# MANITOBA PUBLIC UTILITIES BOARD

# CENTRA GAS MANITOBA INC.

# 2019/20 GENERAL RATE APPLICATION

**Evidence Prepared By**

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**On Behalf of**

**Consumers' Association of Canada (Manitoba Branch) (CAC)**

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## 1.0 Executive Summary

Centra Gas Manitoba Inc. (Centra or Company) is requesting approval of Supplemental Gas, Transportation and Distribution rates effective November 1, 2019, which include the refund of prior gas cost deferrals of $6.4 million, reduction of non-Primary Gas costs of $3.8 million and the discontinuance of funding of the Furnace Replacement Program and removal from rates of the associated costs which amounts to $3.8 million on an annualized basis.

For the typical residential customer, the annualized bill impact of the base rate changes is estimated to be a decrease of 4.3% or $29 per year, with the billed rate changes estimated to be a decrease of 5.5% or $38 per year.

Centra states it is not requesting a general revenue increase as the non-gas revenues at existing rates are sufficient to recover its non-gas revenue requirement of $148.5 million and produce a projected net income of $2.9 million for the 2019/20 fiscal year.

The purpose of this evidence is to independently evaluate Centra's revenue requirement (non-gas), cost of service and rate design proposals and make rate-setting recommendations to the Public Utilities Board of Manitoba (PUB) for Centra's 2019/20 Test Year.

### 1.1 The 4% Cumulative Rate Increases Forecast at the Last GRA Have Been Offset by Accounting Changes and Lower than Expected Operating Costs and Interest Rates

The financial forecasts available at the 2013/14 GRA, projected that non-gas revenue requirements would increase by $18 million or 12% and that cumulative general rate increases in the order of 4% would be required to 2019/20.

Fortunately for Centra and its customers, the need for these rate increases did not materialize as the underlying cost pressures have been offset by accounting changes and lower than expected operating costs and interest rates.

However, caution is recommended, in that it unlikely that the offsets to cost/rate pressures will reoccur to the same extent in the next 5 to 10 Years and that active cost management by Centra and regular regulatory reviews by the PUB with participation by interested parties, will be necessary in the future to minimize rate increases and protect the public interest.

### 1.2 Centra's Projected Level of Financial Reserves for Rate-Setting Purposes of $96 million for 2019/20 are the Highest they Have Been Under MH's Ownership

The purpose of financial reserves in a crown-owned monopoly like Centra is to promote rate stability for customers. Centra's financial reserves had essentially remained flat (around the $34 million level) over the 2002/03 to 2011/12 period and there was significant concern at the

2013/14 GRA that financial reserves could move into a deficit position if the Company was required to write-off its rate-regulated assets when it transition to IFRS. Forecasts with the continuation of regulated accounting projected increases in financial reserves to $55 million in 2018/19.

Centra has recorded $49 million of actual net income in the six-year period from 2012/13 to 2017/18. In the most recent Centra forecast, the level of financial reserves projected for 2018/19 has essentially doubled to $80 million or 45% higher than the level forecast at the last GRA for 2018/19.

It is recommended that the PUB direct Centra to include the cumulative profit adjustment ($15 million) related to the capitalization of gas meter exchange labour from 2014/15 to 2018/19 as part of the financial reserves for rate-setting purposes. Gas customers have funded these costs in rates during this period and it was Centra's prior intent to make this change coincident with the transition to IFRS. With this adjustment, Centra's financial reserves are projected at approximately $96 million for 2019/20, the highest under Manitoba Hydro (MH) ownership.

### 1.3 It is Recommended That the PUB Adjust Centra's 2019/20 Non-Gas Revenue Requirement Downward by $6 Million for Rate-Setting Purposes

As was the case at the recent MH 2019/20 Rate Application, there are significant concerns with respect to the reliability of Centra's 2019/20 O&A forecast for rate-setting purposes. Based on an analysis of these concerns and considering the PUB's decisions on MH's O&A targets in Order 69/19, it is recommended that the PUB make the following adjustments to the 2019/20 O&A forecast for rate-setting purposes, which total $5.0 million:

1. Adjust the allocation of the VDP and Supply Chain initiative savings upward by $2.7 million (downward adjustment to O&A) to reflect a more appropriate allocation to gas operations of 8% of the savings (compared to 4% proposed by Centra);
2. Adjust the escalation assumptions for 2018/19 and 2019/20 to 1% (compared to 2% proposed by Centra) to reflect the assumption of a productivity factor and for consistency with Order 69/19 related to MH, for a cumulative downward adjustment of $1.2 million; and
3. Adjust the 2019/20 O&A target for an unallocated general contingency of $1.1 million as this contingency has no planned expenditures and has not been justified for rate-setting purposes.

It is also recommended that the PUB re-establish the Power Station minimum margin guarantee of approximately $ 1 million, consistent with the PUB's direction in Order 118/03, which should be included in other income for rate-setting purposes to allow for all customer classes to benefit from the reduced non-gas revenue requirement. This results in the total rate setting adjustments of $6 million, which is equivalent to an overall rate reduction of approximately 1.9% based on current revenues of $308 million, including gas costs.

Other recommendations to the PUB with respect to non-gas revenue requirements are as follows:

1. The PUB should direct Centra to develop an Integrated Cost Allocation Methodology (ICAM) report on an annual basis that can be used to support the allocation of consolidated operating costs and shared costs between Centra and MH at future gas and electric rate setting proceedings;
2. The PUB should obtain further information on the impacts of the 2018 province wide re-assessment on the 2019/20 property tax forecast before approving this forecast into rates. Centra has forecast a 3% increase in property taxes for 2019/20 and had previously forecast property tax increases for the 2012 and 2016 re-assessments but there were actual decreases as a result of the re-assessments;
3. The PUB should direct Centra to provide additional information on its debt management strategies, policies and metrics in future GRA filings and review and report back at the next GRA on identified issues concerning the application of debt policy guidelines. Centra's finance expense is expected to grow significantly in the next 10 years and optimal debt management practices are important to managing these costs; and
4. The PUB should provide further clarification, directives or recommendations with respect to the disposition or alternate use of the $17 million of excess Furnace Replacement Program funding collected from SGS customers. This program was originally directed by the PUB and the excess funding has been outstanding for many years. The Province of Manitoba has recently released a regulation proposing that this excess be transferred to Efficiency Manitoba to offset the cost of gas DSM initiatives.

### 1.4 It is Recommended that the PUB Direct Centra to Address Its Concerns on Strategic Direction, Risk Assessment and Management Structure as Part of the Current Centra Board of Directors Review and Provide the Results at the Next Centra GRA

In Orders 85/13 and 108/15, the PUB outlined its expectations that it would review Centra's strategic vision/plan, management structure, risk analysis and capital expenditure plan at the next GRA to gain a better understanding of the investments the Company is undertaking, the level of service that customers are receiving for these investments, the issues and risks that are facing the utility on a go-forward basis and the level of financial reserves that are required for rate-setting purposes.

The overall assessment of the information in Centra's 2019/20 GRA filing, is that it has not adequately responded to the PUB's concerns as the information remains high-level, concentrated mainly on electric operations, with little information specific to gas operations to assist the PUB in carrying out its rate-setting mandate with respect to Centra.

