BEFORE THE NOVA SCOTIA UTILITY AND REVIEW BOARD

In the Matter of an Application of the Town of Mahone Bay, on behalf of its Electric Utility, for Approval of Amendments to its Schedule of Rates and Charges for the provision of electric supply and services to its customers and its Schedule of Rules and Regulations

(NSUARB M10832)

Evidence of
Melissa Whited

On Behalf of
Counsel to Nova Scotia Utility and Review Board

January 11, 2023

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I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name, title, and employer.

A. My name is Melissa Whited. I am a Senior Principal at Synapse Energy Economics, Inc. ("Synapse"), located at 485 Massachusetts Avenue, Cambridge, MA 02139.

Q. Please describe Synapse Energy Economics.

A. Synapse is a research and consulting firm specializing in electricity and gas industry regulation, planning, and analysis. Our work covers a range of issues, including economic and technical assessments of demand-side and supply-side energy resources; energy efficiency policies and programs; integrated resource planning; electricity market modeling and assessment; renewable resource technologies and policies; and climate change strategies. Synapse works for a wide range of clients, including attorneys general, offices of consumer advocates, public utility commissions, environmental advocates, the U.S. Environmental Protection Agency, U.S. Department of Energy, U.S. Department of Justice, the Federal Trade Commission, and the National Association of Regulatory Utility Commissioners. Synapse's staff includes over 35 professionals with extensive experience in the electricity industry.

Q. Please summarize your professional and educational experience.

A. I have 13 years of experience in economic research and consulting. At Synapse, I have worked extensively on issues related to utility regulatory models and rate design. I have been an invited speaker in numerous industry conferences, including as a panelist for the National Association of Regulatory Utility Commissioners (NARUC) Subcommittee on Rate Design at the 2021 Winter Policy Summit and the 2018 Annual Meeting.

I have sponsored testimony before the Newfoundland and Labrador Board of Commissioners of Public Utilities, the Massachusetts Department of Public Utilities, the Illinois Commerce Commission, the New Hampshire Public Utilities Commission, the Georgia Public Service Commission, the Rhode Island Public Utilities Commission, the Maine Public Utilities Commission, the California Public Utilities Commission, the Hawaii Public Utilities Commission, the Public Service Commission of Utah, the Public Utility Commission of Texas, the Virginia State Corporation Commission, and the Federal Energy Regulatory Commission. I hold a Master of Arts in Agricultural and Applied Economics and a Master of Science in Environment and Resources, both from the University of Wisconsin-Madison. My resume is attached as Appendix A.

Q. Have you previously testified before the Nova Scotia Utility and Review Board?

A. Yes. I testified in Matter Nos. M09777, M10176, M10431, and M10810.

Q. On whose behalf are you providing evidence in this case?

A. I am providing evidence on behalf of Counsel to the Nova Scotia Utility and Review Board ("Board").

Q. What is the purpose of your evidence?

A. My evidence addresses certain aspects of the General Rate Application of the Town of Mahone Bay Electric Utility ("TOMBEU" or "the Utility"), including cost allocation, rate design, and its proposed allowance for storm costs and a deferral account.

II. SUMMARY OF CONCLUSIONS AND RECOMMENDATIONS

Q. Please describe your conclusions.

A. My conclusions are as follows:

- TOMBEU's cost of service study relies on the minimum system method, which inappropriately classifies a portion of distribution system costs as customer-related.
- The Utility's cost allocation factors are overly reliant on assumptions based on the judgement of TOMBEU management and the Utility's consultant rather than actual data or analysis.
- The Utility's proposal to increase rates by an equal percentage for all classes other than Yard Lighting is not supported by the Utility's cost of service study and would perpetuate inter-class inequities.
- Increasing the service charge for the Domestic class is not justified on a cost-causation basis.
- The existing declining block rate structure is not supported by analysis and may lead to wasteful consumption and intra-class inequities.
- The Utility's proposed storm cost allowance is not adequately justified.
- In principle, the Utility's proposal for a deferral account for purchased power cost increases appears reasonable. The cost increases are both unknown and outside of TOMBEU's control, the deferral account would help to mitigate further rate increases in the near-term, and the existing flow-through mechanism does not appear to apply in this case.

