0	72	246	P-16
(24)	PREFERRED DIVIDENDS	0	0	0	0	0	0	0	0	0	0	0	P-16
(25)	CORPORATE TAXES	-1,757	-1,201	-66	-347	-21	-38	-43	-18	0	-5	-17	P-16
(26)	**Non-Operating Revenue:**												
(27)	POLE SERVICES	-5,490	-3,734	-206	-1,083	-78	-120	-138	-63	0	-19	-51	P-21
(27)	OTHER REVENUE	-346	-224	-12	-65	-4	-7	-8	-4	0	-1	-20	O-10
(28)	RETURN (PROFIT/LOSS)	35,952	24,574	1,353	7,100	429	787	882	376	0	102	349	P-16
(29)													
(30)	**Streetlights:**												
(31)	OPERATING & MAINT.	813	0	0	0	0	0	0	0	0	0	813	EXH 6A
(32)	GRANTS IN LIEU OF TAXES	327	0	0	0	0	0	0	0	0	0	327	P-9A
(33)	Depreciation	4,481	0	0	0	0	0	0	0	0	0	4,481	EXH 6D
(34)	INTEREST NET OF AFUDC	871	0	0	0	0	0	0	0	0	0	871	P-16B
(35)	PREFERRED DIVIDENDS	0	0	0	0	0	0	0	0	0	0	0	P-16B
(36)	CORPORATE TAXES	-60	0	0	0	0	0	0	0	0	0	-60	P-16B
(37)	RETURN (PROFIT/LOSS)	1,236	0	0	0	0	0	0	0	0	0	1,236	P-16B
(38)	**Subtotal**	7,668	0	0	0	0	0	0	0	0	0	7,668	
(39)													
(40)	**TOTAL DISTRIBUTION**	161,065.07	104,641	5,764	30,288	1,960	3,355	3,790	1,701	0	466	9,100	
(41)													
(42)	**TOTAL DEMAND**	**$657,881.398**	**$435,335**	**$22,684**	**$122,091**	**$12,391**	**$12,762**	**$15,840**	**$9,240**	**$8,447**	**$7,598**	**$11,492**	

NOVA SCOTIA POWER INC.

FOR THE YEAR ENDING DECEMBER 31, 2026
(IN THOUSANDS OF DOLLARS)

		(1) TOTAL COMPANY	(2) DOMESTIC	(3) SMALL GENERAL	(4) GENERAL	(5) GENERAL LARGE	(6) SMALL INDUSTRIAL	(7) MEDIUM INDUSTRIAL	(8) LARGE INDUSTRIAL	(9) PHP	(10) MUNICIPAL	(11) UNMETERED	(12) ALLOCATION FACTOR
	ENERGY CLASSIFICATION												
	GENERATION												
(1)	FUEL	$434,033	220,600.0	14,745.4	91,293.8	14,101.8	10,377.1	17,475.9	26,845.9	30,392.9	5,082.8	3,117.3	See BCF
(2)	PURCHASES - OTHER THAN BIOMASS AND WIND	$10,086	4,875.7	339.1	2,164.5	352.5	253.3	437.8	679.3	798.2	107.9	78.0	See BCF
(3)	PURCHASES - BIOMASS	$14,874	7,239.06	504.77	3,203.41	519.57	372.05	635.94	988.43	1,133.97	163.14	113.61	See BCF
(4)	MARITIME LINK	$109,426	52,743.3	3,685.4	23,561.4	3,847.3	2,740.5	4,747.9	7,396.7	8,676.5	1,178.0	848.9	See BCF
(5)	PURCHASES - WIND ERIS	$18,243	8,948.68	614.10	3,887.65	624.95	452.50	776.26	1,198.05	1,403.95	198.97	138.33	See BCF
(6)	PURCHASES - WIND NRIS	$60,877	30,002.73	2,047.07	12,928.21	2,066.72	1,503.33	2,578.18	3,976.64	4,647.45	667.34	459.78	See BCF
(7)	IMPORTS	$94,391	44,139.24	3,170.98	20,577.38	3,451.42	2,422.41	4,259.35	6,707.37	7,924.44	975.96	762.24	See BCF
(8)	BUTU CAPACITY CREDIT	$0	-	-	-	-	-	-	-	-	-	-	See BCF
(8)	OPER. & MAINT. - STEAM	60,957	30,440	2,062	12,907	2,031	1,481	2,523	3,895	4,476	693	449	E-1A
(9)	OPER. & MAINT. - HYDRO	1,940	969	66	411	65	47	80	124	142	22	14	E-1A
(10)	OPER. & MAINT. - WIND/BIOMASS	8,635	4,312	292	1,829	288	210	357	552	634	98	64	E-1A
(11)	OPER. & MAINT. - BIOMASS	6,955	3,473	235	1,473	232	169	288	444	511	79	51	E-1A
(12)	OPER. & MAINT. - LM6000	665	332	22	141	22	16	28	42	49	8	5	E-1A
(13)	OPER. & MAINT. - OTHER CT's	0	0	0	0	0	0	0	0	0	0	0	E-1A
(14)	OPER. & MAINT. - GENERATION BATTERIES	0	0	0	0	0	0	0	0	0	0	0	E-1A
(15)	OPER. & MAINT. - RADIAL TO GENERATION TRANS	1,507	753	51	319	50	37	62	96	111	17	11	E-1A
(16)	DSM	0											See DSM Allocation
(17)	FCR DEFERRAL	0	0	0	0	0	0	0	0	0	0	0	P-17
(18)	REG. AFFAIRS - ADVOCACY EXPENSE	747	363	57	294	0	33	0	0	0	0	0	R-2
(18)	GRANTS IN LIEU	12,142	6,063	411	2,571	405	295	503	776	892	138	89	P-10
(19)	DEPRECIATION	62,324	31,123	2,108	13,197	2,076	1,514	2,580	3,982	4,576	709	459	EXH 6D
(20)	INTEREST NET OF AFUDC	38,007	18,979	1,285	8,048	1,266	923	1,573	2,428	2,791	432	280	P-17
(21)	PREFERRED DIVIDENDS	0	0	0	0	0	0	0	0	0	0	0	P-17
(22)	CORPORATE TAXES	-2,636	-1,316	-89	-558	-88	-64	-109	-168	-194	-30	-19	P-17
(23)	**Non-Operating Revenue:**												
(24)	EXPORT SALES	0	-	-	-	-	-	-	-	-	-	-	See BCF File
(25)	STEAM AND ASH SALES	-3,723	(1,851.14)	(126.09)	(790.84)	(124.90)	(90.88)	(154.77)	(239.20)	(275.11)	(42.05)	(27.61)	O-11
(26)	OTHER REVENUE	-2,490	-1,238	-84	-529	-84	-61	-104	-160	-184	-28	-18	O-11
(27)	RETURN (PROFIT/LOSS)	53,952	26,942	1,825	11,424	1,797	1,311	2,233	3,447	3,962	614	397	P-17
(28)													
(29)	**TOTAL GENERATION**	980,912.547	487,892	33,221	208,351	32,900	23,942	40,772	63,011	72,467	11,084	7,273	
(30)													
(31)	**TRANSMISSION**												
	Transmission - HV (not aplicable as a separate item)												
(33)													
(34)	OPERATING & MAINT. (Before Storm Expense)	0	0	0	0	0	0	0	0	0	0	0	E-1B
(35)	OPERATING & MAINT. (Storm Expense)	0	0	0	0	0	0	0	0	0	0	0	E-1B
(36)	REG. AFFAIRS - ADVOCACY EXPENSE	0	0	0	0	0	0	0	0	0	0	0	R-2
(36)	GRANTS IN LIEU	0	0	0	0	0	0	0	0	0	0	0	P-11A
(37)	DEPRECIATION	0	0	0	0	0	0	0	0	0	0	0	EXH 6D
(38)	INTEREST NET	0	0	0	0	0	0	0	0	0	0	0	P-18A
(39)	PREFERRED DIVIDENDS	0	0	0	0	0	0	0	0	0	0	0	P-18A
(40)	CORPORATE TAXES	0	0	0	0	0	0	0	0	0	0	0	P-18A
(41)	**Non-Operating Revenue:**												
(42)	OTHER REVENUE	0	0	0	0	0	0	0	0	0	0	0	O-12A
(43)	RETURN (PROFIT/LOSS)	0	0	0	0	0	0	0	0	0	0	0	P-18A
(44)													
(45)	**TOTAL - HV**	0	0	0	0	0	0	0	0	0	0	0	
(46)													
(47)	**Transmission - EHV and HV combined**												
(48)	OPERATING & MAINT. (Before Storm Expense)	0	0	0	0	0	0	0	0	0	0	0	E-1A
(49)	OPERATING & MAINT. (Storm Expense)	0	0	0	0	0	0	0	0	0	0	0	E-1A
(50)	REG. AFFAIRS - ADVOCACY EXPENSE	0	0	0	0	0	0	0	0	0	0	0	R-2
(50)	GRANTS IN LIEU	0	0	0	0	0	0	0	0	0	0	0	P-11B
(51)	DEPRECIATION	0	0	0	0	0	0	0	0	0	0	0	EXH 6D
(52)	INTEREST NET	0	0	0	0	0	0	0	0	0	0	0	P-18B
(53)	PREFERRED DIVIDENDS	0	0	0	0	0	0	0	0	0	0	0	P-18B
(54)	CORPORATE TAXES	0	0	0	0	0	0	0	0	0	0	0	P-18B
(55)	**Non-Operating Revenue:**												
(56)	FCR DEFERRAL	0	0	0	0	0	0	0	0	0	0	0	P-18B
(57)	OTHER REVENUE	0	0	0	0	0	0	0	0	0	0	0	O-12B
(58)	RETURN (PROFIT/LOSS)	0	0	0	0	0	0	0	0	0	0	0	P-18B
(59)													
(60)	**TOTAL - EHV**	0	0	0	0	0	0	0	0	0	0	0	
(61)													
(62)	**TOTAL TRANSMISSION**	0	0	0	0	0	0	0	0	0	0	0	
(63)													
(64)	**TOTAL ENERGY**	**$980,912.547**	**$487,892**	**$33,221**	**$208,351**	**$32,900**	**$23,942**	**$40,772**	**$63,011**	**$72,467**	**$11,084**	**$7,273**	

NOVA SCOTIA POWER INC.
ALLOCATION OF OPERATING EXPENSES
FOR THE YEAR ENDING DECEMBER 31, 2026
(IN THOUSANDS OF DOLLARS)

		(1) TOTAL COMPANY	(2) DOMESTIC	(3) SMALL GENERAL	(4) GENERAL	(5) GENERAL LARGE	(6) SMALL INDUSTRIAL	(7) MEDIUM INDUSTRIAL	(8) LARGE INDUSTRIAL	(9) PHP	(10) MUNICIPAL	(11) UNMETERED	(12) ALLOCATION FACTOR
(1)	**CUST. CLASSIFICATION**												
(2)													
(3)	**DISTRIBUTION**												
(4)	OPERATING & MAINT.	$64,149	$57,999	$3,266	$1,442	$2	$271	$18	$3	$0	$0	$1,146	EXH 6A
(5)	REG. AFFAIRS - ADVOCACY EXPENSE	230	112	18	90	0	10	0	0	0	0	0	R-2
(5)	GRANTS IN LIEU	7,553	6,745	384	258	1	49	4	1	0	0	112	P-12
(6)	DEPRECIATION	48,099	42,951	2,443	1,646	3	311	27	6	0	0	711	EXH 6D
(7)	INTEREST NET OF AFUDC	20,085	17,950	1,020	672	1	127	11	2	0	0	301	P-19
(8)	PREFERRED DIVIDENDS	0	0	0	0	0	0	0	0	0	0	0	P-19
(9)	CORPORATE TAXES	-1,393	-1,245	-71	-47	-0	-9	-1	-0	-0	-0	-21	P-19
(10)	**Non-Operating Revenue:**												
(11)	POLE SERVICES	-10,874	-9,850	-553	-226	-0	-42	-2	-0	0	-0	-200	P-22
(12)	OTHER REVENUE	-370	-332	-19	-11	-0	-2	-0	-0	-0	-0	-6	O-13
(13)	RETURN (PROFIT/LOSS)	28,512	25,481	1,448	954	2	180	15	3	0	0	427	P-19
(14)													
(15)	**TOTAL DISTRIBUTION**	155,990.484	139,811	7,936	4,780	9	895	72	15	0	0	2,471	
(16)													
(17)	**RETAIL**												
(18)	METER READING & ELECTRIC INSPECT.	9,991.881	7,441	943	822	33	120	53	50	42	1	486	EXH 6A
(19)	CUSTOMER EXPERIENCE AND SOLUTIONS	8,638.505	5,191	901	1,426	203	155	249	394	0	24	95	O-15
(20)	CALL CENTRE	13,495.312	10,995	740	863	60	116	88	92	80	7	454	C-3
(21)	BILLING SERVICES	3,800.130	3,096	208	243	17	33	25	26	23	2	128	C-3
(22)	ELECT. WIRING INSP. - H/O	0.000	0	0	0	0	0	0	0	0	0	0	C-7
(23)	METER DATA SERVICES	729.727	46	66	116	106	76	80	113	3	123	0	O-16
(24)	PAYMENT SERVICES	0.000	0	0	0	0	0	0	0	0	0	0	C-7
(25)	CREDIT SERVICES	4,968.617	4,174	118	608	0	68	0	0	0	0	0	EXH 6C
(26)	MARKETING & SALES	0.000	0	0	0	0	0	0	0	0	0	0	O-15
(27)	REG. AFFAIRS - ADVOCACY EXPENSE	28.237	14	2	11	0	1	0	0	0	0	0	R-2
(27)	COGS	0.000	0	0	0	0	0	0	0	0	0	0	C-7
(28)	GRANTS IN LIEU	426.486	381	22	15	0	3	0	0	0	0	6	N/A
(29)	DEPRECIATION	6,250.665	5,582	317	214	0	40	3	1	0	0	92	N/A
(30)	INTEREST NET OF AFUDC	5,115.017	4,021	215	495	57	62	104	104	0	19	38	N/A
(31)	PREFERRED DIVIDENDS	0.000	0	0	0	0	0	0	0	0	0	0	N/A
(32)	CORPORATE TAXES	(354.765)	-279	-15	-34	-4	-4	-7	-7	-0	-1	-3	N/A
(33)	**Non-Operating Revenue:**												
(34)	LATE PAYMENT CHARGE	(5,743.057)	-4,690	-267	-616	-3	-69	-92	-1	0	0	-5	R-3
(35)	CONNECTION CHARGES AND METER REMOVAL	(3,494.065)	-3,300	-135	-45	-4	-5	-0	-0	0	0	-5	R-4
(36)	NSF	(158.508)	-154	-3	-2	-0	-0	-0	0	0	0	-0	R-5
(37)	RETAIL SALES	(1,490.5)	-47	0	-768	-105	-56	-311	-177	0	-26	0	R-6
(38)	WIRING INSPECTIONS	(7,253.478)	-5,180	-769	-633	-21	-94	-36	-32	-27	0	-462	C-8
(39)	AMI OPT OUT CHARGE	(830.884)	-701	-47	-55	-4	-7	-6	-6	-5	-0	0	C-6
(40)	OTHER REVENUE	(141.684)	-109	-8	-13	-1	-2	-2	-2	-0	-1	-3	O-14
(41)	RETURN (PROFIT/LOSS)	7,261.241	5,708	306	703	80	88	148	147	0	28	54	N/A
(42)													
(43)	**TOTAL RETAIL**	41,238.829	32,187	2,594	3,351	414	527	297	701	116	176	876	
(44)	-		32,187										
(45)	**TOTAL CUSTOMER**	**197,229**	**171,998**	**10,531**	**8,131**	**423**	**1,422**	**369**	**716**	**116**	**176**	**3,347**	
(46)													
(47)	**TOTAL NET EXPENSES**	**1,836,023**	**1,095,225**	**66,436**	**338,573**	**45,713**	**38,126**	**56,981**	**72,968**	**81,030**	**18,858**	**22,112**	$22,112

