Nova Scotia Utility and Review Board

IN THE MATTER OF *The Public Utilities Act*, R.S.N.S. 1989, c.380, as amended

2013 Nova Scotia Power Cost of Service Study

CONFIDENTIAL (Appendices Only)

June 28, 2013

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1.0 EXECUTIVE SUMMARY

This filing begins the formal stage of Nova Scotia Power's (NS Power, Company) Cost of Service (COS) proceeding. It follows nine months of preliminary work with participating parties. The evidence contained within this Application reflects the efforts of NS Power staff and its consultants, together with input from the Utility and Review Board (UARB, Board) staff, its consultants and counsel, as well as consultants for the Consumer Advocate (CA), the Small Business Advocate (SBA), various industrial customers, and the Municipal Electric Utility Cooperative (MEUNSC).

The process identified 42 items for consideration. Working collaboratively, the parties have reached consensus on 23 of these 42 items. The parties did not reach consensus on the other 19 issues. This filing outlines NS Power's position on the unresolved items, and attempts to summarize the views of the other participating parties.

The Cost of Service analysis undertaken to date includes several encouraging elements:

- NS Power engaged an external consultant, Christensen Associates Energy Consulting (CAEC), who has confirmed that NS Power's Cost of Service model aligns with current, industry-accepted Cost of Service practices;

- CAEC indicated that NS Power's Cost of Service model is robust and accurate. Most of the areas requiring attention are administrative and will not have a material effect on the assignment of costs to various classes;

- NS Power and stakeholders have thoroughly vetted the unresolved areas of greatest materiality, and all parties have articulated their views clearly. Although these issues would benefit from further collaboration, the parties' efforts to date have built a solid foundation for continued constructive discussions aimed at resolving them.

1.1 Summary of Proposed Changes to COS

NS Power seeks approval of the following 11 changes to its Cost of Service model. For the first 10 of these requested changes, NS Power has identified the cost redistribution effect and has provided it in Appendix S to this Application. The parties who have actively participated in the pre-filing engagement process have reached agreement on three of these changes.

1. Eliminate dedicated substations in Exhibit (Exh) 3b in the current Cost of Service Study. The current Cost of Service model distinguishes between dedicated and non-dedicated substations and allocates costs to rate classes by each substation category. This is based on a historic formulaic approach and does not follow industry best practice. NS Power has reached consensus on this recommendation with participating parties' consultants.

2. Update customer weighting factors (Exh 8a of the current Cost of Service Study). The customer weighting factors are dated and based on professional judgment. NS Power has proposed a new approach to calculate these weighting factors at the time of each General Rate Application (GRA).

3. Update of meter costs (Exh 3g of the current Cost of Service Study). The unit meter costs allocate meter investment to rate classes by number of customers and unit meter costs. The unit meter costs currently used are from the late 1970s. NS Power has prepared a current estimate of the unit meter costs to allocate this investment to rate classes. NS Power has reached consensus on this recommendation with participating parties' consultants.

4. Correctly allocate the interruptible supply credit among rate classes (Exh 6). The current COS model under-allocates this cost to the Large Industrial rate class. NS Power proposes that this be correctly aligned. NS Power has reached consensus on this recommendation with participating parties' consultants.

5. Alignment of the Transmission and Distribution rate base with financial records (Exh 2 of the current Cost of Service Study). Since 1995, NS Power has been redistributing a portion of the transmission rate base to distribution by way of manual adjustment. This practice is no longer an aid or improvement to the Cost of Service and should be ended.

6. Disaggregate the distribution depreciation expenses (Exh 4, Exh 4 Detail A, Exh 4 Detail B and Exh 5 of the current Cost of Service Study). Provide a greater level of detail respecting depreciation expenses to allow a more accurate classification of these costs and therefore a more appropriate allocation among rate classes. CAEC has advised that this is consistent with industry practice.

7. Change the COS treatment of NS Power-owned wind (Exh 2a and Exh 2b of the current Cost of Service Study) to align the COS treatment of wind generation with system capacity planning, and eliminate the distinction between Renewable Electricity Standard (RES) and non-RES investments.

8. Change the treatment of purchased power (Exh 6 of the current Cost of Service Study). NS Power proposes to align treatment of purchased power costs with treatment of its own generation and evaluate this based on the underlying types of generation and their designation as firm or variable contracts.

9. Update implementation of cost levelization by voltage levels of transmission (Exh 8b in COSS) and distribution (Exh 9b in the COSS) within each class to be consistent with the intended COS design. NS Power has determined that:

    (a) Distribution customers from the Large Industrial and Municipal classes are treated as transmission customers for cost allocation purposes, which is inconsistent with the COS design.

(b) The COS does not recognize the extra high voltage transmission level at which some customers, within the Large Industrial Class, are served.

(c) The COS supporting processes of load research sample design and line loss determination could be improved to increase accuracy in cost allocation.[1]

NS Power requests that the UARB approve the following seven CAEC recommendations, six of which are not opposed by stakeholders,[2] concerned with improving the quality of the COS-supporting processes of load research sample design and maintenance and line loss determination:

No	Recommendation	Subject
4	R3.1-4	Levelize customers at actual voltage service levels.
7	R3.3-1	Undertake a comprehensive loss analysis. This should enable more accurate line loss determination by class and provide for a consistent treatment of line losses among Coincident Peaks, Non-Coincident Peaks and energy requirements.
8	R3.3-2	Develop class profiles by service levels to determine losses. Currently, there is one class load shape used for all CP and NCP voltage levels. Each voltage level should be permitted a separate load shape within a class.
9	R3.3-3	Review loss factors associated with the generation energy allocator.
10	R3.3-4	Review transformer loss adjustments in allocator development. The 1.75% line loss adjustment factor may indeed still be the right value but it should be re-examined since it's dated.
37	R4.4-9 (updated)	A new sample should be drawn to return the LR sample quality to its originally intended level.
38	R4.4-10	Institute plan for periodic Load Research sample updates.

[1] For the purpose of quantifying proposed changes to mass market customer classes in this submission, NS Power used proxy estimates. Going forward, these estimates should be replaced with improved results of class load shape and line loss analyses based on a voltage-service differentiated approach.
[2] Consensus has not been reached to date regarding issue No 4; this is discussed further in section 6.2.3.

10. With respect to classification and allocation of transmission (Exh 2a, 2b, 3 and 5 of the current Cost of Service Study), NS Power recommends that transmission investment be classified as 100 percent demand and allocated among rate classes on a 12 CP (Coincident-Peak) basis.

11. NS Power recommends the retention of the current approach of the functionalization of distribution poles and wires until secondary pole inventory count results are available, at which point a more robust market replacement approach should be considered. Regarding classification of these costs, NS Power proposes that the current approach, based on professional judgment, also be retained. The cost redistribution effect of a new approach cannot be known with precision in advance of finding an appropriate solution; however, NS Power expects the effect to be contained within a 1 percent change in costs for most classes.

For all other items, NS Power submits that the current Cost of Service methodology employed is appropriate and should be maintained.

NS Power appreciates the efforts of participating parties in this process. If we have erred in our efforts to represent their views, we trust that subsequent stakeholder engagement will set the record straight.

NS Power intends to continue working with stakeholders in the months leading to the October hearing, with the objective of resolving those Cost of Service issues that remain contentious. This filing seeks to give the Board and interested parties a complete record of activity over the past year. We look forward to the continued constructive engagement of all intervenors.

2.0 INTRODUCTION

During Nova Scotia Power's 2012 General Rate Application, the Company's Cost of Service Study was raised as a matter requiring review. In particular, the Small Business Advocate and counsel for a group of NS Power's large industrial customers (then identified as the Avon Group, now identified as the Industrial Group), requested that the Board direct a Cost of Service Study proceeding be convened.[3]

The Utility and Review Board's decision dated November 29, 2011 concerning the 2012 GRA provided:

> [56] The Board has considered the evidence provided and agrees with most Intervenors that there is merit to review the current COSS. The evidence presented notes that some of the assumptions and principles used in the COSS such as the current generation mix (including renewables) and emission control requirements need a review.
>
> [57] The Board's current 2012 Regulatory Schedule does not allow enough time for a review of the COSS. Therefore, the Board orders that NSPI plan for a COSS hearing in 2013 and provide a schedule in its Compliance Filing.

Subsequent to this directive, the Company filed a schedule for the Board's approval. This was approved by the Board in its letter dated February 22, 2012.

Following the initial informal engagements with stakeholders, a proposed amendment to the schedule was filed with the Board on December 21, 2012. The amendment was supported by the Consumer Advocate, SBA, Industrial Group, and the Municipal Electric Utilities of Nova Scotia Cooperative. The revised schedule was approved by the Board in its letter dated January 10, 2013. Subsequent to this, the Board has advised the Company and participants to the Cost of Service engagement that it has reserved the week of October 21 to 25, 2013 for a hearing in this matter.

[3] 2012 General Rate Application, NSPI-P-892/M04104, Closing Submission on behalf of the Small Business Advocate, October 3, 2011, pages 9-17; 2012 General Rate Application, NSPI-P-892/M04104, Closing Submission on behalf of the Avon Group, October 7, 2011, pages 8-11.

In late May NS Power made a request which was supported by stakeholders that the UARB extend the date for filing of Evidence to the end of June. This was approved by the Board in its letter dated June 3, 2013.

This document presents NS Power's Application in this proceeding. The Company has, from the outset of its engagement with stakeholders, worked towards consensus on as many issues as possible, thus narrowing the issues required to be resolved by the Board through formal process.

Since the content has been influenced significantly by interaction between the Company and stakeholders and the input of engaged experts on Cost of Service matters, the Company has sought to provide the Board with a complete record of correspondence on this matter, including all Data Request responses (DRs), analysis completed by the Company in support of its interactions with stakeholders, copies of the Company's Strawman Report documents previously circulated for stakeholder comment, and copies of the stakeholder comments received throughout the process. This information is provided in the attached appendices (Appendices A – M).

The Company is encouraged by the constructive input of the parties to date. The collaborative and transparent approach has served to resolve many of the issues associated with the Cost of Service methodology. This will allow the Board, stakeholders and the Company to focus future efforts on material matters, where differing views exist among stakeholders.

With respect to matters where consensus has not emerged, the Company remains optimistic that the parties, working together in the coming weeks, will be able to resolve these issues and present the Board with a consensus proposal, which is aligned with good utility practice and delivers an efficient, effective and customer-endorsed Cost of Service methodology. The Company will keep the Board apprised of progress in this regard.

Since the Board provided the directive to undertake a Cost of Service review, two items have arisen for which it was suggested that the Cost of Service Study proceeding could be the appropriate forum for further consideration. These items are: a) the determination of the appropriate threshold for the implementation of demand meters in the General Demand Class,[4] and b) the potential for Time of Use (TOU) rates in the agricultural sector.[5]

NS Power has continued to work with stakeholders on these two matters contemporaneous with, but separate from, the Cost of Service Study activity. The Company is engaged with representatives from the Canadian Federation of Independent Business (CFIB), the Canadian Foodservices and Restaurant Association, the Halifax Chamber of Commerce, the Nova Scotia Chamber of Commerce, and the Tourism Industry Association of Nova Scotia on the Demand Threshold issue, and the Nova Scotia Federation of Agriculture (NSFA) on the issue of TOU rates for the agricultural sector.

In discussions with NSFA President, Mr. Henry Vissers, NS Power proposed that a TOU pricing pilot project be established to gather more data on consumption patterns and price sensitivities of eligible customers. Mr. Vissers agreed. The parties continue to discuss implementation of this pilot project.

As indicated in NS Power's response to CFIB DR-1,[6] the parties are working together on a proposed alternate pricing solution to the change in the demarcation point between the Small General and General rate classes. The proposal consists of offering pricing choice between General Class rates to General customers whose consumption falls into a lower annual kilowatt (kWh) range. The discussions are ongoing and, subject to reaching consensus on this matter, NS Power will file an application to the Board requesting appropriate changes in the General class tariffs.

[4] Please refer to the Board's letter included in Appendix U.
[5] Please refer to the Board's letter included in Appendix V.
[6] Appendix C.

These two pricing projects have no effect on the Cost of Service matters considered in this proceeding.

It is important to note that the COS process is separate and distinct from rate-setting. Where the Cost of Service determines cost responsibility by customer class, rate-setting is the process by which class costs are recovered by billing determinant (e.g. Customer charge, energy or demand charge). As well, once the Cost of Service is determined, the recovery by class is determined according to the class revenue-to-cost (R/C) ratio within a band (currently +/- 5 percent). All of these elements are examined in detail by the Board and stakeholders as part of a General Rate Application.[7]

[7] Please note that the appropriateness of the overall +/-5% of the R/C ratio band and its method of implementation in rate cases is also a subject of this proceeding.

3.0 COS BACKGROUND[8]

3.1 COS in the Context of the Ratemaking Framework at NS Power

NS Power is regulated according to a traditional Cost of Service framework. The framework is intended to provide the fair allocation of utility costs among classes based on established principles of cost causation and asset utilization.

