GCH Barristers & Solicitors
GANGE COLLINS HOLLOWAY

William S. Gange	Writer's Name:	William S. Gange
Jacqueline G. Collins	Writer's Direct:	204-953-5401
R. Ivan Holloway*	Writer's Email:	wsg@gchlaw.ca
David M. Cordingley		
Kalyn B. Bomback	Assistant's Name:	Lynne Cooke
	Assistant's Direct:	204-953-5413
	Assistant's Email:	lec@gclaw.ca

*Services through R.I. Holloway Law Corporation
*Also of the Alberta Bar

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Delivered by Email: Kurt.Simonsen@gov.mb.ca

Manitoba Public Utilities Board
400 – 330 Portage Avenue
Winnipeg, MB R3C 0C4

Attention: Kurt Simonsen, Associate Secretary

Dear Mr. Simonsen:

Re: Green Action Centre Written Submission on Issues Not Subject to Oral Hearing. Our File No. 16874 WSG

Setting the Context for COSS

The interest of Green Action Centre (GAC) in these and other proceedings is to ensure that the contributions of Manitoba Hydro to a prosperous, sustainable and just Manitoba are optimized. We bring these considerations to bear in the setting of just and reasonable rates.

We also defend a robust conception of justice that combines the fair allocation of costs between classes, intergenerational equity, and social justice that includes meeting basic needs (as well as opportunity and respect) for Manitobans.

The present exercise, reviewing Manitoba Hydro's COSS, is focused primarily on the first of these, the fair allocation of short-term embedded costs to customer classes through the application of notions of "cost causation" or "cost responsibility" for those costs.

We further note that there are many other costs than those that appear on the books of Manitoba Hydro, as the following excerpt from Manitoba Hydro's Rebuttal Evidence in the 2005/2006 COSS hearing demonstrate (3,4).

> **Concept of Cost for Rate Regulation**
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> **The witnesses for MIPUG state in their evidence that: "In Manitoba, under the current legislation, the system in place is regulated rate making based on cost – there is no provision for market pricing to domestic customers …" Do you agree with this statement?**
>
> Manitoba Hydro does not agree with the MIPUG witnesses that the utility and regulator are constrained from considering any concepts of cost other than embedded cost in determining just and reasonable rates and, further, Manitoba Hydro does not agree that there is no provision for market pricing to domestic customers.
>
> Market based pricing is already offered to Manitoba Hydro's domestic customers through the Surplus Energy Program (SEP), a rate offering approved by the PUB in Order No. 90/00. SEP and its predecessor surplus energy rate offerings, going back to the Interruptible Dual Fuel Rate established in 1990, were designed to provide a potentially lower cost option to customers prepared to accept less than firm service and upon terms comparable to the terms offered to the export market. A restricted definition of cost to that of embedded cost would not have allowed such rate offerings.
>
> The MIPUG witnesses have noted in their response to MH/MIPUG-3 that the SEP Program and its predecessors should be viewed as exceptions to the strict cost basis of rate design, apparently because "the customer elects to accept service that can be interrupted by the utility in accordance with market or other specified conditions." However, Manitoba Hydro is not aware of any legislation or regulatory directive that limits consideration of market pricing to offerings such as SEP.
>
> The assertion of the MIPUG witnesses also fails to recognize that there are multiple accepted interpretations of the term "cost", including historic cost, marginal cost, avoided cost and replacement cost. In *Principles of Public Utility Rates*, James Bonbright discusses the many conflicting interpretations and notes that "a cost-based standard is subject to many different interpretations and that the interpretation which would best comport with any single objective of ratemaking is almost sure to be ill-adapted to the attainment of the other objectives" (page 113). Manitoba's legislators appear to have recognized the need to continually balance various objectives and refrained from imposing a definition of cost, instead electing to create a system of ratemaking allowing for the consideration of not only costs but also other relevant policy considerations.

> Consequently, the PUB is empowered to look beyond strict historic cost considerations or past practices in determining fair and reasonable allocation of cost among customer classes or as a basis for just and reasonable rates. In particular, the PUB is empowered to consider such concepts as market based rates, or the treatment of export revenues inside or outside a cost of service study on bases other than those adopted to date.

