BEFORE THE NOVA SCOTIA ENERGY BOARD

In the Matter of
The Public Utilities Act, R.S.N.S. 1989, c.380, as amended
- and -
An Application by Nova Scotia Power Incorporated for Approval of Certain Revisions to its Rates, Charges, and Regulations

(NSUARB M12451)

Redacted Evidence of Caroline Palmer

On Behalf of Counsel to Nova Scotia Energy Board

December 2, 2025

Table of Contents

I. INTRODUCTION 1

II. SUMMARY OF CONCLUSIONS AND RECOMMENDATIONS 2

III. COST OF SERVICE STUDY 3

Overview of Cost of Service Studies 3

NS Power Should Not Classify Distribution Costs Using a Minimum System Study 4

Recommendations in the Context of the Consensus Agreement 16

I. INTRODUCTION

Q. Please provide your name, title, and business address.

A. My name is Caroline Palmer. I am a Principal Associate at Synapse Energy Economics ("Synapse"), located at 485 Massachusetts Avenue, Suite 3, Cambridge, MA 02139.

Q. Please describe Synapse.

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 state 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 has over 40 professional staff with extensive experience in the electricity industry.

Q. Please summarize your professional and educational experience.

A. I am a Principal Associate at Synapse where I provide expert witness and consulting services on behalf of public interest clients in regulatory proceedings. The issues I cover in these cases include marginal and embedded cost-of-service studies, revenue allocation, advanced rate design, low-income rate design, large load/data center cost allocation and safeguards, decoupling, distributed energy resource ("DER") interconnection and compensation, and electric vehicle ("EV") infrastructure investments. Prior to joining

Synapse I worked at Strategen Consulting for five years performing similar work. I have submitted expert testimony in 21 dockets across ten jurisdictions.

I was awarded a Fulbright Research Fellowship to Greece in 2019 and supported clean energy policy consulting at Meister Consultants Group (now Cadmus) before that. I hold a Master of Public Policy from the Goldman School at UC Berkeley and a Bachelor of Science from Georgetown University. My resume is attached as Exhibit 1.

Q. Have you previously testified before the Nova Scotia Energy Board?

A. Yes, I testified in M11874. I have also sponsored testimony in the United States before the Michigan Public Service Commission, Connecticut Public Utilities Regulatory Authority, New Hampshire Public Utilities Commission, Missouri Public Service Commission, New York Public Service Commission, the Massachusetts Department of Public Utilities, Maine Public Utilities Commission, the Oklahoma Corporation Commission, and the North Carolina Utilities Commission.

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

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

Q. What is the purpose of this evidence?

A. The purpose of this evidence is to address Nova Scotia Power's ("NS Power" or "the Company") cost of service study.

II. SUMMARY OF CONCLUSIONS AND RECOMMENDATIONS

Q. Please describe your conclusions and recommendations.

A. NS Power's use of the minimum size method for classifying substantial portions of its distribution system in its COSS does not reflect cost-causation principles and inflates cost allocations to residential customers.

I recommend that the Board direct the Company to discontinue the minimum size method and adopt the Basic Customer Method for distribution cost classification, which limits customer-related costs to those directly tied to the number of customers, such as metering and billing.

However, considering the context of NS Power and parties' consensus agreement in this case, I recommend that the Board direct that use of the minimum system method – and several other COSS and rate design methodologies – be subject to a future proceeding and determination by the Board.

III. COST OF SERVICE STUDY

Overview of Cost of Service Studies

Q. What is the purpose of a COSS?

A. A COSS 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. How is a COSS performed?

A. A COSS typically follows three steps. First, costs are functionalized by separating utility plant and expenses according to the primary functions they serve, such as generation, transmission, and distribution. Second, the functionalized rate base and operating costs are classified based on their primary cost drivers – typically as energy-related (commodity), demand-related (capacity), or customer-related. Finally, costs are either directly assigned to specific customers or allocated among customer classes using allocation factors based on energy use, peak demand, or customer counts.