EXHIBIT 6
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NOVA SCOTIA POWER INC.
ALLOCATION OF OPERATING EXPENSES
FOR THE YEAR ENDING DECEMBER 31, 2026
(IN THOUSANDS OF DOLLARS)

		(1) TOTAL COMPANY	(2) DOMESTIC	(3) SMALL GENERAL	(4) GENERAL	(5) GENERAL LARGE	(6) SMALL INDUSTRIAL	(7) MEDIUM INDUSTRIAL	(8) LARGE INDUSTRIAL	(9) PHP	(10) MUNICIPAL	(11) UNMETERED
(1)	**COSTS BY FUNCTIONAL AREAS**											
(2)	**Generation**											
(3)	FAM-related	$911,705	$477,611	$30,674	$187,829	$28,408	$21,216	$34,890	$53,968	$60,068	$10,733	$6,308
(4)	Non-FAM-related	435,203	256,053	15,178	89,230	12,354	9,783	14,982	12,001	17,200	5,656	2,766
(5)	Non-Operating Revenue Credit	-8,374	-4,477	-281	-1,705	-252	-191	-309	-478	-524	-100	-56
(6)	**Subtotal**	1,338,534	729,187	45,571	275,353	40,510	30,808	49,563	65,491	76,745	16,289	9,018
(7)												
(8)	**Transmission**											
(9)	**Operating Costs**											
(10)	EHV	$139,476	$89,581	$4,580	$24,851	$2,827	$2,546	$3,265	$5,069	$4,178	$1,931	$648
(11)	HV	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(12)	Subtotal	$139,476	$89,581	$4,580	$24,851	$2,827	$2,546	$3,265	$5,069	$4,178	$1,931	$648
(13)	Non-Operating Revenue Credit	($281)	($181)	($9)	($50)	($6)	($5)	($7)	($10)	($8)	($4)	($1)
(14)	**Subtotal**	$139,194.860	$89,400	$4,571	$24,801	$2,821	$2,541	$3,259	$5,058	$4,170	$1,927	$647
(15)												
(16)	**Distribution**											
(17)	Non-Streetlight-related	$326,468	$258,591	$14,489	$36,453	$2,051	$4,422	$4,011	$1,784	$0	$486	$4,179
(18)	Streetlight-related	$7,668	$0	$0	$0	$0	$0	$0	$0	$0	$0	$7,668
(19)	Non-Operating Revenue Credit	($17,081)	($14,140)	($790)	($1,385)	($83)	($171)	($148)	($67)	($0)	($20)	($277)
(20)	**Subtotal**	$317,055.555	$244,451	$13,700	$35,068	$1,969	$4,250	$3,863	$1,717	$0	$466	$11,571
(21)												
(22)	**Retail**											
(23)	Operating Costs	$60,351	$46,368	$3,825	$5,483	$552	$759	$743	$920	$148	$203	$1,351
(24)	Non-Operating Revenue Credit	($19,112)	($14,181)	($1,230)	($2,132)	($138)	($232)	($446)	($219)	($32)	($27)	($474)
(25)	**Subtotal**	$41,238.829	$32,187	$2,594	$3,351	$414	$527	$297	$701	$116	$176	$876
(26)												
(27)	**Total**	**$1,836,023.258**	**$1,095,225**	**$66,436**	**$338,573**	**$45,713**	**$38,126**	**$56,981**	**$72,968**	**$81,030**	**$18,858**	**$22,112**
(28)												
(29)	**Costs by Functional Areas (relative shares)**											
(30)	Generation	73%	67%	69%	81%	89%	81%	87%	90%		86%	41%
(31)	Transmission	8%	8%	7%	7%	6%	7%	6%	7%		10%	3%
(32)	Distribution	17%	22%	21%	10%	4%	11%	7%	2%		2%	52%
(33)	Retail	2%	3%	4%	1%	1%	1%	1%	1%		1%	4%
(34)	**Total**	100%	100%	100%	100%	100%	100%	100%	100%		100%	100%
(35)												
(36)	**AVERAGE CUSTOMER COST CALC**											
(37)	**Customer Related Costs**											
(38)	Distribution bfr Non-Operationg Credit	167,235	149,993	8,508	5,017	9	940	75	16	0	0	2,676
(39)	Retail bfr Non-Operatin Credit	60,351	46,368	3,825	5,483	552	759	743	920	148	203	1,351
(40)	Subtotal	227,586	196,361	12,332	10,501	562	1,699	818	936	148	203	4,027
(41)												
(42)	**Misc Rev Credit**											
(43)	Distribution	(11,244.3)	-10,182	-572	-237	-0	-44	-2	-0	-0	-0	-206
(44)	Retail	(19,112.2)	-14,181	-1,230	-2,132	-138	-232	-446	-219	-32	-27	-474
(45)	Total	(30,356.5)	-24,363	-1,802	-2,369	-139	-277	-449	-219	-32	-27	-680
(46)												
(47)	**Total**	197,229.3	171,998	10,531	8,131	423	1,422	369	716	116	176	3,347
(48)	% of Total Cost	10.7%	15.7%	15.9%	2.4%	0.9%	3.7%	0.6%	1.0%		0.9%	15.1%
(49)												
(50)	Customers	539,847	488,926	27,443	11,240	20	2,102	175	36	1	1	9,903
(51)	Bill Months	6,478,161	5,867,114	329,312	134,880	240	25,219	2,105	434	12	12	118,832
(52)												
(53)	**Average Monthly Cost per Customer**	**30.45**	**29.32**	**31.98**	**60.29**	**1,762.34**	**56.39**	**175.35**	**1,651.60**		**14,673.78**	**28.17**

EXHIBIT 6
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NOVA SCOTIA POWER INC.
ALLOCATION OF OPERATING EXPENSES
FOR THE YEAR ENDING DECEMBER 31, 2026
(IN THOUSANDS OF DOLLARS)

(1) **INTERR. RIDER DMD ADJ.**
(2)
(3) Peak Dmd. in KWs (at Generator) 69,594
(4) Int Credit Amount 11,165
(5)
(6) **PHP DEMAND ADJUSTMENT CALCULATION**
(7)
(8)

			Demand Usage				Annual Credit Amount Calculation					
			Winter Month kW Coincident Demand	Power Factor Adjustment	Winter Month kVA Coincident Demand	Sum of 12 Month kVA Demands	LIR Int Credit ($/kVA)	Base Amount	% Premium For Priority Interruptions	Priority Premium ($/kVA)	Preimum Amount	Total Amount
(9)												
(10)												
(11)	Sum of Monthly Demands in KVAs (at the Meter)	829,787	65,000	1.06	69,149	829,787	($7.638)	($6,338,009)	10.0%	($0.764)	($633,801)	($6,971,810)
(12)	Int Credit Amount - PHP	6,338										
(13)												
(14)	**Priority Interruption Demand Adjustment Calculation**											
(15)												
(16)	Sum of Monthly Demands in KVAs (at the Meter)	829,787										
(17)	Int Credit Amount - PHP	634										

FIGURE 6-8

NOVA SCOTIA POWER INC.
CAPACITY BASED ANCILLARY SERVICES
2026 REVENUE REQUIREMENT AND RATE DESIGN

	(1) Revenue Requirement ($/kW-yr)	(2) Services Required (MW)	(3) Revenue Requirement ($000/yr)	(4) Usage (MW)	(5) Rate for Network ($/MW-yr)	(6) Rate for Network ($/MW-mo)	(7) Rate for Pt.-to-Pt. ($/MW-mo)	(8) Rate for Pt.-to-Pt. ($/MW-wk)	(9) Rate for Pt.-to-Pt. ($/MW-dy)
Regulation and Frequency Response									
Regulation	$ 159.35	32	$5,099.09	1,940	$2,628.40	$219.03	$219.03	$50.55	$7.20
Load Following	$ 172.64	122.6	$21,166.11	1,940	$10,910.36	$909.20	$909.20	$209.81	$29.89
Operating Reserves (Contingency Reserves)									
Spinning (10 Minute)	$ 131.45	32	$4,206.37	1,940	$2,168.23	$180.69	$180.69	$41.70	$5.94
Supplemental (10 Minute)	$ 122.07	101	$12,328.77	1,940	$6,355.04	$529.59	$529.59	$122.21	$17.41
Supplemental (30 Minute)	$ 120.25	50	$6,012.71	1,940	$3,099.33	$258.28	$258.28	$59.60	$8.49

NOTES:
1. Revenue Requirement is from OATT Allocation attachments

FIGURE 6-10

NOVA SCOTIA POWER INC.
2026 REACTIVE SUPPLY AND VOLTAGE CONTROL
RATE DESIGN

	(1) Revenue Requirement ($000/yr)	(2) Billing Determinants (MW)	(3) Yearly ($/MW-yr)	(4) Monthly ($/MW-mo)	(5) Weekly ($/MW-wk)	(6) On-Peak Daily ($/MW-dy)	(7) Off-Peak Daily ($/MW-dy)	(8) On-Peak Hourly ($/MW-hr)	(9) Off-Peak Hourly ($/MW-hr)
Reactive Supply and Voltage Control									
Total	$4,118								
Less: Credits	0.0								
Net	4,118								
Point-to-Point	$644.6	330	$1,953.42	$162.79	$37.57	$7.51	$5.35	$0.47	$0.22
Network Services	$3,473.4	1,940	$1,790.40	$149.20					
	$4,118.0	2,270							

NOTES:
1. Point-to-Point and Network Services Reactive Supply and Voltage Control Revenue Requirements are segregated as per Figure 5-10, Col. 3.

Annually Adjusted Rates for 2026 (M12551)
NSPI Responses to REI Information Requests

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Request IR-13:

Reference: Energy Balancing Service Tariff, pages 31-32 and Appendix F2.

(a) Please compare the forecasted export sales for 2025 and 2026 and provide an explanation.

(b) Please explain how the transmission loss factor is calculated or determined.

(c) With respect to Figure 9, please add a column to show the percentage change for each component of the EBS compared to 2025 rates. Where the change is greater than 10% for a particular component, please provide a detailed explanation of the driver(s), including the relative contribution of each driver to the total change.

Response IR-13:

(a) By design, the Energy Balancing Service (EBS) rate calculations are predicated on the cost-of-service studies (COSS) filed in General Rate Applications (GRA). The EBS rates approved for use in 2025 reflect the cost inputs, inclusive of the export sales revenues, from the test year 2023 COS from the 2023-2024 GRA. The export sales forecast, set at $0, in this AAR application comes from the 2026 COS filed in the 2026-2027 GRA proceeding.

(b) Please refer to Section 7 of the 2026-2027 GRA Appendix 12A and Appendix12C[1] filed as Exhibit N-9 in NSEB depository.

(c) Please see the figure below.

[1] M12451: 2026-2027 General Rate Application (GRA)

Energy Balancing Service Tariff Charges				
	2025	**2026**	**Variance**	
			Amount	**Percent (%)**
Administration Charge ($/customer/month)	$401.58	$414.63	$13.05	3.25
Energy Charge (cents per kWh)	-	-	-	-
Fuel Cost (cents per kWh)	8.919	6.736	(2.183)	(24.47)
Fixed Cost Adder	3.264	2.166	(1.099)	(33.66)
Total	**12.183**	**8.902**	**(3.281)**	(26.93)
Energy Credit (cents per kWh)	**8.919**	**6.736**	**(2.183)**	(24.47)

The double percent digit reduction in the fuel cost components are due to the overall lower cost of energy generation as provided in Figure 1: Cost of Energy Generation in the evidence of the Application.

The reduction of 33.66 percent in the Fixed Cost Adder is due to the following causes as reflected in the 2023 and 2026 COSS.

- Change in the COS methodology which resulted in a smaller proportion of generation rate base being classified to energy. In the 2023 COSS this proportion was 64.4 percent whereas in the 2026 COSS it is 54.7 percent. As a result of this, the share of the energy-related non-fuel generation costs went down.

- Increase of 13 percent in the annual TWh energy requirement of the above-the-line (ATL) rate classes due to migration of PHP load of 0.8 TWh from the below-the-line (BTL) to ATL rate classes and a significant growth in the domestic load.

- Overall decrease of 9 percent in the non-fuel generation costs primarily due to the reduction in generation rate base of over 8 percent.

Annually Adjusted Rates for 2026 (M12551)
NSPI Responses to REI Information Requests

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Request IR-14:

Reference: Standby Service, page 34.

With respect to Figure 10, please add a column to show the percentage change for each component of the Standby Service Tariff compared to 2025 rates. Where the change is greater than 10% for a particular component, please provide a detailed explanation of the driver(s), including the relative contribution of each driver to the total change.

Response IR-14:

Please see the figure below.

	2025	2026	Variance	
			Amount	Percent
Administration Charge ($/customer/month)	401.58	414.63	13.05	3.25
Demand Charge ($/kW)	3.397	5.452	2.055	60.5

The increase of 60.5 percent in the Demand Charge is due to the following causes as reflected in the 2023 and 2026 Cost-of-Service Study (COSS).

- Change in the COSS methodology which resulted in a bigger proportion of generation rate base being classified to demand. In the 2023 COSS this proportion was 35.6 percent whereas in the 2026 COSS it is 45.3 percent. This caused an increase in the non-fuel demand-related costs of 24 percent. Also, please refer to REI IR-13 for discussion of changes in the fixed cost adder in the energy charge under the Energy Balancing Service (EBS) Tariff.