The three sequential steps employed in the development of utility rates are:

1. revenue requirement (RR) determination
2. COS development
3. rate design (RD) studies

The revenue requirement includes operating and maintenance expenses, depreciation, taxes and financing, including return on common equity. The Cost of Service Study serves to apportion these costs among rate classes.

Where possible, costs are assigned directly to rate classes. Costs not directly assigned are allocated to rate classes in the following Board-approved three-step process:

1. Costs are functionalized as generation, transmission, distribution or retail;

2. Costs by function are classified as energy, demand or customer categories;

3. The energy, demand and customer categories are allocated to the various classes of service on the basis of their respective demands, energy use, customer number or other established allocator base.

[8] The narrative in this section is drawn from the Strawman Version 1 report issued in this process. The complete report is attached to this filing as Appendix H.

3.2 Changes in Operational and Regulatory Landscape Since 1993

The period from 1995 to 2004 was a period of relative price stability for NS Power customers, when the effect of moderate increases on revenue requirements was largely offset by growth in sales and hence, revenues.

Beginning in 2005, this load and cost relationship changed. Increases in the cost of imported fuel, coupled with new provincial requirements for renewable energy generation and stricter air emission standards, gave rise to the long-term strategy to replace coal-fired generation with renewable generation. The strategy has required significant investments in generation and transmission assets.

The nature of the utility's asset additions has also changed in recent years. In contrast to the last build-out of large, high cost generation investments from more than 20 years ago, NS Power is experiencing today continued steady growth of smaller capital additions. These include the Nuttby Mountain, Digby and Point Tupper wind projects, the biomass generation facility at Port Hawkesbury, the baghouse at Trenton 5 and installation of mercury and nitrogen oxide containment equipment on NS Power's solid fuel generation plants. In addition to the direct generation cost, a number of these projects have required transmission system enhancement.

This transition has been accompanied by a shift from the exclusive dependence on Company-owned generation resources to other energy providers. Independent Power Producer (IPP), Community Feed-In Tariff (COMFIT) and net-metering suppliers are becoming a significant element of the Company's generation portfolio. Compliance with the 2020 RES requirement will drive further expansion over the next several years.

Over the same period, the industrial load has fallen, driven primarily by a decline of the pulp and paper sector and the expansion of investment in demand-side management programs. The combined effect of these factors on unit revenue over the periods examined has been material as presented in the table in Appendix W.

3.3 NS Power's COS: An Outcome of an Evolutionary Ratemaking Process

The COS methodology in effect today is the outcome of gradual and evolutionary change which took place over several decades culminating in a generic COS hearing conducted in 1993. The changes in methodology were incorporated at a specific time to reflect planning conditions, capacity additions, data availability, and system usage and service characteristics.

The cost standard used in the COS has evolved from a purely embedded approach to one that recognizes, to a limited extent, marginal costs. In its 1995 COS decision, the Board provided the following:

> The Board recognizes that marginal costs can play a significant role as a benchmark in reviewing the classification of embedded cost by causation at the point of generation and at various voltage levels in the system, and also in rate design.[9]

These comments paved the way for the introduction in the 1996 General Rate Application of the marginal cost based interruptible credit in the COS, as well as other rate submissions predicated on the application of marginal costs such as the voltage-based 1 Part Real-Time-Pricing (RTP) Rate and 2 Part RTP Rate.

The major focus of past Cost of Service Study (COSS) revisions has been the classification and allocation of generation costs. NS Power's approach falls into the category of "Energy Weighting" methods, which recognize that generation and transmission assets were constructed to provide either lower cost or cleaner energy in addition to capacity.

[9] NSPI 1995 In the Matter of a Generic Hearing respecting Cost of Service and Rate Design, UARB Decision, NSUARB-NSPI-P-864, September 22, 1995, Page 20 of 24.

The methods for allocation of generation and transmission costs to energy and demand have evolved as better quality data has become available, from a basic Non-coincident Peak approach to a more refined Average and Excess Method, to the current method based on coincident peak (3CP) allocation. The effect of these changes was a slow shift towards a growing energy-related cost category and a declining demand-related one.

The method in effect today, which NS Power refers to as the System Load Factor Method,[10] reclassifies about 2/3 of fixed costs of transmission and base load generation as energy-related and allocates these costs to rate classes based on the rate classes' shares of total energy. Under this approach, the high load factor, large industrial classes bear a larger proportion of responsibility for fixed costs.

In contrast to the fairly intense debate on the Cost of Service methodology around generation costs there has been, until the 2012 GRA hearing, a fairly muted discussion of treatment of the costs of the distribution and retail areas. Since the 1995 decision, there have been only two minor activities in the area of streetlight services. In 2006, the UARB, in response to concerns presented by the Halifax Regional Municipality (HRM), directed NS Power to review the appropriateness of the weighting factors used in allocation of certain customer-related expenses and the treatment of capital contributions made by developers to streetlight capital. In its 2012 GRA decision, the UARB approved NS Power's proposal that the costs of light-emitting-diode (LED) streetlights be determined outside of the COSS and that the streetlight depreciation costs for these units be directly applied rather than being determined through proration of aggregated totals.

[10] The System Load Factor method employed in Nova Scotia does not have an equivalent in NARUC's Electric Utility Cost Allocation Manual. It falls into a category of energy weighting techniques.

Other COS matters discussed in the 2012 GRA included the following:

- Meter Costs and Weighting Factors: The average unit cost of installing a meter and customer weighting factors for each class continue to use the figures developed at the inception of the COS model in the 1970s.

- Sub-functionalization of distribution poles and wires between primary and secondary voltage levels, as well as classification of these assets between demand and customer related categories, have not been reviewed since 1982.

- The valuation of dedicated distribution substations by a proxy method has not been revisited since 1995.

4.0 STAKEHOLDER ENGAGEMENT

Beginning with the initial project scoping exercise in July 2012, through development of the project Terms of Reference, issuance of responses to stakeholder data requests, technical conferences and issuance of the two COS Strawman documents, NS Power has sought to provide complete and accurate information regarding the Company's COS practices, and practices that are commonly applied in the industry. As well, NS Power has attempted to clearly communicate its perspective on COS issues and understand and incorporate stakeholder and expert opinion on these matters to its position documents. To this end, the Company has:

- Engaged electricity industry Cost of Service expert consultant, Christensen Associates Energy Consulting, to review the Company's Cost of Service framework and practices, provide comment with respect to the consistency of these with accepted utility practice, and provide recommendations for improvement;

- Held three technical conferences on this matter;

- Developed Terms of Reference to establish the objective of this process, approach, scope and decision-making criteria;

- Developed an FTP site and populated this with information relevant to the NS Power COS model;

- Issued responses to 128 data requests received from stakeholders, including 47 sensitivity analyses identifying the effect on customer class costs of alternative COS approaches;

- Issued Strawman Report Version 1, which provided:

    - Background to the Company's COS methodology;

    - The report of the Company's COS consultant, Christensen Associates Energy Consulting, concerning NS Power's COS framework and processes;

    - Results of COS surveys conducted by various consulting companies and NS Power;

    - The Company's position on recommendations presented by CAEC;

- Issued Strawman Report Version 2, which provided:

    - Feedback of stakeholders on Strawman Report Version 1;

    - Amended positions of the Company with respect to CAEC recommendations and other issues raised by stakeholders;

    - Identified areas where consensus had been developed, where consensus had not, and those areas requiring further analysis;

- Held numerous teleconferences with Board staff and stakeholder consultants.

As a result of this work, a shared understanding of the Company's Cost of Service processes and related issues and their materiality to customer rates has emerged. This is a significant achievement given that it has been twenty years since this was last examined in detail.

This shared understanding is essential to moving this process forward in an efficient and constructive manner. It is aligned with the view that solutions to technical, data-intensive matters such as those faced in a Cost of Service proceeding are enhanced by working directly with stakeholders, prior to presenting these to the Board for consideration. This provides for the free exchange of positions on matters and recognizes that, despite the quantitative foundation which underlies a COS model, significant elements of the framework remain, at least in part, subjective.

The fact is, expert opinions can and do differ. Therefore, negotiation on matters is desirable and the most effective solution is likely to be one on which consensus is achieved. This is likely to require a measure of compromise from all parties.

To date, it appears that a consensus position has developed on 23 of the 42 issues identified in the process. There are 19 other recommendations upon which, to date, consensus has not been achieved.

This progress is encouraging. It supports continued dialogue and work in these areas among parties as the formal portion of the COS proceeding begins.

5.0 COST OF SERVICE FRAMEWORK REVIEW

In the following section of this report, a discussion of items identified through the COS review is provided. Before beginning this, it is important to consider the criteria for the COS review established in the Terms of Reference (TOR) and consider general themes which have emerged through the work undertaken to date by CAEC, NS Power and interested parties.

The agreed upon criteria are as follows:

- Alignment with Bonbright's Ratemaking Principles;
    - The electric industry has relied on ratemaking principles developed by Professor Bonbright in the 1960s in conducting ratemaking studies. The principles are desired characteristics of rates, some of which can conflict (e.g. equitability and efficiency, equitability and simplicity, stability and efficiency).
- Consistent with the established regulatory framework;
- Alignment, to the extent possible, with the established COS framework.
- Ability to be fully examined within the Board-approved schedule.

The Company's consultant report (provided in Appendix H)[11] states:

> NS Power's COS methodology is largely within the bounds of established industry standards. Those departures from predominant industry practices are still accepted practice and appear to reflect NS Power's circumstances. We recommend some limited modifications in methodology. We recommend that NS Power conduct an update of customer levelization by

[11] Appendix H pages 49 to 99 of 261.

> service levels. … We also recommend that NS Power review the information and analyses that support the various allocators and update them where necessary.[12]

NS Power's analysis has served to:

- Determine the relative materiality of COS issues identified through this process;
- Identify opportunities to streamline the Cost of Service model by eliminating immaterial elements;
- Identify continued information gaps and plans to address these;
- Identify errors and inconsistencies in the application of the current COS framework and plans to address these;
- Provide an important perspective on the interplay between Cost of Service precision and the Revenue/Cost ratio band employed in this jurisdiction.

The input of parties has served to:

- Clearly identify areas to be examined through this process;
- Provide direction with respect to prioritization of matters;
- Provide a thorough vetting of the information presented by the Company;
- Confirm their agreement with certain issues identified through the process;

[12] Appendix H, CAEC Report, page 90 of 261.

- Identify those areas where they disagree with the Company's position and provided support for their positions.

The Board and parties should be encouraged that the analysis to date has demonstrated that the COS framework in place in Nova Scotia is robust. Despite the passage of time and changes to the Company's operational and planning environments, we believe the COS model continues to provide a fair allocation of cost responsibility among customer classes. The COS model remains, for the most part, aligned with accepted industry practice and provides a solid foundation to consider refinements going forward.

The following section of this Evidence discusses the individual COS issues.

6.0 ISSUES

NS Power's 2013 and 2014 revenue requirements as approved by the Board are $1.2 billion and $1.3 billion, respectively.[13] Allocation of these amounts across customer classes, as approved by the Board and in accordance with the Cost of Service methodology currently in place in Nova Scotia, is summarized in the table below:

	2013			2014		
	TOTAL OPER. EXPENSES ($K)	**TOTAL RATE REVENUE ($K)**	**% REVENUE TO EXPENSES**	**TOTAL OPER. EXPENSES ($K)**	**TOTAL RATE REVENUE ($K)**	**REVENUE TO EXPENSES (%)**
Domestic	651,142	641,289	98.49	680,281	672,437	98.85
Small General	33,851	35,543	105.00	35,358	37,000	104.64
General	294,661	305,496	103.68	309,019	318,043	102.92
Large General	41,887	41,338	98.69	42,617	42,341	99.35
Small Industrial	30,047	30,976	103.09	31,732	32,513	102.46
Medium Industrial	52,613	52,225	99.26	55,875	55,016	98.46
Large Industrial	75,356	73,257	97.21	76,798	74,836	97.44
ELI 2P RTP	N/A	N/A	N/A	N/A	N/A	N/A
Municipal	20,670	20,102	97.25	21,676	21,170	97.67
Unmetered	24,407	24,407	100.00	23,789	23,789	100.00
Total	**1,224,633**	**1,224,633**	**100.00**	**1,277,146**	**1,277,146**	**100.00**

In its report concerning NS Power's COS methodology, CAEC developed a list of 40 recommendations designed to address:

- Issues raised by CAEC under its mandate to provide a comprehensive review of NS Power's COS from a variety of perspectives including industry standards;

[13] The numbers above correspond to the post-rate stabilization revenue requirement. The pre-rate stabilization revenue requirement for 2013 and 2014 is $1.3 billion. The table above does not include miscellaneous revenues.

- Issues raised by stakeholders in past proceedings, in particular the 2012 General Rate Application;

- Issues brought up by NS Power as a result of its review of the COS.

In addition, two other recommendations, 41 and 42, have been added to CAEC's list as raised by the CA's consultant and the Industrial Group in their submissions, in response to the Strawman Version 1 report.[14]

The recommendation listing, including the numeric identifier, has been retained by the Company through the two Strawman reports issued to stakeholders and has been maintained throughout this Evidence. A complete listing with an overview of each item is presented in Appendix N and the applicable sensitivity analysis is found in Appendix O. The following categorizes these items according to (1) items on which consensus has been reached and (2) those where consensus has not been achieved to date.