Q. How do analysts determine the appropriate approaches to cost classification and allocation?

A. When selecting classification factors or allocators, the goal is to fairly allocate costs among different customer classes based on cost causation. Cost causation reflects the notion that the customer or set of customers that caused a cost should pay for the cost.[1] To determine cost causation, analysts often rely on economic theory and power system engineering considerations.

Q. In your view, has the Company selected appropriate COSS methods?

A. No. I am concerned that the Company classifies portions of the distribution system as partially "customer-related" based on a flawed minimum system methodology.

Q. How should a COSS be used in a rate case?

A. Parties and the Board should exercise judgement when using a utility COSS to inform revenue allocation or rate design, as it is an inherently imprecise tool in which cost analysts make numerous subjective determinations that may dramatically impact the study results. As such, utility cost of service studies should be one of several considerations used to guide decision-makers in revenue allocation and rate design, rather than being viewed as the sole determinant or final authority.

NS Power Should Not Classify Distribution Costs Using a Minimum System Study

Q. Did NS Power classify certain distribution system costs as both customer-related and demand-related?

[1] NS Power indicates that its COSS framework is "based on established principles of cost causation." *See* N-9: 2026-2027 GRA Appendix 12A - Cost of Service Study Process – Redacted p.10.

A. Yes. The Company considers primary and secondary poles, fixtures, overhead lines, and underground lines to have both demand- and customer-related components.[2] The Company used a minimum system study to determine the share of each of these investments to classify as customer-related versus demand-related.

Q. What is the minimum system study?

A. The minimum system study is a cost analysis that estimates what the cost of the distribution system would be if all poles, fixtures, and wires were sized to minimum specifications. NS Power considers the cost of a hypothetical system made up of minimum-sized equipment to be customer-related, reasoning that the "cost of a system with minimal demands…approximate[s] the cost of serving each customer if there were no capacity constraints."[3] The Company considers the remaining cost of the actual distribution system "to be the portion of costs incurred to meet peak demands" and thus to be demand-related.

Q. Does the minimum system study deem significant portions of plant to be customer-related?

A. Yes. The minimum system study classifies [redacted] poles and underground wires and [redacted] overhead wires as customer-related.[4]

Q. What are your concerns with the minimum system methodology?

A. I have three concerns with the minimum system methodology:

- It does not align with the Company's definition and treatment of customer costs;
- It inflates the costs classified as customer-related; and
- It is unsound to use as the basis for determining cost causation.

[2] N-9: 2026-2027 GRA Appendix 12B – Elenchus NSP COSS Consultation Report p.37-38.
[3] N-9: 2026-2027 GRA Appendix 12B – Elenchus NSP COSS Consultation Report p.37.
[4] 2026-2027 GRA SR-01 Att 02 PCON EO Exhibits 3c, 3e, 3g.

I discuss each concern sequentially.

Q. Why doesn't the minimum system methodology align with the Company's definition and treatment of customer costs?

A. Per the Company, customer-related costs "vary with the number of customers served."[5] This definition echoes the 1992 National Association of Regulatory Utility Commissioners ("NARUC") Electric Utility Cost Allocation Manual ("NARUC Electric Manual"), which defines customer costs as "directly related to the number of customers served."[6] Indeed, after classifying customer-related costs, the Company allocates those costs based on the number of customers associated with each rate class.

Although the minimum system methodology classifies large portions of distribution plant as customer-related, to be allocated based on the number of customers, the equipment in those accounts does not vary directly with the number of customers. That is, the costs of poles and wires often do not increase when a customer is added to the grid. Rather, these costs tend to vary with customer demand and geography.

For example, if the Company adds a new residential customer with a negligible level of demand in a populated area, the additional distribution costs to serve that customer—aside from dedicated customer infrastructure—would generally also be negligible, because no significant demand is being added by the new customer. If, however, the new customer were to add a substantial amount of additional demand, then distribution system upgrades would be required, increasing costs. Thus, these costs are primarily driven by demand, rather than by the number of customers. It is only when the distribution system must be expanded to a new geographic area that an incremental

[5] 2026-2027 GRA SR-01 Attachment 1a p.4.
[6] National Association of Regulatory Utility Commissioners (NARUC) *Electric Utility Cost Allocation Manual.* 1992 p.20.

customer impacts distribution system costs independently from the customer's level of demand.