Thus, it is important to keep in mind that the COSS is only one tool for rate-making, which seeks to depict as accurately as possible the cost responsibility of customer classes on the basis of embedded costs. It fails, however, to represent other kinds of costs that may also be relevant to resource planning and rate-making, such as the long-term marginal costs of load growth that requires the building of expensive new plant, the external costs of building a gas generation plant vs. a hydro dam, or external opportunity costs to displace fossil-fueled generation in other jurisdictions.

These considerations explain why it is important to heed the following principles of Mr. Chernick for employing the COSS (Ex. GAC-14, slide 3).

> **PCOSS informs, but does not drive, revenue allocation**
> **PCOSS does not drive rate design**

The considerations also led the PUB to include the following directive to MH in Order 117/06 (77).

> 2. Future Cost of Service filings should also include supplemental information by customer class, including approximate revenue to costs ratios, related to the inclusion of marginal cost information and the allocation of notional environmental emissions costs.

We urge the PUB to reiterate this directive for the next GRA.

GAC believes that causality and equity require eight changes to the methodology proposed by Manitoba Hydro in PCOSS14 Amended for issues not subject to the oral hearing:

1. Subtransmission is an integral part of the transmission system, reduces Manitoba Hydro costs, and should be functionalized, classified and allocated with all other load-related transmission.

2. If transmission at voltages below 100 kV is to be sub-functionalized as subtransmission separately from higher-voltage transmission, those costs should be allocated on load served through the subtransmission system. The load served through the subtransmission

system is 100% of GSL 30–100 kV, plus 65% of the load of distribution customers, since 35% of distribution load is served from the high-voltage transmission system without using subtransmission.

3. Each sub-transmission line serves a wide variety of classes. If subtransmission is functionalized separately from high-voltage transmission, it should be allocated on an estimate of class contribution to the peak loads on the subtransmission lines.

4. Distribution lines (poles, conductors, cable and conduit) are installed due to load, and should be classified entirely as demand-related.

5. The primary/secondary split of distribution lines should be reduced to reflect the fact that secondary service does not increase pole costs. Manitoba Hydro should gather data on the portion of conductors and conduit that operates at secondary voltage.

6. The demand allocator for distribution substations and primary feeders (poles, conductors, cable and conduit) should reflect an estimate of class contribution to the peak loads on those facilities.

The allocation of service drops should be corrected to reflect the number of customers in multi-family housing, served through shared service drops.

7. The weighting of the allocators that Manitoba Hydro classifies as "customer-related" are poorly documented and must be reviewed and corrected.

General Observations

All parties have agreed that causality should guide cost allocation, other than COW, whose witness testified that causality is "notional" and suggested that the Board should not pay much attention to cost causation (COW Ex 9, slide 4). Nonetheless, some parties have suggested that the Board look to other utilities' practice to determine which allocation approach to use for Manitoba Hydro, independent of any evidence that the other utilities' approaches reflected causality.[1] Mr. Harper warns that "the practice of other utilities should not be taken as determinative of what is appropriate for Manitoba Hydro" (Coalition Rebuttal at 3). But he

[1] Mr. Harper (Rebuttal at 2-3, 7, 8 and 10) relies on the same Leidos report (Coalition Rebuttal Exhibit A) cited by Manitoba Hydro (rebuttal at 20) and Mr. Bowman (evidence at 12, 23) for information about the allocation of hydroelectric generation, which is a hearing issue. The functionalization of DSM costs is also a hearing issue.

recommends that the Board rely on the policies of a small number of other utilities to guide its decisions on DSM (ibid), the allocation of substation costs (ibid at 8), the classification of distribution lines (ibid at 8–9) and the treatment of subtransmission (Direct at 74), rather than relying on cost causation.[2]

The Board may want to look to other utilities to confirm the computational feasibility of specific approaches to developing sub-functionalization, classification and allocation factors. But ratemaking is not a popularity contest.

If reliance on other utilities' existing approaches were taken to its logical conclusion, no utility would ever develop a new cost-of-service study factor approach, since there would be no precedent for the new approach. The Leidos report considers just nine utility/jurisdiction combinations, other than Manitoba Hydro, but there is even less real variety of utilities and jurisdictions in this sample:

- two of the observations are the same utility (Avista) in different states,
- three of them are in the same jurisdiction (Avista, Puget Sound, and Seattle are all in Washington State),
- two are in another jurisdiction (Avista and Idaho Power in Idaho),
- one (Bonneville Power) has no distribution costs and serves as a regional generation and transmission supplier to six of the other utilities (the Washington and Idaho utilities and Portland General), and
- most of the classification and allocation factors are unavailable for various utilities.