Q. What are your recommendations?

A. I recommend that the Board:

- Direct TOMBEU to utilize the basic customer method for classifying distribution costs as demand- or customer-related. Under this method, conductors, poles and fixtures, and transformer costs, are classified as 100 percent demand-related.
- Direct TOMBEU to file a proposal within the next 18 months to enhance the data and analysis used to develop cost allocation factors and rates. The proposal should provide:

  - the estimated costs associated with conducting a load research study (either for TOMBEU alone or jointly with other utilities);
  - the costs and benefits associated with alternatives to a load research study, such as using publicly available class coincidence statistics from other winter peaking utilities and the availability of data from the revenue meter used by Nova Scotia Power for billing purposes;
  - TOMBEU's preferred option; and
  - TOMBEU's proposed timeline for implementation.
- Direct TOMBEU to conduct further analysis to determine appropriate customer weightings for its cost of service study, and to file this analysis in its next rate application.
- Direct TOMBEU to adjust rates in a manner that better reflects each class's contribution to costs, as detailed in my evidence below. Assuming an overall rate increase of 34.8 percent, my proposal would increase rates for Street Lighting by 43.5 percent and reduce rates for Yard Lighting by 14.8 percent. Rates for all other classes would be increased by 34.9 percent.
- Reject TOMBEU's proposal to increase all components of the Domestic rates by an equal percentage, and instead require TOMBEU to maintain the Domestic class service charge at current levels and implement the rate increase for the Domestic class through volumetric rates only.
- Direct TOMBEU to file a proposal to eliminate the declining block rate structure in its next rate application, unless such rate structure can be adequately supported by evidence that it is cost-reflective.
- Reject TOMBEU's proposal for a storm cost allowance at this time.
- Approve the Utility's proposal for a deferral account but require that the Utility submit an application to the Board for approval to recover any amounts accumulated in the account under terms to be approved by the Board.

III. COST OF SERVICE STUDY

Q. What is the purpose of a cost of service study?

A. A cost of service study is used to assign the utility's revenue requirement to each customer or rate class in proportion to the costs imposed on the system by those customers. Thus, a cost of service study seeks to determine what costs are incurred to serve each class of customers.

Q. Please provide an overview of the Utility's cost of service study.

A. TOMBEU's cost of service study follows three standard steps. First, costs are functionalized by separating utility plant and expenses according to the primary functions served. Second, the functionalized rate base and operating costs are classified according to the primary cost drivers: the number of customers on the system (customer-related costs), the need to meet peak demand (demand-related costs), and the amount of electricity consumed (energy-related costs). Finally, the costs are either directly assigned to customers or allocated using cost allocation factors based on class non-coincident and coincident demand, energy consumption, and number of customers. The ratio between each class's revenues and allocated costs (the revenue-to-cost ratio) provides a guide for determining changes in revenue and rates for each class.

Q. Were any corrections identified to the cost of service study?

A. Yes. In response to Synapse's information request IR-16 regarding a large increase in net plant costs in Exhibit 1-2 assigned to Street Lighting, TOMBEU responded that $60,000 was incorrectly "posted to Street Lighting System" and "should have been posted to distribution systems."

Q. Did you make any adjustments to TOMBEU's cost of service study to account for this error?

A. Yes. I reduced the net plant costs assigned to street lighting by $60,000 and increased the other distribution costs by an equal percentage[1] to account for this error. Although this should remedy most of the error, I recommend that the Board require TOMBEU to file a corrected cost of service study for Board review prior to the finalization of new rates with the correct total net plant for each account.

Q. How does your correction impact the costs allocated to each class?

A. The costs allocated to Street Lighting decreased by 26 percent while the costs allocated to all other classes increased by between 1 and 4 percent, as shown in the table below.

[1] TOMBEU did not identify the specific distribution account(s) to which the $60,000 should have been posted. I therefore used an equal percentage increase to all other distribution accounts as a proxy, but the final values should be based on corrections provided by TOMBEU.

