PRE-FILED TESTIMONY OF
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IN REGARD TO CENTRA GAS
2019/20 NATURAL GAS RATE APPLICATION

Submitted to:

The Manitoba Public Utilities Board

on behalf of

Industrial Gas Users Group

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1.0 INTRODUCTION

This Pre-filed Testimony has been prepared for the Industrial Gas Users Group ("IGU") by InterGroup Consultants Ltd. ("InterGroup") under the direction of Mr. Andrew McLaren. Mr. McLaren's qualifications are provided in Attachment A.

For this Pre-Filed Testimony, InterGroup has been asked to identify and evaluate issues arising from Centra Gas's 2019/20 General Rate Application for 2019/20 ("GRA" or "Application") of interest to IGU members.

1.1 APPLICATION OVERVIEW

Centra's 2019/20 General Rate Application ("GRA" or "Application") requests approval from the Public Utilities Board ("PUB" or "Board") of changes to its Supplemental Gas, Transportation (to Centra) and Distribution (to Customers) rates to be effective August 1, 2019 as well as the disposition of balances in certain deferral accounts. Centra is also requesting approval to changes to its Terms & Conditions of Service and final approval of several interim orders.[1] Centra's previous GRA was for the 2013/14 test period.

While Centra is not proposing increases to its overall general (non-gas costs) revenue in this GRA, its rate proposals result in a wide rate of bill impacts for different types of customers. Bill impacts at base rates (i.e. excluding rate riders) in Centra's proposal range from decreases of up to 9%[2] to increases of up to 41%[3] Centra states that the bill impacts for Transportation Service customers is primarily the effect of reversing the bill decrease that these classes experienced as a result of Directive 5 of Order 108/15 that directed the non-gas components of rates revert back to levels approved in 2010 effective August 1, 2017. Centra states the bill impact to the Special Contract customer is the result of a significant increase in non-gas costs allocated to this class driven by large transmission related investments since the last GRA.[4]

1.2 IGU MEMBERS

IGU is an informal association of companies who are substantial users of natural gas in both Sales Service and T-Service. IGU members include:

- Gerdau Long Steel North America – Manitoba Mill;
- Koch Fertilizer Canada ULC;
- Maple Leaf Foods; and
- Simplot Canada (II) Limited (Simplot)

[1] Tab 2, page 7 line 31 through page 8 line 10 of the Application.
[2] For certain MLC sales service customers as shown at row 47 of Schedule 11.1.0.
[3] For certain MCL t-service customers as shown at row 54 of Schedule 11.1.0.
[4] Tab 2, page 9 line 25 through page 10 line 6.

The purpose of the Industrial Gas Users is to work together on issues of common concern related to natural gas rates in Manitoba. The association's key concerns related to natural gas are to ensure rates reflect the cost to provide service, are fair and reasonable, and stable and predictable.

1.3 SUMMARY OF RECOMMENDATIONS

Based on the analysis outlined in this report, we make the following recommendations:

- The Board should defer approving any rate adjustments based on the results of Centra's cost of service study until it has had the opportunity for a full review of Centra's cost of service methods. Such a review could be modelled after the review undertaken for Manitoba Hydro's cost of service study that resulted in the Board's Order 164/16. Key elements of such a review are detailed further in section 3 of this report.
- The Board should not approve Centra's proposed changes to its terms and conditions of service related to balancing fees as currently proposed. Options to modify and monitor the implementation of any proposed changes are further described in section 4.
- Centra's current approach to discharging the balances in the Heating Value Margin Deferral Account does not sufficiently recognize the differences in revenue risks for each customer class owing to the different rate structures and different volumetric or commodity charges in place. The Board should direct Centra to allocate the balances in the Heating Value Margin Deferral Account in the current application on the basis of total revenues from volumetric charges or a similar allocation metric that recognizes the different level of revenue risks because of different rate structures for each customer class.

2.0 SCOPE OF REVIEW

InterGroup was asked to review issues of particular concern to industrial customers related to cost allocation, rate design and terms and conditions of service, including Centra's proposed changes to balancing fee penalties. This report focuses on those issues where industrial customers have different concerns than other consumer groups, in particular:

- Cost of service and rate design issues
- Proposed changes to balancing fees
- Allocation of balances in the heating value deferral account

This helps to limit the number of topics IGU must address and prevents duplication of effort on topics where IGU's interests are broadly aligned with other customers.

In preparing this report, InterGroup has relied on the following sources of information:

1. Centra's General Rate Application, including attachments, appendices and updates.
2. Responses to Information Requests to Centra from IGU, the PUB and other intervenors.
3. Previous PUB decisions and Centra rate applications that are publicly available.
4. Other public sources of information.

Centra filed a motion on confidentiality pursuant to Rule 13 (2) of the Public Utilities Board Rules of Practice and Procedure to redact portions of its application and maintain portions of the Application in confidence. Centra notes that as part of the TransCanada Pipelines Limited (TCPL) RH-001-2014 Mainline Tolls proceeding before the National Energy Board, Centra declined to provide information on its peak day requirements and details on its gas contracts, although such information had been in the past publicly posted, on the grounds the information was commercially sensitive.[5] The PUB agreed to hold portions of the Application in confidence and notified parties by letter dated February 26, 2019. IGU filed a motion with the PUB on April 12, 2019 to obtain access to the confidential portions of the filing for its consultants and counsel. The Board granted IGU access to portions of the confidential filing in Order 77/19 dated June 4, 2019.

InterGroup has reviewed the confidential information provided pursuant to Order 77/19 but this report does not disclose or reproduce any of that information. InterGroup has prepared a short confidential attachment that will be provided to the PUB in confidence.

[5] Centra Gas Letter to the Public Utilities Board dated November 30, 2018.

3.0 COST OF SERVICE STUDY AND RATE DESIGN

3.1 PURPOSE OF A COST OF SERVICE STUDY

In its Order 164-16 on Manitoba Hydro's cost of service study, the Board noted the public hearing process was the first review of Manitoba Hydro's Cost of Service Study (COSS) methodology in a decade.[6] With respect to the purpose of a cost of service study, the Board stated:

> The Board finds that, in the process to determine the appropriate COSS methodology, the principle of cost causation is paramount. Further, the Board finds that ratemaking principles and goals should not be considered at the COSS stage…
>
> …Cost causation as defined by the Board takes into consideration both how an asset is planned and how that asset is used. This takes into account how an asset fits into Manitoba Hydro's current system planning, as well as the current use. This methodology is to apply to assets currently in service, as well as future assets, such as Keeyask and Bipole III.
>
> …The Board finds that, as acknowledged by Manitoba Hydro, it is not bound by prior Board decisions. As such, the Board has approached this review of Manitoba Hydro's COSS methodology through applying the principles discussed above to the evidence in the present proceeding.[7]

Centra states it is not proposing any changes in its approach to cost allocation in the 2019/20 GRA.[8] In its 2013/14 GRA, Centra also stated it had not made any substantive changes to its cost allocation study.[9] Board Order 85/13 on Centra's 2013/14 noted only a change to reflect how DSM programs were functionalized. This did not change the total costs allocated to each customer class, only how those costs were recovered within each class.[10] Therefore it appears there have been no substantive review of or changes made to Centra's cost allocation study or methods for quite some time.