6.1 Recommendations on Which Parties Have Reached Consensus

The table below identifies those 23 items/recommendations for which consensus has developed.

No	Recommendation	Subject
3	R3.1-3	Adjust Transmission losses to reflect HV and EHV functions
6	R3.2-1	Eliminate dedicated substations
7	R3.3-1	Undertake a comprehensive loss analysis. This should enable more accurate line loss determination by class and provide for a consistent treatment of line losses among Coincident Peaks, Non-Coincident Peaks and energy requirements.
8	R3.3-2	Develop class profiles by service levels to determine losses. Currently, there is one class load shape used for all CP and NCP voltage levels. Each voltage level should be permitted separate load shape within a class.

[14] Appendix J, Page 31 of 112.

No	Recommendation	Subject
9	R3.3-3	Review loss factors associated with generation energy allocator.
10	R3.3-4	Review transformer loss adjustments in allocator development. The 1.75% line loss adjustment factor may indeed still be the right value but it should be re-examined since it's dated.
11	R3.4-1	Maintain current approach with respect to ancillary services
20	R4.3-1	Retain current classification of distribution substations
22	R4.3-3	Review Line Transformer classification
23	R4.3-4	Retain current allocators for distribution demand costs
24	R4.3-5	Recognize different voltages in the calculation of class NCP
25	R4.3-6	No need to classify any distribution costs as energy
27	R4.3-8	Update data supporting meter cost allocators
28	R4.3-9	Defer review of Unmetered until LED conversion is complete
29	R4.4-1	No change to O&M classifications and allocations
30	R4.4-2	No change required re treatment of Miscellaneous revenues
31	R4.4-3	No change required re allocation of earnings
32	R4.4-4	No change required re allocation of taxes and DSM
33	R4.4-5	Modify allocation of interruptible credit
34	R4.4-6	Consider effectiveness of designating substations by service level/rate class
37	R4.4-9 (updated)	A new sample should be drawn to return the LR sample quality to its originally intended level
38	R4.4-10	Institute plan for periodic Load Research sample updates
40	R5.0-2	Exclude Fuel costs from R/C ratio calculations

These recommendations can be categorized into three groups:

- Routine cost matters raised by CAEC, as part of its comprehensive review of the NS Power Cost of Service Study (No 3, 20, 23, 28, 29, 30, 31, 32, 34, 40);

- Housekeeping matters such as updating cost allocation coefficients or certain methodological revisions regarding functionalization or classification as raised by stakeholders (No 6, 7, 8, 9, 10, 11, 22, 24, 25, 27, 37, 38);

- Matters discovered by NS Power, which are either a correction to inconsistencies between the original COS design and its current maintenance or are clear improvements for transparency and accuracy of the costing process (No 33).

6.1.1 Housekeeping Matters

6.1.1.1 Load shape-based cost allocators (No. 7, 8, 9, 37, 38)

These recommendations concern the load shape-based cost allocators; specifically the reliability of the load research sample in determination of class load shapes (No 37, 38) and the line loss by rate class determination approach (No 7, 8, 9). The allocators include class coincident and non-coincident peaks used to determine the class utilization of the demand-related portion of the utility's infrastructure.

These matters affect the accuracy of the COSS; however, from a conceptual standpoint, they do not create a methodological challenge. No 37 and 38 relate to maintaining the intended quality of load research sample data,[15] while No 8 is concerned with the end result of the load research sample: reliable load statistics by the primary and secondary distribution voltage levels within each class.[16]

The proposed fixes were characterized by the Board's consultant, Multeese Consulting Inc., as fine tuning.[17] NS Power agrees. Multeese, the SBA's consultant and Industrial Group support these changes.[18] No other party has opposed them. The CA's consultant indicated in a teleconference that he reserved final judgment on this matter until he reviews the Load Research report recently prepared by CAEC. The report is included in Appendix P. Its conclusions align with the preliminary recommendations under No 37 and 38.

[15] This is captured in the targeted 90/10 confidence level in estimating population load statistics which means that 90% of the time estimated statistics are expected to be within +/- 10% of the population statistic.
[16] This requirement is reflected in Exhibit 9B in the COS, which calls for voltage level based non-coincident peak information. The information is used in the allocation of primary and secondary voltage-related distribution costs. To make the determination of class CP and energy requirements consistent with their NCP (non-coincident peak) treatment, they should also be differentiated by voltage level in Exhibit 9A, as is the case in Exhibit 9B. This is proposed in No 7 and addresses concerns raised in MEUNSC DR-2, DR-3 and DR-6 (Appendix D) respecting methodological consistency in determination of line losses associated with each class' energy sales, coincident peaks and non-coincident peaks.
[17] Appendix I page 20 of 31, item (e).
[18] Appendix I page 20 of 31 (Multeese), Appendix I page 25 of 31 (SBA), Appendix K page 20 of 39 (Industrial Group).

In its responses to CA DR-2 and DR-74,[19] the Company provided details respecting its line loss determination process. CAEC's recommendations, which we number 7 and 8, recommend examination of this matter and adoption of line loss determination by voltage levels within relevant rate classes. The current approaches to determination of line losses of class energies, coincident peaks and non-coincident peaks are determined through separate processes. This yields inconsistent results as indicated in questions asked by MEUNSC in DR-2, DR-3 and DR-6. NS Power agrees. As indicated in CA DR-74,[20] NS Power remains open to stakeholders' suggestions on how to improve its current process.

6.1.1.2 Review transformer loss adjustments in allocator development (No. 10)

This matter concerns the adjustments in customer bills based on meter location as contained in NS Power's rates, for the purpose of compensating for transformer losses. This matter, as indicated in our response to MEUNSC DR-8, will require a longer lead time to examine extending beyond the time horizon of this proceeding. NS Power is committed to its resolution. However, it is a pricing matter that does not need to be resolved at this time and does not stand in the way of reaching consensus on the COS methodology.

6.1.2 Other Items on Which Consensus Has Been Reached

The effect of the remaining issues, individually and in aggregate, is minor. There is no further discussion of these recommendations in the body of this evidence.[21]

[19] Appendix B page 10 and 788 of 791.
[20] Appendix B page 788 of 791.
[21] Additional information on these items can be found in Strawman Version 1 (Appendix H), Strawman Version 2 (Appendix J), and the comments from stakeholders received regarding both Strawman reports (Appendices I and K).

6.2 Recommendations on Which Parties Did Not Reach A Consensus

The table below identifies those 19 issues/recommendations for which consensus has not been reached to date.

No	Recommendation	Subject
1	R3.1-1	Service Definitions as it relates to voltage levels appropriate
2	R3.1-2	Consider individual customer circumstances, such as accident of geography versus intended customer's choice, in developing Service Levels
4	R3.1-4	Levelize customers at actual voltage service levels
5	R3.1-5	Maintain HV and EHV transmission categories
12	R4.1-1	Review alternate approaches for generation classification
13	R4.1-2	Consider Equivalent Peaker method for generation classification
14	R4.1-3	Hold current method of generation classification unless superior approach identified
15	R4.1-4	Adjust classification of Regular Purchased Power
16	R4.1-5	Classify wind purchases based on role in system planning
17	R4.1-6	Classification of non-wind purchases
18	R4.2-1	Classify Transmission 100% Demand
19	R4.2-2	If Transmission not 100% Demand, classify using other than SLF
21	R4.3-2	Update functionalization and classification of poles and wires
26	R4.3-7	Review weights in customer allocators
35	R4.4-7	Align COS treatment of transmission substations with OATT. The financial accounting system should dictate functional cost assignment as it does with OATT.
36	R4.4-8	Disaggregate distribution depreciation expense
39	R5.0-1	Relax R/C ratios
41	CA	Port Hawkesbury Biomass classification
42	The Industrial Group	Muskrat Falls effect and treatment of Lingan 1 and 2

A discussion of each of these issues and the Company's and stakeholder positions on the matters is presented in the following section. NS Power has grouped these recommendations into a few themes. They are addressed in the order of their declining materiality in class cost responsibilities.

6.2.1 Classification and Allocation of Generation Costs (No 12, 13, 14, 41, 42)

Generation by far accounts for the biggest share of the Company's total rate base and total operating costs[22] and was the central theme of the last COS proceeding held in 1993. Perhaps the most important aspect in the treatment of generation costs is their classification between energy and demand-related components. In general, the more these costs are classified to energy, the higher the overall cost responsibility of the high load factor customer classes such as the Large Industrial class.

The following discusses the treatment of generation in two subcategories: base load generation and renewable generation.

6.2.1.1 Base Load Generation

As provided in response to Avon DR-16,[23] historical treatment of generation in our jurisdiction has fallen within the energy weighting methods, which recognize that these assets were constructed for the reasons of providing lower cost energy, in addition to capacity. The methods for allocation of generation and transmission costs gradually evolved, starting in the 1970s from Non-coincident Peak to the Average and Excess Method, ending eventually in 1995 with the current System Load Factor (SLF) based method.

The SLF method reclassifies about two thirds of fixed Generation and Transmission costs to energy, based on the System Load Factor. The energy portion of these costs is allocated to rate classes based on their relative shares in annual energy requirements, while the demand-related portion is allocated based on the rate classes' relative shares in the sum of three winter monthly coincident peaks for the months of January, February and December.

[22] The generation rate base accounts for about 2/3 of the total, while generation expenses, inclusive of fuels, account for 3/4.
[23] Appendix A page 28 of 147.

The agreed upon criteria for the COS review in the Terms of Reference[24] call for staying within the established COS framework, unless a compelling case is developed for pursuing a change. NS Power believes that the review of generation should be conducted within the confines of energy weighting methods. No party took a position opposed to this.

To facilitate discussion on alternate treatments of base load generation, NS Power provided modeling results and qualitative comments on various classification and allocation techniques, as recommended by stakeholders, in its response to Avon DR-16.[25] The tested classification methods were:

1. Peak Demand Methods
2. Energy Weighting Methods of Equivalent Peaker
3. Time Differentiated Methods

Within each classification method, NS Power considered further variations of assumptions concerning the types of generation used and methods of allocation.

Stakeholders' Positions

The CA's consultant and the Industrial Group advocate departure from the currently used System Load Factor-based classification of base load plant.[26] They both are of the opinion that the SLF approach is not a fully causation-based method. The MEUNSC's consultant and Board Counsel's consultant expressed a preference for staying with the current SLF-based method,[27] whereas the SBA's consultant indicated that, while the SLF-based method does not necessarily provide the best insight into cost causation, it may offer a suitable compromise among alternatives.[28]

[24] Appendix M.
[25] Appendix A page 28 of 147.
[26] Appendix K page 11 (CA), page 20 (Industrial).
[27] Appendix K page 31 (MEUNSC), Appendix I page 20 item (a) (Multeese).
[28] Appendix I page 26.

The CA's consultant is in favor of implementing the Equivalent Peaker Method (EPM) in conjunction with both base load and wind generation plants.[29] The EPM aligns more closely with the cost causation in the generation planning process as stated in NARUC's manual:

> Equivalent peaker methods are based on generation expansion planning practices, which consider peak demand loads and energy loads separately in determining the need for additional generation capacity and the most cost-effective type of capacity to be added.[30]

Under this method, a portion of the unit fixed cost of each generation unit is set equal to the unit cost of the proxy generation for capacity and classified to demand, with the balance of cost classified to energy. The analysis, to the extent possible, should be conducted on the basis of viable market replacement alternatives available to the utility.

Such an approach is problematic, as not all currently used types of generation, such as coal or nuclear, are being constructed anymore.[31] This method was recommended by NS Power and the Board's consultant, Mr. George Baker, in the 1993 Generic COS Proceeding. It was not accepted by the UARB as it was determined to be impractical due to its computational challenges concerning the determination of a common dollar denominator for generators of varying vintages and year by year variations between costs of base load and peaking units. NS Power has modeled a few variations of this approach, addressing the issue of age-based diversity in asset value by applying an inflation adjustment.

[29] Appendix K page 11 of 39.
[30] NARUC Manual, January 1992, page 52.
[31] This challenge is currently faced by SaskPower. Elenchus recommends as a second best Peaker Credit approach or relying on benchmarking survey results. This is discussed on page 36 of the Elenchus Survey (Appendix H page 136 of 261).