- Decrease in ancillary generation related costs of 19 percent between the submitted OATT applications in the 2023-2024 GRA and the 2026-2027 GRA.

- Exclusion of the interruptible credit amount of $11.2 million from the generation costs applicable to the standby demand charge.

- As a result of the above changes the costs applicable to the demand charge went up by 76 percent.

- The above total cost change effect is partially mitigated by an increase in demand usage of 6 percent.

- The residual imbalance from 60.5 percent is attributable to the cross-over effect.

Annually Adjusted Rates for 2026 (M12551)
NSPI Responses to REI Information Requests

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Request IR-15:

Reference: Appendix F3, page 137 Standby Demand Charge Calculation.

(a) Please explain in detail the source and derivation of the Interruptible Service Credit, including the methodology, assumptions, and calculations used to determine the credit amount.

(b) As this Interruptible Service Credit was not part of the 2025 AARs (or prior years), please confirm whether this relates to the Pilot Interruptible Service in the RtR market.

(c) Please provide the Board order or tariff provision authorizing this credit and explain the rationale for its inclusion in the 2026 Standby Demand Charge calculation.

Response IR-15:

(a) The Company applied the following calculations.

- The interruptible service credit of $14.053 per kW of monthly standby contract demand represents monthly instalment of an annual credit of $168.638 per kW ($168.638/kW/year / 12 = $14.053/kW/month)

- The annual credit of $168.638 per kW is a ratio of an interruptible credit amount of 11.165 million, applicable to the Large Industrial (LI) class, and an average of three winter month coincident peaks (3CP) of the interruptible load of the LI class of 66,208 kW at the delivery point form the transmission system (system coincident peak of the interruptible load of the LI class net of transmission losses). ($11.165 million / 66,208,000 kW = $168.638 per kW).

- The LI interruptible credit of $11.165 million is a product of the levelized annual capacity cost of $160.44/kW-Yr and the coincident peak of the interruptible load of the LI class of 69,593 kW. ($160.44/kW-Yr x 69,593 kW = $11.265 million). Please refer to cell C349 of Exh 6 of 2026 Cost of Service Study filed as SR-01 Att 02 PCON in the 2026-2027 GRA (M12451).

(b) Confirmed.

(c) Please refer to NSEB IR-9.

Annually Adjusted Rates for 2026 (M12551)
NSPI Responses to REI Information Requests

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Request IR-16:

Reference: RtR Transition Tariff (RTT) – Annual Energy Cost Adjustment, page 35 and Appendix F4, page 138.

Preamble: This portion of the tariff considers differences between marginal fuel costs and average fuel cost to calculate the impact to NS Power from load migration to an LRS. LRS Forecasts are being provided to NS Power, and there is an increasing role of environmental costs and regulations in determining marginal costs, so REI believes closer scrutiny of the calculation of the Annual Energy Cost Adjustment is warranted.

(a) Please confirm that NS Power considered REI's forecasted market uptake in its load forecast and calculation of average and marginal costs for 2026. If not, please explain why REI's forecast was not considered and what load migration assumptions were actually used.

(b) If yes, please confirm that the calculation of the RTT Annual Energy Cost Adjustment properly accounts for REI's forecasted load migration and explain in detail how this is reflected in the calculation, including the specific line items and formulae affected.

(c) Please confirm whether NS Power's comparison is of average fuel costs (accounting for load migration) compared to marginal fuel costs (also accounting for load migration). If this is not the correct characterization, please explain precisely what comparison is being made and provide the formulae used.

(d) Please provide a detailed analysis of an alternative approach by which NS Power calculates the comparison of average fuel costs to marginal costs *before* LRS load migration to determine the Annual Energy Cost Adjustment and the impact to NS Power of load migration to RtR. Please quantify the difference between the current methodology and this alternative approach for 2026.

Response IR-16:

(a) Confirmed. Due to a recent delay in the forecast commencement of REI service uptake from early 2025 to March 31, 2027 (the most recent Board-approved deadline), NS Power's marginal fuel cost calculations do not include REI in the 2026 AAR for calculation purposes.

(b) Confirmed. By design, the RTT Annually Adjusted Energy Savings Credit (AAESC) reflects a differential between the system average unit costs, as recovered through base cost rates, and marginal unit fuel costs. In the initial stage of the RtR market development, when the RtR service uptake represents a small fraction of the total system load, its effect on the AAESC is minor. Due to a late load migration to the RtR market commencing in by March 31, 2027 (the most recent Board-approved deadline) its effect is not material and therefore it's not reflected in the 2026 AAESC.

(c) Not Confirmed. By design the comparison is between the average fuel costs, as embedded in base cost rates, and the average marginal costs reflective of load migration to the RtR market to the extent it is distinguishable.

(d) The proposed RTT AAESC does not reflect REI's load forecast. Please see part (b).

Request IR-17:

(a) Under the current RTT framework, please confirm whether the Annual Energy Cost Adjustment would require NS Power to provide a credit to the RtR customer in circumstances where the Average Marginal Cost (or the average avoided cost of the departing load) exceeds the average system fuel cost paid by FAM customers. If not, please identify the specific tariff provision that would prevent such a credit.

(b) In such a situation where avoided costs exceed system fuel costs, would the full value of the difference be payable to the RtR participant, or are there any limitations, offsets, or adjustments that would reduce the credit amount? Please explain with reference to specific tariff provisions.

(c) Please indicate whether NS Power believes that any cap, limit, floor, or other constraint applies to the magnitude of the credit payable under the Annual Energy Cost Adjustment, whether such constraint is explicit or implicit in the tariff design.

(d) If NS Power believes a cap exists:

(i) Please identify the specific tariff provision, Board order, or Board approval that establishes such cap, and provide the history of how this cap was determined;

(ii) Quantify the maximum amount that could be payable to an RtR customer in a given year under the cap and explain how this amount was calculated.

(e) If NS Power believes no cap exists, please confirm that under the current tariff structure, the Annual Energy Cost Adjustment may result in an uncapped credit owed to the RtR customer when avoided costs exceed system fuel costs, and explain

whether NS Power believes this outcome is consistent with the original policy intent of the RTT.

Response IR-17:

Preamble: For clarity, NS Power assumes that the use of the terms "RtR customer" and "RtR participant," refers to the Licensed Retail Supplier (LRS) taking service under the Renewable to Retail Market Transition Tariff (RTT). Further, the Annually Adjusted Energy Savings Credit (AAESC) mechanism applies to the LRS' Energy Charge, not to an end-use RtR customer/participant, and applies as an adjustment to the LRS' billed charges under the RTT, not a direct credit or payout to an LRS or an LRS' (end-use) RtR customer/participant. Please also refer to REI IR-18.

(a-c) Consistent with RTT Applicability provision (4), if NS Power's average avoided cost by the LRS' supply of electricity exceeds NS Power's average system fuel cost, the AAESC would apply as a reduction to the Energy Charge. The AAESC operates within the RTT calculation of the Energy Charge applicable to an LRS and, where other components of the RTT result in a positive Energy Charge, the AAESC reduces that charge but does not create a negative charge (i.e. no net payout). Applicability provision (1) further provides:

> The RTT is applicable to the LRS, and is in addition to (and not in substitution of) any charges owing by the LRS to NS Power under the Open Access Transmission Tariff (OATT), the Standby Service Tariff, or the Energy Balancing Service Tariff. **A charge under the RTT will only apply to the extent the cumulative amount calculated under the RTT for the calendar year is equal to or greater than zero**. [emphasis added]

While there are no additional limitations, offsets, caps, or other adjustments to the calculated AAESC, RTT Applicability provision (1) contemplates that the total RTT charge cannot be negative. Please also refer to part (e).

(d) Please refer to the Preamble and part (a-c).

(e) Not confirmed. While the current RTT framework does not preclude an uncapped reduction in the AAESC when avoided costs exceed system fuel costs, RTT Availability provision (1) explicitly requires the RTT charge be equal to or greater than zero. This aligns with the Board's prior decisions. In its 2023 AAR Decision, the Board provided:

> The Board does not agree that fuel savings realized by NS Power from customers leaving the company's service for the RTR should be regarded as a credit to the LRS. The Board agrees with NS Power that the RTT is designed to recover fixed costs from customers switching to the RTR. New customers who were not previously NS Power customers are expected to contribute to fixed costs and should not be omitted from the Fixed Cost Adder.[1]

The RTT is designed to provide for the recovery of fixed costs previously recovered from customers opting for RTR service, thereby avoiding a cost transfer to NS Power's bundled service customers. The elimination or reduction of this charge as benefits accrue to the system from RTR load departure represents the extent to which those benefits flow through to RTR customers. Allowing the RTT to result in a credit would not be consistent with the legislative framework requiring the RTT or with the Board's findings in the 2023-2024 General Rate Application (M1041) regarding cost responsibility. Accordingly, under the current RTT structure, the AAESC cannot result in a negative RTT charge or a credit payable to the LRS.

Further, the competitive retail market has not yet materialized. As the market develops, more information will become available which may warrant review of these issues. Please also refer to the Preamble, part (a-c), REI IR-18, and SBA IR-6.

[1] M10959 – Board Decision, 303484, page 6. June 7, 2023.

NON-CONFIDENTIAL

Request IR-18:

Reference: Annually Adjusted Energy Savings Credit, page 35, lines 12-17.

> **The Annually Adjusted Energy Savings Credit is designed to credit the LRS with any non-fuel energy-related cost savings arising from freed-up capacity on NS Power's system as a result of a departure of its bundled service load to the RtR market. The Company's ability to mitigate this cost is limited by its ongoing requirement to maintain generation capacity in the event the RtR customer returns to NS Power's bundled service. The Company does not project savings in this cost category and proposes that the current value of zero remains in effect in 2026.**

Reference: RTT Demand Savings Credit, page 36, lines 17-23.

> **The Annually Adjusted Demand Savings Credit is designed to pass to the LRS any non-fuel demand-related cost savings arising from freed up capacity on NS Power's system because of the departure of its bundled service load to the RtR market. As is the case with the Annually Adjusted Energy Savings Credit, the Company's ability to mitigate this cost is limited by its ongoing requirement to maintain generation capacity in the event the RtR customer returns to NS Power's service. The Company does not project savings in this cost category and proposes that the current value of zero remain in effect in 2026.**

(a) Please confirm the assumptions in 2026 regarding load transitioning from NS Power's bundled service to RtR, including the MW amount, customer class, load profile, and timing of transition.

(b) What specific assumptions were made regarding firm capacity contributions from third-party generators serving the RtR market, including the MW amount of firm capacity, the reliability standard applied, and how such capacity contributions were verified or validated?

(c) Please provide a copy of Robert Cary's Market Design White Paper, regarding avoided cost of ECR as filed in the original application for RTR approval.

(d) Where NS Power maintains it has an obligation to serve the RtR load even if such load is under contract with an LRS and to provide sufficient firm capacity plus a reserve to meet its own customer demand, RtR customer demand and municipal customer demand (N-30 GRA NSPI (REI) IR-6), please explain how or under what specific circumstances these two savings credits (Energy Savings Credit and Demand Savings Credit) would ever be given any value greater than zero. If there are no such circumstances, please explain the purpose of including these tariff components.

Response IR-18:

(a) The 2026 AAR forecast assumes no load served under RTR. Please refer to REI IR-16.

(b) The 2025 10 Year System Outlook includes a firm capacity contribution for the third-party generators supporting the RtR market based on the marginal effective load carrying capability (ELCC) of ten percent of the total installed capacity. This is in reference to the potential system benefit on the supply side (firm capacity contribution) and not a reflection of the impact to the peak demand. Please refer to part (a) of the 2026-2027 GRA (M12451) NSEB IR-22 for an explanation of the RtR market impact at peak. As the RtR market develops, the relationship between the commercial nature of the third-party generators supporting the RtR market and system requirements will continue to be evaluated.

(c) Please see Attachment 1.

(d) The Annually Adjusted Energy Savings Credit (AAESC) and Annually Adjusted Demand Savings Credit (AADSC) mechanisms were developed as part of the original RtR Tariff proceeding (M06214) and approved in 2016. The RTT, by design, contemplated that NS Power's embedded cost recovery could be reduced to reflect forecast savings (or additions)

enabled by LRS supply of renewable energy.[1] With the caveat that competitive retail market activity has yet to materialize, some circumstances that result in an AAESC or AADSC adjustment may include:

- changes in system conditions such that NS Power avoids higher-cost generation (AAESC); or

- avoided investments in new capacity due to RtR generation contributing firm capacity (AADSC).

The inclusion of these adjustment mechanisms in the original design of the RTT provided the necessary framework to adapt to RtR market developments when, and if, the contemplated savings materialize. While, at present, these circumstances remain prospective, it is also premature to conclude that these adjustments would continue to be valued at zero indefinitely. Finally, as the market continues to develop more information will become available, which may warrant a review of these, among other, RtR Market mechanisms.

[1] As described in Section 8 of the Cary Report (M06214).

Nova Scotia Power

Renewable to Retail Project

RtR Design Basis Report

Robert Cary & Associates Inc.

28th August, 2015

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1 Introduction

1.1 Design Basis Report

This report provides an overview of the proposed implementation of a Renewable-to-Retail (RtR) market framework in the Province of Nova Scotia. It includes discussion of options considered and the basis for selection of particular design elements. It also describes how this framework is implemented through specific tariffs and other instruments.

1.2 Role of Robert Cary & Associates Inc

Robert Cary & Associates Inc (RCAI) was engaged by Nova Scotia Power Inc (NS Power or Company) in September, 2014 to assist and make recommendations to the Company with respect to the development in Nova Scotia of the framework of the RtR market prescribed in the *Electricity Act (Nova Scotia)* as amended by the *Electricity Reform (2013) Act (Nova Scotia).*

Robert Cary has extensive experience in electricity market design, in commercial arrangements within electricity markets, and in the governance of electricity distribution utilities. Mr Cary's resume is attached as Appendix A to this report. In undertaking this assignment, Mr Cary has brought to bear his particular knowledge of the Nova Scotia electricity market as well as his experience in the integration of renewable low impact (principally wind) generation in the Ontario market. His Nova Scotia experience includes:

- Nova Scotia electricity market design (as implemented), including: independent review of the recommendations of the Nova Scotia Electricity Marketplace Governance Committee with respect to achievement of Energy Policy objectives, and to practicality; advice to NSPI on tariff design issues and market documentation; and drafting of market rules for the Nova Scotia electricity market for the Nova Scotia Department of Energy under the oversight of a steering committee including stakeholder representation.
- Nova Scotia renewable energy trading system design (not implemented), including: preparation of discussion papers to outline options for implementation of renewable electricity trading systems, followed by leadership of discussion forum, collation of stakeholder responses, and finalization of policy options as a basis for possible legislation and regulation; and assistance in determining terms of reference for a wind power integration study.