3.2 POSTAGE STAMP RATEMAKING

Centra states that it uses a postage stamp approach to ratemaking where rates for service of each customer class are set without regard for the location of individual customers. Centra provides references to two Board Orders from the 1980s approving the use of postage stamp rates and states the following:

> Postage stamp rates have been an accepted rate making philosophy in Manitoba for several decades. The PUB also provided its views on the acceptance of postage stamp ratemaking in Manitoba, in Order 158/86 in which it found: "Postage stamp rates present the fairest rates for customers in a similar class" (page 49 of Order 158/86).

[6] Page 14 of 116. Board Order 164/16 dated December 20, 2016.
[7] Summarized from pages 27 and 28 of Board Order 164/16.
[8] IGU/CENTRA I-10 (a) to (c).
[9] Tab 11, Page 1, lines 8 and 9. Centra Gas Manitoba 2013/14 GRA dated February 22, 2013.
[10] Pages 46 and 47 of Board Order 85/13 dated July 26, 2013.

> At that time two gas distribution companies provided natural gas service in Manitoba;
>
> the Greater Winnipeg Gas Company, and ICG Utilities (Manitoba) Ltd. ICG Utilities purchased Greater Winnipeg Gas, and the consolidation of the two utilities involved the combination of two separate rate bases into a single rate base, with the corresponding consolidation and harmonization of natural gas rates for all customer classes.
>
> In Order 142/89, arising from a ICG Utilities (Manitoba) Ltd. General Rate Application, the PUB found "The Board considers it appropriate that all customers of a similar type having similar load characteristics be allocated the same costs. It endorses the company's intent to gradually move all SGS customers on its system to the same rates." (page 59 of 142/89).[11]

Three things are notable about the Board Orders quoted by Centra:

1. The quotes relate to harmonizing rates for customers in the same class (that is, customers of a similar type having similar load characteristics). Nothing in the quotes provided by Centra suggest that cost allocation or rate design cannot reflect reasonable differences in characteristics of customers in different classes.
2. The Board's comments appear to have been made during a period of consolidation of natural gas service over 30 years ago. As the Board has noted in its Order 164-16 it is not bound by prior Board decisions and it is reasonable to approach the review of cost allocation methods taking into account how an asset fits into current system planning as well as the current use.
3. The Board's comments were made during a period when large industrial customer loads were quite different than today. Centra notes the Order 156/86 was issued prior to the full implementation of Transportation Service. Order 142/89 was issued at a time when the estimated combined percentage of Special Contract and Transportation Service volumes represented approximately 13% of system load.[12]

3.3 SYSTEM CHANGES AFFECTING COST ALLOCATION

Board Order 164-16 noted that cost causation principles should reflect how a utility's system is planned and used. Centra's system today is different than the system that was in place at the time many of the current cost of service methods were implemented. This section reviews some changes in Centra's operations and operating environment since the 2013/14 GRA.

[11] IGU/CENTRA I-8 (m),(n),(o).
[12] IGU/CENTRA II-25 (a) and (b).

3.3.1 Winnipeg North West Transmission Project and Future Transmission Capital Planning

The Winnipeg North West Project is a material portion of the recent increases in Transmission rate base, approximately $27.7 million since 2015/16.[13] Centra estimates the annual revenue requirement impact of the Project is approximately $2 million.[14]

Centra's justification for the Phase I project notes that "the risk of not proceeding with this upgrade is a loss of reliable gas supply to our natural gas customers on the Winnipeg NW MP network under <u>peak flow conditions</u> during cold weather.[15] Centra's capital project justification for Phase 2 of the project states "the extension of an existing natural gas pipeline from the Rosser Station (GS-031) in Winnipeg to the City of Selkirk (GS-004) is necessary to provide additional capacity to the areas northwest of Winnipeg and to provide a redundant gas source to meet reliability and operational requirements in the Winnipeg natural gas transmission network.[16] Based on these statements it appears the need for this project is driven by capacity and growth issues for customers in and around the City of Winnipeg.

In terms of cost responsibility, Centra provided an estimate of annual revenue requirement impacts of approximately $107,000 allocated to the Special Contracts class and $48,000 allocated to the Main Line class.[17]

Centra notes that the build out of the transmission function assets has changed the transmission function classification of costs to Demand from Energy due to the change in rate base such that in 2019/20 61.3% of transmission rate base is classified to demand compared to 43.5% in the 2013/14 GRA.[18] Further, Centra noted that it anticipates incremental revenue requirement costs related to planned transmission projects in CEF18 in the range of $3.0 to $4.0 million per year through 2028.[19] Centra states that it is unable to determine rate class responsibility for the additional transmission investments included in the 10 year forecast, as not all cost allocation study inputs are available beyond the test year.[20]

Given the magnitude of the costs involved with these projects, it may be timely for the Board to review whether certain assets should be sub-functionalized or directly assigned in a way that recognizes certain customer classes are not directly responsible for these costs and do not directly benefit from the assets.

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[13] IGU/CENTRA I-5 (a) and (b). This is the sum of Winnipeg North West Phase 1 and Winnipeg North West Phase 2.
[14] IGU/CENTRA I-8 (b).
[15] Page 36 of 370 of the attachment to PUB/CENTRA I-73. Emphasis added.
[16] Page 56 of 370 of the attachment to PUB/CENTRA I-73.
[17] PUB/CENTRA II-54. This may understate the actual impact depending on the degree to which this project is weighted toward a demand classification.
[18] IGU/CENTRA II-14 (a).
[19] IGU/CENTRA II-17 (b).
[20] IGU/CENTRA II-17 (c).

3.3.2 Migration of Customers from Interruptible Service

Centra has noted that the number of customers in the interruptible class in the 2019/20 forecast has declined compared to 2013/14 due to the migration of interruptible customers to the High Volume Firm class.[21] Over the past 10 years, Interruptible Service is down from a total of 46 customers to 20 customers today and Centra has not been permitting new customers to take Interruptible service.[22] This is important to cost allocation because interruptible service customers generally do not contribute to demand at the time of the system coincident peak. Part of the justification for using a peak and average approach to demand allocation is that a coincident demand approach will not allocate costs to interruptible customers. As customers migrate away from interruptible service this may be less of a concern, relative to understating the degree to which coincident peaks drive investment in capacity serving infrastructure. It may be timely for the Board to review whether this change warrant re-evaluating the use of the peak and average approach to demand allocation.

3.4 DEMAND ALLOCATION

The NARUC Gas Distribution Rate Design Manual states the following with respect to the allocation of demand or capacity costs:

> Demand or capacity costs are allocated to customer classes based upon an analysis of system load conditions and on how each customer class affects such costs. These are largely joint or common costs, and their allocation generates the largest controversy surrounding a cost of service study. This subject has been studied and argued for years without resolution, and often represents the largest item which can dramatically alter the result of a study.[23]

Because of this, it is important to consider whether or not Centra's demand classification and allocation methods remain reasonable, particularly when there have been changes in the characteristics of Centra's customers or in the way the system is planned, built and operated.