The EPM method recommended by the CA's consultant comes in several variations, of which NS Power has modeled four.[32] Under the more likely methods to be implemented, peaker by proxy[33] or peaker credit,[34] the cost redistribution effects results for the Residential and Industrial class were as follows:

1. Residential class – reduction from 1% to 2%
2. Industrial class – increase from 2.5% to 5%

Other Industrial and General classes experience smaller increases, while the Municipal and Unmetered (UNM) rate classes see approximately neutral results.[35] These results were documented in sensitivity analysis cases W and Z.[36]

Regarding allocation of generation costs, the CA's consultant proposes an increase in the number of monthly peaks beyond the three winter peaks to incorporate peaks of non-winter months for which there is evidence of empirical utilization of combustion turbines.[37]

The CA's consultant is opposed to the Industrial Group's proposal to reclassify a portion of Lingan 1 and 2 costs to demand, based on recent change in the utilization of these units.[38]

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[32] Appendix A pages 33 to 35 of 147 (Avon DR-16 pages 6 to 8).
[33] NS Power has also tested the equivalent peaker method using updated peaker costs. The results were directionally opposite to this one with the residential class seeing a 0.6% increase and other classes a decrease.
[34] Peaker by proxy and peaker credit were the two approaches identified by the Board's consultant, George Baker, in 1993 as the most appropriate to use (see Appendix Q).
[35] As indicated in Avon DR-16 (Appendix A page 28 of 147), NS Power applied tested classification and allocation methods to both Generation and Transmission. For the purposes of this discussion, only Generation should be modified; thus, the results presented in the analysis overestimate the cost redistribution effect by approximately 10% to 20%.
[36] COSS Sensitivity analysis can be found on NS Power's FTP site (See Appendix T).
[37] Appendix K page 13 of 39.
[38] Appendix K page 12 of 39.

The Industrial Group is in favour of implementing a time-differentiated energy weighting method, referred to as Base Peak (BP) or its more complex variation Base, Intermediate Peak (BIP).[39]

The time-differentiated cost of service methods allocate fixed plant costs to different time periods based on their utilization and costs.[40] The costs are separated according to the part of the system load curve served by various types of units. NS Power performed sensitivity analyses for one such method: a Base Peak method concerned with separation of costs between peak and base load generation. The Company also considered its ability to carry out analysis of a Base, Intermediate Peak method which separates costs among three periods.

These methods can have several variations.[41] The approach recommended by the Industrial Group's consultant in the 2009 GRA[42] (sensitivity case AA[43]) would result in a smaller degree of reclassification of fixed costs from demand to energy than under the SLF-based approach. This results in a cost transfer of 4 percent to the Residential class and a decrease for all other classes, of which the Large Industrial class experiences the largest benefit, an 11 percent decrease in cost allocation.

Further, the Industrial Group recommends that the currently less heavily utilized base load coal fired plants of Lingan 1 and 2 be treated as intermediate generation.[44] NS Power believes the effect of this change would be to classify a bigger portion of Lingan 1

[39] Appendix K page 21 of 39.
[40] The most common approach to allocation of these time-differentiated costs to rate classes is to use class peak demands in allocation of peaking costs, and class energy requirements up to a breakeven point between two different types of generation on system load duration curves to allocate intermediate and base load costs. The time differentiated methods are claimed by some to better align with the cost causation as used by generation planning in that extra capital costs are incurred once the system is expected to run for a certain minimum number of hours. Once the minimum hour threshold, or break-even point, is reached, it is no longer relevant to the investment decision in base load generation as to how many more additional hours the base load unit will run. According to NARUC's manual it is not certain, however, whether or not system planners always recognize the difference between on-peak and off-peak hours in their investment decisions to build base load plant.
[41] Avon DR-16, pages 9 to 11 (Appendix A pages 36 to 38 of 147).
[42] Avon DR-16, page 10, Base Peak (BP) using the system load factor classification method (Appendix A page 37 of 147).
[43] COSS Sensitivity analysis can be found on NS Power's FTP site (See Appendix T).
[44] Appendix I page 14 of 31.

and 2 fixed cost plant to demand than is the case under the SLF approach resulting in a further shift of costs away from the Industrial classes. The Industrial Group also recommends that the redesign of the COS methodology incorporate the anticipated effects of 2018 Muskrat Falls energy and the 2020 40 percent RES requirement.[45]

NS Power's Position

CAEC recommended that NS Power review its current SLF method and compare its performance under suitable criteria to alternative methods. CAEC suggested that NS Power consider an EPM method and an alternative to an energy weighting approach of a Peak Demand (PD) method,[46] which classifies all fixed plant costs to demand.

NS Power confirmed in its Strawman reports that it supports maintenance of the SLF approach, as long as no superior alternative is found. In the Company's assessment, there were no convincing arguments put forward to confirm an alternative method would be superior.

The application of the EPM and BP methods to classification of base load generation were examined in the 1993 COS proceeding and were rejected in favor of the current SLF-based method. Though the operational landscape of NS Power has changed since that time, the characteristics of the EPM and BP methods have not. The table below provides NS Power's qualitative assessment of generation classification approaches, as based on the discussion of their pros and cons in the response to Avon DR-16[47], relative to established ratemaking criteria.

[45] Appendix I page 12 of 31.
[46] The PD method, also referred to as the fixed/variable split method, increases the number of system peaks on the basis of which fixed costs are allocated. The PD method can be used to produce cost allocation results that approximate those under various energy weighing methods while avoiding their complexity.
[47] Appendix A page 28 of 147.

Criterion	SLF	EP	BP/BIP	PD
Initial cost redistribution effect	Very Good	Fair	Poor	Poor
Rate stability going forward	Good	Fair	Poor	Fair
Alignment with cost causation	Fair	Good	Very Good	Poor
Simplicity	Good	Poor	Poor	Very Good
Transparency	Fair	Fair	Fair	Poor
Noncontroversial	Poor	Poor	Poor	Poor
Overall assessment	**Good**	**Fair**	**Fair**	**Fair**

As far as allocation of demand-related costs of generation is concerned, NS Power does not find evidence in support of a departure from the current three coincident peak (3CP) approach. As provided in response to CA DR-42, 43 and 44, NS Power remains a winter peaking utility and combustion turbine (CT) usage during non-winter months is not a significant factor with respect to generation investment decisions.

The treatment in the COS of future developments such as the operation of Lingan Units 1 and 2 beyond 2014, and the potential for the Maritime Link, if approved, or 40 percent RES requirements, should be deferred until the Company and the Board determine the outcome of these issues.

NS Power maintains its position that the current approach to classification of base load costs is superior to the alternatives and should be maintained.

6.2.1.2 Renewable Generation

The current approach to classification and allocation of NS Power-owned renewable generation is primarily rooted in the UARB's decision on the Generic COS Proceeding. The proposed amendments by NS Power in subsequent GRA submissions and the Board's rulings have also contributed to the current approach.

The Board's decision on the Generic COS hearing provided as follows:

> The Board directs that
>
> (i) all generation costs associated with environmental compliance and fuel conversion are to be classified as energy related;
>
> (ii) annual fixed costs associated with steam and hydro generation plant rate base asset are to be classified to energy on the basis of annual system load factor;[48]

At the time of the UARB's COS decision in 1995, NS Power did not own any wind or biomass power plants. Therefore, these assets were not specifically mentioned in the Board's decision. There were no Renewable Electricity Standards in effect at that time either. Notwithstanding the above, the underlying principle stemming from the UARB's decision to classify, as energy, those assets whose acquisition allows NS Power to produce energy more economically, is aligned with the investments which enable NS Power to produce energy in conformance with environmental regulations.

Wind generation assets added prior to 2005 were classified between demand and energy using a 30/70 percent split. This was documented in NS Power's response to UARB IR-73 in the 2007 GRA. At that time, environmental consideration was not given to these projects as these investments were not driven by the RES requirements.

The logic of this approach is a reversal of the load factor based classification of dispatchable base load generation. To the extent base load generation is producing energy, it should be classified to energy. To the extent it is not, it should be considered demand-related.

The same logic cannot be applied directly to non-dispatchable wind generation, assumed to operate at 30 percent capacity factor, because it would credit 70 percent of its value to demand. Given that this non-dispatchable source has been credited for its capacity

[48] COS & Rate Design Generic Hearing Board Order, September 22, 1995, page 23.

contribution to the system reserve planning to the extent of its capacity factor, NS Power used this to determine its classification to demand.[49]

The investments in wind generation made after 2009 were classified in the COSS in the 2012 GRA as energy-related only, because they were driven by RES targets and were justified as such in their capital work order applications to the UARB. This approach was documented in NS Power's responses to CA IR-32 and NPB IR-35 from the 2012 GRA proceeding. The Board's directive to classify dispatchable biomass generation based on system load factor, in its 2013 GRA decision,[50] set a paradigm for treatment of dispatchable renewable generation.

The classification of the operating expenses of wind and biomass plants is consistent with the classification of their underlying rate bases. The operating costs of steam, hydro, wind, biomass and LM6000 units are classified using the same one composite coefficient in the COSS, which is already reflective of the weighted averaging effect of their underlying rate bases. Its effect on total classified operating costs is exactly the same as that that would be produced by distinct classifications of operating expenses of individual generation types.

Stakeholders' Positions

All parties, except the CA's consultant, are in agreement with NS Power's proposal to change the approach to renewable generation to align it with the current treatment for generation planning purposes.[51] The SBA's consultant suggests that it may be appropriate to consider the Equivalent Peaker approach in classification of wind generation that is not driven by RES considerations.[52] The SBA's consultant would like to see additional discussion of this issue, however is inclined to support NS Power's

[49] This treatment of RES compliant wind investments explains why the weighted average split of the total wind generation rate base of NS Power between demand and energy does not match the 30/70 split.
[50] 2012 NSUARB 227 Decision, M04972, December 21, 2012, Page 128 of 136.
[51] Appendix K page 33 of 39 (Multeese), page 39 (SBA), page 22 (Industrial), Appendix I page 18 of 31 (MEUNSC).
[52] Appendix K Page 39 of 39.

proposal. Board Counsel's consultant concludes that NS Power's proposal is reasonable, however has reserved final judgment until NS Power provided responses to a few clarifying DRs asked by the consultant in its submission in response to Strawman Version 2.[53] NS Power circulated to stakeholders its responses to these questions on June 5, 2013.

The CA's consultant is opposed to the idea of classifying wind generation to demand based on its capacity factor and recommends that NS Power should either apply a SLF approach to wind generation or use the EPM method.[54] The CA's consultant recommends that the Port Hawkesbury biomass plant should be allocated 70%-100% on energy.[55]

NS Power's Position

As provided in Appendix 5 to the Company's Strawman Version 2 report,[56] NS Power proposed a new approach to classification of wind generation that would align with its current treatment in generation planning process. In particular, NS Power proposes that renewable generation arising from the RES mandate no longer be classified entirely to energy.

As indicated in the Company's response to Avon DR-16[57] and confirmed in the Strawman Report Version 1 under recommendation R4.1-2, the treatment of wind generation for capacity planning purposes at NS Power has changed. Wind projects are now designated as a Network Resource Interconnection Service (NRIS)[58] or an Energy Resource Interconnection Service (ERIS).[59] Going forward, NS Power proposes to credit

[53] Appendix K Page 34 of 39.
[54] Appendix K page 11 of 39.
[55] Appendix K Page 12 of 39.
[56] Appendix J page 97.
[57] Appendix A page 28 of 147.
[58] The NRIS-designated wind generation is deemed as firm capacity planning because the necessary transmission capacity is available to ensure their full operation in all hours of the year.
[59] The ERIS-designated wind generation is deemed as energy-related only because it is subject to transmission constraints or congestion and as such is not credited with any contribution to system capacity.

20 percent of the installed wind generation capacity, designated as Network Resource Interconnection Service, towards its generation planning reserves. NS Power treats all wind generation in the province, whether its own or belonging to independent power producers, in the same manner.

To align the COS treatment of wind generation with system capacity planning, no distinction would be made between RES versus non-RES types of investments. As is the case with the treatment of the Port Hawkesbury biomass project, the classification of the wind generation would not be subject to RES consideration. NS Power proposes to classify 20 percent of all wind generation costs, designated as NRIS, to demand while the remaining 80 percent of this generation, and 100 percent of ERIS-designated generation, would be classified to energy. In the event an Equivalent Peaker (EP) method were to be adopted for classification of base load generation in lieu of the current System Load Factor based approach, the EP would be used to re-classify the demand-portion of wind generation costs to energy.

As described in NS Power's response to Avon DR-14,[60] NS Power recommends against the CA consultant's proposal to classify wind based on SLF. NS Power does not support the application of EPM to classification of wind, absent broad acceptance of this method as a general classification method for its generation plant.[61]

NS Power proposes no changes to classification of wind operating costs and allocation of total wind generation costs to rate classes.

Regarding the treatment of the Port Hawkesbury biomass project, NS Power recommends the status quo because the Company is not aware of changes in circumstances since the Board's decision was rendered in December 2012 that would warrant a deviation from the Board's directive in this regard.

[60] Avon DR-14, page 2 (Appendix A page 25 of 147) lines 4 to 12.
[61] NS Power took this view in its response to Avon DR-14, page 3 (Appendix A page 26 of 147), lines 18 to 22.

In view of the above, NS Power maintains its proposal regarding the treatment of wind and biomass generation as presented in Strawman Version 2.

6.2.2 Classification and Allocation of Transmission Costs (No 18, 19)

As is the case with generation, NS Power classifies its transmission between energy and demand-related categories using a System Load Factor approach. This approach is an outcome of the Board's Decision in 1995, which viewed transmission as an extension of generation. The approach is atypical in the North American electric industry, as the costs of transmission are primarily driven by demand and are usually classified to demand.