Hence, the sample is limited in number and variety.

In fact, there are utilities that allocate distribution substations on estimates of the coincident demand on the substations (including some in the Leidos sample, which Mr. Harper misconstrues on the Leidos summary table) and classify distribution lines as entirely demand-related.

[2] Mr. Harper's position regarding the classification of distribution lines is vague, but he may be suggesting that the retention of legacy approaches by other utilities places a burden on any party that wants to bring classification into line with reality.

Subtransmission Cost-Allocation Issues

Manitoba Hydro sub-functionalizes transmission below 100 kV as subtransmission and allocates the associated cost on the non-coincident peaks of the various classes.

Subtransmission should not be functionally separated from other transmission

Mr. Chernick explained that lower-voltage transmission (<100 kV) serves the same function as higher-voltage transmission (>100 kV), but at lower cost. (Chernick Direct at 38–41) Subtransmission complements transmission, and is not an additional cost. The lower-voltage lines serve customers and substations that could have been served at higher voltage, if there were some reason to do so.[3] Charging more per kW of load to customers using a lower-cost service is inequitable (ibid at 40, lines 1–4).

Mr. Chernick also explains that the differentiation of transmission by voltage makes no more sense in terms of causality than differentiating by type of supporting structure or between overhead and underground (Chernick Rebuttal at 23-24). Indeed, the Leidos sample of utilities (Coalition Rebuttal Attachment A, Table C-6) shows that Manitoba Hydro is the only utility that subfunctionalizes subtransmission.[4]

In its Rebuttal, Manitoba Hydro disputed Mr. Chernick's conclusions regarding subtransmission. Manitoba Hydro's arguments do not support its conclusions (Chernick Rebuttal at 21–22).

One of Manitoba Hydro assertions is that the combination of the <100 kV and >100 kV equipment does not constitute a unitary system, because they work together, with the high-voltage lines directly serving some areas and the lower-voltage transmission extending service from the high-voltage lines to other areas. (Manitoba Hydro Rebuttal at 28, lines 13–18) Yet working together to provide equivalent service to different locations is the very definition of a complementary function; the subtransmission does the same job as high-voltage transmission, where the high voltage is not needed for other reasons. Everything Manitoba Hydro says in this part of its rebuttal supports keeping subtransmission in the transmission function.

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[3] In contrast, distribution is a separate and additive function to transmission, since Manitoba Hydro must run distribution lines to serve customers located adjacent to transmission lines, who cannot take power directly from the higher voltages. Distribution lines do not usually avoid the need for transmission lines. Similarly, secondary distribution is additive to primary distribution, since secondary service adds costs of transmission (and often secondary lines running parallel to the primary lines).

[4] GAC does not wish to overstate the importance of the allocation decisions by other utilities, but various parties, especially the Coalition, have treated the Leidos sample as if it provided useful evidence of appropriate allocation approaches.

Manitoba Hydro also points out that there are “stations that convert subtransmission voltage…to distribution voltage levels” and that “where distribution customers are served from substations that convert direct from transmission voltage, Manitoba Hydro incurs costs for transmission voltage to distribution voltage reductions. On the other hand, customers who accept service at voltages > 100 kV bear the cost of transformation to their utilization voltage” (Rebuttal at 28, lines 23–30). Again, Manitoba Hydro is correct in its facts, but those facts do not support its position. Customers served at distribution voltages are and should be allocated the cost of distribution substations. This observation does not address whether subtransmission substitutes for high-voltage transmission.

Manitoba Hydro indicates (ibid at 29, lines 1–5) that the use of subtransmission to connect generation should be reflected by functionalizing that subtransmission as generation, which is consistent with GAC’s position, but is an issue for the hearing.

Finally, Manitoba Hydro agrees that the inclusion of radial transmission in the transmission function argues for the inclusion of subtransmission in transmission, but asserts that some unidentified costs should be subject to “appropriate direct assignment” (ibid at 29, lines 6–8).