Centra states that it allocates capacity related costs using the peak and average allocator that recognizes the peak day, but also gives weight to the average use of the system so that all customer classes pay some portion of the capacity costs.[24] An issue with the peak and average demand approach is that although it is referenced as a demand related method, it incorporates a consideration of annual volumes more typical of an energy classification. This mutes the ability to track costs related to the peak capacity of the system. Mathematically, the peak and average approach appears equivalent to classifying assets between demand

[21] Tab 10 of the Application. Page 11 of 14 lines 19 through 24.
[22] CAC/CENTRA I-24(b)
[23] Page 25, Gas Distribution Rate Design Manual. National Association of Regulatory Utility Commissioners. 1989.
[24] Tab 10, page 5 of 14. Rows 11 through 13 of the Application.

and energy based on the system load factor. As a result, a substantial portion of costs follow annual volumes rather than peak day requirements.

In their 2012 report, Christensen and Associates stated that Centra's application of the peak-average allocation (PAVG) methodology rests on solid institutional precedent.[25] They also noted that PAVG allocators tend to shift cost allocation away from peak-coincident classes, such as those receiving firm service, to other classes and customers, such as non-firm service customers.[26] Christensen and Associates went on to say:

> However, discussions with planners and general intuition suggest that transport costs are driven largely by peak demand and transport distance (line length), and secondarily by the type of terrain and factors associated with infrastructure density.19 Peak day demand (maximum daily throughput) is an observable causal factor for cost allocation. However, length of transmission and distribution mains attributable to customers is less observable[20] and it is also difficult to associate distance measures with customers or customer classes because of practical and institutional limitations.[27]

Ultimately, Christensen and Associates made the following recommendation:

> If cost causation is the paramount criterion for selection of an allocator, then Centra may wish to explore the development of a combination allocation metric that includes maximum day and number of customers.[28]

Christensen and Associates also recommended that Centra explore whether load factor conforms adequately to the impacts of the underlying two main cost drivers (peak day, distance) on facility costs.[29]

If the Board determined that capacity related costs are generally caused by the need to meet the system peak, an approach that allocates capacity or demand costs based on the coincident peak demand may be more appropriate. For example, Fortis BC Energy Inc. (FEI)' s 2016 Rate Design Application states that transmission costs are classified as 100% demand-related, since system capacity requirements are driven by the peak demand of each customer group.[30] FEI allocates demand related costs using the coincident peak approach to reflect the fact that FEI's delivery system has generally been constructed to meet the peak day (coldest day) demand of all its firm service customers.[31]

[25] Page 31 of 39 of Attachment 10 to PUB Completeness Review.
[26] Page 28 of 39 of Attachment 10 to PUB Completeness Review.
[27] Page 29 of 39 of Attachment 10 to PUB Completeness Review.
[28] Page 30 of 39 of Attachment 10 to PUB Completeness Review.
[29] Page 33 of 39 of Attachment 10 to PUB Completeness Review.
[30] Page 6-18 of FEI's 2016 Rate Design Application dated December 19, 2016.
[31] Page 6-21 of FEI's 2016 Rate Design Application dated December 19, 2016. These methods were approved by the BCUC in Order G-4-18.

3.5 RATE DESIGN AND ZONE OF REASONABLENESS

Centra stated that it is open to the Christensen and Associates recommendation that the cost of service methods accommodate a range of acceptable RCC ratios. Centra notes that it has previously set rates around a 97:103 range in the early and mid 1990s. Centra states its view that it should in most cases strive to align rate levels to costs, it also views that under limited circumstances, deviating from unity may be a reasonable approach to provide rate stability.[32] Centra also stated that an appropriate means of addressing bill impacts caused by plant additions may be to temporarily set aside the concept of setting rates at a revenue/cost ratio of 1.0 for all classes and instead adopt a zone of reasonableness in the setting of class rates.[33]

In Order 164-16 the Board noted that while a cost of service study appears to be arithmetically exact, it involves a number of decisions that require the application of judgement. Because of this, and to address goals of gradualism in the ratemaking process, many utilities do not set rates such that the RCC ratios are exactly unity. Instead many utilities and their regulators recognize a zone of reasonableness.[34]

Other gas regulators have also accepted revenue to cost ranges of reasonableness. For example, in Order G-4-18 the British Columbia Utilities Commission directed Fortis BC Energy Inc. to use a revenue to cost ratio range of reasonableness of 95 percent to 105 percent to inform its rate design and rebalancing proposals.[35] The Alberta Utilities Commission noted in its decision with respect to AltaGas Utilities Inc's 2013-2017 Phase II application resulted in rate class revenue to cost ratios within the 95 to 105 per cent range which had been approved by the Commission in previous decisions.[36]

3.6 SUMMARY AND RECOMMENDATIONS

There are a number of issues that the Board should review related to Centra's Cost of Service and Rate Design methods, including:

- **Peak and Average versus Coincident Demand Allocators:** Changes on Centra's system, in particular the increased transmission spending (that appears to be driven by peak capacity requirements and customer growth) and the migration of customers away from interruptible service merits additional consideration of whether Centra's cost allocation methods are sufficiently tracking the degree to which investments in new capacity related assets are driven by the need to meet system peaks rather than average use throughout the year. If the Board were to determine that

[32] Page 16 of 25. Attachment 11 to PUB Completeness Review.
[33] IGU/CENTRA I-28 (a) and (b).
[34] Page 24 of 116. Order 164/16 dated December 20, 2016.
[35] Page 2 of BCUC Order G-4-18 dated January 9, 2018.
[36] Paragraph 75, Page 17. AUC Decision 2014-139 with respect to AltaGas Utilities Inc.'s 2013-2017 performance based regulation Phase II negotiated settlement dated May 23, 2014.

the cost causation of these assets relates primarily to the design capacity or peak day, then a coincident demand method may better track cost causation.

- **Load factor as the basis to weight peak and average allocator**: Even in the event the Board determined that the peak and average approach remains reasonable, using the load factor as the basis to weight the peak and average allocator means that a substantial portion of costs follow annual energy or commodity use, rather than coincident peak day use. Centra states that using load factor as the basis to weight peak and average appears to be consistent with an approach stated by the National Association of Regulatory Utility Commissioners but its origins in Manitoba are unknown and likely are due to be reviewed. Centra confirmed in the current proceeding it has not undertaken further review of matter to date.[37]
- **Postage Stamp Ratemaking:** Centra has noted that the philosophy of postage stamp ratemaking has its origins during a period when the natural gas system in Manitoba was very different than it is today. Given the considerable impact on some customers of sharing costs for substantial new investments that do not provide direct benefits, it may be timely to investigate alternative methods for sub-functionalizing and/or direct assigning certain costs, such as the Winnipeg North West project, to the groups of customers that are directly causing those assets to be required and directly benefit from their construction.