It is recommended that the PUB direct Centra to consider these issues as part of the comprehensive strategic and financial review that is being undertaken by the MHEB/ Centra Board and provide more fulsome responses at the next Centra GRA.

**1.5 The Level of Projected Indicative Rate Increases (almost 10%) in the Next Eight Years of Centra's Financial Forecast Demonstrates the Need for Regular Regulatory Reviews by the PUB**

Centra's most current financial forecast (CGM18), projects non-gas revenue requirement increases of $36 million or 24% in the next eight years and that cumulative general rate increases in the order of 10% will be required to 2027/28. This compares to approved general rate increases for Centra of around 9% in the last 20 years.

The primary drivers of these projected rate increases include 2% escalation in O&A costs (25%), increases in finance expense, depreciation and capital taxes due to growth in plant assets (64%) and the assumption of an increase in allowed net income (to $7 million) based on the maintenance of an Equity ratio that is around 29% (11%).

Based on the analysis in the evidence, it is concluded that active management/prioritization of operating costs, capital expenditures and Centra's debt portfolio combined with a review of financial reserve target levels is required to alleviate future projected rate pressures on consumers. It is recommended that the PUB reiterate the directive from Order 118/03 that Centra establish regular GRA reviews every three years, given the rate pressures forecast in CGM18.

Regular regulatory reviews will assist the PUB to monitor Centra's progress on cost control, implementation of capital planning/asset management enhancements and management of Centra's debt portfolio and will assist in ensuring that rate pressures that are built up over time or refunds that are due to customers (as well as the finalization of interim Orders) are dealt with on a timely basis.

**1.6 It is Recommended That The Basis For Determining Centra's Financial Reserves for Rate-Setting Purposes Should Be Transitioned to a Minimum Retained Earnings Test Based on a Comprehensive Risk Analysis**

When Centra was under private ownership, gas rates were set for decades based on a rate base/rate of return (RBROR) setting framework with a capital structure not to exceed 40% Equity. The RBROR approach is focused on the maintenance of a desired capital structure (Equity ratio) and the opportunity to earn a fair return on equity (ROE), in order to attract investor equity and issue debt.

Under MH's ownership and since 2005, gas rates have been set based on a modified form of RBROR (MRBROR) where MH's return on its investment in Centra has been limited to the pre-acquisition earnings ($15 million based on a $14 to $16 million range) of the utility when it was an investor owned utility. Based on the MRBROR approach, gas rates have included a $12 million corporate allocation and an allowed net income of $3 million. During this period, the PUB found that the appropriate stand-alone Equity ratio for Centra was 30%, but gas rates have never been set based on this factor.

MH has never set separate financial targets for Centra and for the most part accepted the $3 million allowed net income level. Previously, Centra did not propose actual rate increases or forecast future indicative rate increases based on a 30% Equity ratio. Since the acquisition of Centra, MH's stated policy has been that it does not require a return on investment from Centra and it has proposed rate increases to maintain a reasonable level of financial reserves to promote rate stability for customers. This is consistent with a Modified Cost of Service (MCOS) rate-setting approach.

Centra appears to have adopted a 30% Equity ratio as the basis for its most recent financial forecasts (CGM16 & CGM18) and indicative rate increase projections. It is unclear why Centra has adopted this change in policy or approach and concerning that it has increased its emphasis on the RBROR revenue requirement calculations that continue to be provided in the GRA filings.

In Orders 59/18 and 69/19, the PUB questioned the relevance of the Equity ratio for a crown-owned utility like MH with a provincial debt guarantee and directed the consideration of a Minimum Retained Earnings Test for the purposes of setting electricity rates in the future. There are no appreciable reasons or differences between MH and Centra such that this change in the PUB's rate-setting policy/framework should not be applied to setting gas rates, as well. In fact, the Minimum Retained Earnings Test would be consistent with Centra's status as an integrated crown-owned utility with a provincial debt guarantee, a MCOS rate-setting approach and the previous policy direction to propose rates increases for Centra that maintain a level of financial reserves to promote rate stability for customers.

The recommendations that flow from the evaluation are as follows:

1. That the PUB reject the recommendation of Drazen Consulting Group Inc. (DCGI) that Centra's rates be set using a 30% deemed Equity ratio and a 8.3% ROE, given that this recommendation is inconsistent with the policy intent when MH purchased Centra and the appropriate application of a MCOS approach;
2. That the PUB direct the consideration of the establishment of a Minimum Retained Earnings Test for a future Centra GRA for rate-setting purposes, using the principles, analysis and tools that are to be developed to set MH's rates as a guide, and adapted to Centra's circumstances, as necessary; and
3. That in the interim period, if there is a need for a general rate increase and until the development of a Minimum Retained Earnings Test for Centra is complete, The PUB maintain the $3 million of allowed net income and use the consolidated MH target of 25% Equity, for gas rate-setting.

### 1.7 It Is Recommended That Centra Prepare a Cost Allocation Study At Least Every 2 to 3 Years Even In the Absence of a General Rate Increase

The determination of a regulated utility's rates occurs through three phases, determination of the overall revenue requirements and a reasonable contribution to financial reserves (revenue requirement), the allocation of the revenue requirement to each of the customer classes through the preparation of a cost allocation study, and the design of rates for each of the customer classes (rate design).

A cost allocation study is a basic and necessary tool used for purposes of ratemaking. For Centra with class revenue requirements set to equal class revenue (unity), the cost allocation study is explicitly used to establish rate changes by class. As a result, the preparation and evaluation of a cost allocation study for Centra is not a discretionary exercise.

It is recommended that Centra prepare a Cost Allocation Study at least every 2-3 years, even in the absence of a GRA.

### 1.8 The Evaluation of the Results of the 2019/20 Cost Allocation Study Concludes that the Results Are Reasonable and Consistent with Expectations Even If There Are Significant Impacts to Some of the Customer Classes

Based on an evaluation of the 2019/20 results, compared to both the 2013/14 and 2010/11 Cost Allocation Studies, the results are reasonable, consistent with expectations, but nevertheless produces significant impacts. There is a large divergence from unity (100%) of revenue to cost ratios (RCCs) that flow from the 2019/20 Cost Allocation Study of approximately 60% - 150% (non-gas cost related).

The SGS Class' RCC is 107%, which means that in absence of a cost allocation study and GRA since 2013/14, this class has been overcontributing to cost and subsidizing other customer classes.

The Special Contract Class' RCC is 62% which is almost entirely driven by the additions of Transmission Plant investment since 2013/14 as well as recovery of the portion of the Heating Value Deferral allocated to this customer class. The significant rate impacts to the Special Contract Class as a result of the 2019/20 rate application reflect the fact that Transmission-related costs represent more than 95% of their total cost responsibility.

Growth and plant expansions for the Special Contract Class have been largely met through available transmission capacity over the past couple of decades without an incremental contribution requirement from this Class. Rather, under postage stamp ratemaking policy, all customers have paid a pro-rata share through embedded rates.

Despite the significant impacts to the Special Contract Class and other T-Service customers, Centra's treatment of Transmission (capacity) in the 2019/20 cost allocation study is consistent with its system design and operations. This treatment is consistent with long-standing practice and is a reasonable, principled, and an accepted method of cost allocation.