Table 1. Allocated Costs after Correction of Net Plant Costs Assigned to Street Lighting

Original Filing							
Costs ($)	**Domestic**	**Small General Service**	**General Service**	**Time of Day**	**Net Metering**	**Street Lighting**	**Yard Lighting**
Purchased Power	1,084,447	108,618	745,268	25,343	4,888	8,133	1,629
OM&A	287,161	41,953	212,389	5,906	1,317	118,790	4,835
Amortization Exp.	25,838	3,785	19,600	521	116	12,588	343
Financial Costs	42,470	6,151	32,006	859	191	17,835	542
Total ($)	**1,439,916**	**160,507**	**1,009,263**	**32,629**	**6,512**	**157,346**	**7,350**
After Correction for Street Lighting Costs							
Costs ($)	**Domestic**	**Small General Service**	**General Service**	**Time of Day**	**Net Metering**	**Street Lighting**	**Yard Lighting**
Purchased Power	1,084,447	108,618	745,268	25,343	4,888	8,133	1,629
OM&A	305,356	44,583	226,158	6,273	1,398	83,516	5,068
Amortization Exp.	25,838	3,785	19,600	521	116	12,588	343
Financial Costs	45,210	6,548	34,071	914	203	12,531	577
Total ($)	**1,460,851**	**163,534**	**1,025,097**	**33,051**	**6,605**	**116,767**	**7,617**
Change	20,935	3,026	15,834	422	94	(40,579)	268
Percent Change	1%	2%	2%	1%	1%	-26%	4%

Q. Do you have any concerns regarding TOMBEU's cost of service methodology?

A. Yes, I have two primary concerns. First, the study assumes a 30 percent customer/70 percent demand split for classifying conductors, poles and fixtures, and transformers.[2] This assumption is based on the theory of a "minimum system."[3] The minimum system method classifies costs by estimating the cost of building from scratch a hypothetical system employing the smallest size components typically installed, and then deeming those costs to be customer-related. As I describe below, the minimum system methodology suffers from numerous flaws.

[2] As shown in TOMBEU Exhibit 4-2 and Exhibit 4-3. Although TOMBEU has previously classified conductors and poles and fixtures as 30% customer-related, it previously classified transformers as 100% demand-related. Response to TOMBEU (Synapse) IR-18.

[3] Response to Synapse IR-18.

Second, I am concerned that numerous allocation factors used by TOMBEU were developed based solely on the judgment of TOMBEU management and TOMBEU's consultant, rather than based on any actual data or analysis.

Q. Please explain your concerns with the minimum system method.

A. The minimum system method calculates the minimum size for each distribution plant type (e.g., poles and fixtures, conductors, transformers), and then classifies these costs as customer-related, while the remaining costs for each plant type are classified as demand-related. This approach is at odds with the definition of customer-related costs found in the widely-cited text, *Principles of Public Utility Rates* by Professor James Bonbright.[4] Professor Bonbright defines customer costs as the "operating and capital costs found to vary with number of customers regardless, or almost regardless, of power consumption."[5] The costs associated with conductors, poles and fixtures, and transformers are primarily driven by the need to serve demand on the system, and thus it is not appropriate to classify these costs as customer-related.

Q. Why do some utilities propose to classify conductors, poles and fixtures, and transformers as partially customer-related?

A. Professor Bonbright notes that the argument for classifying costs associated with a hypothetical "minimum system" as customer-related is that these costs vary with the area of the distribution system, and thus indirectly with the number of customers.[6] However, Bonbright argues that there is actually a "very weak correlation between the area (or the

[4] James Bonbright, Principles of Public Utility Rates (New York: Columbia University Press, 1961).

[5] *Id.,* p. 347.
[6] *Ibid.*

mileage) of a distribution system and the number of customers served by this system," given that in many cases an increase in customers does not require an expansion of the distribution system.[7]

Q. Are there other reasons why it is generally inappropriate to use the minimum system method?

A. Yes. Additional shortcomings of the minimum system method have been widely documented. For example, multiple pages in the Regulatory Assistance Project's 2020 manual *Electric Cost Allocation for a New Era* are devoted to examining the flaws of the minimum system method. Key critiques of the minimum system method from the manual include the following:[8]

1) The hypothetical "minimum system," used as the basis for this cost allocation method, still has the ability to serve some load—often a large portion of a typical residential customer's load.

2) A large portion of the cost of the distribution system (e.g., the number of poles and length of conductors) is driven by the size of the territory served, rather than the number of customers.