Based on this, it is recommended that the Board defer approving any rate adjustments based on the results of Centra's cost of service study until it has had the opportunity for a full review of Centra's cost of service methods. Such a review could be modelled after the review undertaken for Manitoba Hydro's cost of service study that resulted in the Board's Order 164/16. Key elements of such a review would include:

- The review of Centra's cost of service study should consider the changes to Centra's customer mix and operations and how those influence the need to adjust existing cost of service study methods.
- The review should consider the methodological issues raised in this report, as well as issues identified by other intervenors and the Board.
- The Board should consider retaining its own independent expert to prepare a report with recommendations that is available to all parties. This could help alleviate some procedural fairness concerns about only certain parties being granted access to confidential materials.[38]

Although not recommended, in the event the Board decides to make some level of rate adjustments arising from this proceeding to reflect the current cost of service study results, the Board should consider the

[37] IGU/CENTRA I-13 (b).

[38] The BCUC used a similar approach in its review of FEI's 2016 Rate Design Application as summarized in page 4 of 38 of Appendix A to Order G-4-18.

substantial impact on some customer groups of the proposed rate and bill increases for some customers proposed in the current application (20 to 40% for base rates to Mainline and High Volume Firm T-Service customers).[39] Allowing some discretion in the range of revenue to cost coverage ratios, rather than targeting exactly 100% cost of service for all customers, would help mitigate these rate increases and be consistent with how rates are set for other utilities in Manitoba. In addition, the Board may consider the principle of gradualism in the transition of rates into the zone of reasonableness.

[39] See Page 2 of 2 of Schedule 11.1.10.

4.0 BALANCING FEES

4.1 BACKGROUND

Centra is requesting approval to change its terms and conditions for transportation service to address imbalances relating to delivery of gas to Centra's system. Centra is also applying to increase the volumetric eligibility threshold that would apply to new T-Service customers. [40] Centra's proposed changes include the following:

- Centra's proposal involves using the same balancing fee formula as the TCPL Mainline but charging for imbalances at 50% of the current TCPL Mainline balancing fees.
- Centra is also proposing to increase the volumetric threshold for eligibility in T-Service for potential new T-Service customers from 200 GJ/day to 2,500 GJ/day.[41]

Centra notes that its practice to date has been to recover its direct costs from the largest volume T-Service customers who periodically drive the utility to incur balancing fees assessed by the TCPL Mainline.[42] Centra also notes that during its engagement with customers on this issue it was noted that the PUB should review and vet proposed changes to T-Service terms and conditions of service.[43] As a result Centra's proposed changes are included as part of the current application.

4.2 REVENUE CHANGES AND CONSIDERATIONS FROM CENTRA'S PROPOSAL

Table 4-1 summarizes Centra's net balancing fees and charges based on its current practice and Centra's proposed changes using 2016/17 and 2017/18 information. Table 4-1 shows that if Centra's proposed terms and conditions had been in place since 2016/17 it would have collected substantially more revenue from T-Service customers than it actually incurred in balancing charges from TCPL ($677,000 more in 2016/17 and $487,000 more in 2017/18). Centra states balancing fees will have no net impact to Centra's income statement because any amounts collected from T-Service customers will be refunded to Sales Service customers with no margin retained by Centra.[44]

[40] Page 1 of Tab 12 of the Application. Lines 23 through 26.
[41] Page 6 of Tab 12 of the Application. Lines 1 through 11.
[42] Page 3 of Tab 12 of the Application. Lines 28 through 30. Additional details on the current calculation method is provided in the response to PUB/CENTRA I-145 (e).
[43] PUB/CENTRA I-146 (b).
[44] IGU/CENTRA I-1 (a).

Table 4-1: Balancing Fees Charges and Recoveries Under Current and Proposed Terms and Conditions of Service

Line No.		2016/17	2017/18
1	TCPL Balancing Charges Incurred by Centra	243,856	273,504
2	TCPL Balancing Charges Recovered by T-Service Customers	(87,693)	(75,209)
3	Net TCPL Balances Charges Applicable to Sales Service	156,163	198,295
4	Pro-Forma Balancing Charges to T-Service Customers based on Centra's Proposal	(920,602)	(760,191)
5	Pro-Forma Net Balancing Charges Applicable to Sales Service based on Centra's Proposal	(676,746)	(486,687)

Sources
Lines 1,2,3 PUB/CENTRA I-147 (a)
Line 4 PUB/CENTRA I-147(b)
Line 5 = Line 1 + Line 4

Centra states that in its view, in addition to direct balancing charges it incurs indirect or opportunity costs related to T-Service imbalances. Centra provides a redacted estimate of it summer opportunity costs in response to IGU/CENTRA II-7 (c). Centra states that in winter months, volumes can vary widely based on weather and operational requirements and that foregone revenue during the winter period exists but cannot be estimated with accuracy.[45] Centra acknowledges that not all direct and indirect costs can be quantified with precision given the challenges associated with valuing transactions that were never executed.[46]

Centra acknowledges that there conceptually could be occurrences where Centra is able to earn additional Capacity Management revenue as a result of T-Service customers offsetting the Sales Service pool but that the T-Service position becomes known to Centra late in the day and therefore in Centra's view the intra-day portfolio optimization is almost certainly lower.[47] Centra also confirmed in response to PUB/CENTRA I-147(d) that at times T-Service customer delivery imbalances have offset imbalances caused by Centra's Sales Service customers resulting in Centra avoiding balancing fees. Centra declined to provide an estimate of such avoided balancing charges.

4.3 OPERATIONAL CONSIDERATIONS FROM CENTRA'S PROPOSAL

Centra states that its preferred outcome is to collect no balancing fees and that ideally T-Service customers will respond to the introduction of the new balancing fee structure by pro-actively managing their positions and mitigating balancing fees to the extent possible.[48] Centra seems to acknowledge that there may be situations where circumstances beyond a customer's control would lead to balancing charges being incurred, including in the event of power outages. Centra notes that TCPL's balancing fee structure applies

[45] IGU/CENTRA II-7 (c).
[46] IGU/CENTRA II-7 (c).
[47] PUB/CENTRA I-148 (b).
[48] PUB/CENTRA I-147 (b).

to customers regardless of whether a shipper is experiencing unplanned maintenance or outages. In the specific case of power outages, Centra states that customers should continue to contact their Manitoba Hydro account representatives and that those situations would need to be assessed and addressed on a case by case basis.[49]

4.4 SUMMARY

In evaluating the merits of Centra's proposal, the PUB should consider the following:

- **Centra's proposal is not a direct cost-based rate:** Centra acknowledges this in its evidence and indicates that in 2016/17 and 2017/18 its proposal would have resulted in charges to T-Service customers well in excess of its direct costs for balancing fees charged by TCPL.
- **Centra acknowledges the fees would apply even when customers have no ability to respond:** Centra states that the fee would apply, even in the case of power outages or other instances when customers may not be able to respond to imbalances.
- **Centra provides no forecast of balancing fee revenues in the test year:** Centra indicates that going forward actual experience will be the best basis on which to forecast revenues.[50]

Given the uncertain implications for future revenues and customer operations, the PUB should be cautious in considering Centra's proposal. There are a number of problematic issues with Centra's current proposal and the PUB should not approve the changes as currently proposed.