**1.9 It Is Not Appropriate to Make One-Off Fundamental Changes to the Centra Cost Allocation Methodology in the Absence of a Full Methodological Review or Phase in Impacts of New Transmission Investment Through a Zone of Reasonableness**

While there are other standard cost allocation methodologies employed by natural gas utilities in Canada, it is not advisable to make arbitrary changes to Centra's current methodology in the absence of a full methodological review that considers the cohesiveness of the full suite of methodologies employed. There are bill mitigation measures that can be employed to address bill impacts and volatility. One-off fundamental changes to address significant bill impacts can lead to unintended consequences.

It is also not reasonable to allow the impacts associated with new Transmission investment to be gradually phased in through a Zone of Reasonableness (allowing customer class RCCs below and above unity for a period of time), given that the SGS Class Customers have been overcontributing to revenues over the period since 2013/14 and this option would perpetuate the overcontribution/cross-subsidization of the impacted classes by the SGS class.

To the extent that the PUB is concerned that the significant bill impacts to larger volume customers warrant an alternate treatment from Centra's rate proposals, a deferral mechanism associated with the impacts of new Transmission investment payable overtime by the participatory classes is an appropriate option that could be considered. Another option open to the PUB to mitigate the impacts to the Special Contract customer customers is to discontinue the allocation of the heating value deferral account to this customer class, recommended as part of the 2012 external review of Centra's cost allocation methodology.

**1.10 It Is Recommended that the PUB Direct Centra to Examine its Cost Allocation & Rate Design Related to the Power Station Class and Undertake a Thorough Review of Its Cost Allocation & Rate Design Methodologies Through a Generic Regulatory Proceeding**

It is recommended that Centra be directed to examine its approach to cost allocation and rate design related to the Power Station Class. In the Interim, until this review occurs, it is also recommended that the Power Station minimum margin guarantee ($947,000) be re-established (consistent with the prior PUB's direction in Order 118/03) to ensure that this customer class has the appropriate cost responsibility and applied as other income as part of Centra's 2019/20 revenue requirement to allow for all customer classes to benefit from a reduced revenue requirement.

It is recommended that Centra be directed to undertake a thorough review of its cost allocation and rate design methodologies and that the outcome of this review be considered at a future generic proceeding.  The last comprehensive review of Centra's cost allocation methodology and rate design occurred in 1996, nearly 25 years ago, and as a result of changes and issues that have emerged since that time, it is appropriate for the PUB to schedule a generic review.

## 2.0 Qualifications and Areas of Responsibility

This section of the evidence provides a brief overview of the qualifications of Mr. Rainkie and Ms. Derksen and their areas of responsibility with respect to the Centra 2019/20 GRA.

### 2.1 Darren Rainkie – Statement of Qualifications & Areas of Responsibility

Mr. Rainkie received his Bachelor of Commerce (Honours with Distinction) from the University of Manitoba in 1988. He received his Chartered Professional Accountant (Chartered Accountant) designation in 1991 and his Chartered Business Valuator designation in 1993.

Mr. Rainkie is the principal of the consulting practice he established in 2017 which leverages his 30-years of experience in energy regulation, utility & financial management and financial advisory services. He specializes in natural gas and electricity energy regulation which is informed by his broad expertise in utility and financial management.

Prior to establishing his consulting practice, Mr. Rainkie was employed with Price Waterhouse, Chartered Accountants from 1988-1994, which included consulting as an accounting and finance advisor to the Manitoba Public Utilities Board (1990-1994). He then was employed with Centra Gas (Westcoast Energy) from 1994-1999, first as Senior Financial Analyst, and then as Senior Regulatory Coordinator. Mr. Rainkie was employed with Manitoba Hydro & Centra Gas from 1999-2017 in various senior leadership roles including Manager of the Regulatory Services Department, Corporate Treasurer, Corporate Controller, Acting President and Chief Executive Officer and Vice-President, Financial & Regulatory Affairs and Chief Financial Officer.

Throughout his career, Mr. Rainkie has gained significant experience in all aspects of energy regulation including policy, strategy, revenue requirement, cost of capital/capital structure, cost allocation, rate design and major project reviews, as well as the planning and management of numerous regulatory applications and associated hearing processes. This experience includes over 17 years of acting as an executive policy witness and subject matter witness at multiple natural gas and electricity applications before the Manitoba Public Utilities Board (PUB).

Mr. Rainkie's last appearance before the PUB was as an independent expert witness on behalf of the Consumers Coalition in the Manitoba Hydro 2019/20 Rate Application proceeding that occurred in April of 2019.

Previously, Mr. Rainkie represented Centra as an executive policy witness at the 2015/16 Cost of Gas Application and the 2013/14 General Rate Application. He also represented Centra as a subject matter witness on numerous occasions since 2000 and his experience with natural gas regulatory matters dates back to 1990 when he consulted as an advisor to the PUB.

Mr. Rainkie's full curriculum vitae was attached as Appendix C to CAC's Intervenor Registration (CAC exhibit #1).

In this regulatory proceeding, Mr. Rainkie led the preparation of evidence and evaluation of Centra's revenue requirement (non-gas) proposals of behalf of the CAC, which is contained in Sections 4.0 to 9.0 of this evidence.

### 2.2 Kelly Derksen – Statement of Qualifications & Areas of Responsibilities

Kelly Derksen received her Bachelor of Science (Chemistry and Mathematics) from the University of Manitoba in 1995 and her Chartered Professional Accountant designation in 2004.

Ms Derksen is the principal of the consulting practice she established in 2018 leveraging from nearly 25-years of experience in both a privately-owned natural gas utility and one of Canada's largest publicly owned, vertically integrated electric and natural gas utilities. She specializes in regulation and ratemaking, with an emphasis on cost of service, and rate design.

Prior to establishing her consulting practice, Ms. Derksen was employed with Centra Gas (Westcoast Energy) from 1994-1999, first as a coordinator, Regulatory Affairs, then as a Regulatory Analyst responsible for the preparation of the Corporation's Revenue Requirement. Ms. Derksen was employed with Manitoba Hydro and Centra Gas from 1999-2017 in various analyst roles including Analyst and Senior Analyst (Gas Rates) and management roles including Manager, Gas Rates & Regulatory Services and Manager, Cost of Service.

Throughout her career, Ms. Derksen gained significant experience in all aspects of utility regulation and ratemaking including strategy, revenue requirement, cost allocation, rate design as well as the planning and management of numerous regulatory applications and associated hearing processes. This includes having testified as a subject matter witness for over 16 years at many natural gas and electric hearings and before the Manitoba Public Utilities Board (PUB). Ms. Derksen testifed before the PUB related to the 2016 Cost of Service Methodology Review, for which she was the driving force and key witness.

Ms. Derksen's last appearance before the PUB was as an independent expert witness on behalf of the Consumers Coalition in the Manitoba Hydro 2019/20 Rate Application proceeding that occurred in April of 2019.

Ms. Derksen represented Centra as a subject matter witness before the on numerous occasions since 2002, the most recent of which was at the 2013/14 General Rate Application. She was also instrumental in the development of Centra's cost allocation and rate design proposals as part of Centra's 2015/16 Cost of Gas Application. Ms. Derksen's experience with natural gas regulatory and rate matters dates back nearly 25 years.