Mr. Bowman endorses and relies on Manitoba Hydro’s muddled critique of Mr. Chernick’s eminently reasonable proposal to treat subtransmission as part of the transmission function (Bowman Rebuttal at 16–17). He restates Manitoba Hydro’s argument equating subtransmission lines with distribution substations, which all parties propose to allocate only to distribution load (ibid at 17).

If subtransmission is treated as a separate function, the allocation to distribution classes should reflect only a fraction of their load

Mr. Chernick shows that 35% of distribution load is supplied through substations served directly from high-voltage transmission, and thus do not use subtransmission any more than the GSL >100 kV class does. (Chernick Direct at 40) Hence, if subtransmission were to be treated as a function separate from transmission, the allocation to distribution classes should be reflect only the 65% of their load that uses subtransmission.

Manitoba Hydro notes that 35% of distribution load is supplied through substations served directly from high-voltage transmission “does not comprise the majority of all distribution customers. The reality is that a large percentage of distribution customers are served from portions of the distribution system that are supported by subtransmission lines and stations.” (Manitoba Hydro Rebuttal at 28, lines 20–26) GAC agrees with Manitoba Hydro that “a large percentage” of distribution load (65%) should be used in the allocation of subtransmission costs, if subtransmission is allocated separately from other transmission.

Mr. Bowman adds to Manitoba Hydro’s confused discussion of subtransmission by suggesting that Mr. Chernick’s alternative proposal (that distribution customers should be charged for subtransmission in proportion to the distribution load that uses subtransmission) would somehow require that Manitoba Hydro rates vary from substation to substation (Bowman rebuttal at 17). He claims that "An analogy might suggest that Vale in Thompson should not be allocated any costs of Bipoles I and II, being located in the north near the major generation" (ibid). GAC does not propose any geographic distinction in rates; indeed, GAC's preferred treatment of subtransmission would eliminate Manitoba Hydro's current geographical discrimination, which charges more to GSL customers who happen to be located in areas served by 33 kV and 66 kV transmission lines.

If subtransmission is allocated separately from other transmission, that allocator should use the class contributions to the peak loads on the facilities, rather than non-coincident peaks

Mr. Chernick discussed in great detail the reality that a typical subtransmission line serves a variety of classes (Chernick Direct at 41–43). Hence, the need for the line, the capacity of the line, and whether it needs to be upgraded to a higher voltage are all determined by the contribution of several classes to the peak load on the line. No party disputed this observation. The Leidos summary (Table C-6) shows all the utilities use various coincident peaks (12 CPs, weighted 12 CPs, high-load hours) for allocating demand-related transmission, other than Manitoba Hydro's subtransmission and Hydro Quebec's customer connections.

In the absence of data on the time of the peak loads on the subtransmission system, Mr. Chernick estimated class shares of subtransmission load based on the substation loads. (Chernick Rebuttal at 30)

Distribution Cost-Allocation Issues

Manitoba Hydro took three controversial positions regarding the allocation of distribution costs. Manitoba Hydro classifies 40% of distribution lines (poles, conductor, cable, and conduit) as being driven by customer number, and the remaining 60% as demand-related.

Manitoba Hydro proposes that all distribution plant (substations, lines, transformers) be allocated on class non-coincident peak.

In addition, Manitoba Hydro implicitly functionalizes 30% of distribution lines as secondary, by excusing the GSL <30 kV class from that portion of the distribution line costs.

Distribution lines should be classified as demand-related

Mr. Chernick explained why distribution lines should be classified as entirely demand-related. (Chernick Direct at 48–53) The reality is that lines are extended primarily for load and revenues, not simply to reach additional customers. Adding customers often requires no additional poles or primary facilities (ibid at 52), and the minimum-system approach often used to classify distribution lines is based on four erroneous assumptions:

- That area-spanning costs are driven by customer number rather than the load that justifies serving the area. (ibid at 48–49)
- That the number of units (feet of wire, number of poles and transformers) is driven by the number of customers, even though higher loads results in more of each of these components. (ibid at 49)
- That the type of equipment (e.g., overhead/underground, voltage) is determined by the number of customers, even though these design issues are often driven by load. (Chernick Direct at 49–50)
- That the smallest currently-installed equipment size (e.g., size of transformer, wire size) would be required for a system with very low loads. (ibid at 51)