NS Power accepted CAEC's recommendation that classification of transmission between demand and energy, as predicated on the SLF approach, be changed to either demand-only or, if energy weighing were to be maintained, to another method than that based on SLF. CAEC's recommendation was based on the following factors:

- Cost causation factors behind transmission construction are predominantly demand-related;

- Consistency with industry practice which predominantly classifies transmission to demand;

- Treatment of transmission as demand-related only under the OATT and 1 Part-Real Time Price riders, which is consistent with what is being proposed;

- Changes in cost causation behind recent investments in transmission investment from those encapsulated in the concept of "coal by wire", which are believed to have given rise to the current classification in the 1995 COS decision.

Stakeholders' Positions

Stakeholders' responses to this matter were divided. The Board Counsel's, CA's and MEUNSC's consultants oppose the recommendations, favouring the status quo.[62] The Industrial Group and the SBA's consultant support the recommendations.[63]

Notable arguments brought by the parties in favour of the status quo include:

- The cost redistribution effect on the residential class of +0.9 percent (CA's consultant);[64]

- Historical cost allocation as a "lasting" purpose behind embedded cost studies (CA's consultant);[65]

- Energy cost causation behind recent investments in transmission as driven by RES consideration (CA's consultant);[66]

- Irrelevance of the "coal by wire concept" to the Board's decision to classify transmission costs to energy (Multeese);[67]

- Irrelevance of transmission treatment under OATT and 1P-RTP to the COS review (Multeese);[68]

- Lack of evidence of superiority of an alternative (MEUNSC's consultant, Multeese).[69]

[62] Appendix I pages 21 to 22 of 31 (Multeese), Appendix K pages 8 to 9 of 39 (CA), Appendix K page 31 of 39 (MEUNSC).
[63] Appendix K page 22 of 39 (Industrial), Appendix I page 28 of 31 (SBA).
[64] Appendix I page 5 of 31.
[65] Appendix I page 5 of 31.
[66] Appendix I page 6 of 31.
[67] Appendix I page 22 of 31.
[68] Appendix I page 23 of 31.

Parties in support of this proposal noted:

- The SLF approach does not seem appropriate for the majority of transmission today (SBA's consultant);[70]

- Change in classification to demand is justified by the change in the use of transmission (Industrial Group);[71]

- Historical considerations behind cost treatment are secondary in importance to current usage and conditions behind asset maintenance and replacement (Industrial Group).[72]

Further to the above, the MEUNSC's consultant submitted that any transition to demand-only classification should be accompanied by a change in cost allocation approach, such as that from 3CP to 12CP,[73] to mitigate cost redistribution effects.[74] The SBA's consultant also indicated that consideration should be given to reclassification to energy of that portion of radial transmission which is dedicated to the delivery of wind power.[75]

NS Power's Position

CAEC, having reviewed the stakeholders' responses, continues to recommend that the SLF approach be abandoned in favour of a demand-only classification of transmission. The primary consideration behind classification of transmission is "peak demand" requirement. The length of transmission radials, as driven by the location of generation,

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[69] Appendix I pages 17 and 23 of 31.
[70] Appendix I page 28 of 31.
[71] Appendix K page 22 of 39.
[72] Appendix K page 22 of 39.
[73] Moving to a 12 coincident peak approach represents further comprise between cost causation behind capacity expansion and stability in cost allocation. It also further mitigates the diversity benefit problem in that it makes seasonal loads responsible for costs of capacity.
[74] Appendix K page 31 of 39.
[75] Appendix I Page 28 of 31.

is of secondary importance, while the amount of energy carried through the lines is not a cost factor at all. To the extent location of generation plays a role in energy causation behind transmission, this can be better addressed by modifications to the coincident peak (CP) allocation approach, such as a change from 3CP to 12CP, which implicitly recognizes energy cost causation. Further, CAEC recommends that NS Power develop a new, demand-only based approach to treatment of transmission, consistent with the industry transmission treatment theory and practice. CAEC also continues to indicate that alignment between COS and OATT is relevant and should be pursued.

Throughout the Company's review of the COS methodology, NS Power has maintained that consistency in cost treatment of asset utilization and service differentiation with the approaches employed in the OATT and 1P RTP was relevant and desirable to minimize controversy going forward. A better alignment in treatment of transmission costs under COS and OATT would produce more efficient price signals to customers seeking alternate suppliers.

Though the UARB did not adopt the "coal by wire" concept in its decision to reclassify a portion of transmission costs to energy, NS Power notes that the transmission/generation linkage did play a role in this decision. This was argued by the Board's consultant Mr. George Baker in his evidence (Appendix Q):

> Transmission costs are fixed and may be classified entirely to demand or partly to demand and partly to energy.
>
> The cost of transmission facilities correlates almost completely with the peak load which must be transmitted and from this point of view a 100% demand classification would be appropriate.
>
> It is, however, also relevant to consider why transmission was built. If the transmission was necessary to connect remote generation to 1oad center, then there is a strong argument for c1assifying the transmission in conformity with the generation.

> NSPI recommends classifying its transmission connecting remote generation 100% to energy on the basis that the generation was remotely sited solely for the purpose of minimizing energy costs. This is a reasonable argument.[76] [emphasis added]

The concept was reflected in Board's analysis of the 1993 proceeding

> One of the major differences of opinion at the hearing was the classification of generation and transmission rate-base assets. This results in a need to determine what portion of fixed costs should be classified as energy and the appropriate allocation of demand related costs to each customer class. For example, a transmission line to a remote base-load plant built to provide least-cost energy to the load centre has an energy related intent. The actual cost incurred, however, is a function of the physical size of the conductor, which relates to its demand capability.[77] [emphasis added]

and further

> It is the Board's opinion that there is an element of energy related cost causation in past generation planning that is present in the NSPI system today. Ms. Chown acknowledges the need for energy recognition in cases such as hydro or nuclear plants, where large capital investments have been made to minimize energy costs. The Board considers that the same rationale applies to the siting of coal fired plants in Cape Breton, as the site was chosen for a combination of reasons which culminated in the least cost solution at that time.[78] [emphasis added]

NS Power submits that factors considered by the Board in its 1993 Decision regarding investment in transmission, as opposed to generation, are significantly reduced today. As indicated in the background section of the Strawman Version 1 report,[79] most of today's transmission rate base was added after the coal-fired generation was built in Cape Breton.

The original premise behind energy weighting in classification of generation assets was choice of investment. Generation is classified between demand and energy because

[76] George Baker's evidence from the 1993 COS proceeding, Appendix Q page 21.
[77] 1995 COS Decision, page 17.
[78] 1995 COS Decision, page 19.
[79] Appendix H, page 8 of 261.

utilities, generally speaking, have a choice between two types of generation: base load generation or peaking generation. Although base load generation is more expensive to build than CTs, it is cheaper to run. This gives rise to an optimal generation mix, where the amount of investment in base load generation is justified by lower overall generation costs. In the Company's view, it makes sense to classify backbone and inter-tie transmission[80] to energy if a significant portion of the investment was undertaken to facilitate lower generation costs, as was the case with the decision to locate coal-fired generation in Cape Breton.

NS Power submits that today backbone transmission corridors are less of a consideration. Power has to be brought to centres of consumption from distant generation sources, which do not have siting alternatives near centers of consumption. These existing transmission corridors serve as conduits of power to load centres from ever-diversifying sources of supply. Thus, costs of refurbishments and upgrades of these corridors are increasingly a function of diversified renewable generation and imports.[81] Little of the value of the original investments made in these transmission corridors remains in today's transmission rate base.

The primary determinant of the backbone transmission system costs is demand. The higher the demand, the heavier the transmission lines, the higher the costs. Therefore, backbone transmission costs should be classified entirely to demand.

As indicated by CAEC, reclassification of transmission to energy is not the common industry practice, and, if present, it is for the reason of transmission radial to remote

[80] NARUC defines backbone and inter-tie transmission facilities to be the network of high-voltage facilities, from 115kV to 765kV or higher through which utilities' major production sources are integrated. NS Power's OATT submission from 2005 refers to it as Bulk Network Assets. Radial to generation is not part of costs included in OATT pricing.

[81] For further discussion, please refer to CAEC's report at Appendix J, pages 109 to 112 of 112 (Strawman Version 2).

generation, which typically accounts for a minor portion of the transmission network and is not part of the backbone transmission system.[82]

This industry practice is also captured in the Elenchus survey:[83]

> Transmission costs are usually classified as 100% demand related since transmission is planned in order to transport electricity at the time of maximum demand in the system. Transmission includes the operation of the grid at different voltages as a single function that transports power from generating stations to the distribution system. Transmission also provides reliability to the electricity system by connecting multiple generation sources.
>
> In some cases transmission is considered an extension of generation, when it is connecting remote generators, and is therefore, classified into demand and energy in the same proportion as the generation it is connecting.[84]

NS Power is proposing that transmission be classified to demand only and allocated on 12CP. This treatment will align with the cost treatment under OATT. Although, this represents a departure from the 3CP approach used currently in allocation of demand-related transmission costs, NS Power believes it is a good compromise between views of the parties to this proceeding and aligns with CAEC's recommendations. While recognizing the dominant role of demand in cost causation of transmission, the 12CP retains recognition for energy in its radial to generation component and also results in a minimum cost redistribution effect on rate classes.[85] The approach would simplify the cost apportionment process and would provide for a more equitable recovery of transmission costs from rate classes.

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[82] The approved 2014 OATT shows that generation-related transmission expenses account for 5.6% of the total transmission expenses.

[83] The Elenchus survey is a comprehensive survey of COS methodologies conducted by Elenchus Research Associates Inc. at the request of SaskPower. NS Power has used this benchmarking study as one of the reference points for evaluation of rate setting methodologies as described in Appendix H, page 13 of 261. The survey is attached in Appendix H pages 101 to 196 of 261.

[84] Appendix H page 119 of 261 (Elenchus Survey, page 19).

[85] The cost redistribution effect of this change has been produced in the sensitivity case AJ, provided on NS Power's FTP site (see Appendix T).

6.2.3 Cost alignment with voltage service levels (No 1, 2, 4, 5)

These recommendations are the most significant in the category of housecleaning items, as they have the most significant cost redistribution effect on rate classes and are a driver behind the recommended changes to the design and maintenance of the Load Research sample. As shown under sensitivity case AO,[86] the cost increases to the Municipal and Large Industrial classes are 3.5 and 0.9 percent, respectively.

At the beginning of the collaborative process, NS Power stressed the importance of adequate reflection of service differentiation by voltage levels in the COS in the delivery of just and reasonable rates.[87] The costs assigned to rate classes should reflect, to the extent practical, their utilization of the transmission and distribution networks. For the ratemaking purposes of COS, the implementation of this concept must find the right balance between simplification of inherent complexities behind cost causation in a network setting and accuracy in cost allocation.

CAEC found that the design of NS Power's COS, which differentiates between transmission and distribution voltage levels, is aligned with industry practice. The COS design calls for allocation of distribution and transmission costs by two voltage service levels each: primary and secondary for distribution, and extra high (EHV) and high (HV) for transmission.

CAEC found the implementation of this concept flawed, as currently not all class loads are classified in this manner. The coefficients used to apportion class distribution loads between primary and secondary voltages of the General, Small Industrial and Medium Industrial rate classes are dated, while loads of large customer classes are not correctly accounted for by distribution and transmission voltage levels.

[86] Sensitivity Analysis is provided on NS Power's FTP site (see Appendix T).
[87] Appendix L pages 4 and 5 of 62 (October 19, 2012 Technical Conference presentation).

CAEC recommended that the Company use CIS-based information to determine actual service levels of all customers and update its load research samples by class voltage levels to provide accurate load-based cost allocation coefficients. Further, CAEC recommended that NS Power investigate low voltage cases of customers billed under Large Industrial and Municipal classes to determine whether they are accidents of geography or customers' requirements to be served at low voltage levels.

Initially, NS Power agreed with these recommendations except for the investigation of low voltage cases, which the Company concluded to be time consuming and potentially contentious. Upon receiving stakeholder feedback on Strawman Version 1, NS Power changed its position regarding the treatment of five distribution customers from the Large Industrial and Municipal classes, who draw power directly from bulk power substations, by agreeing to treat them as transmission customers.

Stakeholders' Positions

<u>Voltage service differentiation by primary and secondary distribution levels</u>

All parties are in agreement with the proposed approach.[88]

<u>Voltage service differentiation between distribution and transmission</u>

In principle, all parties agree to alignment of cost allocation with distribution voltage based service differentiation.[89] No party, except for the MEUNSC's consultant, accepts CAEC's recommendation to examine "low voltage cases". The MEUNSC's consultant makes acceptance of CAEC's Recommendations 1, 2 and 4 conditional on inclusion of "low voltage cases".[90]

[88] Appendix I page 19 of 31 (Multeese), Appendix I page 2 of 31 (CA), Appendix K page 20 of 39 (Industrial), Appendix I page 29 of 31 (SBA), Appendix K page 31 of 39 (MEUNSC).
[89] Appendix I page 19 of 31 (Multeese), Appendix I page 2 of 31 (CA), Appendix K page 20 of 39 (Industrial), Appendix I page 29 of 31 (SBA), Appendix K page 31 of 39 (MEUNSC).
[90] Appendix K page 31 of 39.