Ms. Derksen's full curriculum vitae was attached as Appendix D to CAC's Intervenor Registration (CAC exhibit #1).

In this regulatory proceeding, Ms. Derksen led the preparation of evidence and evaluation of Centra's cost of service and rate design proposals on behalf the CAC, which is contained in Section 10.0 of this evidence.

## 3.0 Introduction & Overview of Centra's 2019/20 Rate Application

The last comprehensive review of Centra's non-gas revenue requirement occurred as part of the 2013/14 GRA, which was filed in January of 2013. The oral hearing of Centra's 2013/14 GRA was held in June and July of 2013 and resulted in Order 85/13.

The last comprehensive cost of gas review occurred as part of the 2015/16 Cost of Gas Application, which was filed in May of 2015. The oral hearing of Centra's 2015/16 Cost of Gas Application was held in September of 2015 and resulted in Order 108/15.

On November 30, 2018, Centra filed an application with the PUB requesting approval of Supplemental Gas, Transportation and Distribution rates, the Primary Gas Overhead rate and the Fixed Rate Primary Gas Service Program Cost rate. The various approvals that Centra requested in the application can be summarized as follows:

1. Approval to dispose the balances in prior period Purchased Gas Variance Accounts for the period November 1, 2014 to October 31, 2018 through rates riders over a 12-month period (estimated net refund of $6.4 million);
2. Approval of adjustments to rates to reflect changes in forecast non-Primary Gas costs for the 2018/19 Gas Year (estimated reduction of $3.8 million);
3. Approval to discontinue funding the Furnace Replacement Program and remove the associated costs from the rates of the Small General Service class (reduction of $3.8 million on an annualized basis);
4. Approval of updated depreciation rates/new depreciation accounts determined during and subsequent to the 2014 Depreciation study, endorsement of regulatory deferral accounts/proposed amortization periods recognized by Centra subsequent to the 2013/14 GRA and endorsement to discontinue and write off the accrued balance the Demand Side Management deferral accounts;
5. Approval of certain proposed storage and transportation costs to be effective April 1, 2020;
6. Approval of changes to the Terms & Conditions of Service;
7. Final approval of actual gas costs for the four gas years from November 1, 2014 to October 31, 2018; and
8. Final approval of a number of interim Orders of the PUB.

Centra updated its application on March 22, 2019 and provided calculations of Base and Billed rate impacts that resulted from the updated application for the various customer classes based on a November 1, 2019 implementation date. The annualized bill impact resulting from base rate changes proposed for November 1, 2019 for the typical residential customer was estimated by Centra to be a decrease of approximately 4.3% or $29 per year. The change in the billed rates was estimated by Centra to result in a decrease for the typical residential customer of approximately 5.5% or $38 per year.

As part of the updated application, Centra updated its outlook for the 2018/19 Test Year, indicating that it was projecting a net income of $4.4 million (original application forecast was $3.3 million). Centra indicated that it was not requesting a general revenue increase as the non-gas revenues at existing rates (after removal of the Furnace Replacement Program funding) were sufficient to recover the projected non-gas revenue requirement for the 2019/20 Test Year of $148.5 million and result in a forecast net income of $2.9 million (original application forecast was $2.3 million). Based on the updated forecasts, Centra is projecting that its Equity ratio for 2018/19 and 2019/20 will be approximately 32%.

Centra intends to file a Pre-hearing update including actual gas costs for the 2017/18 Gas Year, updated forecasts of gas costs for the 2018/19 Gas Year and actual gas cost deferral account balances to the end of April of 2019 with forecast information to October 31, 2019. Centra also intends to provide an update to its interest rate forecast when it files its rebuttal evidence, in accordance with a previous directive of the PUB.

**Purpose and Organization of the Evidence**

The main purpose of the evidence is to evaluate Centra's revenue requirement (non-gas), cost of service and rate design proposals for the 2019/20 Test Year and provide the resulting observations, conclusions and recommendations to the PUB for rate-setting purposes.

The overall organization of the detailed sections of the evidence generally follows the three-step sequential phases of utility rate-setting, revenue requirement, cost of service and rate design. Non-gas revenue requirements and related strategic issues (strategic direction, risk assessment, financial outlook and financial targets) are reviewed first. Then cost allocation and rate design issues are reviewed. Regulatory compliance issues are addressed in the various sections of the issues to which they relate.

The non-gas revenue requirement sections of the evidence are organized as follows:

- Section 4.0 bridges the six-year timeframe since the last GRA in 2013/14 and reviews the financial forecasts, revenue requirement changes and indicative rate increases that were expected at that time;
- Section 5.0 reviews the expectations with respect to financial reserves at the last GRA and contrasts these projections with the current assessment of Centra's financial position;
- Section 6.0 reviews issues associated with the current 2019/20 Test Year application and makes recommendations with respect to these issues;
- Section 7.0 reviews the PUB concerns with respect to forward looking strategic considerations such as Centra's strategic direction and risk assessments;
- Section 8.0 reviews Centra's most up to date financial forecasts including projected revenue requirement and indicative rate increase expectations as well as implications for future regulatory reviews; and

- Section 9.0 reviews future considerations with respect to Centra's financial targets and financial reserves for rate-setting purposes.
- Section 10.0 of the evidence reviews Centra's cost allocation methodology and cost allocation and rate design proposals for the 2019/20 Test Year.

## 4.0 The 4% Cumulative Rate Pressures Forecast at the Last GRA Have Been Offset by Accounting Changes and Lower Operating Costs and Interest Rates

As previously mentioned, the last comprehensive review of Centra's non-gas revenue requirements for rate-setting purposes occurred at the 2013/14 GRA in June of 2013.

This section of the evidence reviews the changes in Centra's non-gas revenue requirements between 2013/14 and 2019/20 and concludes that the forecast increase in non-gas revenue requirements of 12% (equivalent of cumulative general rate increases of around 4%) between 2016/17 and 2019/20 at the last GRA have been offset by accounting changes and lower operating cost and interest rates. This section concludes by cautioning that it is unlikely that the circumstances that offset the rate pressures in the last five or more years will occur to the same extent in the next 5 to 10 years. The implications of this conclusion for future regulatory reviews is further reviewed in Section 8.0 of the Evidence.

### 4.1 Centra was Projecting at the Last GRA That Non-Gas Revenue Requirements Would Increase By 12% and That General Rate Increases in the Order of 4% Would be Required to 2020

As is discussed further in Section 5.2 of the Evidence, at the 2013/14 Centra GRA there was significant uncertainty with respect to the ability of the Company to continue with the practice of rate-regulated accounting. As a result of this uncertainty and the potential negative impacts on Centra's retained earnings (including the prospect of negative retained earnings), the were a number of alternative financial forecast scenarios that were produced and evaluated for the purposes of setting rates for the 2013/14 fiscal year.

The forecast scenario that provides the most appropriate comparison between the outlook at the 2013/14 GRA and the current outlook for 2019/20 and is most reflective of the PUB decisions in Order 85/13, assumed the deferral of the implementation of IFRS by one year, the "grandfathering" of rate-regulated accounting and indicative rate increases necessary to produce an allowed net income for rate-setting purposes of $3 million annually. This financial scenario was provided in the response to PUB/Centra I-16 (d) from the last GRA and has also been provided in the responses to CAC/Centra I-4 (e) attachment and CAC/Centra II-125 (c) in the current proceeding and will be referred to as "CGM12 with RRA" in this Evidence.