3) The minimum system method generally uses commonly installed minimum sizes, rather than the smallest equipment ever used, currently in use, or that could be used. However, a key reason for using larger equipment is due to higher customer

[7] *Id.,* p. 348.

[8] Jim Lazar, Paul Chernick, and William Marcus, "Electric Cost Allocation for a New Era: A Manual" (Regulatory Assistance Project, 2020), 145–49, https://www.raponline.org/wp-content/uploads/2020/01/rap-lazar-chernick-marcus-lebel-electric-cost-allocation-new-era-2020-january.pdf.

demands, and thus the minimum size currently in use does not represent the true minimum that would be required for a hypothetical minimum system.

4) The hypothetical minimum system is assumed to have the same number of units (number of poles, feet of conductors, etc.) as the actual system. In reality, both the size of equipment and the number of units is often driven in part by load.

The manual concludes that the "minimum system analysis does not provide a reliable basis for classifying distribution investment and vastly overstates the portion of distribution that is customer-related."[9]

Q What method do you recommend using instead of the minimum system?

A I recommend using the basic customer method. Under this method, only the meter, service drop, and billing/collection costs would generally be classified as customer-related. These are those costs that increase or decrease with the number of customers on the system. Further, as stated by the Regulatory Assistance Project's manual, the "basic customer method for classification is by far the most equitable solution for the vast majority of utilities."[10]

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[9] *Id,* p. 146.

[10] *Id,* p. 145.

Q. Is the basic customer method used by other jurisdictions?

A. Yes. The Regulatory Assistance Project's manual notes that the basic customer method is currently used by jurisdictions across the United States, including Arkansas, California, Colorado, Illinois, Iowa, Massachusetts, Texas, and Washington.[11]

Q. How would this methodological change impact the results of the cost of service study?

A. As discussed above, the Utility's cost-of-service study classifies 30 percent of distribution costs as customer-related. When these costs are reclassified as demand-related, the results of the cost-of-service study change as shown in following table. In this case, the costs allocated to the Domestic, Time of Day, and Net Metering classes increase by approximately 2-3 percent under the basic customer method, while costs allocated to other classes decrease.

[11] *Ibid.*

Table 2. Comparison of Cost of Service Results using TOMBEU's Method and the Basic Customer Method, after Streetlight Correction

70% Demand, 30% Customer

Costs ($)	Domestic	Small General Service	General Service	Time of Day	Net Metering	Street Lighting	Yard Lighting
Purchased Power	1,084,447	108,618	745,268	25,343	4,888	8,133	1,629
OM&A	305,356	44,583	226,158	6,273	1,398	83,516	5,068
Amortization Exp.	25,838	3,785	19,600	521	116	12,588	343
Financial Costs	45,210	6,548	34,071	914	203	12,531	577
Total ($)	1,460,851	163,534	1,025,097	33,051	6,605	116,767	7,617

Basic Customer Method

Costs ($)	Domestic	Small General Service	General Svc and Lg Gen Svc	Street Lighting	Street Lighting	Yard Lighting	Cable
Purchased Power	1,084,447	108,618	745,268	25,343	4,888	8,133	1,629
OM&A	330,436	40,108	218,888	7,036	1,516	71,584	2,783
Amortization Exp.	27,955	3,411	18,978	586	126	11,584	151
Financial Costs	48,996	5,879	32,960	1,030	221	10,735	233
Total ($)	1,491,834	158,015	1,016,094	33,995	6,751	102,036	4,797
Change	30,983	(5,518)	(9,003)	944	146	(14,732)	(2,821)

Q. Please elaborate on your second concern that many allocation factors are based on judgment rather than data.

A. In many cases, TOMBEU was unable to provide any data or analysis to support the allocation factors used in its cost of service study. For example, in response to TOMBEU (Synapse) IR-15, TOMBEU states that the weightings for customer distribution and billing costs "reflect the judgment of TOMBEU management and BDR [TOMBEU's consultant]. No analysis was carried out." Further, TOMBEU states that it "does not have hourly customer load data or load research, or a metered hourly system load shape,"[12] and thus the demand allocators for coincident peak (CP) and non-coincident peak (NCP)

[12] The Town of Mahone Bay Electric Utility Rate Study (Redacted). October 2022, p. 15.