Mr. Dominie states:

> We would continue to argue, however, that "cost causation" considerations should warrant "investigation of low voltage cases" to determine reasons why, before rate impacts are entertained.[91]

Mr. Dominie considers the "low voltage case" recommendation as warranting historical contributions in aid of construction (CIAC) of distribution assets by these customers.

Both the MEUNSC's consultant and the Industrial Group recommend that any distribution costs assigned to the Municipal and Large Industrial classes be recovered separately so that customers served at transmission level do not pay for distribution costs.[92] For clarity, the relevant costs should be shown separately in the COSS.

Service differentiation by EHV and HV transmission levels

There is a disagreement among parties on the treatment of voltage differentiation at transmission level. The sole cost redistribution effect of service differentiation by voltage level in COS is estimated to produce a transfer of $0.6 million from the Large Industrial class to other classes as documented in sensitivity case AM.

The CA's consultant and Multeese are opposed to the concept, while the Industrial Group is in agreement.[93] SBA provided no comment.

The CA's consultant does not agree in principle with the concept of service differentiation by transmission voltage levels, because transmission systems are considered highly integrated, with many individual transmission lines providing complementary services. Further, the consultant states that the presence of generation

[91] Appendix K page 31 of 39.
[92] Appendix I pages 14 and 16 of 31.
[93] Appendix K pages 2 to 4 of 39 (CA), Appendix K page 33 of 39 (Multeese), Appendix K page 20 of 39 (Industrial Group).

connected to the grid at low transmission voltage poses a further complication in the cost allocation process as generation is a responsibility of all customers on the system regardless of their points of receipt.[94] Thus, EHV customers are seen as beneficiaries of generation connected to the system at lower voltage levels than those of their points of receipt. Hence, the consultant's view is that they should not be exempted from the responsibility for at least this portion of the lower voltage transmission which connects generation.[95]

The CA's consultant indicates that in the event the transmission voltage-based service differentiation were to be implemented in the COS, it should apply to all distribution customers based on their utilization of the transmission network as determined by the voltage of transmission lines bringing power to bulk power substations serving distribution customers.[96]

In view of the constraints in availability of transmission cost data by voltage at NS Power, the complexity and data intensity required for such an analysis, and its minor cost redistribution effect on rate classes, the CA's consultant is not in favor of this approach.[97]

Board Counsel's consultant, in response to Strawman Version 1, supported this recommendation based on the notion from CAEC recommendation 5 that "Since NS Power's COS is structured to do so [differentiated by EHV and HV transmission levels], it can do no harm to continue, and may offer some benefits".[98] However, in view of a change to a more open ended position taken by NS Power on this matter in Strawman Version 2 and presumably upon realizing that NS Power intended to apply this concept to EHV customers billed under the Large Industrial Rate, with its cost reallocation effects, Mr. Whalen revised his position. Mr. Whalen notes:

[94] Appendix K page 2 of 39.
[95] Appendix K page 2 of 39.
[96] Appendix K page 3 of 39.
[97] Appendix K pages 2 to 4 of 39.
[98] Appendix K page 33 of 39.

> The cost differentiation currently in the COSS arose in conjunction with the development of rates to serve extra-large industrial customers and included considerations beyond the voltage level at which these customers were served. These customers no longer take service under rates developed within the COSS. This being the case, allocators D-3A and D-3B in Exhibit 8A are identical in the current cost of service. I see no reason to change this.[99]

Mr. Whalen also noted reasons brought up by Mr. Chernick.[100]

The Industrial Group states that the current approach “is consistent with industry practice. 69kV line used solely for generation interconnection to the grid might be allocable to all customers, but we believe the amount would be small”.[101]

NS Power’s Position

<u>Voltage service differentiation between distribution and transmission</u>

Regarding the MEUNSC’s consultant’s support of recommendation No 2 concerned with “investigation of low voltage cases”, understood by the consultant to include a detailed examination of individual customer’s contribution to the distribution infrastructure and their interconnection diagrams, NS Power submits that the MEUNSC’s consultant’s interpretation of this recommendation is not correct.

CAEC did not intend for the “low voltage cases” to include such examinations. CAEC recommended an examination of original causation behind the distribution service offering. In its view the responsibility for this cost would vary depending on whether this was due to an accident of geography or a low-voltage service, specifically sought by the customer. An accident of geography could potentially exempt a customer’s load from

[99] Appendix K page 33 of 39.
[100] Appendix K page 33 of 39.
[101] Appendix K page 20 of 39.

responsibility for the cost while the customer's need for this service could not. CAEC does not question the presence of distribution costs in serving of these customers, and did not take a position on the appropriateness of CIAC.

NS Power, as all the other stakeholders, remains opposed to the part of recommendation No 2 concerned with "low-voltage cases". However, NS Power, as explained in Strawman Version 2, is open to re-examination of historical CIAC's and customers' interconnection diagrams.

<u>Service differentiation by EHV and HV transmission levels</u>

As noted in the Company's response to this matter in Strawman Version 2, NS Power does not agree with the CA's consultant that transmission voltage based service differentiation should apply to distribution customers. As acknowledged by the CA's consultant, such an approach would make the cost allocation process more complex and data intensive.[102] If applied on a broad scale, it is likely to produce minor cost redistribution effects among rate classes.

The practical way to capture transmission voltage based cost differentials is by voltages at the points of receipt of individual customers. Consideration of power flow paths and the T&D infrastructure associated with it, and attribution of this to various locations on the system is complex and is not typically considered for the purposes of COS in the electric industry.

The concept of applying transmission voltage differentiated service at NS Power has a long tradition dating back to 1995 with the approval of the Large Industrial Expansion Rate.

[102] Appendix K pages 3 to 4 of 39.

The challenges around data collection by EHV and HV transmission level will not go away with the adoption of a unitary approach to transmission, as this information is required for the purpose of ongoing calculation of 1P-RTP adders and the OATT. In the Company's view, the approaches under the COS and the OATT to this cost determination should be reconciled and the same cost assumptions should be used for the purposes of both calculations. The differential in these costs has been on record for some time now and it did not stand in the way of offering EHV treatment to customers billed under the COS-based ELI 2P-RTP rate since its creation in 2007. It would not be good ratemaking practice to treat a new subgroup of EHV customers differently.

The concept of service differentiation by transmission voltage level has been firmly established in the ratemaking practice in our jurisdiction. For the purposes of 1P RTP adder calculations, NS Power has grouped all customers drawing power at an EHV level into a separate category. As is the case with distribution voltage service differentiation, the potential cost redistribution effect of implementation of the approach should not be a reason for its rejection.

Recognition of EHV service at a point of customer receipt for all rate classes is a fair and implementable treatment in COS. It will create opportunities for the creation of price differentials to current and future EHV customers who typically are large industrial power consumers with the highest price elasticity of demand.

NS Power maintains its position regarding the CAEC's recommendations as taken in the Strawman Report Version 2.

6.2.4 Purchased Power Cost treatment (No 15, 16, 17)

The current methodology for the treatment of purchased power costs has evolved over the last couple of decades through several amendments considered in past GRA proceedings. The core philosophy of treating purchased power costs in a similar manner to that of NS Power's own generation dates back at least to the 1993 Generic COS Proceeding. The only new development since 1993 was the introduction of a separate treatment for the purchased wind generation at the time of the 2009 GRA.

Since the time the current philosophy for the treatment of purchased power was established, its relative share in NS Power's generation source mix has increased significantly. Also, the approach was subject to criticism by stakeholders in recent GRAs, indicating to NS Power that the approach should be reviewed.[103]

CAEC, working with NS Power, initially made three recommendations regarding changes in the treatment of purchased power. This gave rise to requests for further clarifications from a few stakeholders, following which NS Power filed its revised proposal in Strawman Version 2,[104] which was endorsed by a CAEC memorandum included with the same report.[105] NS Power retained the same philosophy of aligning purchased power costs with the treatment of its generation, with the following changes:

1. Purchased wind power designated as NRIS to be classified between demand and energy, and that designated as ERIS to be classified 100 percent to energy. The energy-related costs are to be allocated to rate classes based on their shares in annual energy requirements and the demand-related allocated on 3CP.

2. Treatment of non-wind purchased power from local producers to be separated from imports and classified in the same manner as base load fixed generation costs. The cost allocation is to remain as is.

3. Out-of-province imports, all of which are non-firm,[106] to be classified to energy and allocated on a monthly as opposed to annual basis.

[103] 2012 General Rate Application, Evidence of Drazen Consulting Group, page 18 of 21.
[104] Appendix J pages 97 to 102 of 112.
[105] Appendix J pages 109 to 112 of 112.
[106] A majority of imported power falls into an interruptible category. This is due to the presence of capacity constraints on the New Brunswick tie which puts limits on the utilization of firm contracts.

The proposed changes have been modeled in case sensitivity AN.[107] No class experienced a higher cost increase than 0.1 percent.

Stakeholders' Positions

In general, stakeholders have indicated agreement with NS Power's approach to continue to treat purchased power in the same fashion as its own like generation.[108] However, there are some differences regarding technicalities of the implementation.

The CA's consultant agrees only with the proposed treatment of imports. He considers the proposed treatment of non-wind purchases flawed because NS Power treated these costs entirely as fixed and ignores the fuel cost component which, according to the CA's consultant, should have been classified to energy.[109] Further, the proposed SLF approach is considered by the CA's consultant to be inadequate as average load factor of these purchases is, in his view, much higher than the system load factor; therefore, NS Power does not classify enough costs to energy. With respect to wind purchases, the CA's consultant is critical of NS Power's reliance on a wind generation capacity factor in the classification breakdown between energy and demand.[110] Further, he believes that demand-related costs, determined in such a manner, are overestimated because wind generation costs are not a true measure of capacity costs and that an Equivalent Peaker approach should be used instead.

The Industrial Group and the SBA's consultant appear to support NS Power's proposal in most respects. The SBA's consultant would like to see more discussion on determination of wind capacity costs. The Industrial Group indicated a need for further clarification regarding regular purchased power and capacity constraints on the New Brunswick tie.[111]

[107] Sensitivity analysis can be found on NS Power's FTP site (see Appendix T).
[108] Appendix K page 34 of 39 (Multeese), page 7 of 39 (CA), page 22 of 39 (Industrial), page 39 of 39 (SBA), Appendix I page 18 of 31 (MEUNSC).
[109] Appendix K pages 7 to 8 of 39.
[110] Appendix K page 8 of 39.
[111] Appendix K page 22 of 39.

Board Counsel's consultant supports NS Power proposal, while the MEUNSC's consultant did not provide comments on this issue.[112]

NS Power's Position

Regarding the CA's consultant's comments, NS Power believes that its proposed treatment of local non-wind power as a strictly fixed cost is appropriate.

Non-wind power purchases come from dispatchable renewable generation,[113] which includes a variety of generation types such as landfill gas, small scale hydro and wood waste. The IPPs sell power to NS Power based on long-term contracts. They are must-run units whose output does not vary with demand on NS Power's system. In that sense, costs of these purchases are fixed to NS Power. NS Power's planning process recognizes the contribution of this generation to the system's capacity at 100 percent of its operating capacity. These purchases are concerned with acquisition of energy and are typified by a high load factor.

NS Power proposes that these costs be treated in the same manner as NS Power's own fixed baseload generation costs, which are classified between energy- and demand-related components based on the System Load Factor. The energy-related costs are proposed to be allocated on annual energy requirements, and the demand-related ones based on 3CP.

Regarding classification of purchased wind power, NS Power proposes continued application of assumed wind generation capacity factor for planning purposes. Our reasoning regarding this matter was provided in response to Avon DR-14.[114]

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[112] Appendix K page 34 of 39.
[113] The generation is dispatchable only from the IPP's perspective. From NS Power's perspective, this is must-run generation.
[114] Avon DR-14, page 2, lines 8 to 12 (Appendix A page 25 of 147).

In view of limited opposition to NS Power's proposal, where only one stakeholder, the CA's consultant, takes a clearly opposing view on 2 of 3 aspects of this matter,[115] and other stakeholders either support it or do not provide comments, NS Power maintains its proposed approach.

6.2.5 Revenue to Cost Ratio Considerations (No 39)

CAEC recommended that NS Power consider applying to the UARB to relax the requirement of close adherence to the 95/105 ratio for a limited time, or for certain classes of customers, to enhance its pricing flexibility. NS Power disagrees with this recommendation on the following grounds:

1. Stakeholders were not concerned with the band being too narrow but rather too broad;

2. NS Power's surveys suggested that the 95/105 band is commonly used in Canada;

3. NS Power, in review of the R/C ratio determination mechanism, was concerned with finding a way that would set class revenues closer to unity rather than allow further departures.

Participating parties,[116] except for the CA's consultant,[117] agree with NS Power's recommendation to maintain the existing R/C ratio.