Figure 1 provides a summary of the key financial parameters contained in CGM12 with RRA for the period between 2013/14 and the current 2019/20 Test Year:

**Figure 1 - Summary of CGM12 with RRA Financial Outlook**

| | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|---|---|
| Rate Increase | 1.19% | 1.48% | -1.49% | 1.50% | 1.03% | 0.47% | 0.82% |
| Cumulative Rate Increase | 1.19% | 2.69% | 1.16% | 2.68% | 3.74% | 4.24% | **5.09%** |
| Cumulative Additional Revenue | 4 | 9 | 4 | 9 | 13 | 15 | 17 |
| Annual Additional Revenue | 4 | 5 | -5 | 5 | 4 | 2 | 2 |
| Net Income | 3 | 3 | 3 | 3 | 3 | 3 | 3 |
| Retained Earnings | 39 | 42 | 46 | 49 | 52 | 55 | 58 |
| Equity Ratio | 20% | 20% | 20% | 20% | 20% | 20% | 20% |
| | | | | | | | |
| Net Plant in Service | 439 | 454 | 477 | 502 | 515 | 528 | 541 |
| Net Regulated Assets | 78 | 76 | 73 | 69 | 63 | 57 | 49 |
| Other Assets | 78 | 76 | 75 | 74 | 75 | 77 | 79 |
| **Total Assets** | **595** | **606** | **625** | **645** | **653** | **662** | **669** |

**Source: CAC/Centra I-4 e & CAC/Centra II-125 c**

The key observations from Figure 1 are as follows:

1. CGM12 with RRA was prepared assuming that the transition to IFRS would be deferred to 2015/16, that rate-regulated accounting would be grandfathered throughout the timeframe of the forecast and included indicative rate increases to maintain an allowed net income of $3 million throughout the period of the forecast;
2. In CGM12 with RRA, Centra was projecting that its total assets would increase from $595 million in 2013/14 to $669 million in 2019/20, an increase of $74 million or 12%. Over that time frame Centra's net plant in service was projected to increase from $439 million to $541 million, an increase of $102 million or 23%;
3. The indicative rate increase for 2014/15 of 1.48% was offset by an indicative rate decrease for 2015/16 of 1.49%;
4. Indicative rate increases for 2016/17, 2017/18, 2018/19 and 2019/20 were projected at 1.50%, 1.03%, 0.47% and 0.82%, respectively;
5. For the period between 2016/17 and 2019/20, cumulative rate increases of 3.87% (in the order of 4%) were projected related to non-gas revenue requirements. This accumulates to additional revenues of $13 million ($17-$4) between 2016/17 and 2019/20;
6. The Equity ratio was forecast to be maintained at the 20% level throughout the period of 2013/14 to 2019/20; and
7. Retained earnings were projected to increase from $39 million to $58 million between 2013/14 and 2019/20, an increase of $19 million or 49%.

Figure 2 provides a summary of the components of projected non-gas revenue requirements from 2014/15 to 2019/20, with a comparison of the base year in the analysis of 2013/14:

| Figure 2 - CGM12 with RRA Non-Gas Revenue Requirement | | | | | | | |
|---|---|---|---|---|---|---|---|
| | **2014** | **2015** | **2016** | **2017** | **2018** | **2019** | **2020** |
| Operating & Administrative | 69 | 71 | 70 | 71 | 73 | 74 | 76 |
| Finance Expense | 17 | 19 | 20 | 22 | 23 | 23 | 24 |
| Depreciation & Amortization | 30 | 31 | 30 | 31 | 32 | 32 | 33 |
| Capital & Other Taxes | 19 | 19 | 19 | 19 | 20 | 20 | 20 |
| Corporate Allocation | 12 | 12 | 12 | 12 | 12 | 12 | 12 |
| Less: Other Incone | (2) | (2) | (2) | (2) | (2) | (2) | (2) |
| **Net Non-Gas Expenses** | **145** | **150** | **149** | **153** | **158** | **159** | **163** |
| Net Income | 3 | 3 | 3 | 3 | 3 | 3 | 3 |
| **Total Non-Gas Revenue Requirement** | **148** | **153** | **152** | **156** | **161** | **162** | **166** |
| | | | | | | | |
| **Source: CAC/Centra I-4 e & CAC/Centra II-125 c** | | | | | | | |

Figure 3 provides an analysis of the year over year and cumulative increases in the components of projected non-gas revenue requirements from 2014/15 to 2019/20, using 2013/14 as a base year:

| Figure 3 - CGM12 with RRA Non-Gas Revenue Requirement Changes | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | **2015** | **2016** | **2017** | **2018** | **2019** | **2020** | **Increase 2020 vs. 2014** | **Average Annual Increase** |
| Operating & Administrative | 2 | **(1)** | 1 | 2 | 1 | 2 | 7 | 1.2 |
| Finance Expense | 2 | 1 | 2 | 1 | 0 | 1 | 7 | 1.2 |
| Depreciation & Amortization | 1 | **(1)** | 1 | 1 | 0 | 1 | 3 | 0.5 |
| Capital & Other Taxes | 0 | 0 | 0 | 1 | 0 | 0 | 1 | 0.2 |
| Corporate Allocation | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Less: Other Incone | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Net Non-Gas Expeneses** | **5** | **(1)** | **4** | **5** | **1** | **4** | **18** | 3.0 |
| Net Income | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Total Non-Gas Revenue Requirement** | **5** | **(1)** | **4** | **5** | **1** | **4** | **18** | **3.0** |
| | | | | | | | | |
| **Percentage Increase:** | | | | | | | | |
| Net Non-Gas Expeneses | 3.5% | -0.7% | 2.7% | 3.3% | 0.6% | 2.5% | **12.4%** | 2.1% |
| Total Non-Gas Revenue Requirement | 3.4% | -0.7% | 2.6% | 3.2% | 0.6% | 2.5% | **12.2%** | 2.0% |

The key observations from Figure 2 and Figure 3 are as follows:

1. Total non-gas expenses (excluding net income) were expected to increase from $145 million in 2013/14 to $163 million in 2019/20, an increase of $18 million or 12.4%. This equates to an average annual increase of approximately $3.0 million or 2.1% per year;
2. Total non-gas revenue requirements (including net income) were expected to increase from $148 million in 2013/14 to $166 million in 2019/20, an increase of $18 million or 12.2%. This equates to an average annual increase of approximately $3.0 million or 2.0% per year;
3. O&A was projected to increase by $7 million or $1.2 million per year, which appears to be primarily a function of the assumption of 2% annual escalation in CGM12;
4. Finance Expense was projected to increase $7 million or $1.2 million per year, Depreciation & Amortization (D&A) was projected to increase $7 million or $1.2 million per year and Capital & Other Taxes is projected to increase $1 million or $0.2 million per year. These three expense categories increase on average about $1.9 million per year with the primary driver being the increase in projected net plant as a result of planned capital expenditures. It is noted that there are other drivers of these expense categories such as changes in forecast interest rates and property taxes, but it expected that the primary driver is growth in plant assets;
5. Net income was projected to remain at $3 million in each year of the forecast period and was not contributing to the expected requirement for indicative rate increases; and
6. In total, all of the categories of non-gas revenue requirements are increasing at an average rate of about $3.0 million per year which based on overall projected revenues in the order of about $350 million (including gas costs) result in projected indicative general rate increase of about 0.8% per year.