for each class were based on assumptions as to the times of system peak and nature of the loads for each class,[13] as well as using data from Berwick Electric Commission.[14]

Q. Is it reasonable to rely primarily on judgment and proxy data to develop allocation factors?

A. Generally, no. However, I recognize that TOMBEU is a small utility and that the cost to conduct a detailed load research study may outweigh the benefits. Nevertheless, there are likely numerous opportunities to cost-effectively leverage data and analysis to develop more robust allocators. For example:

- To develop the weighting factor for billing costs, TOMBEU should analyze the difference in meter costs for each customer class, differences in costs associated with billing frequency, and other such relevant factors.
- As noted in response to TOMBEU (Synapse) IR-22(b), TOMBEU could analyze data from the revenue meter used by Nova Scotia Power, Inc. for billing purposes and collect data from other winter-peaking utilities to support its coincident and non-coincident load assumptions.

In addition, TOMBEU could investigate the costs of conducting a load research study (either independently or in conjunction with other nearby utilities) to determine the reasonableness of this option.

[13] *Ibid.*

[14] Response to TOMBEU (Synapse) IR-13 describes how the CP was estimated for Small General Service by adopting a CP factor from Berwick Electric Commission's Rate Study filed in M09820 on August 20, 2020. However, it is not clear whether the coincident peak factor from Berwick Electric Commission's rate study is based on actual meter data, or whether it represents an estimate itself.

Q. What is your recommendation with respect to the allocation factors used in TOMBEU's cost of service study?

A. I recommend that the Board direct TOMBEU to file a proposal within the next 18 months to enhance the load data that it uses to develop cost allocation factors and rates. The proposal should provide:

- the estimated costs associated with conducting a load research study (either for TOMBEU alone or jointly with other utilities);
- the potential for sharing the cost of a load research study with other nearby utilities, such as the Riverport Electric Light Commission;
- the costs and benefits associated with alternatives to a load research study, such as using publicly available class coincidence statistics from other winter peaking utilities and the availability of data from the revenue meter used by Nova Scotia Power for billing purposes;
- TOMBEU's preferred option; and
- TOMBEU's proposed timeline for implementation.

In addition, I recommend that the Board direct TOMBEU to conduct further analysis to determine appropriate customer weightings, and to file this analysis with its next cost of service study.

IV. COST ALLOCATION

Q. Do you have any concerns regarding the Utility's cost allocation proposal?

A. Yes. TOMBEU proposes to increase rates equally for all classes other than yard lighting by 34.9 percent. Yard lighting would receive no increase. However, TOMBEU's cost allocation proposal would not meaningfully address the substantial under-contribution by the Street Lighting class. In addition, an equal percentage rate increase would result in a significant over-contribution by the Yard Lighting class when using the basic customer method for classifying distribution costs.

Q. Please compare the revenue-to-cost (RTC) ratios resulting from TOMBEU's cost allocation proposal under the minimum system method and the basic customer method.

A. Table 3 below shows the revenue-to-cost (RTC) ratios resulting from TOMBEU's proposal to increase rates equally for all classes, except for yard lighting.

- Under the minimum system method, all classes are within an RTC ratio of 95 percent to 105 percent, with the exception of Street Lighting (at 56 percent), Yard Lighting (at 92 percent), and Time of Day (at 93 percent).

- Under the basic customer method, however, the Yard Lighting class is substantially over-contributing at 104 percent, while the Street Lighting class is still substantially under-contributing (at 63 percent) and the Time of Day class slightly under-contributing (at 91 percent).

Table 3. Revenue-to-Cost Ratios under an Equal Percentage Increase for Non-Yard Lighting Classes

	Domestic	Small General Service	General Service	Time of Day	Net Metering	Street Lighting	Yard Lighting
TOMBEU's Proposed Rate Change	35%	35%	35%	35%	35%	35%	0%
Minimum System	101%	97%	104%	93%	101%	56%	92%
Basic Customer	99%	100%	105%	91%	99%	63%	144%

Q. Is TOMBEU's cost allocation approach reasonable?

A. No. My primary concern with TOMBEU's cost allocation approach is that it does not adequately address the under-contribution from Street Lighting, regardless of the classification method used for distribution costs. Second, Yard Lighting is significantly over-contributing under the basic customer method.