The only witness to discuss this issue was Mr. Harper, whose rebuttal did not offer any evidence that the number of customers significantly affects the cost of the distribution system, but did indicate a preference for continuing to use Manitoba Hydro's assumption, although he concedes that "there continues to be merit in the PUB directing Manitoba Hydro to undertake a review as to the appropriate split for poles and wires (and also transformers) between demand and customer-related costs." (Harper Rebuttal at 9)

Mr. Harper offers only two arguments in support of his position. First, he notes that "there are utilities that do not classify distribution poles and wires as 100% demand-related" and that "the Leidos Study…indicates that ½ of the utilities surveyed classify a portion of fixed cost associated with Distribution Lines as customer-related" (Harper Rebuttal at 8–9). The observation that some jurisdiction or utility has retained a legacy cost allocation is hardly evidence that the legacy method is based on cost causation.

Furthermore, Mr. Harper's count of Leidos utilities is incorrect: five of the eight non-Manitoba entities in Leidos Table C-8 classify distribution lines entirely to demand, and only three include any customer component.[5] In addition to the Leidos utilities, Mr. Harper ignores eleven specific utilities that Mr. Chernick identified as classifying lines entirely to demand, and the

[5] Mr. Harper does not tell us how he got the 50% value, but he may have failed to note that Leidos includes all distribution line costs for Portland and Seattle (both of which use marginal costs in the cost-of-service study) in the O&M column.

entire state of Texas (which has at least ten investor-owned utilities—Oncor, AEP Texas North, AEP Texas Central, Texas-New Mexico Power, Centerpoint, Entergy Texas, El Paso Electric, Sharyland, Southwest Power and Southwest Public Service). Based on the utilities cited in this proceeding, the ratio of demand-only to demand-and-customer classifications is twenty-six to three.[6]

Second, Mr. Harper misstated Mr. Chernick's testimony on this issue, claiming that Mr. Chernick's "criticism of the Minimum-System Method…is largely based on the fact that the minimum system established through the analysis is capable of carrying some demand and therefore does not separate out what would be considered strictly customer-related costs" (Harper rebuttal at 9).[7] Mr. Chernick's evidence included an entire section on "Inherent Errors in Minimum-System Analyses," spanning pages 48–53 of his evidence. In over five pages of testimony on this topic, Mr. Chernick's reference to the load-carrying capacity of the so-called minimum system comprises only two lines: "The 'minimum system' would still meet a large portion of the average residential customer's demand requirements." (page 51, lines 12–13). GAC does not understand how Mr. Harper concluded that Mr. Chernick's analysis was based on this single sentence, representing less than 2% of the relevant section of Mr. Chernick's evidence.

Mr. Chernick made a strong factual case for concluding that there was no customer-related portion of distribution lines, based on the reality of Manitoba Hydro line-extension rules, which limit Manitoba Hydro's distribution investment to "three times forecast annual revenue" (Chernick Direct Evidence at 45, lines 17–23; MFR 18) In addition, Mr. Chernick listed four specific problems with the minimum-system method (Direct Evidence at 51–53) that Mr. Harper ignores: these are listed in the beginning of this section.

[6] Mr. Harper identifies FortisBC and the Ontario Energy Board as classifying some distribution costs as customer-related. (Harper Rebuttal at 9) GAC does not advocate that the Board rely on any survey of utility practice to determine its decisions on allocation. Clearly, there is no practical obstacle to classifying the costs of distribution lines entirely as demand-related.

[7] Mr. Harper says that "utilities and regulators have addressed this criticism by determining the peak load carrying capability of the minimum system and incorporating an adjustment into the allocation process" (Rebuttal at 9), and provides links to three documents he believes present "examples" of this process. The OEB document simply says that utilities can include that adjustment, without providing a method. The Fortis document (not at the page cited by Mr. Harper, but in Appendix B) says that the Fortis engineers estimated a credit of 1 kW per customer, which would represent about 30% of Manitoba Hydro's residential load (453,563 customers × 1 kW/customer = 453,563 kW, compared to residential loads of 800,000 to 1,700,000 kW, for various combinations of CP/NCP and season; data from "2012 Load Research at Generation Peak for PCOSS14").