Measures the PUB may wish to consider to mitigate the proposal could include:

- Directing Centra to work further with customers to revise the proposal. Particular areas of focus could include limiting the applicability of the fees during periods when customers cannot respond to balancing issues, particularly related to power outages; and consideration of options to work with Centra and/or other T-Service customers to ensure the system as a whole remains in balance;
- Given the uncertainty in customer response, phase in the charges more gradually than the 50% of TCPL figure selected by Centra and report regularly to the PUB on charges collected and direct costs incurred.
- Capping charges applicable to customers under the proposal to only the amount Centra actually incurs in balancing charges from TCPL, at least until Centra can provide more detailed documentation of its claims for indirect costs than it has made available in the current proceeding.

[49] IGU/CENTRA I-22 (o).
[50] IGU/CENTRA I-1 (a) to (c).

5.0 HEATING VALUE MARGIN DEFERRAL ACCOUNT

5.1 BACKGROUND

Centra states the purpose of the Heating Value Margin Deferral Account is to "…keep Centra and its customers whole with respect to gross margin (non-gas revenue) which would otherwise be affected by variations in the heating content of the natural gas received from the TCPL Mainline compared to the value of the heating content assumed in the design of rates. Centra's volume forecast and approved rates are based on a constant heating value. On an actual basis heating values can fluctuate above and below that amount."[51] Centra states the Heating Value Deferral Account balance "…is allocated to each customer class based on actual volumes for each customer class since this deferral is entirely volume related."[52]

Centra notes the current balance to be recovered of approximately $2.5 million is larger than historically experienced largely due to the fact that the balance has accumulated over a three year timeframe.[53]

As part of the current application, Centra filed a report titled Review of Cost-Of-Service Methods of Manitoba Hydro prepared by Christensen Associates Energy Consulting dated June 8, 2012.[54] Centra also provided a response to the recommendations from the Christensen Associates report dated July 19, 2012.[55]

Christensen Associates stated its view that with respect to the reconciliation of the heating value deferral accounts, Centra should include only customers with monthly bills that are determined according to energy sales volumes of customers.[56] In its response to the Christensen Associates Report, Centra stated:

> Centra accepts CA's recommendation with respect to the allocation of the disposition of the heating value deferral. Centra currently assigns heating value residuals to all customer classes on the basis of each class' contribution to total annual throughput. Heating value residuals accumulate if the heating value of gas delivered is greater or less than forecast resulting in customers consuming volumes that are greater or less than forecast. The deferral has been put in place to track the impact to gross margin that occurs when the energy content of gas is greater to or less than forecast. For most customer classes, gross margin is largely collected through volumetric rates. The Special Contract Class rate structure is predominantly fixed (with only unaccounted for gas collected volumetrically), and should not, therefore, participate in the disposition of the heating value deferral.[57]

Centra confirmed that it has continued to apply the Heating Value Deferral Account to all customer classes in the current application.[58]

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51 IGU/CENTRA I-27 (a).
52 IGU/CENTRA I-27(c).
53 IGU/CENTRA II-12 (i).
54 This document was provided as Attachment 10 of the PUB Completeness Review.
55 This document was provided as Attachment 11 of the PUB Completeness Review.
56 Page 33 of 39 of Attachment 10 of the PUB Completeness Review.
57 Pages 15 and 16 of 25 of Attachment 11 to the PUB Completeness Review.
58 IGU/CENTRA I-27(g).

5.2 REVENUE RISK RELATED TO HEATING VALUE

Centra is exposed to revenue risk based on variations in heating value. However, Centra's risk is different for different types of customers depending on the degree to which revenues for each customer class or rate option rely on volumetric sales. As stated by Centra:

> Variations in heating content would not have an effect on the recovery of costs through fixed monthly charges.
>
> Variations in heating content would have some effect on the recovery of capacity costs through demand charges, as billing demand is measured as the peak daily consumption for the month. Therefore, variation in heating content may have a slight impact on the demand level measured on a peak day for a customer.
>
> Variations in heating content would have a greater effect on the recovery of costs through volumetric charges where fixed costs are largely being recovered through volumetric charges as found in the SGS and LGS customer classes.[59]

In the extreme example, the Special Contract class has no material revenue risk related to the variations in heating value, owing to a rate structure that is based almost entirely on a basic monthly charge that does not vary with volume or heating value.[60] However, the rate designs for other customer classes and service options also expose Centra to different levels of revenue risk due to changes in heating value.

For example, Centra notes the Basic Monthly Charge does not recover all of the customer related costs for the Small General Service or the Large General Service classes. All customer costs in excess of those collected in the Basic Monthly Charge plus all capacity and commodity related costs are recovered in the Volumetric Charges for both the Small General Service and Large General Service classes.[61] This means that Centra is more exposed to revenue risk for these customers because a greater portion of their class revenues rely on the volumetric charge. This is also evident by reviewing the proposed rates in Schedule 11.2.1 of the Application. The rates for the Small General Service and Large General service are much higher per cubic meter, meaning that when volumes vary due to heating value for these customer classes it has a much higher impact on Centra's revenues than volume variances for other classes.

The differences in revenue recovered from volumetric charges as a percentage of total class non-gas revenues are clearly illustrated in the response to IGU/CENTRA II-12 (c).[62] Schedule 5.1 to this report compares the contribution of each class to total volumetric or commodity based revenues and the contribution of each class to the total actual volumes for 2015/16 through 2018/19. Schedule 5.1 shows there are materially different levels of revenues associated with volumetric or commodity-based charges for each customer class. On that basis, the risk faced by Centra due to heating value changes relates not

[59] IGU/CENTRA II-12 (d).
[60] Centra appears to agree with this in its response to the CA report on page 16 of 25 of Attachment 11.
[61] Tab 10, page 14 of 15 lines 16 through 20.
[62] Refer to the table that responds to parts ii) through v) of the information request.

solely to the total volume consumed by a customer, but rather on the degree to which Centra's revenues rely on the volumetric charge for each type of customer and the magnitude of the rates charged on a volumetric basis.

Centra appears to calculate the charges or credits to the heating value deferral account using a single blended commodity base sales rate.[63] This blended commodity base sales rate appears to include primary gas, distribution sales and transportation sales rates. Not all customers pay these rates in the same proportion and therefore the use of a single blended sales rate in calculating the balance seems likely not to capture the degree to which different customers and service options contribute to balances or credits in the account.

Therefore, the current allocation method based only on customer volumes poorly tracks the level of revenue risk Centra is exposed to for each customer class. The Board should direct Centra to allocate the balances in the Heating Value Margin Deferral Account on the basis of total <u>revenues from volumetric charges</u> or a similar allocation metric that better matches the contribution of each customer class to Centra's revenue risk from variations in heating value.