Stakeholders' Positions

The CA's consultant is of the view that "the 95% - 105% bandwidth is unlikely to cover the full range of uncertainty in the R/C ratios that results from such elements as the

[115] Appendix K page 8 of 39.
[116] Appendix I page 20 of 31 (Multeese), Appendix K page 23 of 39 (Industrial), Appendix K page 38 of 39 (SBA), Appendix I page 18 of 31 (MEUNSC).
[117] Appendix K page 16 of 39.

necessary reliance on judgment, the use of simplified methods, and load and forecasting error."[118] In response to Strawman Version 1, the CA's consultant requested that NS Power provide analysis of the effect on R/C ratio of changes in class CPs and NCPs from the low to high end of the range of uncertainty.[119]

NS Power's Position

NS Power performed the requested analysis and found that changes in load shape statistics within the designed tolerance band of 90/100 have cost redistribution effects falling within the 95/105 R/C band for most classes. This analysis can be found in COSS sensitivity models AP + 10 and AP – 10.[120]

NS Power submits that the 95/105 R/C band is appropriate and recommends it be maintained.

6.2.6 Functionalization and Classification of Poles and Wires (No 21)

In keeping with the principle of voltage-based service differentiation in allocation of costs, as discussed in section 6.2.3 above, the COS model provides a breakdown of primary and secondary distribution poles and wires before they are classified between demand- and customer-related costs. These costs are then allocated to rate classes based on their utilization of these assets as measured through levelized class non-coincident demands. The breakdown of poles and wires between secondary and primary voltage components, or sub-functionalization, has not been revised since it was originally established with professional judgment in 1977. It splits the value of these assets 65 percent to primary and 35 percent to secondary. The first 30 percent of these assets, functionalized as primary, is classified to demand, while the remaining portion of primary and entire secondary are classified evenly between demand and customer using a 50/50

[118] Appendix K page 16 of 39.
[119] Appendix I page 10 of 31.
[120] Sensitivity analysis can be found on NS Power's FTP site (See Appendix T).

split. The end result is that 65 percent of these assets are classified to demand and 35 percent to customer-related category.

CAEC in its evaluation of this practice concluded that "the Company's methodology results in ratios and relationships that fall within industry norms."[121] NS Power has also found that these results fall within the range of outcomes reported in the Elenchus Survey.[122] CAEC recommended that NS Power update sub-functionalization of these assets via detailed analysis into accounting data or even a sampling of circuits. Also, CAEC recommended that NS Power review their classification giving consideration to empirical approaches such as the minimum size or zero intercept methods.[123]

NS Power does not maintain the net book value of these assets by primary and secondary voltage levels. It has been determined that the Company knows the number of its primary poles and length of its primary conductor. However, this information is not available for secondary voltage poles and wires. This precludes a precise determination of the rate base breakdown by primary and secondary components.

In view of these data constraints, NS Power proposed for stakeholders' consideration a second best, marginal cost-based approach to sub-functionalization of poles. The approach produced a change in the overall sub-functionalization between primary and secondary components from a 65/35 split to a 70/30 split.[124] Due to higher granularity of primary voltage conductor data, NS Power did not attempt similar analysis of conductors. Rather, NS Power applied splits from pole analysis to conductors to keep them the same, as is the case with the current model.

NS Power also proposed that the approach to classification remain as is, given the questionable reputation of the zero intercept and minimum size methods.[125]

[121] Appendix H page 80 of 261, item R4.3-2.
[122] Appendix H page 14 of 261, lines 15 to 22.
[123] Appendix H page 80 of 261, item R4.3-2.
[124] Sensitivity analysis case on NS Power's FTP site labeled AG (See Appendix T).
[125] Please see Appendix 6 to Strawman Version 2 (Appendix J pages 103 to 108 of 112).

The proposed approach resulted in a minor cost redistribution effect with only two classes showing increases, rounded to one tenth of a percent, at 0.2 and 0.3 percent.

Stakeholders' Positions

The CA's consultant does not believe the results of a 70/30 split between primary and secondary assets are plausible based on examination by the consultant of photographs of rural and urban streets of Nova Scotia available on the internet-based Google Maps.[126] The consultant formed an opinion that in populated rural areas, secondary poles comprise 20 percent of poles, while in urban areas and in between settlements there would not be secondary poles. In view of the assumption that costs of secondary poles are lower than the cost of primary poles, the consultant asserts that overall the percentage of poles to be functionalized to secondary should not exceed 10 percent.

The consultant also provided feedback regarding NS Power's proposed approach, which found NS Power's analysis to be interesting; however, flawed regarding several assumptions.[127]

The CA's consultant believes that secondary poles do not add costs to the system. Rather, their installation results in lower costs because they help reduce the number of installed primary poles. In view of the above, the deficiency of available data and the inconsistencies in NS Power's analysis, the consultant supports allocation of all distribution poles on demand. In general, the consultant does "not believe that that customer number has much effect on [costs of] lines and poles and will push for a smaller customer-related portion."[128]

[126] Appendix I page 4 of 31.
[127] Appendix K pages 4 to 7 of 39.
[128] Appendix I page 9 of 31.

Regarding the proposed approach to the treatment of conductors, the CA's consultant does not believe that it is appropriate to apply the results from the pole analysis to wires. The consultant recommends a separate analysis that should also distinguish between overhead and underground conductors.[129]

The SBA's consultant supports an update of sub-functionalization of poles and wires based on up-to-date information on the design of the actual distribution system. The consultant concludes that NS Power did not provide "strong justification" for not reconsidering updating its classification.[130]

The Industrial Group and the MEUNSC's consultant did not comment on this issue, while Board Counsel's consultant reserved judgment until further evidence is brought forward by the CA's consultant.[131]

NS Power's Position

<u>Sub-functionalization of Distribution Poles and Wires</u>

As indicated earlier in this submission, NS Power considers alignment of cost treatment with service differentiation by voltage levels an important principle of COS. The implementation of this concept was intended by the design of the current COS. CAEC found NS Power's voltage definitions for levels of service appropriate and consistent with industry practice.[132] CAEC considers its implementation to be an issue "of cost causation and fairness".[133] The determination of sub-functionalization of these costs warrants serious consideration and analysis.

[129] Appendix K page 7 of 39.
[130] Appendix I pages 29 to 30 of 31.
[131] Appendix K page 34 of 39.
[132] In addition, Elenchus survey results reported on page 64 (Appendix H page 164 of 261) indicate distinction in treatment of costs by primary and secondary voltage levels in cost of service studies of utilities participating in the survey.
[133] Appendix H page 61 of 261.

NS Power appreciates the efforts of the CA's consultant in examining NS Power's distribution network via Google maps. However, NS Power does not agree that this examination represents conclusive evidence in this matter. The approach provides a limited number of locations or streets out of many thousands of sites available on the website. As well, the computer screen does not provide insight into interior sections of served premises to count the number of secondary poles located out of street sight.

The CA's consultant's claim that 90 percent of the cost of poles in Nova Scotia should be functionalized to primary should not be accepted until this can be tested through the results of a proper inventory count of secondary poles.

NS Power agrees with the CA's consultant that the proposed marginal cost-based methodology may not be robust and appreciates the comments regarding the Company's assumptions. The Company has taken this feedback into consideration and has made some adjustments. For the discussion of these technical matters please refer to Appendix R.

The updated pole analysis produced a shift in sub-functionalization between primary and secondary components from 70/30 to 90.64/9.36. The CA's consultant raised several issues with NS Power's proposed approach, many of which NS Power declined to accept on the grounds of insufficient data inputs. If the proposed changes were incorporated into the analysis it would produce untenable results, with the primary service share exceeding 100 percent.

NS Power views these findings as significant and agrees with the CA's consultant that the proposed approach and its applicability to the COS is questionable. In view of this outcome, NS Power does not believe that the proposed empirical approach, constrained by lacking secondary pole count data, can produce superior results to the current approach based on professional judgment.

In our view, efforts to find a better solution, grounded in empirical data, should continue. The Company's recommended course of action is to retain the current approach until secondary pole inventory count results are available, at which point a more robust market replacement approach should be considered for both pole and wire cost determination.

Classification of Distribution Poles and Wires

Regarding classification of these costs, NS Power proposes that the current approach, based on professional judgment, be retained. The consultants for the CA and SBA have opposing views on this matter. The CA's consultant favours classification of poles entirely to demand.[134] It is not clear whether the intent is to treat conductors in the same fashion. This approach to classification combined with sub-functionalization of all poles and wires entirely to the primary category, based on the consultant's judgment, would result in a transfer of about $14 million of these costs to other rate classes.[135]

In NS Power's view, the suggested approach is unorthodox and does not align with industry practice.[136] The customer-related cost causation has been long recognized by such agencies as NARUC[137] and APPA.[138] NS Power does not believe that there is no customer causation in pole and wire costs, and therefore classification between demand and customer should be maintained.

The SBA's consultant supports re-examination of this matter using a conventional approach of a minimum size method.[139] As indicated in Strawman Version 1, NS Power does not favour these techniques, as they are labour intensive and are deemed to be inaccurate. The minimum size (MS) method was in effect at NS Power until 1982 when a decision was made to replace it with professional judgment. The MS method classified

[134] Appendix K page 7 of 39.
[135] Please refer to Sensitivity Analysis AT (Appendix T).
[136] Elenchus Survey, reports on page 64 that 9 out of 11 surveyed utilities recognize presence of customer cost causation behind their distribution pole and wires in their COS methodologies (Appendix H page 164 of 261).
[137] NARUC Manual, January 1992, page 87, TABLE 6-1, Classification of Distribution Plant.
[138] American Public Power Association, Chapter IX, Functionalization and Classification of Costs of Service, page IX-9.
[139] Appendix K pages 38 to 39 of 39.

63 percent of joint pole investment and 59 percent of joint wires to the customer-related category. These results do not align with those reported in the Elenchus survey where on average a smaller portion of these costs is classified as customer-related. A decision to switch to judgmental approach was motivated by the superiority of the judgmental alternative. As reported in Strawman Version 1 on page 14,[140] NS Power's demand-related distribution costs, currently representing about two thirds of the total, fall well within the range reported in the Elenchus survey.

The empirical results of such a method, to be credible, should fall within ranges reported in utility surveys. Such results, though, would not produce significant departures from the current results.[141] Yet the amount of data entering the COSS would increase considerably, complicating ratemaking oversight. Given the poor reputation of these methods for accuracy and stability of results, NS Power advises against taking this route.

6.2.7 Review weights in customer allocators (No 26)

Customer weighting factors are used in allocation of customer-related or customer care expenses, which primarily vary with the number of customers served.[142] They include such items as billing, meter readings, customer accounting, collection costs, customer field expenses, and responding to customer inquiries. These services are labour intensive and the costs associated with their delivery can vary with factors other than customer counts, such as customer type, size and complexity of the rates under which these customers are billed. In order to reflect more accurately the cost causation behind these services, there is a need to weigh customer counts by these other cost factors. Although it

[140] Appendix H page 14 of 261.

[141] As evidenced in case sensitivity AS (provided on NS Power's FTP site (see Appendix T)), a return to a classification from 1978, which utilized results of a minimum size method classifying all poles to demand and customer at a ratio of 37/63 and all wires at a ratio of 41/59 would cause a cost redistribution effect among rate classes falling in a range of -2.4% to 1.4%. This would result in the cost transfer of over $10 million from the General, Large General, Small Industrial, and Medium Industrial classes to residential and Small General classes. NS Power finds these customer weights high in consideration of results reported in the Elenchus Survey (Appendix H page 154 of 261).

[142] There are also customer-related expenses which do not necessarily vary with number of customers. These include costs of exhibitions, displays or advertising designed to promote utility services, or regulatory costs such as customer advocate costs. Such costs should be directly assigned to each customer class when data is available.

is desirable to base customer weighting factors on empirical cost data, in practicality this is difficult to accomplish, as there is often no readily available accounting data to support such an approach. Thus in the costing world of a utility, compromises have to be made between a mixture of judgmental and empirical inputs.

The current approach to weighting customer costs, with the exception of the Unmetered Class, is based entirely on professional judgment. No empirical evidence was used in the weight development. The approach has not been reviewed since 1977.[143]

In an effort to improve this process and in response to CAEC's recommendation, NS Power proposed an approach for stakeholders' consideration in Appendix G to Strawman Version 1.[144] The approach is based on two accounting data inputs: number of bills sent to each class, with assigned weight of 90 percent, and class revenues with assigned weight of 10 percent. The approach attempts to incorporate empirical evidence as well as Canadian electric industry experience. The approach resulted in increases in total costs of Unmetered (1.8 percent) and Small General (1.1 percent) classes, and a decrease of 1.5 percent to the Small Industrial Class.

Stakeholders' Positions

The CA's consultant considers the NS Power proposed approach to be judgmental. If the approach were to be accepted, then he would like to see higher than 10 percent allocation on revenues. Otherwise, he indicates the matter should continue to be explored with examination of cost causation factors and available empirical data.[145]

The MEUNSC's consultant considers the 90 percent weighting assigned to the number of bills too heavy and would like the Company to give consideration to other class specific cost causation factors such as regulatory costs of the CA and SBA, some unmetered

[143] Please refer to CA DR-56 for more information (Appendix B page 308 of 791).
[144] Appendix H pages 258 to 260 of 261.
[145] Appendix I page 6 of 31.

costs, and other general costs such as credit collection activity, and any other non-billing and /or revenue related cost centres. "Some judgmental criteria may still be appropriate for this issue given the impacts and overall level of customer costs."[146] The consultant believes a review of the classification criteria from other jurisdictions may be appropriate.