This example demonstrates that the presence of a residential customer does not necessarily impose additional distribution costs (apart from costs related to that customer's demand) unless the system must be expanded to a new geographic area. Indeed, NS Power states that the customer-related portion of feeder investment "is driven by the need to bring electric service to geographically dispersed customer locations."[7] Thus, there is little justification for classifying costs in these accounts as customer-related.

Q. If the system must be expanded to a new geographic area, will geography influence distribution costs more than the number of customers?

A. Yes. The number of poles or miles of wires required to serve a housing development is likely to vary more based on the distance of the development from other infrastructure, such as if the development is located within 0.1 versus 10 miles of the rest of the system, than based on whether there are 10 or 50 houses in the development.

Q. Does the minimum size methodology account for geographic dispersion?

A. No. The study categorizes costs as either related to demand or customer count, as does the COSS. There is no measure of geographic dispersion, and geography is not necessarily well-correlated with the number of customers. Therefore, the number of customers is not a very representative allocator for shared distribution system costs.

Q. Does industry literature consider customer count to be a good proxy for geographic dispersion?

[7] 2026-2027 GRA SR-01 Attachment 1a p.4.

A. No. James Bonbright's widely recognized *Principles of Public Utility Rates* notes that there is "a very weak correlation between the area (or the mileage) of a distribution system and the number of customers served by the system."[8]

Q. Is it particularly inappropriate to classify the primary electric system as customer-related?

A. Yes. In its minimum system study, the Company included distribution lines that serve voltages up to 25,000 volts.[9] However, the residential customer class likely does not receive service directly at primary voltage. Per the example above, it is unreasonable to suggest that the cause for installing primary equipment is the presence of a residential customer on the distribution system, regardless of that customer's demand, when residential customers likely receive service at a fraction of primary voltage.

Q. Does the Company's minimum system also meet customers' demands?

A. Yes. Poles and wires of any size have load-carrying capacity and will necessarily serve a portion of customers' demand. In fact, it is likely that the Company's minimum system can support substantial portions of certain customer classes' demand requirements.[10]

Q. What are the cost allocation impacts of using a study that inflates the costs classified as customer-related?

A. Inflating the costs classified as customer-related has meaningful implications for the residential class. Customer-related costs are far more heavily allocated to residential customers compared to demand-related costs simply because the residential class has many more customer accounts than the other classes. Thus, assigning costs based on the

[8] Bonbright, James. *Principles of Public Utility Rates.* 1961, p. 348.
[9] N-29: NSPI Response to Synapse Information Request IR-6.
[10] When asked for the amount of demand per customer that could be accommodated by the minimum conductors, NS Power stated that it does not collect or calculate this information. *See* CA DR-67, included in 2026-2027 GRA Direct Evidence Appendix 12A(2) p.925. However, my experience in other jurisdictions indicates that the capacity of even the minimum sized equipment on a utility's system tends to exceed average residential individual peak demands.

number of customers will allocate the majority of these costs to the residential class. In contrast, the COSS assigns demand-related costs based on the relative class non-coincident peak demand (NCP), to which the residential class contributes a relatively lower level of demand.

Q. Can you demonstrate how cost allocation varies when customer allocators are used rather than demand allocators?

A. Yes. For poles and wires, using the number of customers to allocate costs results in over [redacted] percent of costs being assigned to domestic customers, whereas using demand would allocate only [redacted] percent of costs to the domestic class.[11]

Q. Is the minimum system method unsound to use as the basis for determining cost causation?

A. Yes. The method requires distinguishing a hypothetical system that only serves customers' minimum demand requirements. To create this imaginary system, NS Power must make assumptions that oversimplify system engineering and impact the study results in unquantifiable ways, forming an unreliable basis on which the Company has assigned substantial costs among classes with significant impacts on revenue allocation.

Q. Given that geography is not an allocation factor, that customer count is not a good proxy for geography, and that the minimum size study overstates the costs classified as customer-related, is it reasonable to treat all of NS Power's poles, fixtures, and wires as demand-related?