GAC has provided the only substantive analysis of the appropriate classification of distribution lines. The Board should instruct Manitoba Hydro to classify distribution lines as 100% demand-related.

The primary/secondary split of distribution lines should be reduced

Manitoba Hydro assumed that 30% of distribution line costs (poles, conduit and wires) are due to the additional costs of delivering energy at secondary voltage, rather than primary, but provided no data or computations to support that estimate. Mr. Chernick explained why secondary service does not increase pole costs, and produced an alternative estimate that 20% of line costs are due to secondary (Chernick Direct at 60-66).

No other party commented on this issue, so GAC's position is unopposed.

Primary distribution costs should be allocated on class contribution to the peak loads on those facilities

Manitoba Hydro proposed to allocate the costs of demand-related primary distribution (substations and lines) and subtransmission in proportion to class NCP. Mr. Chernick explained that typical subtransmission lines, substations and feeders serve multiple classes, and that the sizing, design and number of these facilities are driven by the coincident load on line, substation or feeder, not the separate NCP loads of the various classes (Chernick Direct at 54–58). Mr. Chernick also pointed out that the substation peak loads are spread over many hours in many months (ibid), and suggested that "until better information is available about the mix of classes and the timing of distribution loads.…The best available measure of distribution loads in the short term may be the 2CP allocator used for transmission, with the summer weighted about 50%" (ibid at 58).

No party commented on the allocation of substations or subtransmission (if the Board decides to separate subtransmission from higher-voltage transmission).

The Coalition and Manitoba Hydro commented on the allocator for distribution lines. Mr. Harper expressed a strong desire to see "Manitoba Hydro reaffirming (through analysis of its load research data regarding customer class monthly load profiles) that 1 NCP continues to be the appropriate NCP allocation factor for the demand-related portion of Distribution Poles and Wires." (Harper Rebuttal at 10) His basis for this preference appears to be based on confusion regarding the meaning of various approaches to describing demands, and the popularity contest described by the NARUC Manual and the Leidos sample (which Mr. Harper describes as a "survey," despite its tiny sample size).

First, Mr. Harper says that “while Mr. Chernick’s rationale would suggest that NCP is not a perfect allocator for these costs it also suggests, since primary lines will peak at different times, that an allocation using a CP allocator would not be entirely appropriate either.” (ibid at 10) He may be thinking that Mr. Chernick was suggesting the use of one summer CP and one winter CP (with the latter weighted twice as much), when in fact Mr. Chernick was referring to the Manitoba Hydro allocators based on the top 50 winter hours and the top 50 summer hours, with the summer given half the weight of the winter. Mr. Chernick acknowledged that the use of the top 50 hours was useful as a temporary approximation of the pattern of the distribution peak loads (Direct at 58), and explained how Manitoba Hydro should improve on that estimate (ibid at 57, lines 6–11). Mr. Harper, by contrast, offers no suggestion for developing distribution allocators, other than hoping that Manitoba Hydro would reconfirm the meritless class NCP allocator.

Second, in rebuttal, Mr. Chernick actually developed allocators for substations (which he suggested also be used for feeders) and subtransmission, using all the data that Manitoba Hydro provided on the timing of substation peak loads and of the customer classes at the time of monthly peak. (Chernick Rebuttal at 27–30). Manitoba Hydro may be able to improve the analysis with additional substation and class load data before the PCOSS is considered in the hearings on the pending rate application.

Third, Mr. Harper says that “most utilities favour using NCP as the allocator, suggesting that Manitoba Hydro’s use of an NCP allocator is reasonable.” (Rebuttal at 10) Again we repeat that the Board should not treat selection of the cost-allocation method as a popularity contest.