Following discussions with NS Power, RCAI prepared a report[1] and made a related presentation to stakeholders on October 9, 2014. The report and presentation set out four basic framework options to be considered in design of the RtR Market.

Following evolution of the design with regard to stakeholder comments, RCAI prepared a report[2] on Embedded Cost Recovery approaches, and made a related presentation to stakeholders on December 15, 2014. This report and presentation discussed options for embedded cost recovery, and provided the basis for the discussion on 15th December and subsequent stakeholder feedback.

On March 2, 2015, RCAI presented to stakeholders an update on the evolving basis of the RtR market design[3]. In addition to providing an update on certain decisions made to that date on the development of the more detailed design, this presentation identified certain of the outstanding issues remaining to be resolved.

Since the March meeting, RCAI has consulted with and advised NS Power with respect to the finalization of design of the RtR Market framework and of the various specific tariff instruments. RCAI has also participated in the preparation and review of the various RtR tariffs and related documents proposed by NS Power, including the following:

- Distribution Tariff
- LRS Terms and Conditions and Participation Agreement;
- Renewable to Retail Market Energy Balancing Service Tariff;
- Renewable to Retail Market Standby Service Tariff;
- Renewable to Retail Market Transition Tariff;
- Open Access Transmission Tariff; and
- Market Rule amendments.

This design basis report is therefore the work of RCAI. It includes discussion of the issues that were required to be addressed in key decisions made by NS Power and the basis for those decisions.

1.3 Overview of the RtR Market

The RtR market is to be established in accordance with the *Electricity Act (Nova Scotia)* as amended by the *Electricity Reform (2013) Act (Nova Scotia).*

[1] The Market Design White Paper dated 2nd October, 2014

[2] The Embedded Cost Recovery White Paper dated 2nd December, 2014

[3] The Renewable to Retail Project Design basis development presentation dated March 2015

The RtR supply chain will comprise:

- Generators of renewable low impact electricity located in Nova Scotia, as certified by the Nova Scotia Department of Energy;
- Retail Suppliers, who will be licenced and subject to regulation by the Nova Scotia Utility and Review Board (UARB or Board) for this purpose; and
- Retail electricity customers in Nova Scotia.

Retail Suppliers licenced by the Board are referred to throughout this report as Licenced Retail Suppliers, or "LRSs". The functions of generators and of LRSs are distinct and they may be performed by separate entities or both functions may be performed by the same entity. They are described in this document as separate entities, but there is no requirement under the *Electricity Act* that they be separate.

Each certified generator will sell[4] its production to an LRS, which will utilise services procured from NS Power to deliver electricity to retail customers and to reconcile between the timing of generation and the timing of load. Those services are designed such that the reliability of electricity supply received by RtR customers is the same as that received by those same customers taking Bundled Service from NS Power. The proposed services to be provided by NS Power include physical delivery services as well as backup and balancing services.

The RtR framework proposed by NS Power is based on and assumes all RtR tariffs and associated cost recovery being applicable to all RtR based transactions, regardless of the location of the generator relative to the load.

The Nova Scotia Department of Energy's processes for certification of generators and the UARB's processes for licencing of LRSs, including the posting of associated Retailers Regulations and Code of Conduct, are expected to provide RtR consumer protection including, in particular, that each LRS must provide to the grid in each two-year compliance period sufficient renewable low impact electricity to fulfill the supply to its retail customers and the associated transmission and distribution losses.

1.4 Executive Summary of the Market Design as Proposed

The RtR Market design is embodied in a number of instruments:

- Each RtR generator is required to execute a Wholesale Market Participation Agreement by which it is bound by the relevant provisions of the Wholesale and RtR Market Rules and of the Open Access Transmission Tariff (OATT), and it is required to execute a Generator Interconnection Agreement. Collectively these provide for the generator to maintain acceptable

[4] To the extent that Generator and LRS are the same entity, there is no "sale".

technical standards and to communicate with and accept direction from the Nova Scotia Power System Operator (NSPSO) while supplying electricity to the LRS to which it is contracted.

- Each LRS is required to execute an LRS Participation Agreement and a Wholesale Market Participation Agreement by which it is bound by the relevant provisions of the revised Market Rules and of the OATT, as well as the Standby Service tariff, the Energy Balancing Service tariff, and the RtR Transition Tariff. The terms and conditions attached to the LRS Participation Agreement govern such aspects as customer transfer arrangements, metering, settlement, security, and confidentiality.
- The design of the generation-related tariffs is intended to collectively provide for NS Power to backup the RtR supply to achieve equivalent reliability of supply, to accept from the LRS the excess RtR generation that may arise in any hour, and to recover from each LRS the embedded costs stranded by the LRS's activities. Generation-related tariffs are charged (or credited) to each LRS in respect of the aggregate load served by that LRS and the aggregate of generation supplied by that LRS. The proposed generation-related tariffs comprise:
    - The Standby Service tariff provides for the availability of the capacity necessary to ensure overall system adequacy in respect of the RtR load, and the availability of NS Power generation facilities to support hourly RtR customer load in excess of hourly RtR generation. The monthly charge is based on the costs of overall capacity required to serve the aggregated RtR customer load, less the capacity self-supplied by the LRS.
    - The Energy Balancing Services tariff provides for the actual operation of NS Power generation facilities for the top-up energy necessary to supply RtR customers in any hour when the RtR generation is unavailable or insufficient to meet that customer load, and it provides for NS Power to manage the operation of its generation facilities in any hour in order to receive surplus RtR generation above RtR customer load. The fuel component of the top-up charge and spill credit are proposed to be set prospectively on annual basis based on the forecasts of annual incremental costs of top-up energy and avoided costs of spill energy, respectively.
    - The RtR Transition Tariff provides for payments by the LRS to keep NS Power's remaining customers whole in respect of fixed generation costs not collected through the above tariffs and not otherwise capable of avoidance or mitigation.

  The specific charges under these three tariffs are all based on the Cost of Service analysis model used for consideration of Bundled Service rates, and are set so that they should together collect for NS Power the total generation cost excluding that allocated to the provision of OATT Ancillary Services, less the NS Power cost avoided due to the displacement of NS Power generation by RtR supply and any mitigation available to NS Power.
- The OATT provides for the delivery of the rebalanced generation supply (ie inclusive of top-up but exclusive of spill) to meet metered loads of any transmission-connected RtR customer or energy requirements adjusted to transmission level of distribution-connected RtR customers. It includes all ancillary services associated with such delivery. The OATT charges are unchanged

from those currently in effect, with the exception of modification of the hourly imbalance service in schedule 4 to avoid double counting with the Energy Balancing Services tariff. OATT charges are charged to each LRS in respect of the aggregate load served by that LRS.

- Each distribution-connected RtR customer will maintain a relationship with NS Power through the proposed Distribution Tariff. NS Power will determine individual customer charges each month. NS Power will bill these to each LRS, and each LRS will bill and collect the distribution charges directly from RtR customers. Section 10 of the UARB's draft Code of Conduct requires that the bill amount under the NS Power Distribution Tariff be charged without markup to the LRS's customers. The charge rates in the Distribution Tariff correspond to the distribution and retail elements of the Bundled Service[5] Cost of Service analysis model.
- Any transmission connected RtR customer will not be subject to the proposed Distribution Tariff, but will maintain a customer relationship with NS Power through an operating agreement.

1.5 Conclusions and Opinion

This report describes the proposed RtR Market framework and the instruments to be used by NS Power for its implementation. It outlines the consultations with stakeholders. And it includes discussion of the issues that were required to be addressed in key decisions made by NS Power, and the basis for those decisions.

It is the opinion of RCAI that the proposed market framework as described herein:

- has been designed to meet the requirements of the *Electricity Act (Nova Scotia)* as amended by the *Electricity Reform (2013) Act (Nova Scotia);*
- has been designed with due regard to stakeholder inputs;
- represents a rational approach which utilises to an appropriate extent the existing tariff framework and the Cost of Service analysis behind the existing Bundled Service and other tariffs;
- will provide for transparent, fair, equitable and reasonably stable rates for services provided by NS Power to the RtR supply chain, and for the recovery of embedded costs associated with service to RtR customers that would otherwise be borne by remaining NS Power customers; and
- will be capable of evolution to meet changing requirements as the RtR market itself develops.

[5] See Section 2.2 of NS Power's application. Bundled Service refers to electrical service taken from NS Power under existing NS Power tariffs. This takes the form of having generation, transmission, distribution, ancillary services and all other items associated with the provision of such service blended or bundled within the rate.

2 RtR Participation Arrangements

2.1 LRS Participation Agreements

Each LRS will be required to execute an LRS Participation Agreement with NS Power. The proposed form of the LRS Participation Agreement is attached as Appendix B to the LRS Terms and Conditions, and will bind the LRS and NS Power to the LRS Terms and Conditions. As proposed, these terms and conditions include the obligation on the LRS to subscribe to all of the LRS Tariffed Services comprising:

- RtR Market Standby Service Tariff, which provides for NS Power to provide capacity required to fulfill its obligations in respect of overall system adequacy and in order to provide energy top-up;
- RtR Market Energy Balancing Service (EBS) Tariff, which provides for NS Power to provide energy top-up and accept energy spill due to mismatch of an LRS's generation and its load;
- RtR Market Transition Tariff (RTT), which provides for embedded cost recovery in respect of generation; and
- OATT, which provides for transmission and ancillary services.

The LRS Participation Agreement and the associated LRS Terms and Conditions will also establish the framework for customer service transfers and for access to metering data.

In addition, each LRS will execute a Wholesale and RtR Market Participation Agreement by which the LRS will become a Market Participant and will be bound by the Market Rules.

An RtR generator that is not also an LRS will be required to execute a Wholesale and RtR Market Participant Agreement by which it will become a Market Participant and will be bound by the Market Rules.

2.2 Alternative Options Considered

2.2.1 Selected Option; LRS Participation Agreement

The selected option of the LRS Participation Agreement has the benefit of clarity. It has been drafted specifically for this purpose and has embedded all necessary provisions in a single document. It creates a clear contractual relationship between each LRS and NS Power. It can allow for unified administration and settlement of all the various tariffs and payment security provisions.

2.2.2 Rejected Option; Modified WMP Agreement and Market Rules

Consideration was given to an alternative option based on the Market Rules. Under this option, the Wholesale Market Participation (WMP) Agreement and the Wholesale Market Rules and Market Procedures would have been modified and expanded to specify all the terms and conditions necessary to govern the relationship between NS Power and the LRS and the obligations of each.

This alternative was rejected for two reasons:

- The purpose of the Market Rules is to define the rights and obligations of the NSPSO towards Market Participants, and of Market Participants towards the NSPSO. The RtR Participation arrangements relate to the rights and obligations of NS Power and the LRS towards each other.
- The addition to the WMP Agreement and Wholesale Market Rules of all the necessary obligations would be irrelevant to Wholesale Market Participants, and cause potential confusion.

The Market Rule amendments required under the selected option are relatively minor.

2.2.3 Rejected option; Obligation though UARB licence

A further option proposed during the stakeholder consultations was that the granting of a licence by the UARB to an LRS should create a deemed contract between the LRS and NS Power. The proposal was considered by NS Power and not selected for the following reasons:

- Absent a deemed form of contract, the terms could be ambiguous, and once the deemed form of contract is established, the deeming process offers no benefits;
- It would be unclear how deemed contract provisions could be enforceable between the deemed parties other than through the UARB itself;
- It would be unclear how such deemed provisions could survive licence termination; and
- The UARB would become potentially involved in the commercial relationships over which it has regulatory oversight, thus creating a conflict with the regulatory role of the UARB.

2.3 Customer Relationship with NS Power

As noted below, customers connected at distribution voltage will become distribution customers. The request to switch to RtR service will trigger a change from being a Bundled Service customer to distribution access customer. The retail customer will be an NS Power distribution customer notwithstanding billing arrangement through the LRS. NS Power has proposed amendments to its standard Regulations to provide for this.

Customers connected at transmission voltage level are not distribution customers. It is intended that they maintain a customer relationship direct with NS Power through an individual operating agreement that will set out the mutual obligations of the parties. This will not, however, provide for payments direct between the customer and NS Power.

3 Customer-facing design

3.1 Billing and Collection: High Level

NS Power identified options for NS Power consolidated billing, split billing, and LRS consolidated billing. Stakeholders' feedback indicated a preference for LRS consolidated billing[6]. As a result, the RtR design framework has been developed on the basis of LRS consolidated billing. LRS Tariffs provide for the provision of all RtR Tariffed Services to the LRS, in the expectation that the LRS will incorporate recovery of the costs for these services into its rates to its customers. The Distribution Tariff will establish a direct relationship between NS Power and RtR electricity consumers / customers, but will provide for the LRS to effect LRS-consolidated billing. NS Power will bill to, and receive payment in full from, each LRS in respect of services provided to its customers in respect of Distribution Tariff charges. Detail is developed in section 3.7 below.

3.2 Service Duration

NS Power's Bundled Service tariffs are designed to provide appropriate cost recovery over each calendar year, subject to certain specific deferred cost recovery provisions. RtR tariffs are all designed on the same basis with an assumption that customers would switch to RtR service for contract periods not less than a year. In the event that NS Power notes significant incidence of more frequent switching, NS Power should consider the addition of controls that would identify and preclude more frequent switching except following approval in response to special and unplanned changes of circumstance.

3.3 Interruptible Service

Interruptible service has been made available by NS Power as a Bundled Service option to qualifying large industrial customers. Those customers undertake to interrupt their load on demand (or by remote trigger) of the NSPSO. Failure to implement such interruption triggers a penalty up to twice their monthly bill (at the applicable bundled firm service rates).

NS Power relies on the fact that such interruptible customers do not contribute to the firm load on the system, and therefore are not included in the determination of the firm dependable capacity requirement of the system. The notice provisions for switching back to firm service reflect the time that would be required for NS Power to develop additional firm dependable capacity to fulfill the increased system adequacy requirement.

In discussion with stakeholders, it was indicated that any switch between Bundled Service and RtR service would take place without changing the interruptibility of the customer. The exercise of that

[6] As noted in RCAI presentation on design basis development, March 2015, slide 6.

interruptibility would be independent of bundled / RtR status, and would be independent of whether RtR generation was operating at that time. The possible carry-over of existing facility interruptible status would require a number of issues to be resolved:

- Interruption communications would need to be to the load customer, who would continue to be NS Power's distribution customer or RtR Customer Network Operating Agreement customer;
- Contractual arrangements would have to be executed reflecting *inter alia* the two part penalty arrangements comprising Threshold and Performance components as in effect for the bundled service.;
- The proposed Standby Service Tariff and RTT would both require further amendment to include provisions to reflect interruptibility; and
- NS Power would expect that the LRS and RtR customer would negotiate for the RtR customer to receive the benefit of the reductions due in the Standby Service Tariff and RTT.