A. Yes.

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

A. I recommend classifying distribution costs using the Basic Customer Method. As described in the Regulatory Assistance Project's manual *Electric Cost Allocation for a New Era*, this method is used across North America and is intuitive and data-based, as it

[11] 2026-2027 GRA SR-01 Att 02 PCON EO Exhibit 8a.

includes only costs that are directly related to the number of customers on the system. Specifically, the Basic Customer Method generally classifies only costs associated with services, meters, meter reading, and billing as customer-related.

Not only have utilities in numerous United States jurisdictions used the Basic Customer Method,[12] but public utility commissions have also explicitly rejected the minimum system method or otherwise required that utilities classify primary and secondary distribution costs as 100 percent demand-related. For example:

- The Rhode Island Public Utilities Commission has repeatedly rejected the minimum system study.[13]
- The Maryland Public Service Commission has repeatedly rejected a minimum cost of service methodology.[14]
- The Arkansas Public Service Commission found that accounts 364–368 should be classified as 100 percent demand-related due to insufficient evidence to warrant a determination that these accounts reflect a customer component necessary for allocation purposes.[15]
- The Illinois Commerce Commission has repeatedly rejected the minimum distribution or zero intercept approach.[16]
- Washington administrative code specifies approved electric cost of service

[12] For example, National Grid in Massachusetts does not use a minimum system study for classification. *See* Exhibit NG-PP-1 in D.P.U. 23-150 (November 16, 2023) at 18, stating "the Company has not performed a minimum system study in its last four distribution rate cases, or more, and…did not perform a minimum system study for this ACOSS."

[13] Decision and Order, *In Re: The Application of the Narragansett Electric Company d/b/a National Grid for Approval of a Change in Electic[sic] Base Distribution* Rates, at 142 (April 29, 2010), Docket No. 4065 (State of Rhode Island and Providence Plantations Public Utilities Commission).

[14] Order No. 83907, *In the Matter of the Application of Baltimore Gas and Electric Company for Revisions in its Electric and Gas Base* Rates, at 81–82 (March 9, 2011) Case No. 9230 (Public Service Commission of Maryland).

[15] Order, *In the Matter of the Application of Entergy Arkansas, Inc., for Approval of Changes in Rates for Retail Electric Service*, at 124–26 (Dec. 30, 2013) Docket No. 13-028-U (Arkansas Public Service Commission).

[16] Lazar, J. et al., *Electric Cost Allocation for a New Era: A Manual.* Montpelier, VT: Regulatory Assistance Project (2020) (Hereafter: "RAP Electric Manual"). at 145

classification and allocation methodologies, requiring distribution substations, line transformers, and poles and wires to be classified as demand related.[17]

- The Michigan Public Service Commission rejected a party's recommendation to require a minimum size study, finding that both the minimum system and minimum intercept methods have serious conceptual flaws and imply a direct correlation between the number of customers and distribution system costs that does not exist.[18]
- Alaska administrative code prohibits customer-related costs from including "any portion of the distribution system costs, which will be considered and classified as demand-related costs."[19]

Q. If the Board chooses not to approve the Basic Customer Method, would a hybrid classification method be more appropriate than NS Power's approach?

A. Yes. If the Board does not approve the Basic Customer Method, it is still possible to better align the minimum size methodology with system cost drivers. In that case, I recommend that the Company classify primary distribution costs as 100 percent demand-related and only apply the minimum size methodology to secondary distribution costs, which are the lower-voltage lines that connect most customers to the grid. Primary infrastructure is shared, is more likely to peak at the same time as system peaks, and is likely higher-voltage than the customer-specific equipment (meters and services) directly serving the majority of electricity customers.

Q. If the Board approves any form of minimum size study, whether for only secondary plant, or for primary and secondary distribution plant, should any adjustments be made to recognize that the minimum system also meets all or a portion of customers' maximum demands?

[17] Washington Administrative Code 480-85-060. https://app.leg.wa.gov/WAC/default.aspx?cite=480-85-060.
[18] Order, *In the matter of the application of Consumers Energy Company for authority to increase its rates for the generation and distribution of electricity and for other relief*, p.152. (December 22, 2021). Case No. U-20963 (Michigan Public Service Commission).
[19] 3 Alaska Admin. Code § 48.540.