5.3 CENTRA'S POSITION ON CHANGES TO HEATING VALUE DEFERRAL ACCOUNT

In response to IGU/CENTRA II- 4(a) Centra states:

> Centra continues to be supportive of the recommendation made by Christensen Associates that the Special Contract class should not be included in the refund or collection of the balance in the Heating Value Deferral Account. However, when considering the appropriate time to implement the recommendation, it is necessary to take into account the regulatory principles of fairness and equity as between and amongst customer classes with respect to the refunds and collections to date with respect to the Heating Value Deferral account.

In response to IGU/CENTRA II-12 (e) Centra states:

> In the period from 1999 to 2014, the Heating Value Deferral Account was consistently refunding amounts to customers as the heat content of gas was lower than the heat content level used in setting rates. In that time period Centra applied those refund amounts to all customer classes. Given that all customer classes participated in the refund of those amounts over that period of time, Centra has continued to include all customer classes in the recovery of amounts owing to Centra in the period of time since the heat content of natural gas has increased…

Based on these responses, it appears that Centra chose to continue to apply refunds to all customer classes in 2013 and 2014, even after accepting the recommendation of Christensen and Associates in 2012. It is not apparent why Centra would continue to apply refunds to all customer classes in 2013 and 2014 after

[63] IGU/CENTRA I-17 (h).

accepting the recommendation of Christensen and Associates if Centra were concerned about the principles of fairness and equity as between and amongst customer classes.

In response to IGU/CENTRA II- 4(a) Centra states:

> With the Special Contract class having received a net benefit from this deferral over the course of 15 years, Centra believes there is a fairness argument that dictates that the current balances to be collected from customers should be apportioned in the same manner that previous balances have been refunded.

Centra appears to be saying it will wait to change its method until the special contract customer has "caught up" on charges related to the heating value variation. There are a number of reasons why this approach should not be approved by the PUB:

1. There is no guarantee going forward that heating values will continue to result in charges instead of credits to the account. If Centra chooses whether or not to continue using the method based on whether or not it likes the outcome to the special contract customer, then it will be engaging in blatant discriminatory ratemaking.
2. Centra is effectively seeking a backdoor method to unwind previously PUB approved and long since discharged balances. This amounts to retroactive ratemaking.
3. Centra is now going on seven years of perpetuating an inferior rate design after accepting a consultant's recommendation that it should be changed.

For all of these reasons the PUB should reject Centra's proposal to continue its current approach. Centra and the PUB have an opportunity in the current application to correct a poor rate design that has continued for seven years since Centra accepted it should be changed. The PUB should direct Centra to implement changes to better reflect risk causation as part of the current application.

5.4 SUMMARY

In summary, with respect to the Heating Value Margin Deferral Account:

1. Centra accepted the 2012 recommendation of Christensen and Associates that the Special Contract Class rate structure is predominantly fixed and therefore should not participate in the disposition of the heating value deferral.
2. Notwithstanding this, since 2012 Centra has continued to use its inferior method during periods where the fund was in both credit and debit positions.[64]

[64] Centra has acknowledged the fund was generally in a refund position until 2014 in IGU/Centra II-12 (e) and PUB Order 108/15 at page 19 shows the fund in a collection from customers position for 2015 amounts.

3. Centra provides no timeline or plan for when it proposes to stop using the method it accepted should be changed seven years ago.
4. Centra's argument that implementing the recommendation it has already accepted should be put off even longer until a decade or more of historically approved charges have been unwound amounts to rate discrimination and retroactive ratemaking and should be rejected by the Board.
5. Schedule 5.1 to this report clearly shows the level of revenue risk exposure to variations in heating value are materially different for each customer class and this level of risk exposure is poorly tracked by an allocation method based only on volumes without a consideration of the different volumetric rates and revenues for each customer class.

Based on these considerations, the Board should direct Centra to allocate the balances in the Heating Value Margin Deferral Account in the current application on the basis of total <u>revenues from volumetric charges</u> or a similar allocation metric that recognizes the different level of risks because of different rate structures for each customer class. This would ensure Centra's current and future collections or refunds better match the contribution of each customer class to Centra's revenue risk due to variations in heating value.

June 21, 2019

Schedule 4.1 Comparison of Revenues and Costs Associated with Centra's Proposed Balancing Fees

Line No		2016/17	2017/18
1	TCPL Balancing Charges Incurred by Centra	243,856	273,504
2	Total TCPL Balancing Charges Recovered by T-Service Customers	(87,693)	(75,209)
3	Net TCPL Balances Charges Applicable to Sales Service	156,163	198,295
4	Pro-Forma Balancing Charges to T-Service Customers based on Centra's Proposal	(920,602)	(760,191)
5	Pro-Forma Net Balancing Charges Applicable to Sales Service based on Centra's Proposal	(676,746)	(486,687)
6	Centra's Estimate of summer opportunity and direct costs	[redacted]	
7	Pro-Forma Net Balancing Charges Applicable to Sales Service based on Centra's Proposal	[redacted]	

Sources
Lines 1,2,3 PUB/CENTRA I-147 (a)
Line 4 PUB/CENTRA I-147(b)
Line 5 = Line 1 + Line 4
[redacted]
Line 7 = Line 5 + Line 6

Schedule 5.1: Comparison of Class Non-Gas Revenues and Volumes

Line	2019/20 Non-Gas Revenues	A Total	B SGS	C LGS	D HVF	E COOP	F ML	G SC	H PS	I INT	J PG	K FSP	L ISP	M FRPGS	Source
1	Basic Montly Charge Non-Gas Revenue	58,718,929	[redacted]												IGU-CENTRA II-12 (c)
2	Demand Transportation Non-Gas Revenue	180,282	[redacted]												IGU-CENTRA II-12 (c)
3	Demand Distribution Non-Gas Revenue	5 016 454													IGU-CENTRA II-12 (c)
4	Total Demand Non-Gas Revenue	5,196,736	[redacted]												Line 2 + Line 3
5	Commodity Transportation Non-Gas Revenue	5,806,226	[redacted]												IGU-CENTRA II-12 (c)
6	Commodity Distribution Non-Gas Revenue	78,797,365													IGU-CENTRA II-12 (c)
7	Total Commodity Non-Gas Revenue	84,603,591	[redacted]												Line 5 + Line 6
8	Total Non-Gas Revenue	148,519,256	102 632,670	32 455,799	6,824,301	8,234	2,057,841	2,246,833	157,799	769,561	[redacted]				Line 1 + Line 4 + Line 7
10	Percentage of Total Commodity Non-Gas Revenue		[redacted]												Line 7 / cell A7
11	Percentage of Total Commodity Distribution Non-Gas Revenue		[redacted]												Line 6/ cell A6

2015/16 through 2018/19 Actual Volumes (10^3M^3) used to allocate Heating Value deferral balance