Given the small number of interruptible service customers and the uncertainty of any demand for interruptible RtR service, NS Power has not at this time provided systems or tariffs for interruptible RtR service. Should any interruptible customer seek RtR service, NS Power would have to review the specific additional requirements noted above and determine how these can be achieved. If satisfactory solutions are identified, these could be addressed through revisions to proposed tariffs and LRS Participation Agreement, and, for a transmission-connected customer (which class represents most of the existing interruptible customer load), the terms of the required operating agreement.

3.4 Full / partial service

Some stakeholders provided design feedback indicating a preference that large customers should have the option to take partial RtR service from NS Power. This was understood by the Company to mean that a portion of the metered customer load should be considered as RtR load, and the balance as Bundled Service load. This concept of partial service is distinct from the discussion of Behind-the-Meter service, which is discussed section 3.5 below.

Parial service could take two forms: unrestricted partial service; and restricted partial service. In unrestricted partial service, the LRS or customer would be able to vary the split between Bundled Service and RtR service. In restricted partial service the customer's hourly load would be split between NS Power Bundled Service and RtR service in a predetermined ratio which would be fixed for a year at a time.

Unrestricted partial service was excluded early in the RtR Market design. The Cost of Service approach to Bundled Service rates and to the various RtR tariff rates is based on the broad characteristics of each class load shape. Unrestricted partial service would distort the load shape of each part of the service when considered separately, and may result in significant distortion of rate impacts, and thus in cost transfer to remaining customers. In order to allow unrestricted partial service while avoiding such cost transfer, the Bundled Service rates could need extensive revision to incorporate time-of-use and

seasonal variability. Costs of such revision would need to be borne by the applicant for such type of service. And such development would depart from the requirement to leverage existing tariffs to the extent possible. Unrestricted partial service was therefore excluded from consideration.

Consideration was then given to enabling large customers to elect a restricted partial RtR service in the form of an annually fixed percentage of metered hourly load. This arrangement would preserve Bundled Service load shape, at lower scale. This was discussed with stakeholders as a design element under consideration. Stakeholders provided no comment on this possible design element. No precedents could be identified for this type of arrangement at the retail level. Implementing such an arrangement would introduce added complexity to settlements. In view of these considerations, NS Power did not include partial service provisions in the design framework.

It should be noted that the full service model (either RtR or Bundled Service) applies separately to each customer account. If a customer has multiple accounts, each account being separately metered and separately identified in billing, the customer may elect RtR service for some such accounts but not for others. Such treatment is permitted and is not considered as partial service.

3.5 Behind-the-Meter RtR supply

During the stakeholder consultations, it was suggested by a stakeholder that the RtR framework should accommodate a model which would permit a LRS to connect a renewable low impact generator directly to a number of customers, apparently behind a single NS Power meter that would measure the net energy withdrawn from the system at that point. Each customer would thus be served by a micro-grid behind that single NS Power meter. It seems to be implicit in this proposal that NS Power would render charges under its Bundled Service tariff to the group customer on the basis of those net energy flows at the interface between the NS Power grid and the LRS microgrid.

In an alternative arrangement, an LRS could install individual generation units at each of its customers' premises, and serve each customer behind its NS Power meter.

The cost impact on NS Power of either behind-the-meter (B-t-M) arrangement is exactly the same as the underlying cost impact of connecting the generation on the system side of any metering. What changes under either of these B-t-M arrangements is the extent of NS Power's recovery of its costs under its Bundled Service and proposed RtR tariffs. The proposed business model would, absent secondary metering or special adjustments discussed below, result in a shift of the cost burden from that nexus of B-t-M generator, the LRS and its customers to NS Power and its remaining Bundled Service customers. This would be inconsistent with the "no-harm" provisions of the *Electricity Act*, which provide that the remaining customers of NS Power are not to be negatively affected by the introduction of the RtR market and that the LRS and its customers are to be responsible for all costs relating to the provision of service by the LRS that would otherwise be the responsibility of NS Power.

The cost transfers referred to above would arise in a number of ways. Under a B-t-M arrangement, NS Power and its remaining customers would be exposed to transfer of embedded costs:

- In either configuration:
    - the amount corresponding to the RtR distribution charge on the B-t-M generation quantity;
    - the amount corresponding to the OATT charges on the B-t-M generation quantity;
    - the amount corresponding to the 20% generation reserve margin portion of the B-t-M generation;
    - the amount corresponding to the RtR Market Transition Tariff (for embedded cost recovery) on the B-t-M generation quantity; and
    - a possible amount arising from any change in the residual customer load shape from the original customer load shape.
- And in the micro-grid configuration:
    - customer monthly charges on all but one customer; and
    - an amount that could arise from consolidation of customer load shape (whereby the diversity is lost to NS Power) and possibly from the customer class of the aggregate being different from the customer classes of the individual end use customers.

The Retailers Regulations issued July 15, 2015, contemplate B-t-M to be a form of RtR supply. The LRS would thus be required to execute an LRS Participation Agreement and be subject to all RtR tariffs, and not to any Bundled Service tariff. There are two ways to accommodate the no-harm requirement within the RtR tariff framework, namely: secondary metering; and enhanced recovery of embedded costs. These are described as follows:

- Secondary metering:
    - Secondary metering would be installed at individual customer premises and would be used as the basis for determining charges under all RtR tariffs including charges to the LRS in respect of distribution access[7].
    - Secondary metering is probably required by the LRS to measure its sales to its customers; NS Power would require that such secondary metering be capable of hourly recording and remote polling by NS Power.
    - In the case of a single customer B-t-M arrangement, the secondary meter could be a virtual meter for which the readings are derived by the summation of the primary NS Power meter and the meter that would record generator production.

[7] The last leg of the end use customer connection is the micro-grid owned by the LRS, so that end use customer would not be an NS Power customer and would not have a direct customer relationship with NS Power. The LRS would be the distribution customer at the interconnection of the micro-grid to the NS Power system. In order to avoid stranding of embedded distribution system costs, the LRS Participation Agreement would provide that the settlement of the Distribuition Tariff (*inter alia*) be based on the secondary metering at end use customer delivery points.

- Enhanced recovery of embedded costs:
    - As noted above, without secondary metering for use in RtR tariff settlement, a B-t-M arrangement would strand certain costs. In order to avoid transfer of those costs to remaining NS Power customers, those costs need to be recovered from the particular LRS serving RtR customers by a B-t-M arrangement.
    - The most appropriate way to do this would be by a special B-t-M Transition Tariff or equivalent. This would aggregate all of the foregone amounts noted above. The accurate way to do this would be by the use of secondary metering. Absent secondary metering, NS Power would have to estimate the foregone amounts for payment by the B-t-M LRS.

The secondary metering option provides the simpler solution. It utilises the already proposed RtR tariffs, avoids stranding additional costs, and therefore avoids the potentially onerous need to create a special B-t-M Transition Tariff.

NS Power has therefore adopted the secondary metering approach.

3.6 Meter Ownership and Related Issues

In accordance with NS Power's initial proposal, which was generally supported by stakeholders[8], NS Power will continue to own and to read the meters. In requesting RtR service, RtR customers would authorise NS Power to provide metering and relevant billing data to the LRS.

The settlement for balancing and other services provided by NS Power to each LRS requires determination of hourly generation and load quantities. Generation facilities will normally have metering capable of providing such hourly production data. Domestic and other smaller bundled service customer class metering requirements currently only provide cumulative energy consumption quantities over each (typically 2 month) meter reading cycle. They do not provide hourly data.

NS Power noted stakeholder support for its proposal to minimise the cost of implementation by utilising the existing cumulative energy metering, and creating inferred hourly consumption quantities by utilising research-based class load profile data. On further consideration NS Power concluded that:

- While there is an initial cost saving in the use of existing cumulative energy meters, there is also an administative cost increase in the inference of hourly consumption data. The task is complex due to the need to consolidate inferred data from customers each of whom may have different meter reading cycles.

[8] One stakeholder requested the option of LRS meter ownership for purposes of installing hourly interval meters. In the context of NS Power's present plans to utilise interval meters for all RtR service, this option is now redundant.

- The use of inferred data adds two months to the settlement cycle for the relevant NS Power services to each LRS.
- Existing infrastructure for remote polling of interval meters has capacity to accommodate at least the initial uptake by RtR customers.

NS Power therefore considers that it is more effective to move directly to remote polled interval metering as a requirement for all RtR customers at commencement of the RtR market. Meters would be upgraded following receipt by NS Power of an RtR service request for customers requiring such meter upgrades.

The hourly class standard load profile for any customers in unmetered classes will be as used to infer hourly load profiles for any RtR customers in such classes.

3.7 Billing and Collection

Billing and collection arrangements between each LRS and its customers are matters for consideration in the Retailers Regulations and Code of Conduct, and are not part of this design basis document.

Billing and collection arrangements between NS Power and each LRS should be considered in three tranches:

- Customer-specific billings to the LRS or customers;
- Aggregate billings to the LRS; and
- Fuel Adjustment Mechanism, DSM cost recovery, and miscellaneous charges.

3.7.1 Customer-specific Billings to the LRS or Customers

For service under the Distribution Tariff, NS Power will invoice the LRS monthly for each individual customer charge.

3.7.2 Aggregated Billings to the LRS

The following tariffs will use charge determinants that reflect the aggregate of all RtR customer loads:

- Transmission service under the OATT, including:
    - Network service under schedule 10;
    - Ancillary services under schedules 1, 2, 3, 5, and 6;
    - New schedule 4A in place of existing schedule 4, all as discussed in section 5.3.2; and
    - Self-supply of transmission losses in accordance with schedule 9, using renewable low impact electricity generated in Nova Scotia.
- Standby Service;

- Energy Balancing Service, comprising:
    - Top-up service;
    - Spill, including at a discounted rate for the annual excess of spill over top-up beyond a certain percentage of total RtR customer load;
- RtR Market Transition Tariff in respect of embedded cost recovery.

Having adopted remote polled interval metering for all RtR customers, NS Power will be able to bill the LRS for all these services following each calendar month end.

3.7.3 Fuel Adjustment Mechanism (FAM), DSM Cost Recovery, and Miscellaneous Charges

The FAM tariff includes a provision that outstanding FAM balances in respect of customers migrating to non-FAM be charged to those customers. NS Power will therefore charge or credit any outstanding FAM balances to those customers in accordance with the FAM. No special provision is required in the RtR tariffs to accommodate this process.

The means of recovery in respect of all DSM costs remains to be determined. It is expected that DSM cost recovery will apply to Bundled Service customers and to RtR customers alike, or possibly in the case of RtR customers to their LRS. NS Power would be able to charge all customers in accordance with that DSM cost recovery mechanism as an element embedded into the Cost of Service analysis used in the determination of Bundled Service and RtR tariff charges. No special provision would be required in the RtR tariffs to accommodate this.

Costs of interval meter installation and other miscellaneous charges will be recovered at cost in accordance with NS Power Regulation 7.1[9]. The interval metering charges will be billed to the LRS, as the interval metering is necessary for aggregation of the LRS's customer load, and not necessary for determination of Distribution Tariff charges which could be billed using a standard cumulative energy meter.

4 Tariff Design: General

4.1 Disaggregated Tariff Approach

RCAI's October, 2014 Market Design White Paper identified a range of RtR design options to stakeholders, and sought stakeholder feedback.

[9] Approved NS Power Rates and Regulations can be found at http://www.nspower.ca/en/home/about-us/electricity-rates-and-regulations/rates/default.aspx

The financial market option as presented would have left NS Power Bundled Service tariffs in place for all customers. Under this model, NS Power would have credited each LRS with NS Power's costs avoided by virtue of the RtR generation, and the LRS would have in effect billed its customers for the cost of the renewable attributes associated with its supply. This framework would have the simplest implementation and lowest administrative costs, however it did not satisfy stakeholder preferences for a more physically defined RtR "product".

The remaining alternatives were described as a disaggregated tariff approach, an avoided cost approach, and a hybrid between these two. Notwithstanding its higher complexity, there was clear stakeholder preference for the disaggregated tariff approach. While the total amounts to be recovered by NS Power under each option are the same, stakeholders preferred the greater transparency associated with the disaggregated tariff approach. As a result, NS Power has adopted the disaggregated approach in the design of its various RtR tariffs. While the tariffs are disaggregated into their individual elements, they are designed to operate as a suite of interrelated tariffs that collectively provide for the appropriate levels of service and cost recovery. The design does not contemplate an LRS being able to select some but not others. Execution of the LRS Participation Agreement would bind an LRS as a customer under all of the RtR tariffs.

The tariffs fall into two categories:

- The Distribution Tariff, under which each individual customer meter reading is used as a charge determinant; and
- LRS tariffs, under which the charge determinant is an aggregate for each LRS derived from many different customers and in many cases generator characteristics or meter readings.

In its development of the disaggregated tariff approach, NS Power gave careful consideration to the applicability of the existing OATT to the RtR Market. With the exception of schedule 4, it was concluded that the existing wholesale market OATT is generally appropriate for application in the RtR market. Schedule 4 is replaced by schedule 4A for RtR Market Participants, as discussed in section 5.3.2 below.

4.2 Avoiding Negative Impacts on Other Customers

The tariff design was strongly driven by the *Electricity Act* requirement that other remaining customers of NS Power are not to be negatively affected if some retail customers choose to purchase renewable low impact electricity from an LRS.

The avoidance of negative impacts on other customers is achieved in the disaggregated tariff approach by the use of the same Cost of Service model and cost allocation approach as is used to support Bundled Service rate setting. Costs are allocated for recovery from the RtR supply chain on a forward-looking basis compatible with the Bundled Service approach. The proposed RtR tariffs have been designed to ensure that NS Power should bear the same aggregate risk of actual outcomes in respect of RtR load as it does for Bundled Service load.

RtR rates are therefore expected to be adjusted, if required, in parallel with Bundled Service rates, including where applicable in parallel with the annually adjusted rate processes.

4.3 Rates and Expense Recovery

As noted in the 2014 Cost-of-Service analysis[10], the revenue recovery per retail rate class varies from 4.4% below allocated expense for the Large Industrial class to 4.4% above allocated expense for the Small General class. The Residential class rates recover 0.9% below allocated expense. These differences are small. They arise from historical rate development and a policy of continuity, as opposed to any present policy purpose that should be carried forward into RtR rate setting.

Recovery ratios are determined at the level of the Bundled Service aggregate per customer class. The only RtR tariff based on customer classes is the Distribution Tariff, and the recovery factors are not necessarily valid for this specific tariff in isolation. Bundled Service recovery ratios are therefore not carried forward into RtR rate determination. The Distribution Tariff rates are in effect set for recovery ratios of 1.00 for every class.