A. Yes. As recognized by the Staff of the Ontario Energy Board (OEB), "A Minimum System has a certain load carrying capability which can be viewed as being demand-related. As a result, the customer-related costs will have a demand component in them. If no adjustment is made, some customers (e.g. small users) may be allocated a disproportionate share of demand-related costs. If the Minimum System Method is preferred for categorization, Staff would recommend that distributors be required to also adjust for the [Peak Load Carrying Capacity] of the assumed Minimum System."[20]

In turn, the OEB enshrined a peak load carrying capability (PLCC) adjustment in its report "provid[ing] the cost allocation methodology directions approved by the Board."[21]

Q. Please explain how an adjustment should be made to account for the load carrying capacity of the assumed minimum system.

A. A load carrying capacity adjustment reduces the non-coincident peak demands used for determining demand allocators by the amount of demand that can be served by the hypothetical minimum system. For example, if the minimum system can meet 1 kW of demand, then the residential class's NCP allocator is reduced by the product of 1 kW and the number of residential customers. In Ontario, the assumed load carrying capacity of the minimum system is 0.4 kW per customer.

Ontario continues to use this method, as the OEB has since reaffirmed the original report dictating that electricity distributors use the methodology in a 2007 Board report,[22]

[20] Ontario Energy Board. Cost Allocation Review: Staff Discussion Paper. September 2005. At 21-22. Available at https://www.oeb.ca/documents/cases/EB-2005-0317/staffdiscussionpaper_160905.pdf.

[21] Ontario Energy Board. Cost Allocation: Board Directions on Cost Allocation Methodology for Electricity Distributors. September 2006. At 53-55. https://www.oeb.ca/documents/cases/EB-2005-0317/report_directions_290906.pdf.

[22] Ontario Energy Board. Application of Cost Allocation for Electricity Distributors - Report of the Board. November 2007. At 1. https://www.oeb.ca/documents/cases/EB-2007-0667/Report_Cost_Allocation_Review_20071128.pdf.

which the OEB again referenced in its Filing Requirements For 2024 Electricity Distribution Rate Applications.[23]

Q. Have other utilities implemented a load carrying capacity adjustment?

A. Yes. For the most recent several rate cases, Northern States Power Company (dba Xcel Energy) in Minnesota and South Dakota[24] has assumed a load carrying capacity of 1.5 kW per customer for the minimum system and applied this adjustment to its distribution capacity cost allocation factors. In Minnesota, Xcel has used this methodology since before 2015, noting in its 2015 rate case that it "assumes the minimum-size distribution equipment used in the Minimum System Study has load-carrying capability of 1.5 kW per customer."[25] This is the same assumption that Xcel made in the rate case prior to 2015[26] and in the most recent 2024 rate case.[27]

National Grid recently proposed an even simpler approach in New York, allocating residential and small commercial customer classes $0 of the demand-related portion of the minimum-system distribution infrastructure, reasoning that "the minimum system would be able to meet the peak load for all or almost all customers in [the relevant classes]; that is, no further investment in higher capacity conductors would be required.

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[23] Ontario Energy Board. Filing Requirements For Electricity Distribution Rate Applications - 2023 Edition for 2024 Rate Applications. Chapter 2 - Cost of Service. December 2022. At 44. https://www.oeb.ca/sites/default/files/OEB-Filing-Reqs-Chapter-2-2023-Clean-20221215.pdf.

[24] Results of Xcel Energy Minimum Distribution System & Zero Intercept Studies. Docket No. EL22-017 - Application of Northern States Power Company dba Xcel Energy for Authority to Increase its Electric Rates. June 30, 2022. Exhibit___(CJB-1), Schedule 6 p.10.

[25] Direct Testimony and Schedules of Kelly A. Bloch. Docket No E002/GR-15-826. Application of Northern States Power Company for Authority to Increase Rates for Electric Service in Minnesota. November 2, 2015. p.91-92. Provided as Attachment LFE-83-3.