Q. What is your recommendation for rate adjustments for the Street Lighting and Yard Lighting classes?

A. I recommend that the rates for Street Lighting be increased and the rates for Yard Lighting be decreased to bring these classes into a more reasonable RTC ratio range as follows:

- For Street Lighting, I recommend applying a rate change of 125 percent of the system-wide average. This results in a rate increase of 43.5 percent for Street Lighting relative to an average increase of 34.8 percent across all classes.
- For Yard Lighting, I recommend that the over-contribution be reduced by half. Under current rates and the basic customer method, the Yard Lighting class has an RTC ratio of 144 percent. I recommend a rate reduction of 15 percent to bring the Yard Lighting RTC ratio down to 122 percent.

Q. Why do you propose to increase rates for Street Lighting by only 25 percent more than the average rate increase?

A. I propose to cap the rate increase for the Street Lighting class at 125 percent of the overall rate increase in order to avoid rate shock. The magnitude of the overall rate increase is already considerable – nearly 35 percent. The ability of customers to manage rate increases beyond this amount should be considered when taking steps to mitigate interclass inequities.

Q. Do you have concerns regarding the RTC ratio for the Time of Day class?

A. No. Although the Time of Day class appears to have an RTC ratio of 91 percent, this value is highly dependent upon assumptions regarding the class's contribution to coincident and non-coincident peak demand, and I have concerns regarding how these assumptions were developed. Despite the Utility using data regarding the Time of Day customers' energy consumption during on-peak periods and off-peak periods for billing purposes, such data do not appear to have been leveraged in the development of allocation factors. Instead, the Company simply assumed that the Time of Day customers have a load factor that is five percent higher than the Domestic class.[15]

Given the lack of supporting data for the demand allocation factors for the Time of Day class and that the RTC ratio falls within a range of 90 percent to 110 percent, I do not find further adjustments to the Time of Day rates to be warranted. Instead, I recommend increasing the rates for the Time of Day class by the same percentage as the Domestic class.

Q. Please summarize your cost allocation recommendation.

A. My recommendations are summarized in the following table.

[15] Exhibit 3, Load Forecast.

Table 4. Proposed Cost Allocation Results

	Domestic	Small General Service	General Service	Time of Day	Net Metering	Street Lighting	Yard Lighting
Change in Revenues	378,587	40,385	272,154	7,862	1,714	20,716	(1,020)
Change in Rates	34.9%	34.9%	34.9%	34.9%	34.9%	43.5%	(14.8%)
Resulting RTC Ratio	99%	100%	105%	91%	99%	67%	122%

V. RATE DESIGN

Q. Please provide an overview of the Utility's rate design proposal.

A. The Utility states that it "has not performed an in-depth review of rate designs for purposes of this Application, and proposes to continue the same methodologies pending future analysis and subject to any Order of the Board."[16] In general, the rates would retain the same overall rate structures as currently in place and simply increase each rate component by an equal percentage.

Q. Do you agree with this approach?

A. No. An equal percentage rate increase for each rate component results in rates that are not necessarily reflective of how costs are incurred, and thus does not provide accurate price signals. In particular, a substantial increase to the service charge for the Domestic class is not justified by the cost of service results, and the Utility was unable to provide any cost analysis justifying its declining block rate structures.[17]

[16] TOMBEU Rate Study (Redacted), p. 17.
[17] Response to (Synapse) IR-5 and (Synapse) IR-6.

Q. What do you propose with respect to the Domestic class service charge?

A. I recommend that the Domestic class service charge be maintained at its current level of $11.91 rather than being increased by more than 30 percent. Under the Basic Customer method, the customer-related cost per month is approximately $5.00 for the Domestic class. The current service charge of $11.91 is already more than double the cost justified by the cost of service study. Even under the minimum system method used by TOMBEU, the customer-related costs for the Domestic class total only approximately $13.00 per month. Thus, an increase in the Domestic service charge to nearly $16.00 is not justified under either method.