The Board's consultant agrees with the proposed approach,[147] while the SBA's consultant and the Industrial Group provided no comments.

NS Power's Position

NS Power believes that the proposed determination of customer weighting factors is based on a reasonable mixture of empirical (billing and revenue data) and judgmental factors (90 percent and 10 percent splits). As provided in Appendix G to Strawman Version 1,[148] the attempt to recreate a more data intensive solution, proposed by NS Power in 2006 – incorporating billing, call centre, head office and field service expenses – was found to be questionable due to difficulties in getting reliable data inputs. Regarding the MEUNSC's consultant's comments on the treatment of regulatory expenses associated with the CA and SBA's services, these are currently included in Operating, Maintenance and General expenses allocated to classes based on their utilization of rate base, and not customer counts. As indicated above, a more appropriate way to modify class specific expenses, such as these, if stakeholders so desired, would be to assign them directly to rate classes.

Regarding the treatment of the Unmetered class, and in keeping with NS Power's intent to simplify the approach, NS Power does not recommend retaining the 2006 negotiated solution for this class.

[146] Appendix I, page 17 of 31.
[147] Appendix I page 20 of 31.
[148] Appendix H pages 258 to 260 of 261.

The path of data intensive analysis is not the one that NS Power recommends for this matter. The Company believes that the regulatory ratemaking would be better served if the approach were based on a mixture of judgmental and empirical inputs as proposed.[149]

6.2.8 Align COS treatment of transmission substations with Open Access Transmission Tariff (OATT) (No 35)

As indicated in response to Avon DR-17,[150] NS Power considers the matter of aligning COS treatment of transmission substations with the Open Access Transmission Tariff (OATT) to be of a housekeeping nature. Currently, under the COS, a small portion of the transmission substation rate base is re-functionalized to distribution using a dated proration approach. The approach dates back to the mid-1990s.

The COS adjustment of transmission rate base to distribution rate base runs counter to the ratemaking principle of functionalizing assets and costs in the COS directly from the FERC-mandated Uniform System of Accounts[151] maintained by the utility. It is also inconsistent with the transmission cost treatment under the OATT, which aligns with the financial records of the Company.

The approach is supported by CAEC consultants who consider the current approach to be no longer an aid or improvement to the COS.

[149] Appendix H pages 258 to 260 of 261.
[150] Appendix A page 135 of 147.
[151] National Association of Regulatory Utility Commissioners, Electric Utility Cost Allocation Manual, page 87.

Stakeholders' Positions

Participating parties are in agreement with the proposed approach except for the MEUNSC's consultant, who reserved judgment on this matter subject to clarification of the accounting treatment of customer capital contributions.[152]

NS Power's Position

NS Power's view is that the re-functionalization of transmission substations in the COS is an unnecessary step and should be discontinued. The proposed change results in a class cost redistribution effect not exceeding 0.5 percent.

6.2.9 Distribution depreciation cost disaggregation (No 36)

Depreciation costs of all distribution assets, except for the streetlight fixtures,[153] are currently being classified to demand and customer-related categories[154] based on the weighted average classification of the entire distribution net plant. This is a broad-brush approach, which yields less accurate results than a more detailed treatment by member asset subgroups would produce.

The inaccuracy is due to the fact that depreciation costs are a function of the assets' gross plant value, as opposed to the net plant value on the basis of which they are classified. The underlying member asset subgroups can vary in the extent to which they have been depreciated and in the way they are classified between demand and customer categories. Some are classified only as demand-related, some only as customer-related, and yet others are classified to both demand and customer categories.

[152] Appendix I page 17 of 31 (MEUNSC), Appendix I page 20 of 31 (Multeese), Appendix I page 7 of 31 (CA), Appendix K page 23 of 39 (Industrial), no comment from SBA.
[153] As requested by NS Power in its 2012 GRA submission and approved by the UARB in its GRA Decision depreciation costs of streetlight fixtures are currently being allocated directly from the Company's financial information systems.
[154] This is done in line 8 of page 3 of Exhibit 5 in COSS.

For some time, the distribution-related depreciation expenses have been available from NS Power's financial system by individual rate base categories, as reported in schedule 2 of the COSS, in lines 10 through 20.

NS Power conducted sensitivity analysis (case U),[155] testing the cost redistribution effect of such a change and found that even though the overall rate effects on individual classes are a fraction of 1 percent of each of the class' costs, the cost redistribution can be as high as $1 million in some cases. In NS Power's view, the current approach is no longer appropriate and should be replaced with a disaggregated classification of distribution depreciation expenses.

CAEC supports this initiative as it will improve the accuracy of cost allocation and this is commonly done throughout the industry.

Stakeholders' Positions

All stakeholders support this recommendation except for the CA's consultant who stated that "this change sounds reasonable" however reserved his judgment until NS Power provides more information.[156]

NS Power's Position

The current approach is no longer appropriate and should be replaced with a disaggregated classification of distribution depreciation expenses.

[155] The sensitivity analysis is available on the NS Power FTP site (please see Appendix T).
[156] Appendix K page 10 of 39.

7.0 RECOMMENDATIONS

Appendix S presents the cost redistribution effect of NS Power's current positions. NS Power recommends participants in the Cost of Service proceeding continue to work together collaboratively to develop a consensus proposal for the Board's consideration.

The Company notes that the parties who have been actively participating in the engagement process to date are in agreement on the following issues:

No	Recommendation	Subject
3	R3.1-3	Adjust Transmission losses to reflect HV and EHV functions
6	R3.2-1	Eliminate dedicated substations
7	R3.3-1	Undertake a comprehensive loss analysis. This should enable more accurate line loss determination by class and provide for a consistent treatment of line losses among Coincident Peaks, Non-Coincident Peaks and energy requirements.
8	R3.3-2	Develop class profiles by service levels to determine losses. Currently, there is one class load shape used for all CP and NCP voltage levels. Each voltage level should be permitted separate load shape within a class.
9	R3.3-3	Review loss factors associated with generation energy allocator.
10	R3.3-4	Review transformer loss adjustments in allocator development. The 1.75% line loss adjustment factor may indeed still be the right value but it should be re-examined since it's dated.
11	R3.4-1	Maintain current approach with respect to ancillary services
20	R4.3-1	Retain current classification of distribution substations
22	R4.3-3	Review Line Transformer classification
23	R4.3-4	Retain current allocators for distribution demand costs
24	R4.3-5	Recognize different voltages in the calculation of class NCP
25	R4.3-6	No need to classify any distribution costs as energy
27	R4.3-8	Update data supporting meter cost allocators
28	R4.3-9	Defer review of Unmetered until LED conversion is complete
29	R4.4-1	No change to O&M classifications and allocations
30	R4.4-2	No change required re treatment of Miscellaneous revenues
31	R4.4-3	No change required re allocation of earnings
32	R4.4-4	No change required re allocation of taxes and DSM
33	R4.4-5	Modify allocation of interruptible credit
34	R4.4-6	Consider effectiveness of designating substations by service level/rate class

No	Recommendation	Subject
37	R4.4-9 (updated)	A new sample should be drawn to return the LR sample quality to its originally intended level
38	R4.4-10	Institute plan for periodic Load Research sample updates
40	R5.0-2	Exclude Fuel costs from R/C ratio calculations

For the issues noted below, it appears consensus has not been reached. The Company's position is stated for each.

No	Recommendation	Subject	NS Power Position
1	R3.1-1	Service Definitions as it relates to voltage levels appropriate	Agree
2	R3.1-2	Consider individual customer circumstances, such as accident of geography versus intended customer's choice, in developing Service Levels	Disagree
4	R3.1-4	Levelize customers at actual voltage service levels	Agree; however NS Power will exempt 5 distribution customers and treat them as HV transmission level for COS purposes.
5	R3.1-5	Maintain HV and EHV transmission categories	Agree
12	R4.1-1	Review alternate approaches for generation classification	Agree - propose to retain current SLF method.
13	R4.1-2	Consider Equivalent Peaker method for generation classification with consideration to breakeven hours as well as fuel cost allocation	Agree - propose to retain current SLF method.
14	R4.1-3	Hold current method of generation classification unless superior approach identified	Agree
15	R4.1-4	Adjust classification of Regular Purchased Power	Agree as per modified CAEC recommendation in Appendix 7 to Strawman Version 2.
16	R4.1-5	Classify wind purchases based on role in system planning	Agree

No	Recommendation	Subject	NS Power Position
17	R4.1-6	Classification of non-wind purchases	Agree as per modified in CAEC recommendation in Appendix7 to Strawman Version 2.
18	R4.2-1	Classify Transmission 100% Demand	Agree
19	R4.2-2	If Transmission not 100% Demand, classify using other than SLF	Agree
21	R4.3-2	Update functionalization and classification of poles and wires	Agree with updating functionalization but not classification .
26	R4.3-7	Review weights in customer allocators	Agree
35	R4.4-7	Align COS treatment of transmission substations with OATT	Agree
36	R4.4-8	Disaggregate distribution depreciation expense	Agree
39	R5.0-1	Relax R/C ratios	Disagree
41	CA	Port Hawkesbury Biomass classification	Disagree
42	The Industrial Group	Muskrat Falls effect and treatment of Lingan 1 and 2	Disagree

In this filing NS Power has attempted to fairly represent the views of other contributing parties received to date. If the Company has erred in undertaking this, it trusts the parties will correct this in subsequent submissions.

The views of the parties in contributing positively to this proceeding to date are respected and appreciated. The Company looks forward to further discussion toward development of an effective and efficient Cost of Service framework that is supported by all stakeholders.

8.0 RELIEF SOUGHT

NS Power respectfully requests the Board:

1. Approve changes to the current Cost of Service Study as follows:

   (a) Elimination of dedicated substations in Exhibit (Exh) 3b in the current Cost of Service Study.

   (b) Update customer weighting factors (Exh 8a of the current Cost of Service Study) to calculate these weighting factors at the time of each General Rate Application (GRA) using the approach NS Power proposed in section 6.2.7 of this Evidence.

   (c) Update of meter costs (Exh 3g of the current Cost of Service Study). The unit meter costs allocate meter investment to rate classes by number of customers and unit meter costs.

   (d) Correctly allocate the interruptible supply credit among rate classes (Exh 6).

   (e) Align the Transmission and Distribution rate base with financial records (Exh 2 of the current Cost of Service Study).

   (f) Disaggregate the distribution depreciation expenses (Exh 4, Exh 4 Detail A, Exh 4 Detail B and Exh 5 of the current Cost of Service Study). Provide a greater level of detail respecting depreciation expenses to allow a more accurate classification of these costs and therefore a more appropriate allocation among rate classes.

(g) Change the COS treatment of NS Power-owned wind (Exh 2a and Exh 2b of the current Cost of Service Study) to align the COS treatment of wind generation with system capacity planning, and eliminate the distinction between Renewable Electricity Standard (RES) and non-RES investments.

(h) Change the treatment of purchased power (Exh 6 of the current Cost of Service Study) to align treatment of purchased power costs with treatment of NS Power's own generation and evaluate this based on the underlying types of generation and their designation as firm or variable contracts.

(i) Update the cost levelization by voltage level (Exh 9b of the current Cost of Service Study) to levelize customers at actual voltage service levels, and direct NS Power to:

(i) Undertake a comprehensive line loss analysis by rate class as proposed by NS Power in section 6.1.1.1 of this Evidence;

(ii) Develop class profiles by voltage-based service levels to determine losses as proposed in section 6.1.1.1;

(iii) Review loss factors associated with the generation energy allocator as proposed in section 6.1.1.1;

(iv) Review the 1.75% transformer loss adjustment factor, as proposed in section 6.1.1.2;

(v) Update the Load Research sample as discussed in section 6.1.1.1;

(vi) Institute a plan for periodic Load Research sample updates as discussed in section 6.1.1.1.

(j) With respect to classification and allocation of transmission (Exh 2a, Exh 2b, Exh 3 and Exh 5 of the current Cost of Service Study), that transmission investment be classified as 100 percent demand and allocated among rate classes on a 12 CP (Coincident-Peak) basis.

(k) Approve retention of the current approach of the functionalization and classification of distribution poles and wires until secondary pole inventory count results are available, at which point a more robust market replacement approach should be considered. Regarding classification of these costs, approve that the current approach, based on professional judgment, be retained. The cost redistribution effect of this change cannot be known with precision in advance of finding an appropriate solution; however, NS Power expects the effect be contained within a 1 percent change in costs for most classes.

2. With respect to all other aspects of current the Cost of Service Study, confirm that the existing methodology employed is appropriate and should be maintained.

NS Power intends to continue working with stakeholders in the months leading to the October hearing, with the objective of resolving those Cost of Service issues that remain contentious. This filing seeks to give the Board and interested parties a complete record of activity over the past year. We look forward to the continued constructive engagement of all intervenors.