In summary, at the time of the 2013/14 GRA, Centra was forecasting cumulative indicative rate increases in the order of 4% for the six-year period between 2014/15 and 2019/20. Of the $18 million projected increase in non-gas revenue requirements, O&A increases were driving about $7 million or 39% of the increase and capital expenditures and growth in net plant were driving a significant portion of the increases in Finance Expense, Depreciation & Amortization (D&A) and Capital & Other taxes that total $11 million or 61% of the increase.

## 4.2 The Rate Pressures Forecast at the Last GRA Were Offset by Accounting Changes and Lower than Expected Operating Costs and Interest Rates

In contrast to the forecast of cumulative indicative rate increases in the order of 4% at the last GRA, there were no general rate increases requested by Centra between 2014/15 and 2018/19 and Centra has indicated in the 2019/20 GRA filing that it is not requesting a general rate increase for non-gas costs in the 2019/20 Test Year.

A normal part of the review at each GRA proceeding is for the PUB and Intervenors to understand the changes that have occurred in costs and revenues (as well as rates) from the prior GRA. At a detailed level, such an analysis would include the changes in revenues at existing rates as a revenue deficiency or sufficiency in a particular test year is a function of both non-gas cost changes and volumetric changes. In the circumstances of Centra, this analysis would also consider changes in the level of funding of the Furnace Replacement Program which is embedded in the base rates charged to the SGS customers.

For the purposes of the analysis in this section of the Evidence, the high-level focus is on the changes in the non-gas revenue requirements. A comparison of the non-gas revenue requirement deficiency including volume/revenue changes and the Furnace Replacement Program is provided in Section 6.1 of the Evidence.

Figure 4 provides two comparisons (1) a comparison of non-gas revenue requirements, assets and retained earnings for the 2019/20 fiscal year between CGM18 and CGM12 with RRA and (2) a comparison of the same financial metrics between CGM18 for 2019/20 and CGM12 with RRA for the 2013/14 fiscal year:

**Figure 4 - Comparisons of CGM18 & CGM12 with RRA - Rate Setting Comparison (Net Movement Allocated)**

| | **CGM18 2020** | **CGM12 2020** | **Change 2020** | | **CGM18 2020** | **CGM12 2014** | **Change 2020 vs.2014** |
|---|---|---|---|---|---|---|---|
| Operating & Administrative | 60 | 76 | (16) | | 60 | 69 | (9) |
| Finance Expense | 22 | 24 | (2) | | 22 | 17 | 5 |
| Depreciation & Amortization | 33 | 33 | 0 | | 33 | 30 | 3 |
| Capital & Other Taxes | 20 | 20 | 0 | | 20 | 19 | 1 |
| Corporate Allocation | 12 | 12 | 0 | | 12 | 12 | 0 |
| Less: Other Incone | (2) | (2) | 0 | | (2) | (2) | 0 |
| **Net Non-Gas Expeneses** | **145** | **163** | **(18)** | | **145** | **145** | **0** |
| Net Income | 3 | 3 | 0 | | 3 | 3 | 0 |
| **Total Non-Gas Revenue Requirement** | **148** | **166** | **(18)** | | **148** | **148** | **0** |
| | | | | | | | |
| Net Plant in Service | 579 | 541 | 38 | | 579 | 439 | 140 |
| Net Regulated Assets | 95 | 49 | 46 | | 95 | 78 | 17 |
| Other Assets | 103 | 79 | 24 | | 103 | 78 | 25 |
| **Total Assets** | **777** | **669** | **108** | | **777** | **595** | **182** |
| | | | | | | | |
| Retained Earnings | 83 | 58 | 25 | | 83 | 39 | 44 |

**Sources:**
CGM18 - Appendix 5.12 (Updated), Figures 2 & 3 and Appendix 3.6
CGM12 with RRA - CAC/Centra I-4e

The key observations from Figure 4 are as follows:

1. The presentation in CGM18 has been adjusted from the financial reporting perspective to the rate-setting perspective (other expenses and net movement in regulatory accounts have been allocated to other expense items) to improve the comparability with CGM12 with RRA and is based on the reconciliation provided by Centra in Appendix 5.12, Figures 2 & 3, pages 3 and 4;
2. In the first comparison, the total non-gas revenue requirement in 2019/20 for CGM18 is $148 million which is $18 million lower than the projections contained in CGM12 with RRA for 2019/20;
3. In the first comparison, total assets in 2019/20 are $777 million for CGM18 or $108 million (16%) higher than the projections contained in CGM12 with RRA for 2019/20;
4. In the second comparison, the total non-gas revenue requirement in 2019/20 for CGM18 is $148 million which is consistent with the level of non-gas revenue requirement forecast for 2013/14 in CGM12 with RRA; and
5. In the second comparison, total assets in 2019/20 are $777 million for CGM18 or $182 million (31%) of asset growth over the level of total assets that was projected for 2013/14 in CGM12 with RRA.

**Comparison of CGM18 for 2019/20 Versus CGM12 with RRA for 2019/20**

The implication of the first comparison is that the $18 million of growth in non-gas revenue requirements that was forecast at the last GRA for the period of 2014/15 to 2019/20 did not materialize despite the fact that total assets are expected to be $108 million or 16% higher in 2019/20 than was forecast at the last GRA. This explains why the projected 4% cumulative general rate increases projected in the last GRA were not needed.

**Comparison of CGM18 2019/20 Versus CGM12 with RRA for 2013/14**

The implication of the second comparison is that the level of non-gas revenue requirements for 2019/20 in CGM18 has not changed in a material way (both are at the $148 million level) since the 2013/14 GRA despite a growth in assets of $182 million or 31%. This explains why Centra is not requesting a non-gas revenue requirement increase for the 2019/20 Test Year.

**Analysis of Changes in Non-Gas Revenue Requirements Since the 2013/14 GRA**

The ability to analyze and explain the reasons for the changes in the forecast of non-gas revenue requirements for 2019/20 since the 2013/14 GRA is complicated by (1) the passage of time since the last GRA and compounded by (2) the transition to IFRS which has resulted in the introduction of net movement in regulatory accounts and other expenses as well as numerous reclassification changes and (3) the sheer number of variables that impact Centra's revenue requirement forecasts.

Centra's financial reporting systems and GRA minimum filing requirements are designed to produce year over year comparisons and budget versus actual comparisons for one fiscal year but are not designed to produce meaningful multi-year comparisons spanning six years.