[26] Results of Xcel Energy Minimum Distribution System & Zero Intercept Studies. Docket No E002/GR-15-826. Application of Northern States Power Company for Authority to Increase Rates for Electric Service in Minnesota. November 2, 2015. Exhibit___(MAP-1), Schedule 11 p.9 (PDF p.131). Provided as Attachment LFE-83-4.

[27] Minimum System/Zero Intercept Study Results. Docket No. E002/GR-24-320 - Application of Northern States Power Company for Authority to Increase Rates for Electric Service in Minnesota. November 1, 2024. Exhibit___(CJB-1), Schedule 8 p.9 (PDF p.126). Provided as Attachment LFE-83-1.

Therefore, no demand-related costs for [FERC accounts 364-367] were allocated" to Residential, Residential Time of Use, and Small General Non-Demand classes.[28]

Q. Does industry literature acknowledge that minimum-size distribution equipment can be viewed as a demand-related cost?

A. Yes. The NARUC Cost Allocation Manual, which NS Power cites to justify the minimum size method,[29] notes that "when using the minimum-size distribution method…the analyst must be aware that the minimum-size distribution equipment has a certain load-carrying capability, which can be viewed as a demand-related cost.[30]

Q. If the Board approves use of NS Power's minimum system study, do you recommend a load carrying capacity adjustment?

A. Yes. I recommend that NS Power implement a load carrying capacity adjustment for any infrastructure costs classified using its minimum size study. Identifying the specific load carrying capacity of NS Power's minimum system is an exercise that would require thoughtful analysis from NS Power and other stakeholders.[31] However, the approaches utilized in other jurisdictions can be applied to NS Power's COSS in the absence of a Company-specific calculation. Unless the Company demonstrates an appropriate alternative, I recommend that the Company credit each customer class with 1.5 kW per customer, applying the credit to the NCP demands used for determining minimum system demand allocators.

Q. What is the COSS impact of using the basic customer distribution classification?

[28] Testimony of the Electric Rate Design Panel for Niagara Mohawk Power Corporation d/b/a National Grid in 24-E-0322. May 2024. At 33-34. The case resulted in a settlement that did not comment on COSS methodologies.
[29] N-9: 2026-2027 GRA Appendix 12B – Elenchus NSP COSS Consultation Report p.38-39.
[30] National Association of Regulatory Utility Commissioners (NARUC) *Electric Utility Cost Allocation Manual.* 1992 p.95.
[31] N-29: NSPI Response to Synapse Information Request IR-7.

A. Using the Basic Customer Method impacts the COSS output, which the Company uses to inform its proposed class revenue increases. Table 1 shows each customer class's revenue to cost (R/C) ratio under the Company's COSS[32] and the basic-customer COSS.[33] Under the Basic Customer Method, the domestic R/C ratio increases from 0.90 to 0.92, while the general demand R/C ratio shrinks from 1.03 to 0.96. The Basic Customer Method reveals a higher cost to serve higher-usage classes due to their relatively higher contributions to class NCP demand.

Table 1. 2026 R/C Ratio Under Different Classification Methods

Rate Class	Company's COSS	Basic Customer Method
Domestic	0.90	0.92
Small General	0.96	0.99
General	1.03	0.96
Large General	1.09	1.05
Small Industrial	1.03	0.97
Medium Industrial	1.11	1.05
Large Industrial	1.12	1.1
PHP	N/A	N/A
Municipal	1	0.98
Unmetered	0.88	0.94

Q. Do the results of the Basic Customer COSS impact the Company's determination of revenue responsibilities by rate class?

A. Yes. Table 2 compares required class revenue increases based on the Company's COSS[34] and based on the basic-customer COSS,[35] both derived using the Company's revenue allocation methodology. While the Company's revenue allocation approach deemed the domestic class to require an 8% increase when using its COSS as an input, the

[32] 2026-2027 GRA SR-01 Att 07.
[33] 2026-2027 GRA SR-01 Att 07, adapted using values provided in 2026-2027 GRA NSEB IR-128 Att 01.
[34] 2026-2027 GRA SR-01 Att 07.
[35] 2026-2027 GRA SR-01 Att 07, adapted using values provided in 2026-2027 GRA NSEB IR-128 Att 01.

Company's revenue allocation approach under a COSS that used the Basic Customer Method deems the domestic class to require a 6% increase.