Line		A	B	C	D	E	F	G	H	I	J	K	L	M	Source
12	2015/16 Actual Volumes	[redacted]	[redacted]												IGU/CENTRA I-27 (k)
13	2016/17 Actual Volumes														IGU/CENTRA I-27 (k)
14	2018/19 Actual Volumes														IGU/CENTRA I-27 (k)
15	Class Percentage Share of Total 2015/16 Actual Volumes	100.0%	[redacted]												Line 12/ cell A12
16	Class Percentage Share of Total 2016/17 Actual Volumes	100.0%													Line 13/ cell A13
17	Class Percentage Share of Total 2018/19 Actual Volumes	100.0%													Line 14/ cell A14

Notes

[redacted]

ATTACHMENT A

RESUME OF A. MCLAREN

InterGroup CONSULTANTS

ANDREW McLAREN

PRINCIPAL AND CONSULTANT

AREAS OF EXPERIENCE:

- Utility Regulation
- Socio-economic and Environmental Assessment
- Economic Impact Assessments, Feasibility Studies and Program Evaluations
- Fee Setting and Policy Advice for Environmental Stewardship Programs in Canada

EDUCATION:

- MNRM (Master of Natural Resources Management), Natural Resources Institute, University of Manitoba, 1999
- Bachelor of Science (Environmental Science), University of Manitoba, 1996

PROFESSIONAL EXPERIENCE:

InterGroup Consultants Ltd., Winnipeg, Manitoba

2000 – Present – Research Analyst / Research Consultant / Consultant / Principal

<u>*Utility Regulation*</u>

- **For Northwest Territories Power Corporation (2000-Present):** Provided technical support and analysis during the Corporation's 2001/03 Phase I and Phase II General Rate Applications; 2006/08 Phase I and Phase II General Rate Application; 2010 rate rebalancing application; 2012/14 Phase II General Rate Application and 2016/19 Phase I and Phase II General Rate Applications. Other responsibilities have included assisting with preparing rate stabilization fund rider applications and applications for major project permits. Prepared evidence and provided expert testimony on revenue requirement and rate design topics before the Northwest Territories Public Utilities Board in the NTPC 2016/19 Phase I and Phase II General Rate Applications.
- **For Qulliq Energy Corporation (QEC) (2008-Present):** Lead consultant responsible for assisting QEC with preparation of the 2010/11 Phase I General Rate Application. Provided

advice on proposed return on equity, reasonableness of revenue requirement and rate design. Lead consultant responsible for assisting QEC with preparation of the 2010/11 Phase II General Rate Application. This was the first Phase II application undertaken by the Corporation since separating from the Northwest Territories Power Corporation. Provided advice on classification and allocation methods for the Corporation's cost of service study and rate design options. Lead consultant responsible for assisting QEC with preparation of the 2014/15 Phase I General Rate Application. Other responsibilities have included preparing fuel rider applications and capital project permit applications. Lead consultant responsible for assisting QEC with preparation of the 2018/19 Phase I and Phase II General Rate Application.

- **For Saskatchewan Rate Review Panel (2013-Present):** Technical advisor to the Panel with respect to SaskEnergy's 2013 delivery service rate application. Prepared an independent report analysing SaskEnergy's application and made recommendations to the Panel. Topics addressed included load forecasts, reasonableness of operations and maintenance expense forecasts and rate design. Technical advisor to the Panel with respect to SaskEnergy's 2014 commodity rate application. Topics addressed included reasonableness of commodity rate forecast and rate design. Technical advisor to the Panel with respect to SaskPower's 2016 and 2017 rate application. Technical advisor with respect to SaskPower's 2018 rate application. Prepared consultant reports reviewing the reasonableness of SaskPower's revenue requirement and rate design proposals.
- **For the Office of the Utilities Consumer Advocate of Alberta (2018 – Present):** Analysis and strategic support of the 2017-2020 ENMAX Energy Corporation Regulated Rate Option Non-Energy Tariff Application.
- **For City of Penticton (2015-Present):** Technical consultant on utility financial planning and rate proposals for the City's electric, water, sewer and stormwater utilities. Prepared financial forecasts and rate design options for review by City staff, ratepayers and City Council.
- **For Regional District of Okanagan-Similkameen (2016):** Prepared a technical memo on rate options for the community of West Bench for moving from a fixed charge water rate structure to a rate structure that included a variable component. Participated in a public consultation session with local residents and made a presentation to the District Council.
- **For North Salt Spring Island Water District (2016):** Prepared a technical report on revising the parcel tax for the district to recover a portion of the costs of operating the utility. Made a presentation to the water district board recommending new parcel tax categories.
- **For Towns of Chestermere and Cochrane, City of Airdrie and Strathmore County (2012-2014):** Provided technical analysis support to municipalities who receive water and wastewater service from the City of Calgary with respect to the City of Calgary's financial forecast, cost of service study and proposed rate design. Responsibilities included reviewing material provided by the City of Calgary, drafting briefing notes and participating in negotiation meetings with municipal officials.
- **For BC First Nations Energy and Mining Council (2011-2013):** Represented BCFNEMC on the Technical Advisory Committee (TAC) for BC Hydro's 2013 Integrated Resource Plan.

Responsibilities included preparing briefing notes for BCFNEMC executives and preparing submissions to BC Hydro on First Nations perspectives on the IRP process and recommendations.

- **For Manitoba Industrial Power Users Group (MIPUG) (2001-2012):** Prepared analysis for regulatory proceedings before the Manitoba Public Utilities Board representing large industrial energy users during Manitoba Hydro's 2001 Status Update Filing and 2004 General Rate Application. Prepared evidence and provided expert testimony on cost of service and rate design methods before the Manitoba Public Utilities Board in the 2006 Cost of Service Study hearing. Prepared evidence and provided expert testimony on revenue requirement, cost of service and rate design topics (with Patrick Bowman) before the Manitoba Public Utilities Board in the Manitoba Hydro 2008 General Rate Application. Prepared evidence and provided expert testimony on revenue requirement and rate design topics (with Patrick Bowman) before the Manitoba Public Utilities Board in the Manitoba Hydro 2010 General Rate Application.
- **For Industrial Customers of Newfoundland and Labrador Hydro (2001-2008):** Prepared analysis related to Newfoundland Hydro's 2001 and 2003 General Rate Applications on behalf of large industrial energy users. Topics addressed included revenue requirement issues and rate design. Submitted pre-filed testimony (with Patrick Bowman) on behalf of the Island Industrial Customers in regards to the Newfoundland and Labrador Hydro 2006 General Rate Review before the Board of Commissioners of Public Utilities. Topics addressed included revenue requirement development, cost-of-service and rate design studies. Lead consultant for the Industrial Customers in a working group with Newfoundland and Labrador Hydro in 2008 to develop and review a marginal cost based rate proposal.