However, at a high-level a number of the drivers of the offsets to the cost (increase in non-gas revenue requirements of $18 million) and rate pressures (indicative rate increases in the order of 4%) that were forecast to 2019/20 at the last GRA include:

- A reduction in O&A expenses of $4.1 million from the $68.8 million forecast level included in rates in 2013/14 to $64.7 million in 2016/17 (Appendix 5.12 Updated – Figure 2) due to cost containment efforts (staff reductions) and underspending in a number of gas operating programs (reduction in hours spent on gas programs);
- An estimated reduction in O&A expenses of $2.7 million related to labour savings from the VDP and Supply Chain Initiative between 2017/18 and 2019/20 (response to CAC/Centra I-12 (d)(e);
- An estimated reduction in O&A expenses of $3.0 million related to the change in the accounting policy to capitalize gas meter exchange costs in 2019/20 (Appendix 5.9, Page 4); and
- An estimated reduction in Depreciation & Amortization expense of $5.4 million (for 2019/20) related to the removal of negative salvage value from gas depreciation rates upon transition to IFRS (Appendix 5.11, Page 3).

There are many complex variables that form part of the finance expense forecasts and it is expected that interest rate projections for 2019/20 are likely significantly lower than those which were projected at the 2013/14 GRA and would contribute to the reduction in projected non-gas cost revenue requirements as compared to the last GRA. There does not appear to be quantification of the impact of lower than expected interest rates on the record of this proceeding.

It is noted that the current long-term debt interest rate (including the provincial guarantee fee) projected in the current proceeding for 2019/20 is 4.80% (Appendix 3.8, Page 4). While forecasts for the 2020/19 fiscal year from the last GRA are not readily available a point of comparison from forecasts of that timeframe would be the forecast of the long-term debt interest rate on page 3 of IFF12 for the 2021/22 fiscal year of 6.30% (including the provincial guarantee fee). It is also noted that on a year over basis, Centra's weighted average interest rate has declined from 4.89% in 2013/14 to a projected level of 4.76% in 2019/20 (response to PUB/Centra II-27) while its average debt has grown from $327 million to $433 million (an increase of $106 million) over that timeframe.

While this analysis is at a high-level and complicated by a number of factors as noted above, the overall conclusion is that the current non-gas revenue requirement is consistent with the level reviewed at the last GRA (approximately $148 million) and the rate pressures that were forecast in CGM12 with RRA have been offset by accounting changes and lower than expected operating costs and interest rates.

### 4.3 It is Unlikely that the Offsets to Cost/Rate Pressures that have Occurred in the Last Six Years Will Occur to the Same Extent in the Next 5 to 10 Years

It has been relatively fortunate for Centra and its customers that the cost/rate pressures that were forecast at the last GRA have been largely offset and the requirement for the projected general rate increases in the order of 4% has not materialized.

However, the high-level review of the reasons for the ability to manage cost/rate pressures over the last six years (Section 4.2) would appear to indicate that the PUB and interest parties to the Centra rate-setting process should not expect or assume that these circumstances can continue at the same level or repeat themselves in the near future for a number of reasons:

1. There will always be expectations of on-going active cost control by a publicly owned regulated monopoly like Centra, but it cannot be assumed that a broad-based VDP will occur again in the near future;
2. Financial reporting standards are always evolving, but it cannot be assumed that a transition of the magnitude of IFRS with the associated accounting changes that have reduce expenses (O&A and D&A) will occur in the future;
3. Interest rates may not rise at the pace that has been projected due to lower than expected economic growth, but it cannot be expected that comparatively low interest rates will continue indefinitely; and
4. While Centra is planning to develop and implement improved capital planning and asset management practices and systems to better understand, justify and prioritize future required capital expenditures, Centra’s plant is aging and the number of customers that it services are growing and as such it is expected that plant will continue to grow in the future.

The conclusion from this section of the evidence is that it is unlikely that the offsets to cost/rate pressures that have occurred in the last six years will occur to the same extent in the next 5 to 10 Years.

The long-term cost/rate pressures and projected indicative rate increases contained in CGM18, as well as the implications for future regulatory reviews, will be reviewed in Section 8.0 of the Evidence. The magnitude of future cost/rate pressures will require careful and active management by Centra, regular regulatory reviews by the PUB and participation by interested parties in order to minimise required rate increases and protect the public interest.

## 5.0 Centra's Projected Level of Financial Reserves of $96 million for 2019/20 are the Highest they Have Been Under MH's Ownership

The purpose of financial reserves in a crown-owned monopoly like Centra is to promote rate stability for customers. The last review of Centra's financial reserves for rate-setting purposes occurred at the 2013/14 GRA, when Centra was projecting financial reserves (retained earnings) of approximately $36 million in 2012/13 and $39 million in 2013/14.

This section of the evidence reviews the changes in Centra's financial reserves since the 2013/14 GRA and observes that the projected level of financial reserves for 2018/19 of $80 million have doubled since the last GRA and are 45% higher than forecast at the last GRA. This section concludes by recommending that the $15 million cumulative profit adjustment related to the capitalization of gas meter exchange labour from 2014/15 to 2018/19 be attributed to Centra's financial reserves for rate-setting purposes, resulting in projected financial reserves of $96 million for the 2019/20 test year. This is the highest level of financial reserves under MH's ownership.

### 5.1 Centra's Level of Financial Reserves had Remained Essentially Flat (Around $34 million) Between 2002/03 and 2011/12

Figure 3.5 (section 3.3.3) of the 2019/20 GRA filing contains an analysis of annual earnings and cumulative retained earnings for the sixteen-year period between 2002/03 and 2017/18. The 1990/00 to 2001/02 fiscal years were excluded from the analysis as the consolidated accounting practices were such that these years are not comparable. The key highlights of Figure 3.5 are as follows:

- 2002/03 actual retained earnings = $35.0 million (first year of analysis);
- 2005/06 actual retained earnings = $20.1 million (low point of the analysis); and
- 2011/12 actual retained earnings = $34.3 million (last actual year available before 2013/14 GRA).

As can be seen from the highlights, between 2002/03 and 2011/12 (last year of actual information available before the 2013/14 GRA), actual retained earnings were essentially flat for Centra at the $34 million level and at the time of the filing of the 2013/14 GRA.

Centra expressed concern at the 2013/14 GRA that the approach of allowing a $3 million net income in gas rates since 2003/04 had not resulted in any retained earnings growth, with losses and net income over that period of time essentially being equal and offsetting.

## 5.2 There was Significant Concern Over the Projected Levels of Centra's Financial Reserves at the 2013/14 GRA

**CGM12 Financial Outlook – 2013/14 GRA**

The 2013/14 Centra GRA was based on the financial projections contained in CGM12. At the time of the filing of the 2013/14 GRA in late January of 2013, Centra was projecting that it would be required to write-off rate-regulated assets of approximately $77 million to retained earnings upon the adoption of IFRS in 2014/15.

As a result of the risk of a retained earnings deficit and the concern over the stagnation of retained earnings levels noted above, Centra included proposed and indicative rate increases in CGM12 that were designed to produce an average net income of $6 million in order to gradually reduce the projected retained earnings deficit (deficit between $27 and $2 million) and return to a small surplus position of $13 million of retained earnings by the end of the 10-year period to 2021/22.

These projections were based on the proposed and indicative non-gas rate increases in CGM12 that totalled 5.10% cumulatively between 2013/14 and 2021/22. In CGM12, it was projected that the equity ratio would deteriorate from 34% in 2012/13 to 23% in 2021/22 (response to PUB/Centra I-10 (a) from the 2013/14 GRA).