5 Tariff Design Specifics: Supply Elements

5.1 Context

The supply-related cost represents the largest component of the existing cost of Bundled Service, as it includes the asset-related cost (including financing and return on equity) of all generating plant, the fixed and variable O,M & G associated with that plant, and the fuel cost including electricity purchased under Power Purchase Agreements and as imports, net of any export sales revenues.

If NS Power and its remaining customers are to avoid economic disadvantage from the implementation of the RtR market, then the total amount to be recovered by NS Power under the set of supply related tariffs and ECR payments should equal the total that would have been recovered from RtR customers if they had remained Bundled Service customers, less the costs that NS Power can avoid by virtue of the RtR generation supply to the grid. The total amount to be recovered by NS Power under the set of supply related RtR tariffs and ECR payments will be collected through the combination of:

- Energy Balancing Service (EBS), comprising top-up revenue net of spill credits;
- Standby Service tariff revenue; and
- RtR Market Transition Tariff revenue for embedded cost recovery.

[10] NS Power compliance filing; Appendix 1 – COSS compliance model, electronic format, tab “Exh 1”.

To the extent that NS Power recovers fixed costs through the EBS tariff (top-up net of spill) and the Standby Service tariff, NS Power fixed costs to be recovered though the RtR Market Transition Tariff are lower. To the extent that cost recovery though other tariffs might be reduced, those costs to be recovered though the RtR Market Transition Tariff would increase.

Fuel Adjustment Mechanism amounts and potential DSM cost recovery are separately addressed within section 3.7.3 above.

The proposed RtR Market EBS and Standby Service tariffs were developed with due consideration of the tariffs presently in use by Wholesale Market Customers. The RtR Market tariffs were designed for application in the RtR Market context and do not replace those Wholesale Market Tariffs applicable to Wholesale Market customers.

5.2 Cost Allocation Principles

The Energy Balancing Service, Standby Service, and RtR Market Transition tariffs have been designed to incorporate the same fixed cost classification and allocation principles as in the Cost of Service analysis used in the determination of Bundled Service rates.

In the context of Bundled Service Cost of Service analysis:

- The fixed generation costs comprise fixed asset amortization, financing and returns on equity, as well as associate operating maintenance and general (OM&G) costs, and exclude those costs classified as fuel;
- These fixed generation costs are classified (in two stages) into those recoverable against demand and those recoverable against energy; and
- These costs are then allocated to rate classes according to the rate class contributions to system demand and to energy use.

The first two steps are used in the context of RtR rate setting. There is no explicit allocation by RtR customer rate class, as the relevant RtR tariffs are all settled on an aggregated basis. Instead, the rates used in those tariffs are based on the system-wide unit averages for costs recoverable against each of demand and energy. In aggregate therefore, the costs borne by LRS (and thus indirectly by RtR customers) are the LRS's properly allocated share of the system-wide fixed generation costs.

5.3 Energy Balancing Services (top-up and spill); Design Principles

Top-up and spill services are addressed together under the proposed EBS tariff. As both are energy-based charges, the rate determination of each shares common elements, and settlement of each also shares common elements.

5.3.1 Purpose

The purposes of the top-up and spill services are essentially the time-shifting of the RtR generation supply so that it will match the needs of the RtR load. Each LRS will effectively use the NS Power system as an energy storage system, injecting surplus energy in some hours, and withdrawing to supply excess load in others.

The purpose of the top-up and spill tariff arrangement is to provide compensation to NS Power for the incremental costs of providing top-up when needed, and to the LRS for NS Power's incremental savings from spill. The top-up tariff also provides for recovery of the fixed generation costs classified as energy-related in the CoS model.

5.3.2 Interaction with Imbalance Tariff

OATT Schedule 4 services cover the differences in the Wholesale Market between the scheduled and the actual supply-demand balance (for single point services) or between scheduled and actual quantities separately for each of multiple supply and load points. LRSs are generally expected to serve load located behind multiple transmission delivery points using generation at one or more transmission receipt points, and, as such would (under existing Schedule 4) be subject to separate imbalance charges in respect of each transmission receipt and delivery point.

Careful consideration was therefore given to the interaction of top-up and spill tariffs with the OATT Schedule 4 imbalance tariff. Two options were considered:

- Under option 1, the OATT Schedule 4 would apply without modification. In order to avoid double counting of deviations, the top-up and spill tariff would need to be applied to the differences forecast in any hour between supply and load, while Schedule 4 would be applied to differences between forecast and actual at each receipt or delivery point, irrespective of offsets.
- Under option 2, the top-up and spill service quantities would simply be determined in each hour as the difference between actual supply and load in that hour, irrespective of forecast accuracy. This would exclude consideration of discrepancies between LRS's forecasts and actual outcomes and would naturally provide for offsetting deviations for each LRS within each hour. In order to recognise the additional costs that may arise due to inaccurate forecasts, a forecast discrepancy schedule is proposed as OATT Schedule 4A, to replace Schedule 4 for application in the RtR Market.

Careful consideration was given to the relative costs & benefits, incentives, consistency, and complexity of each of these two options.

Under either option, the variability within each hour is accommodated by the services provided under OATT schedule 3, so does not require to be addressed separately.

- Costs & benefits of each option:
    - The NSPSO is understood to manage its generation fleet and the transmission system using forecasts of load at each transmission delivery point, and forecasts of generation injection by each generator.
    - Processes that add to the accuracy of transmission delivery point forecasts are beneficial, but forecasts below this level may be onerous and add little or no value (depending somewhat on the source of the delivery point forecasts used).
    - The production of generation forecasts is relatively low cost and is an essential contributor to system management.
- Incentives:
    - Under option 1, the imbalance top-up rate under schedule 4 represents the incremental NS Power generation cost only, excluding the recovery of fixed generation costs allocated to energy. An LRS could gain by over-forecasting its supply and / or under-forecasting its load. This would reduce the energy quantity to be provided under the top-up tariff (which includes the fixed cost recovery element) and increase the energy quantity to be provided under the imbalance tariff (which does not include the fixed cost recovery element). This would be a perverse and counter-productive economic incentive to overstate generation forecasts or understate load forecasts.
    - Option 2 is designed to avoid the economic incentive arising under Option 1. There is no incentive to bias forecasts up or down, as the top-up and spill quantities are independent of the forecast. There is an incentive to forecast accurately the generation production in order to minimise costs under Schedule 4A.
- Consistency
    - Except under conditions of transmission constraint (to which OATT section 33 applies), any over-forecasts in one delivery zone and under-forecasts in others would naturally offset each other in system management. The existing OATT schedule 4, as applicable to dispersed load, would however result in net charges to the OATT customer that would not recognise those offsets.
    - Option 2 would not result in such inconsistency, as the generation forecast and actual are compared on an aggregate basis per LRS, and the load forercast is not required.
- Complexity
    - Option 1 requires the use of separate supply and delivery point load calculations for OATT schedule 4 settlement, as well as aggregate supply and load forecast calculations for top-up and spill calculations.
    - Option 2 uses metering results in aggregate to determine top-up and spill, and uses generation forecast and metered production data for settlement of OATT schedule 4A.

While option 2 foregoes the potential benefit of delivery point load forecasts, these forecasts would be onerous to produce and of questionable value.

The option 2 gains in simplicity, consistency, and incentive structure strongly outweigh that loss. NS Power has therefore proceeded with option 2.

5.3.3 Self-supply of Top-up

Consideration has been given to the potential for an LRS to self-supply top-up service from a generator other than its normal supplier(s) of renewable low impact electricity, as is permitted under the OATT. Three scenarios were considered:

- A renewable low impact generator in Nova Scotia could theoretically be available to provide occasional top-up energy: such a generator would have to be operating on a merchant basis (so as to be available as needed) but without any in-Province sink for its energy at other times. This is therefore an impractical scenario and is not recognised in the proposed EBS tariff.
- A non-renewable generator, such as a natural gas or diesel engine, could provide standby and top-up as required, but the top-up would not contribute to fulfilling an LRS's compliance requirement. Any such production would add to the net annual excess spill by that LRS. Such a generator would also have to be operating on a merchant basis, and also without any in-Province sink for its energy at other times. This is also an impractical scenario and is not recognised in the proposed EBS tariff.
- A third option would be energy imported for the purpose of top-up. Any such import would be scheduled in advance, tagged in such a way as to identify it as top-up, and therefore capable of inclusion in the top-up and spill settlement calculations. The imported energy could not qualify as renewable low impact electricity generated in Nova Scotia. It would reduce NS Power's fixed cost recovery under the EBS tariff, and therefore increase the amount to be recovered through the RTT. As a result, for the near-term, this approach would not be a viable option for the RtR market and it is not considered necessary to include the added complexity in the tariffs and processes to support this.

5.4 Energy Balancing Services; Charge Determinant

Top-up and spill quantities will have to be determined for each LRS for each hour, and will not be subject to net-off of quantities from hour to hour. The determination of top-up and spill quantities in each hour will be a joint retrospective calculation, for a month at a time.

It is proposed that the following steps be built into the process to determine the aggregate for an LRS of the hourly top-up and spill quantities in any month:

- Hourly customer meter readings will be aggregated by customer class, and then subject to class distribution energy loss adjustment to arrive at the class aggregate hourly load at transmission delivery points for each LRS.

- Class aggregate hourly load at transmission delivery points will be further aggregated to determine the system aggregate hourly load across transmission delivery points for each LRS.
- Hourly generator meter readings will be aggregated for each LRS, and will be reduced by transmission losses to determine the aggregate supply across all transmission delivery points for each LRS.

The LRS's aggregate hourly load at transmission delivery points is deducted from the LRS's aggregate supply at transmission delivery points in order to arrive at net hourly spill (positive results) and net hourly top-up (negative results).

5.5 Energy Balancing Services; Rates

5.5.1 Overview

The structure of top-up and spill services is driven largely by the cost allocation process summarised in section 5.2 above. On the basis of that discussion the proposed EBS tariff comprises:

- Top-up incremental cost charge per MWh of top-up in each hour;
- Spill incremental cost credit per MWh of spill in each hour, subject to discount in respect of annual excess spill; and
- Top-up energy allocated fixed cost rate per MWh of top-up in each hour.

5.5.2 Incremental Cost Element of Top-up and Spill Charges

The incremental costs of top-up and the avoided costs for spill vary according to the demand-supply balance on the system, and the type of generation that will be capable and most efficient to increment up or down. Two modes of systematic variability have been considered in design of the EBS tariff:

a) Load patterns: there are certain underlying seasonal load patterns and daily load patterns. Absent any variability of generation, these patterns would tend to require top-up to occur at times of high load (with higher marginal cost), and spill to occur at times of low load (with lower marginal cost).

   Load patterns could be accommodated into the tariff in two ways:

   - As time based rates recognising predictable load patterns, or
   - By incorporating a spread between top-up and spill to recognise the typical impact of systematic time differences.

b) Generation patterns: if the production pattern of variable RtR generation is correlated with other variable generation, then top-up requirements will occur systematically when other variable generation production is low and marginal cost is high, and spill will occur

systematically when other variable generation production is high and system marginal cost is low.

Given the unpredictable nature of variable generation, it is not practical to use time-based rates to accommodate the generation pattern variation into rates. The only opportunity to do so is by using a spread between the top-up rate and the spill rate.

Other, non-systematic, variability will occur but should not create systematic differences in incremental cost that need to be reflected in the tariff. Should any such changes be identified at a later time, they could then be subsequently incorporated into a EBS Tariff revision.

It would therefore be possible in theory to adopt:

- Time based rates common to all technologies, with an additional spread superimposed according to generation technology (but this would be challenging to administer if an LRS has a portfolio of different supply technologies), or
- A spread applicable to all technologies, but likely to be applied to higher quantities of top-up and of spill arising with highly variable generation.

In order to avoid undue complexity, it is proposed that the incremental cost element of the rates will not have any seasonal or daily variation, but will reflect a mid-point rate and a spread. The mid-point rate will reflect the average avoided cost per MWh of incremental production weighted according to the hourly demand pattern over a year (which would represent a perfect match of RtR generation to average customer load shape). The spread will be set at a level to recover the reduction in overall avoided cost as the generation pattern departs from that ideal match and creates a need for annually balanced top-up and spill.

5.5.3 Allocated Cost Element

In order to recover the appropriate allocation of fixed generation costs to the production for top-up, the selected tariff structure adds the fixed generation cost allocated to energy to the incremental top-up rate. This is the same as the energy-based charge for fixed generation costs included in the Bundled Service Cost of Service analysis.

5.5.4 Annual Excess Spill Discount

The top-up and spill incremental rates discussed above are designed to recover the costs of providing annually balanced top-up and spill services. Any sustained bias towards top-up service quantity would represent an infringement of the LRS's compliance obligation as set out in the UARB draft Retailers Regulations, and would trigger a refund by the LRS to its customers. As such, it does not require separate tariff consideration. There can, however, be a sustained bias towards spill service, such as during periods when generation investment is ahead of customer recruitment.

This bias will tend to reduce further the costs avoided by NS Power due to spill. The rate payable to the LRS for such extra spill should therefore be discounted from the rate applicable to balanced spill.

5.6 Standby Service Tariff; Design Principles

Standby Service fulfills two functions:

- It provides to each LRS any firm dependable capacity required (in excess of the LRS's self-supplied firm dependable capacity) to support the share of total system adequacy requirement attributable to the LRS's load.
- It provides to each LRS the demand-based element of capacity required to provide top-up service.

If the combined generation fleet of NS Power and the LRSs is adequate to fulfill the firm dependable capacity requirement, then there should be adequate generation in Nova Scotia to meet the system energy requirement at all times, including in respect of each LRS's firm service customers, and during LRS generation outages. The charge determinant for this tariff is therefore based on the need to fulfill the firm dependable capacity requirement.

Given that RtR customers are to be served with the same reliability as equivalent Bundled Service customers, the system adequacy requirement is mandatory in respect of those customers. As a result, the Standby Tariff is a mandatory obligation for the LRS. This is in contrast to the voluntary backup service available to Wholesale Market customers under NS Power's existing Backup & Top-up Service tariff. In that Wholesale Market context, NS Power's obligation with respect to backup is limited to the contract demand.

5.7 Standby Service; Charge Determinant Principles

5.7.1 Concern with Existing Backup Service Charge Determinant

The demand charge portion of NS Power's present Wholesale Market Backup and Top-up Service tariff was reviewed for its applicability in the RtR Market. Based on NS Power's NPCC obligations to maintain system adequacy, the firm dependable capacity required to be available to the system before specific outages but discounted for dependability should be determined as follows:

1.20 x annual system coincident peak firm demand including associated losses

The LRS responsibility should therefore be determined as follows:

1.20 x LRS demand (including associated losses) at time of annual system coincident peak

An LRS will naturally self-supply some quantity of firm dependable capacity through its owned or contracted generation that is connected to the system under Network Resource Integration Service. Self-supply of additional generation capacity from other Nova Scotia resources is not practical for the same reasons as for Top-up service, as described in section 5.3.3. Self-supply of capacity from imports is equally impractical.