Socio-economic and Environmental Assessment

- **For Manitoba Hydro – Conawapa Project (2012-2014):** Overall responsibility for day to day management of the socio-economic studies and public engagement programs for the proposed Conawapa generation project, a 1,300 MW hydro-electric generation project in Northern Manitoba. Planning for the Conawapa project is currently suspended.
- **For Manitoba Hydro – Keeyask Transmission Project (2011-2012):** Lead consultant on the socio-economic effects assessment for the Keeyask Transmission Project. Prepared socio-economic technical study and drafted sections of the environmental assessment report.
- **For two Northern British Columbia First Nations (2003-2009):** Provided strategic advice and analysis on settlement claims for damages related to the development of the Williston reservoir and the GM Shrum hydro-electric generation project. Included community consultations on agreements and planning for new electricity supply.
- **For Yukon Energy Corporation (2009):** Provided senior advice on approach to environmental assessment for the proposed Mayo B Hydro Project. Responsibilities included advising on approach to selection of valued components and assessment methods.
- **For Manitoba Floodway Authority (2003-2005):** Managed the field program for the socio-economic impact assessment of the Floodway Expansion, a $600 million infrastructure project

to improve flood protection for the City of Winnipeg. Responsibilities included planning, conducting and supervising field work, analysis of potential socio-economic pathways of environmental effects and drafting the socio-economic chapter of the environmental impact statement.

- **For Province of Manitoba (2003):** Conducted analysis related to recreation and tourism benefits of summer water level regulation in the City of Winnipeg. Responsibilities included quantitative and qualitative assessments of potential benefits of water level regulation.
- **For Province of Manitoba (2000-2002):** Conducted quantitative and qualitative assessment of socio-economic impacts related to proposed flood control alternatives for the City of Winnipeg, including key-person interviews with stakeholders and presentation of results at public meetings.

Economic Impact Assessments, Feasibility Studies and Program Evaluations

- **For the Manitoba Motion Picture Industry Association (2004)**: Researched and wrote an economic impact study for the film industry in Manitoba. Analysis included interviews with creative and technical workers in the film industry, as well as producers and industry service providers. The assessment included employment estimates, an analysis of spending and Gross Domestic Product as well as revenues flowing to the provincial government.
- **For the Manitoba Industrial Power Users Group (MIPUG) (2006):** Conducted an economic impact assessment of the operations of the members of MIPUG, comprising the largest industrial operations in Manitoba. Analysis included spending and GDP benefits, as well as tax and employment impacts for various levels of government.

Fee Setting and Policy Advice for Environmental Stewardship Programs in Canada

- **Electronics Recycling Fees and Tire Recycling Fee Studies (2009–2015):** Project study director for numerous reviews since 2009 of Environmental Handling Fees and Tire Recycling Fees for electronics and tire stewardship programs in Nova Scotia, Quebec, Manitoba, Saskatchewan and British Columbia. Projects included broad consultation with industry and government stakeholders related to the calculation of fees.
- **Performance Indicators Study:** Project study director for a 2010 study developing performance measurement indicators for public reporting for stewardship programs. Indicators included operational, financial, public awareness and accessibility and environmental indicators.
- **Generic Tire Fee Setting Manual:** Project study director for the development of a generic fee design manual for scrap tire stewardship programs in Canada.

Andrew McLaren Utility Regulation Experience

Utility	Proceeding	Work Performed	Before	Client	Year	Testimony
NTPC	2001/03 Phase I General Rate Application	Analysis and Case Preparation	NWTPUB	NTPC	2000-02	No
NTPC	2001/03 Phase II General Rate Application	Analysis, Assisted with preparation of Company Rate Design Evidence	NWTPUB	NTPC	2002	No
Newfoundland Hydro	2004 General Rate Application	Analysis, assisted with preparation of Intervenor Evidence	NLPUB	Newfoundland Industrial Customers	2003	No
Manitoba Hydro	2004 General Rate Application	Analysis, Assisted with Preparation of Intervenor Evidence	MPUB	MIPUG	2004	No
Nunavut Power (Qulliq Energy)	2004 General Rate Application	Analysis, Preparation of Intervenor Submission	Nunavut Utility Rate Review Commission (URRC)	NorthWest Company (commercial customer intervenor)	2004	No
Manitoba Hydro	Cost of Service Methodology	Analysis, Preparation of Intervenor Evidence and Expert Testimony with Patrick Bowman	MPUB	MIPUG	2006	Yes
Newfoundland Hydro	2006 General Rate Application	Analysis, Preparation of Intervenor Evidence with Patrick Bowman	Board of Commissioners of Public Utilities of Newfoundland and Labrador (NLPUB)	Newfoundland Industrial Customers	2006	No - Negotiated Settlement
NTPC	2006/08 General Rate Application Phase I and Phase II	Analysis, Assisted with Preparation of Company Evidence	NWTPUB	NTPC	2006-08	No
Manitoba Hydro	2008 General Rate Application	Analysis, Preparation of Intervenor Evidence and Expert Testimony with Patrick Bowman	MPUB	MIPUG	2008	Yes
Manitoba Hydro	2008 Energy Intensive Industrial Rate Application	Analysis, Preparation of Intervenor Evidence and Expert Testimony with Patrick Bowman	MPUB	MIPUG	2008	Yes
NTPC	Rate Rebalancing Application	Analysis and assisted with preparation of application	NWTPUB	NTPC	2010	No
Qulliq Energy Corporation	2010/11 General Rate Application	Analysis, Lead Consultant for Preparation of Company Evidence	Utility Rates Review Panel (URRC)	QEC	2010-11	No
Manitoba Hydro	2010/11 and 2011/12 General Rate Application	Analysis, Preparation of Intervenor Evidence and Expert Testimony with Patrick Bowman	MPUB	MIPUG	2010-11	Yes
SaskEnergy	2013/14 and 2014/15 Delivery Service Rates	Lead Technical Advisor to SK Rate Review Panel (SRRP)	SRRP	SRRP	2013	No
Qulliq Energy Corporation	2014/15 General Rate Application	Analysis, Lead Consultant for Preparation of Company Evidence	URRC	QEC	2014-15	No
SaskEnergy	2014 Commodity Rate Application	Lead Technical Advisor to SK Rate Review Panel (SRRP)	SRRP	SRRP	2014	No
SaskEnergy	2014/15 Delivery Service Rates Update	Lead Technical Advisor to SK Rate Review Panel (SRRP)	SRRP	SRRP	2014	No
NTPC	2012/14 Phase II General Rate Application	Analysis, Advisor on Company Evidence	NWTPUB	NTPC	2015	No
SaskEnergy	2015/16 Delivery and Commodity Rate Application	Lead Technical Advisor to SK Rate Review Panel (SRRP)	SRRP	SRRP	2015	No
SaskPower	2016 and 2017 Rate Application	Lead Technical Advisor to SK Rate Review Panel (SRRP)	SRRP	SRRP	2016	No
NTPC	Phase I and Phase II 2016/19 General Rate Application.	Lead witness on load forecasts, cost of service study and rate design.	NWTPUB	NTPC	2017	Yes
SaskPower	2018 Rate Application	Lead Technical Advisor to SK Rate Review Panel (SRRP)	SRRP	SRRP	2018	No
Qulliq Energy Corporation	2018/19 General Rate Application	Analysis, Lead Consultant for Preparation of Company Evidence	URRC	QEC	2017-18	No
Enmax Energy Corporation	2017-2020 RRO Non-energy tariff	Lead consultant to UCA	AUC	UCA	2018-onging	In progress