In fact, the allocation of distribution costs on a single NCP is far from universal. Mr. Chernick noted that “Rocky Mountain Power in Utah allocates primary distribution on monthly coincident distribution peak, weighted by the percentage of substations peaking in each month” (Chernick Direct at 58), which is very similar to the method Mr. Chernick used to develop allocators for Manitoba Hydro subtransmission, substations, and feeders. The Leidos report shows that:

- Puget Sound Electric allocates the substation costs on class contribution to the monthly peaks of each substation (Table C-7) and the feeder costs on class contribution to the monthly peaks of each feeder (Table C-8).[8]
- Seattle City Light allocates substation and feeder costs on 48 high-load hours.
- Three utilities allocate distribution costs on 12 NCPs.[9]

[8] Mr. Harper may have been confused by the fact that Mr. Chernick described the peak load on the substation or line as the “coincident peak” on that equipment, while the Leidos report referred to the peak load on a piece of equipment as a “non-coincident peak,” meaning that the peak on the equipment was not necessarily coincident with the peak load at the system level. Some of the Leidos NCPs are coincident peaks on the substation or feeder.

- Only four utilities use a single NCP for each class.

Hence, even reviewing the methodology of the utilities in the record would indicate that Manitoba Hydro's single-NCP distribution allocator is not the favourite option, by four votes to six. The question is not whether there is a better allocator than the single NCP, but which of the computationally-feasible allocators best represents the loads driving distribution costs.

Manitoba Hydro acknowledges that its existing distribution allocators are conceptually incorrect (Manitoba Hydro Rebuttal at 30), and shows the effect on the RCC of using an ad hoc "75/25 Winter/Summer CP allocator" (ibid, Table 9).[10] While Manitoba Hydro says that "the 75/25 Winter/Summer CP allocator…would represent the most significant change in class RCCs that could be reasonably expected" (ibid), Mr. Chernick's detailed analysis of the monthly distribution of substation peaks would shift cost responsibility even further than Manitoba Hydro's ad hoc allocator (Chernick Rebuttal at 27–29). Even using only winter CPs (either Manitoba Hydro's 50 hours or the average of December–February monthly peaks) would shift the allocators almost as much as Manitoba Hydro's 75%/25% weighting (ibid, Table 1).

While Manitoba Hydro suggests that the 1.1% change in the residential RCC that it estimates for its ad hoc allocator for substations and part of distribution lines is not "substantially different than using NCP" (Manitoba Hydro Rebuttal at 30), that is a shift of over $6 million. The percentage shifts are even higher for other classes: 2.8% for Area & Roadway Lighting, 1.9% for GSM, and 1.3% for GSL <30 kV. The effects would be even larger once distribution lines are more appropriately classified as entirely demand-related and subtransmission is allocated on coincident peaks (either system peaks, if subtransmission is functionalized as transmission, or subtransmission line peaks, if subtransmission is treated as a separate function).

The Board should order Manitoba Hydro to adopt Mr. Chernick's distribution demand allocator for substations and feeders and his subtransmission demand allocator (if subtransmission is treated as a separate function), until it can develop better allocators, based on class contributions to the equipment peak loads.[11]

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[9] The approach recognizes the diversity in substation and feeder loads, if imperfectly.

[10] This may be a weighting of the 50-winter-CP and 50-summer-CP allocators that Manitoba Hydro uses for transmission, but could also be derived from a single summer hour and a single winter hour.

[11] Mr. Harper raised the question of how transformers and secondary conductors should be allocated (Harper Rebuttal at 9, fn 42). GAC suggests that these costs should be allocated on class NCP.

Customer-Classified Costs

Manitoba Hydro allocated a variety of customer-related costs in proportion to customer number, weighted by various factors. The PCOSS did not provide much information on the derivation of the customer weighting factors, and some of the important weighting factors do not appear to be based on actual cost data (Chernick Direct at 67). Mr. Bowman pointed out the inconsistency and lack of clarity in Manitoba Hydro's allocation of costs it includes in the category of "customer service" (Bowman Direct at 37–39, June Tr. at 99)

The Board should continue to encourage Manitoba Hydro to align these customer allocators with the cost drivers and review its progress toward developing data-supported weighting factors for the customer allocators.

In addition, Mr. Chernick (Direct at 67-68, Rebuttal at 32–33) and Mr. Harper (Direct at 79-80) both point out that Manitoba Hydro's allocation of service-drop costs ignores the sharing of service drops by customers in multi-family housing. Manitoba Hydro did not comment on this issue in rebuttal. The Board should require that Manitoba Hydro reflect the shared services in its next PCOSS filing.

GAC asks that the Board give consideration to the issues raised.

Yours truly,

GANGE COLLINS HOLLOWAY

Per:

WILLIAM S. GANGE
WSG/lec