Q. Please explain your concerns regarding TOMBEU's declining block rates.

A. By pricing higher levels of consumption at a lower rate, declining block rates reduce the marginal cost of electricity consumption faced by customers. If such rates do not accurately reflect the costs associated with serving additional load, they may lead to lower-usage customers subsidizing higher-usage customers. Further, lower prices for higher levels of electricity consumption can lead to wasteful usage by reducing incentives for conservation and energy efficiency. This could eventually result in higher generation, transmission, and distribution costs for all customers. For these reasons, many jurisdictions have moved away from declining block rates, particularly for residential customers.

Q. Has TOMBEU provided adequate cost justification for its declining block rates?

A. No. While TOMBEU notes that, in theory, the declining block rate structure attempts to recover fixed costs through the service charge and first (highest-priced) energy block, the utility states that it has not carried out a study of the relationship between the allocated fixed costs of its classes and the costs recovered through the service charge and block price differentials.[18]

Q. What do you propose with respect to the declining block rate structure?

A. I recommend that the Board direct TOMBEU to file a proposal to eliminate the declining block rate structure in its next general rate application, unless such rate structure can be adequately supported by evidence that demonstrates it is cost-reflective.

VI. STORM COSTS

Q. What is the Utility proposing in terms of storm costs?

A. The Utility is proposing to include an allowance in each annual budget of $15,000 to allow it to absorb storm costs, except in the most extraordinary cases.[19]

Q. What is the average storm cost incurred by TOMBEU?

A. TOMBEU states that it has no records of historic storm costs, nor is it aware that it has ever applied for storm cost recovery during the last ten years.[20]

Q. Is the Utility's proposal for a storm cost budget allowance reasonable?

A. No, not at this time, as the costs are unsupported by any data. If the Utility is unable to absorb costs associated with storm recovery, it should submit a separate application to the Board.

[18] Response to TOMBEU (Synapse) IR-6.
[19] TOMBEU Rate Study (Redacted), p.14.
[20] Response to TOMBEU (Synapse) IR-26.

VII. DEFERRAL ACCOUNT

Q. Please provide an overview of the Utility's proposed deferral account.

A. TOMBEU proposes to maintain a deferral account to reflect any liability associated with power purchases from Nova Scotia Power commencing January 1, 2023, for which Nova Scotia Power has received or may receive approval from the Board to recover from TOMBEU. If balances accumulate in this deferral account, TOMBEU would later apply to the Board for approval to recover such balances through rates or rate riders.[21]

Q. What concern is the deferral account intended to address?

A. In response to Synapse's IR-23, TOMBEU explains that it is concerned that the Settlement reached in Nova Scotia Power's ongoing general rate application may result in rates that result in a shortfall for Nova Scotia Power and that will require TOMBEU to make payments to Nova Scotia Power in a future year. If this occurs, TOMBEU seeks the ability to recover such amounts from its customers through use of a deferral account.

Q. Does TOMBEU have an approved flow-through mechanism that it could utilize instead of a deferral account?

A. While TOMBEU notes that it has approval to flow through certain purchased power cost increases, it states that the formula is based on the past two years' purchases from Nova Scotia Power. Because TOMBEU only purchased Back Up energy priced at marginal cost from Nova Scotia Power in the prior two years, TOMBEU states that it "has not been determined that this mechanism could appropriately be employed."[22]

[21] TOMBEU Rate Study (Redacted), p.5.
[22] Response to TOMBEU (Synapse) IR-23(b).

Q. Is the Utility's proposed deferral account reasonable?

A. TOMBEU's proposal for a deferral account appears to be generally reasonable. Increased purchased power costs from Nova Scotia Power are both unknown and outside of TOMBEU's control. Moreover, the deferral account would help to mitigate further rate increases in the near-term. Given that TOMBEU's customers are facing considerable rate increases in 2023, a deferral account could help mitigate rate shock by deferring further rate increases for recovery in the future when purchased power costs are potentially lower. It is also not apparent that the existing flow-through mechanism could be leveraged in this case, as TOMBEU previously purchased Back Up energy from Nova Scotia Power, rather than taking service on Nova Scotia Power's municipal rate.

Q. What do you recommend regarding the deferral account?

A. I recommend that the Board approve the TOMBEU's deferral account proposal, but require that the Utility submit an application to the Board for approval to recover any amounts accumulated in the account over a period to be determined by the Board.

Q. Does this conclude your evidence?

A. Yes, it does.