The quantity of capacity that must be purchased by any LRS from NS Power should therefore be determined as follows:

> *1.20 x LRS demand at time of annual system coincident peak minus the LRS's firm dependable capacity resources made available to the system under Network Resource Integration Service.*

For comparison, the demand determinant of NS Power's Wholesale Market Backup / Top-up Service tariff, interpreted to substitute the LRS peak monthly demand for the contract demand (CD) would give a billing demand under the present tariff of, and assuming that the LRS peak monthly demand exceeds average generation:

> *Billing demand = (20% x average generation) + (LRS peak monthly demand – average generation)*

Or if average generation exceeds LPD:

> *Billing demand = 20% x LPD*

This calculation will generally understate the requirement set out above to cover the costs of system needs. As such, it is appropriate for the RtR Standby Service tariff to utilise a different charge determinant that fully reflects the required contribution to system needs. This is developed in the immediately following section.

5.7.2 Charge Determinant Details

It is expected that customers can and will migrate between bundled service and RtR supply, and among LRSs, at any time of year. This presents a challenge in properly allocating costs for recovery from each LRS. The basis for cost allocation between classes , and for actual charges of large industrial customers uses winter peak demands. But the historical peak demands of an LRS in December, January and February (as used in the large industrial tariffs) will likely be unrepresentative of the customer portfolio a few months after that. In order to achieve an appropriate allocation to the LRS portfolio over the year it is proposed to recalculate an equivalent annual coincident demand on the basis of each month's actual demand of the LRS portfolio coincident with the system peak for that month. The calculation of this equivalent annual peak will reflect the differing load profiles of each customer class. It is proposed that the standby billing demand of an LRS be calculated as follows:

- To determine the firm dependable capacity requirement associated with that LRS's load:
    - Determine in each month the system peak firm demand hour;
    - Determine for that hour the total LRS's firm load in each customer class, including distribution system losses;
    - Apply the applicable adjustment factor to derive the equivalent contribution to annual coincident peak firm demand for each class; and

  - Aggregate the class equivalent annual contributions to determine the LRS total equivalent annual peak firm demand.

- The firm dependable capacity contribution provided by the LRS's owned and contracted generation is the sum of contributions of firm dependable capacity of those generation facilities, excluding any such capacity assigned for self-supply of capacity-based ancillary services under the OATT, and all divided by (1 + 20% reserve margin) to determine the demand served by that capacity.
- The standby charge billing demand of the LRS is the excess of the LRS total equivalent annual peak firm demand over the firm dependable capacity contribution (after discounting for the reserve margin requirement) provided by the LRS's owned and contracted generation.
- If the firm dependable capacity contribution (after discounting) exceeds the LRS total equivalent annual peak demand, there is no payment.

5.8 Standby Service; Rate

The rate applied is the rate per unit of winter peak demand, spread over 12 monthly payments, required to recover the demand-based fixed supply cost under the Bundled Service Cost of Service analysis, after excluding those costs that are recoverable under OATT Ancillary Service rate Schedules 2 to 6.

6 Tariff Design Specifics: Transmission

6.1 Customer-specific or Aggregated Tariff

6.1.1 Concepts

NS Power has considered two conceptual options for the transmission tariff in the RtR Market Context:

- aggregated approach; and
- customer-specific approach.

These are described below. NS Power has selected the aggregate approach for the reasons also set out below.

In both cases the transmission charges would be billed by NS Power to the LRS.

6.1.2 Aggregated Approach (selected)

Under an aggregated approach, each LRS would be a transmission customer subject in general to all provisions and charges in accordance with the OATT. Charges would be determined using a demand

determinant that will reflect a virtual delivery point for the aggregated of each LRS's hourly load at customer meters as adjusted for distribution losses.

OATT schedules 1,2,3,5,6,9 & 10 will apply. Schedule 4 will be replaced for each LRS by proposed Schedule 4A, as discussed below and in section 5.3.2 above.

6.1.3 Customer-specific Approach (not selected)

Under a customer-specific approach, the tariff Network Service terms and conditions would remain broadly applicable, but the service-specific schedules of rates would be replaced by class-specific schedules of rates applicable to individual customer metering results. Rates would utilise the same charge determinants as the new RtR Distribution Access Service rates, and would thus represent the transmission subset of the present Bundled Service Cost of Service analysis plus the fixed generation demand amounts allocated as recoverable under OATT Schedules 2 to 6.

Proposed OATT Schedule 4A would be separately billable to the LRS.

6.1.4 Selection

Absent a specific need to create a new customer-specific tariff with its associated immediate and ongoing administrative and regulatory burden, NS Power has adopted the aggregated tariff approach. This best leverages the use of the existing OATT, maximises consistency with the Wholesale Market, and minimises administrative burden.

6.2 Treatment of Imbalance, OATT Schedule 4

Under the proposed EBS tariff approach, OATT Schedule 4 will not apply to RtR service. It will be replaced by Schedule 4A which would provide for payments at 10% of marginal cost in respect of each MWh in excess of 2.0 MWh by which an LRS hourly generation forecast does not match the actual production, excluding when such mismatch is due to NS Power's curtailment of the generation. Please refer for discussion to section 5.3.2 above.

6.3 Relief in Respect of Generation and Load Connected in the Same Distribution Zone

Consideration has been given to the transmission tariff treatment where RtR generation and load are connected to the same distribution zone, and thus behind the same transmission delivery point. Following initial stakeholder discussion, a stakeholder took the position that if a generator-to-LRS-to-customer system were to be designed with 100% of the generation and consumption taking place on a single distribution network, then the LRS payment for transmission services should be based on the net of load minus same-zone generation.

While such an approach would address the situation where 100% of an LRS's activity is in a single zone, the principles are applicable to any situation where a portion of an LRS's generation and load are in the same zone.

The following issues were considered:

- Use of Transmission for Delivery of Services

  The delivery to the LRS for its customers of Standby Service, Top-up Service and potentially the acceptance of spill all rely on the use of the transmission system. Absent assured 100% reliable delivery of firm energy from the generator, there are expected to be occasions during RtR generator outages when the top-up requirement will be 100% of the load, allowing no reduction in transmission capacity required to that delivery point.

- Ancillary Service Requirements

  The requirement for and use of ancillary services such as system dispatch, load following and operating reserve is not reduced by co-location of generation and load within the same zone.

- Congestion Relief

  Transmission congestion does not generally arise in the last kilometers of transmission delivery, but at a few locations on the Province's bulk transmission system. While there may be differences in impact between RtR generation located in Cape Breton and in the Halifax area, those impacts do not change if the generation is connected to transmission or distribution systems in each location.

- Loss reduction

  There are arguments that generation delivered to load within the same distribution zone should not have to bear the burden of transmission system losses. However, network service transmission relies on the use of average loss factors. The loss factors used by NS Power are averages that reflect that some of their own generation may be similarly located in the same zone as load. In addition, and depending on the particular location, the addition of generation into a distribution zone may change system flows in a way that does not reduce total system losses. It would therefore not be appropriate to use different loss factors according to generator connection point.

- Embedded Cost Recovery

  To the extent that an LRS was to be relieved of transmission charges for generation located in the same zone as load, and this loss of NS Power revenue could not be recovered from Bundled Service customers, this would add to the embedded costs requiring to be recovered from the LRS. It would become necessary to add a transmission cost element to the RtR Market Transition Tariff. This would substantially negate any benefit that an LRS might gain from relief in respect of transmission charges for generation located in the same zone as RtR load.

For all of these reasons, the OATT charge determinant applicable to each LRS should be derived from the aggregate of all RtR customers' metered consumption, adjusted for distribution losses, without offset in respect of any generation located in the same distribution zone as RtR load.

7 Tariff Design Specifics: Distribution & Retail Charges

The Distribution Access Tariff provides for the recovery of costs classified in the Bundled Service Cost of Service analysis as distribution costs and as retail costs.

The Distribution Access Tariff will use the same customer demand and / or energy charge determinants as are applicable to that customer under the applicable class Bundled Service tariff.

The terms and conditions of the Distribution Access tariff will incorporate the NS Power Regulations as amended to account for the RtR market opening.

8 Tariff Design Specifics: Embedded Cost Recovery

8.1 Purpose of the RtR Market Transition Tariff

The proposed RtR Market Transition Tariff (RTT) is designed to recover embedded costs not otherwise recovered thought the tariffs described above. The amounts to be recovered under the RTT in respect of embedded costs comprise:

- The amounts under the demand element for fixed generation costs under the existing Bundled Service tariff that would be foregone as a result of capacity self-supplied by the LRS (ie excluding that recovered as Standby Service charge), minus the benefit of avoided or deferred generation capacity investment, if any[11].
    - This is effectively the Standby Service charge rate multiplied by the LRS self-supplied firm dependable capacity, less any benefit that can be gained in the form of avoided or deferred generation capacity investment. That avoided or deferred investment benefit is expected to be minimal in the near future.
    - This element of the stranded amount is principally determined by the LRS's generation resources, and is not affected under any normal conditions by its load.

[11] NS Power's integrated system plans indicate no new capacity investments until at least the mid 2020s, and therefore no opportunity until then for such avoidance or deferral.

- The foregone amounts under the energy-based charge for fixed generation costs under the Bundled Service tariffs, less that recovered in the top-up charge, minus any mitigation achieved as margin on sales of freed-up production capability.
    - This is effectively the energy based charge rate for fixed generation costs as included in the top-up charge multiplied by the LRS load supplied other than through top-up, less an estimate of mitigation expected to be achievable.
    - This element of the stranded amount is determined by the LRS's load and the nature of the generation supplying it (which affects the quantity of top-up required to support that load).
- Differences between the Bundled Service tariff fuel cost recovery foregone, and the avoided cost arising from RtR supply;
    - The present avoided cost estimates represent the incremental fuel cost associated with the displaced generation. This incremental fuel cost is presently higher than the average fuel cost shown in the Bundled Service Cost of Service analysis. This results in a reduction to the RTT energy charge.
    - The incremental fuel costs presently exceed the average fuel cost for a number of reasons:
        - The least efficient generation would likely be displaced first;
        - Hydroelectric facilities have no fuel cost and reduce the system average fuel cost;
        - The upward averaging caused by the inclusion of renewable PPA purchases is less than the previous two effects.

Should average fuel costs increase in future above incremental fuel costs, then this adjustment would add to the RTT energy rate.

This element of the stranded amount is determined by the LRS's load net of top-up. It is thus affected primarily by the LRS's load, but also by its generation resources.

8.2 Recovery Mechanism

8.2.1 Options

Two potential recovery mechanisms were presented to stakeholders:

- A Retail Access Adjustment based on the extent of the embedded cost recovery required in each year as a result of each LRS's activity, using rates that could be adjusted from time to time; or
- An exit fee associated with each exiting customer, applicable on exit and set to recover estimated embedded cost recovery requirements in respect of each exiting customer. The exit

fee would be based on each customer's historic load and class, using a rate that might be adjusted from time to time but without retroactive adjustment.

8.2.2 Retail Access Adjustment

Characteristics of the retail access adjustment as proposed in the RtR Market Transition Tariff are:

- Charges per unit of stranded demand and energy set in advance and capable of annual adjustment;
- Charge rates are indifferent to an LRS's generation technology, or to the generation deemed to be associated with each customer;
- The quantum of monthly charge would vary with changing balances in an LRS's generation and load portfolios;
- The LRS cost responsibility moves with customers on migration between LRSs, and terminates on any return to Bundled Service;
- Charges per unit are capable of adjustment to reflect new fixed cost additions and new opportunities for NS Power avoidance or deferral of investments or other costs;
- Charges are complementary to EBS and Standby Service tariffs to achieve appropriate and stable cost recovery in total, minimising risks of under- or over-recovery; and
- Capable of continuation for as long as embedded cost recovery is required, and cessation when such embedded cost recovery is no longer required.

8.2.3 Exit fee

Characteristics of an exit fee would be:

- Predetermined for each customer on exit;
- Charges per unit of historic energy consumption and demand set for each customer class in advance and capable of annual adjustment for application to new exit;
- Requires estimate on customer exit of:
    - Impact of specific generation technology expected to serve that customer,
    - Future demand-supply balance, including as a result of RtR generation development,
    - Duration of stranding, recognising limited opportunity for investment avoidance or deferral for many years;
- There is material uncertainty and risk in such estimates, with potential for under- or over-recovery;
- Requires initial cash payment, unless covered by a deferred payment mechanism (with associated financing cost); and
- Would require definition of customer / LRS responsibilities; any customer responsibility would presumably require declaration in marketing materials and comparisons.

8.2.4 Stakeholder input

One stakeholder indicated a preference for an Exit Fee, determined on customer exit but payable over a five year period.

This preference was recognised and considered in selecting the solution, but did not outweigh the fundamental reasons for the selection of the RTT approach as set out in the following section.

8.2.5 Basis for selection

The amount of embedded cost recovery depends in large part on the amounts of NS Power fixed costs recovered by other mechanisms. As noted in the discussion of the EBS and Standby Service tariffs, the amounts recovered under those tariffs depend on RtR load, RtR generation and the relationship between those two. The RTT as proposed mirrors those tariff recoveries. It can effectively avoid material under- or over-recovery and thereby best fulfil the requirements of the *Electricity Act*.

Retail Access Adjustments and Exit Fees could each in theory be set at levels that would target full embedded cost recovery, avoiding either over-recovery or under-recovery. The Exit Fee however depends on estimates, and such estimates will have to recognise the potentially long duration of the embedded cost recovery requirement in Nova Scotia due to the very limited opportunities to defer or avoid investments. Exit Fee estimates would probably be specific to each customer class, would each be specific to generation technology and would have to incorporate assumptions about EBS and Standby Service recoveries which depend on the LRS's supply-demand balance over the duration. Exit Fee estimates would have a high degree of uncertainty, and would add very significantly to the risk profile of NS Power and potentially of each LRS.

The retail access adjustment mechanism, in the form of the proposed RtR Market Transition Tariff, was selected over the Exit Fee mechanism due to its ability to achieve embedded cost recovery on a full and fair basis with the least risk and uncertainty.

8.3 Interaction with Other Tariffs and Retailers Regulations

In the event that NS Power's recoveries under other proposed tariffs are varied from those proposed, the proposed RTT would need to be revised to reflect any such changes in those other tariffs in order that it continue to fulfill the "no harm" requirements of the *Electricity Act*.