Table 2. 2026 Class Revenue Increases (NS Power's Revenue Allocation Method)

Rate Class	Company	Basic Customer
Domestic	8.0%	6.0%
Small General	7.4%	6.0%
General	1.6%	6.8%
Large General	-4.0%	-1.8%
Small Industrial	1.4%	6.1%
Medium Industrial	-6.0%	-2.4%
Large Industrial	-6.8%	-6.5%
PHP	N/A	N/A
Municipal	4.1%	4.7%
Unmetered	13.8%	6.5%

Q. How do the changes in class revenue responsibility translate to rate impacts?

A. The Company's rate schedules[36] do not appear to readily permit revisions that flow from class revenue responsibility increases. I recommend that the Company revise its calculated rate impacts to reflect updated revenue responsibility under the basic customer approach, for both 2026 and 2027.

Recommendations in the Context of the Consensus Agreement

Q. Does NS Power's application represent a negotiated outcome among the Company and parties?

A. Yes. The Company explains that both NS Power and numerous customer representatives support the outcomes requested in this GRA and that the parties do not require and are

[36] 2026-2027 GRA SR-01 Att 08.

not seeking a process that provides an opportunity for them to make information requests or submit evidence.[37]

Q. Does the parties' consensus around the application change your concerns regarding the Company's COSS?

A. For several reasons, the parties' consensus agreement on the proposals in NS Power's application does not change my concern regarding the Company's use of the minimum system methodology or other proposed COSS methods.

First, the parties may have accepted certain negotiated terms for a variety of reasons – such as expediency, avoided litigation risk, or to secure broader benefits – and their acceptance of the overall application does not constitute endorsement of individual provisions within the application.

Second, although the Company describes the lengthy COSS stakeholder process undertaken in 2024 and 2025 and details the outcome of that process, it has not elucidated how the concerns of various parties raised during the stakeholder process – regarding the very proposals ultimately agreed to in this application – were assuaged. While the consensus of the parties may be compelling for this particular GRA, the simple fact of that consensus does not offer a complete evidentiary record to support the reasonableness of the agreed-upon methods for future cases.

Q. Considering the consensus agreement in this GRA, what do you recommend regarding the Company's COSS methods?

A. While I do not support several of the Company's COSS methodologies, particularly the use of the minimum system method for classifying distribution system costs, I recognize

[37] N-3: Direct Evidence DE-03 – DE-04 p.8-9.

that the parties have overcome their own concerns with the proposed methodologies to reach a settlement in this case and I therefore do not oppose their settlement agreement in this GRA. However, I believe that the COSS proposals contained within the settlement should be treated as case-specific and non-precedential in future cases. Therefore, I recommend that the Board find that certain COSS methodologies put forward in this case must be revisited in the next GRA.

In fact, the parties have already specified that the use of the minimum system methodology after the 2026-2027 test period will be subject to a future proceeding and determination by the Board.[38] I recommend that the Board expressly state that not only should the minimum system methodology be subject to a future proceeding and determination by the Board, but that the same requirement should apply to several other COSS methods as well, which either represent substantial departures from current methods or were the source of extensive discussion and differing opinions during the COSS stakeholder process and have not yet been supported by the broader parties beyond agreement to their use in this case. Those methods include:

- NS Power's departure from its current approach to classifying generation costs, in which it now proposes to classify all generation assets using system load factor;[39]
- NS Power's departure from its current approach to classifying transmission costs, in which it now proposes to classify 100 percent of transmission costs to demand;[40]

[38] N-3: Direct Evidence DE-03 – DE-04 p.76.
[39] N-9: 2026-2027 GRA Appendix 12A - Cost of Service Study Process – Redacted p.13.
[40] N-9: 2026-2027 GRA Appendix 12A - Cost of Service Study Process – Redacted p.15-16.

- The potential for NS Power to use more granular and temporal allocators. Further data analysis and discussion would likely be worthwhile in considering moving away from the simplistic three coincident peak generation and transmission demand cost allocation and non-coincident peak distribution demand cost allocation.

Q. Does this conclude your direct testimony?

A. Yes, it does.