As noted in section 3.5 above, the preferred approach to issue of B-t-M settlement, as included in NS Power's Application, is based on the use of secondary metering for settlement of RtR tariff amounts including for Distribution Access Service. Were this approach to be rejected, there would need to be a wide-reaching Behind-the-Meter Transition Tariff developed and put in place to achieve the recovery of those additional embedded costs for which charges under the above tariffs would otherwise be avoided.

9 Connection issues

9.1 Transmission System Cost Impact

The present Generator Interconnection Procedures (GIP) collectively have the effect that network upgrade costs incurred to accommodate a new generation connection will initially be funded by the generator, but then recovered from customers. The recovery from customers of network upgrade costs to accommodate new RtR generation would be inconsistent with the requirements of the Electricity Act. As a result, it will be necessary to amend the GIP and Generator Interconnection Agreement (GIA) to eliminate the provision for cost recovery from customers and credit to generators in respect of RtR generation.

9.2 Other Generator Impact

In addition to other NS Power customers, the *Electricity Act*,as amended, stipulates that existing independent power producers and approved feed-in-tariff producers (collectively "protected producers") should not be negatively affected.

Potential adverse effects that might arise due to technical interactions (eg fault level requirements) should be adequately addressed by the connection processes. Potential negative effects that could arise due to transmission congestion need to be addressed. Either:

a) Physical protection, whereby protected producers should not be subject to additional curtailment as a result of RtR generation, or

b) Financial protection, whereby any losses suffered by protected producers as a result of any additional curtailment should be compensated, and the funds for such compensation should come from the RtR supply chain and not ultimately from NS Power customers.

Curtailment events are most likely to arise in order to mitigate system oversupply. They may also arise under abnormal conditions, or over time due to changing patterns of load[12].

Option (a) should be the preferred option. Administration of this solution requires that the NS Power System Operator prioritise curtailments so that all RtR generators contributing to an oversupply situation be curtailed before any protected generators contributing to that oversupply situation. This avoids situations where protected generators suffer any increase in curtailment due to the operations of RtR generators. NS Power System Operator will incorporate these processes into its Operating Procedures.

[12] NRIS resources would be connected only if they made no material contribution to transmission congestion or if they pay for the network upgrade to offset such congestion.

Each LRS would be expected to ensure that any such curtailment would not jeopardise fulfillment of its compliance obligations under the Retailers Regulations.

Appendix A: Resume of Robert Cary

PROFILE

Robert Cary & Associates Inc. is a consulting business specializing in electricity markets and related commercial issues. Robert Cary is a well-respected consultant in the electricity sector in Ontario and the Maritimes and has previous experience in the development and management of capital projects. Robert Cary has joined Charles River Associates as a senior consultant, and thus undertakes certain work through CRA and certain work independently.

Expertise covers three core areas:

- Consulting in market evolution and development in Ontario and the Maritime Provinces, including market rules development and evolution, system coordination or integration, renewable energy integration, renewable energy trading frameworks, Feed-In Tariff arrangements, clean energy standard offer programs, and greenhouse gas issues.
- High value consulting in commercial and regulatory aspects of the Ontario electricity sector. This is principally from the perspective of generators or on behalf of the OPA in connection with generation contracts, and includes the analysis to support project development and financing, market interaction, contract negotiation, regulatory interfaces, and expert witness assignments for litigation and arbitration.
- Corporate & not-for profit governance: Chair of Horizon Utilities, which is the municipally owned electricity distributor for the Cities of Hamilton and St Catharines, serving 230,000 customers. Vice Chair of St Catharines Hydro Inc. For 15 years, Director of APPrO, the Association of Power Producers of Ontario. Trustee of the Niagara Health System (2010 to 2011). Previously director of companies within the Darchem group in the UK.

More detail on each area is provided on the following pages.

Rob graduated from the University of Cambridge in England, is a Professional Engineer, and an MBA. He has undertaken project management, business and corporate development functions, largely in the energy sector. He has been associated with the Ontario electricity sector since 1990, first for AGRA Monenco, then for Westcoast Power, and since 2000 as an independent consultant.

QUALIFICATIONS

MA (physics & engineering) University of Cambridge, England, 1970
MBA, Cranfield School of Management, England, 1978
P Eng (Ontario)
Chartered Director

SELECTED POLICY DEVELOPMENT AND MARKET DESIGN ASSIGNMENTS

Atlantic Provinces / Maritime region (2001 to date)

Atlantic Region coordination: reports to the Council of Atlantic Premiers energy committee on the opportunities for greater regional integration and on the lessons to be learned from review of electricity sector governance systems elsewhere.

New Brunswick Electricity Market Design: engaged by the Government of New Brunswick to draft New Brunswick market rules in accordance with the design framework established by the Market Design Committee. Follow-on engagements to assist the New Brunswick System Operator in its development of the Market Procedures for rules implementation, including training of Market Advisory Committee members, System Operator staff, and Market Participants and in 2006 to review the opportunities for demand-management participation in the electricity market.

Nova Scotia Electricity Market Design: independent review of the recommendations of the Nova Scotia Electricity Marketplace Governance Committee with respect to achievement of Energy Policy objectives, and to practicality; advice to NSPI on tariff design issues and market documentation; drafting of market rules for the Nova Scotia electricity market for the Nova Scotia Department of Energy under the oversight of a steering committee including stakeholder representation.

Nova Scotia Renewable Energy trading system design: preparation of discussion papers to outline options for implementation of renewable electricity trading systems, followed by leadership of discussion forum, collation of stakeholder responses, and finalization of policy options as a basis for possible legislation and regulation. Assistance in determining terms of reference for a wind power integration study.

Ontario (1999 – date)

Member of the IESO (then IMO) Technical Panel, as stakeholder representative for generators from 1999 to 2004, which period encompassed the development of the market rules in preparation for market commencement and the refinement of the rules thereafter.

Direct participation in IESO working groups on behalf of generator clients to develop the market evolution program with respect to resource adequacy, system optimization, outage management, reliability and market pricing issues, Day-Ahead Market design, wind generation dispatch, capacity markets, etc.

Direct participation in OEB processes to define and later review the transmission system code and to resolve a range of regulatory issues concerning retail & distribution. Participated in IESO tariff hearings and indirectly in transmission tariff hearings.

Nova Scotia Renewable to Retail market design: consulting services to Nova Scotia Power to assist in their development of a mandated renewable to retail market framework in accordance with legislation.

SELECTED COMMERCIAL & REGULATORY CONSULTING ASSIGNMENTS

Generation owners and developers (2000 to date)

Sithe Global and Goreway Power Station: bid support, contract negotiation, project financing support, market interface preparation, and IESO audit response for the 840 MW Goreway combined cycle facility.

Macquarie / Capstone / Cardinal Power: NUG contract amendment, market readiness, successor contract analysis and negotiation support for the 156 MW combined cycle cogeneration facility.

GTAA cogeneration project performance review and ongoing support.

Consortium of all existing large wind generation owners: Took a lead role in the negotiation of market rule changes and contract amendments to enable dispatchability of wind projects.

Member of lenders independent engineer teams for review of market interface issues related to combined cycle and peaker projects under consideration for project financing.

Ontario Power Authority, now merged into the IESO (2007 to date)

Assistance in the development of:

- a generic form of peaker contract based on previous Clean Energy Supply contract models;
- Feed-in-Tariff (version 1) rules and contracts, and associated arrangements; and
- Clean Energy Standard Offer Program / CHP Standard Offer Program.

Assistance in the negotiation of:

- Lower Mattagami Hydroelectric supply agreement negotiations with OPG for the supply of electricity from the 450 MW expansion of the Lower Mattagami system;
- Early Movers successor contract negotiations, supporting the OPA in contract negotiations with early mover owners of gas fired combined cycle generators;
- Hydroelectric Contract Initiative contract development and negotiations, supporting the OPA in these contract developments and negotiations;
- Atikokan biomass conversion contract, supporting the OPA in the negotiation of a long term energy supply agreement with OPG for the conversion of Atikokan to biomass fuel;
- Lennox long term energy supply agreement, supporting the OPA in the negotiation of a long term capacity agreement with OPG for the oil/gas fuelled Lennox Generating Station; and
- Energy storage program, supporting the OPA in the development of the RFQ, RFP and contract for energy storage projects.

Assistance to the OPA in understanding how potential GHG regulation may affect gas fired facilities under contract with the OPA, and in the development of the OPA's policies for treatment of GHG regulation impacts within such contracts.

SELECTED LITIGATION & DISPUTE RESOLUTION ASSIGNMENTS

Expert witness services in support of an independent generator in Ontario in arbitration of a dispute with its gas supplier concerning the continuance of the gas price determination following restructuring of the Ontario electricity market.

Expert witness services in support of an independent generator in Ontario in mediation of a dispute with its gas supplier concerning the continuance of the gas contract and its price determination following restructuring of the Ontario electricity market.

Expert witness services to an independent generator in preparation for its defence against litigation from gas suppliers on gas price determination and contract validity, and assistance in negotiation of a settlement.

Expert witness services to an independent generator in arbitration of a dispute with its gas supplier concerning the detail of gas price determination following restructuring of the Ontario electricity market.

Expert Witness services to a generator in preparation for arbitration over contract cancellation.

DIRECTOR OF BUSINESS AND OTHER CORPORATIONS

St Catharines Hydro Inc (2000 to date)

Director and Vice Chair of St Catharines Hydro Inc, and director of St Catharines Hydro Generation Inc, which operates one hydraulic generating station and is developing a second.

Chair of St Catharines Hydro Utility Services Inc from its corporatization in July 2000 to its amalgamation with Hamilton Hydro Inc in 2005 to form Horizon Utilities Corporation. Co-chair of the joint Board Steering Committee overseeing due diligence and negotiations of the merger.

Horizon Utilities Corporation (2005 to date)

Appointed as director following the creation of Horizon Utilities Corporation from the amalgamation of St Catharines Hydro Utility Services Inc and Hamilton Hydro Inc. From 2006 to 2012, chair of Horizon Utilities Corporation HR & Governance committee. Since Feb 2012, Chair of Horizon Utilities, Horizon Holdings Inc and Horizon Energy Solutions Inc.

APPrO, Association of Power Producers of Ontario (1999 – 2014)

APPrO is a non-profit association of corporate and individual members, including all the significant electricity generators in Ontario. It works to further its members' interests and to promote competitive and environmentally friendly generation. The directors are elected by the members.

Trustee – Niagara Health Service (2010 – 2011)

Appointed in 2010 to the Board of Trustees of the Niagara Health System, and in 2011 elected as Vice-Chair.

Request IR-19:

With respect to Figure 11, page 37, please add a column to show the percentage change for each component of the RTT compared to 2025 rates. Where the change is greater than 10% for a particular component, please provide a detailed explanation of the driver(s), including the relative contribution of each driver to the total change.

Response IR-19:

Please refer to the figure below.

Energy Charge by Components (cents per kWh)	2025	2026	Variance	
			Amount	Percent
Fixed Cost Adder from Energy Balancing Service Tariff	3.264	2.166	(1.099)	(33.7)
Annually Adjusted Energy Savings Credit	0.000	0.000	0.000	
Annual Energy Cost Adjustment	(2.463)	2.198	4.660	(189.2)
Total	**0.802**	**4.363**	**3.562**	**444.3**
Demand Charge by Components ($/kW)				
Demand Charge from Standby Service Tariff	3.397	5.452	2.055	60.5
Annually Adjusted Demand Savings Credit	0.000	0.000	0.000	
Total	**3.397**	**5.452**	**2.055**	**60.5**

The increase of 444.3 percent in the Energy Charge by Components is primarily a result of a change in the Annual Energy Cost Adjustment. Please, refer to Section 7.3.1.3 Annual Energy cost Adjustment of this Application for discussion of the reasons behind the proposed increase in this driver. Also please refer to part (c) of REI IR-13.

Please refer to REI IR-14 for the explanation of the increase in the Demand Charge by Components.

Annually Adjusted Rates for 2026 (M12551)
NSPI Responses to REI Information Requests

NON-CONFIDENTIAL

Request IR-20:

Reference: Board Directive regarding Interruptible Service, p. 37.

(a) Please confirm that REI, in fact, provided a response to NS Power's proposed LRS – Interruptible Pilot Project Terms of Reference on November 7, 2025 and please provide a copy of REI's response.

(b) Please provide a copy of any subsequent response or communication from NS Power regarding REI's November 7, 2025 response, and notes of any discussions regarding Interruptible Service.

(c) The Terms of Reference contemplate the Interruptible Pilot Project will commence when approved by the NSEB. Please provide NS Power's best estimate of when the application for approval will be filed with the Board, including the expected hearing schedule.

(d) Does NS Power perceive any technical, operational, regulatory, or commercial impediments to the Interruptible Pilot Project being available for the winter 2026/2027 season? If yes, please explain each impediment in detail and what steps would be required to overcome them.

Response IR-20:

(a) Confirmed, on the date that 2026 AAR Application was filed, NS Power received a response from REI with comments on the Interruptible Pilot Project Terms of Reference (TOR). REI indicated a desire to confirm the TOR by December 15, 2025. REI is welcome to file the DRAFT document sent to NS Power with its evidence in this proceeding though NS Power cautions that filing a draft document could create confusion or imply that the content is finalized, which is not the case. Once the document has been finalized and agreed

upon, the Company will ensure that any required filings are made in accordance with regulatory requirements.

(b) NS Power has monthly check-ins with REI where relevant matters are discussed orally. REI's comments on the TOR were discussed orally on November 13, 2025 and again on December 9, 2025. NS Power intends to send further comments back on the TOR before the end of 2025.

(c) At this time, there is no specific date determined for filing the application with the Board. Finalization of the TOR represents the initial step in the process, and subsequent timelines will depend on a variety of factors. NS Power will continue to communicate clearly with REI to provide updates as the schedule becomes clearer.

(d) The following issues may arise and delay offering interruptible service for the winter 2026/2027 season:

Technical/Operational Impediments

- Customer Readiness: Certain participating customers may require equipment upgrades or modifications to accommodate interruptions safely.

- Dispatch Protocols: Development, implementation and validation of operational procedures for initiating and managing interruptions.

Regulatory Impediments

- Approval Timelines: The project cannot proceed until the Board approves the Pilot and associated tariff revisions.

- Tariff Design: Interruptible service terms must be incorporated into tariffs and aligned with regulatory requirements.
- Compliance Obligations: New reporting and monitoring processes may be required to meet regulatory standards.

Commercial Impediments

- Cost Recovery: Establishing acceptable cost allocation and recovery mechanisms including penalty collection.

- Mitigation Steps: Early outreach to potential participants, transparent communication of benefits and obligations, and tariff adjustments as required.

While these impediments present challenges, NS Power is committed to addressing them proactively. The Company will continue to provide REI with updates as timelines and requirements become clearer.