Figure 5 summarizes the key financial parameters from CGM12:

**Figure 5 - Summary of CGM12 Financial Outlook**

| | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 |
|---|---|---|---|---|---|---|---|---|---|
| Rate Increase | 2.00% | | | | 0.50% | 0.75% | 0.50% | 0.50% | 0.75% |
| Cumulative Rate Increases | 2.00% | 2.00% | 2.00% | 2.00% | 2.51% | 3.28% | 3.80% | 4.31% | **5.10%** |
| Cumulative Additional Revenue | 7 | 7 | 7 | 7 | 9 | 11 | 13 | 15 | 18 |
| Annual Additional Revenue | 7 | 0 | 0 | 0 | 2 | 2 | 2 | 2 | 3 |
| Net Income | 6 | 9 | 9 | 5 | 5 | 6 | 6 | 5 | 4 |
| Retained Earnings | 41 | **(27)** | **(18)** | **(13)** | **(7)** | **(2)** | 4 | 9 | 13 |
| Equity Ratio | 33% | 27% | 22% | 22% | 23% | 23% | 23% | 23% | 23% |

**Source: PUB/Centra I-10 (a) 2013/14 GRA**

The key observations from Figure 5 are as follows:

1. CGM12 projected a retained earnings deficit of $27 million in 2014/15 that was gradually reduced to a deficiency of $2 million by 2018/19 and balance of $4 million in 2019/20; and
2. CGM12 projected the Equity ratio to be 23% in 2018/19 and 2019/20.

**CGM12 with RRA Financial Outlook – 2013/14 GRA**

After the filing of the 2013/14 GRA, the adoption of IFRS by Centra was deferred by an additional year to 2015/16 and the International Accounting Standards Board (IASB) indicated that it planned to issue a draft standard to continue to permit the use of rate-regulated accounting on an interim basis for first time adopters of IFRS. At the time of the last GRA hearing, there was still uncertainty as to the approval of the interim standard and the final outcome of the IASB's project on rate-regulated activities and whether or not rate-regulated accounting would be permitted over the long-term. The interim standard was issued in April of 2013 and was not approved by the IASB until January of 2014.

During the discovery process, an alternate version of CGM12 was provided that assumed the deferral of adoption of IFRS until 2015/16 and the "grandfathering" of rate-regulated accounting as well as rate increases to reflect a $3 million net income (response to PUB/Centra I-16 (d) from the last GRA). As was noted in Section 4.1 of the Evidence, this scenario is referred to as CGM12 with RRA and is the most appropriate scenario on the record of the 2013/14 GRA that will allow for comparisons to the current 2019/20 GRA.

Figure 1 from Section 4.1 provides a summary of the key financial parameters from CGM12 with RRA. Based on CGM12 with RRA, expectations were that:

- Retained earnings would be $55 million in 2018/19 and $58 million in 2019/20; and
- The Equity ratio would be around 20% in 2018/19 and 2019/20, respectively.

**5.3 Centra's Level of Financial Reserves Projected for 2018/19 of $80 million have Essentially Doubled in the Six Years Since the Last GRA and Are Approximately 45% Higher than Forecast in the Last GRA**

Figure 6 provides a comparison of the net income, retained earnings and equity ratios between CGM12 with RRA and actual results for 2012/13 to 2017/18, as well as for projected results for 2018/19 and 2019/20:

| **Figure 6 - Comparison of CGM12 with RRA and Actual & Projected Results** | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | **2013** | **2014** | **2015** | **2016** | **2017** | **2018** | **2019** | **2020** |
| **CGM12 with RRA:** | | | | | | | | |
| Net Income | 2 | 3 | 3 | 3 | 3 | 3 | 3 | 3 |
| Retained Earnings | 36 | 39 | 42 | 46 | 49 | 52 | 55 | 58 |
| Equity Ratio | 19% | 20% | 20% | 20% | 20% | 20% | 20% | 20% |
| **Actual & Projected Results (CGM18):** | | | | | | | | |
| Net Income | 8 | 20 | 11 | -1 | 4 | 7 | 4 | 3 |
| Retained Earnings | 42 | 62 | 66 | 65 | 69 | 76 | 80 | 83 |
| Equity Ratio | 34% | 34% | 34% | 33% | 33% | 32% | 32% | 32% |
| **Sources:** | | | | | | | | |
| CGM12 with RRA - CAC/Centra II-125 c | | | | | | | | |
| Actual Results 2013 to 2018 - PUB/Centra II-49 a & b | | | | | | | | |
| Projected Results - Appendix 3.6 | | | | | | | | |

The key observations from Figure 6 are as follows:

1. Net income has average approximately $8 million ($49 million total net income/6 years) over the six-year period from 2012/13 to 2017/18;
2. Actual retained earnings have increased from $42 million in 2012/13 to $76 million in 2017/18, an increase of $34 million or 81% ($76/$42);
3. Actual retained earnings of $76 million in 2017/18, are $40 million or 111% ($76/$36) higher than the retained earnings of $36 million that were projected in CGM12 for 2012/13 at the time of the last GRA;
4. Actual retained earnings of $76 million in 2017/18, are $24 million or 46% ($76/$52) higher than the retained earnings of $52 million that were projected in CGM12 for 2017/18 at the time of the last GRA;
5. Retained earnings are projected to increase from $42 million in 2012/13 to $80 million in 2018/19, an increase of $38 million or 90% ($80/$42);
6. Projected retained earnings of $80 million in 2018/19, are $25 million or 45% ($80/$55) higher than the retained earnings of $55 million that were projected in CGM12 for 2018/19 at the time of the last GRA;
7. Projected retained earnings of $83 million in 2019/20, are $25 million or 43% ($83/$58) higher than the retained earnings of $58 million that were projected in CGM12 for 2019/20 at the time of the last GRA;
8. Projected retained earnings for 2018/19 and 2019/20 of $80 million and $83 million in CGM18, are 122% and 131% higher than the $36 million of retained earning projected for

2012/13 and 105% and 113% higher than the $39 million of retained earnings projected for 2013/14 at the last GRA; and

9. Equity ratio projections for 2018/19 and 2019/20 are at 32% compared to 20% that was projected at the last GRA.

In summary, financial reserve levels (retained earnings) projected for 2018/19 are essentially double the levels from the 2013/14 GRA, having moved from the $40 million range to projected balances in the $80 million and are about and are about 45% higher than the level forecast at the last GRA.

This is before considering the impact of the IFRS accounting change related to gas meter exchange labour costs which is discussed in Section 5.4.

## 5.4 It is Recommended that the PUB Direct Centra to Include the Cumulative Profit Adjustment of $15.3 Million Related to the Capitalization of Gas Meter Exchange Labour from 2014/15 to 2018/19 as Part of the Financial Reserves for Rate-Setting Purposes

### Gas Meter Exchange Accounting Policy – 2013/14 GRA and Order 85/13

At the time of the 2013/14 GRA, Centra had yet to transition to IFRS and had not completed its assessment of the financial reporting and rate-setting implications of the transition.

The potential for an accounting policy change related to labour expenses for gas meter exchanges was also reviewed at the 2013/14 GRA. The issue that was reviewed was that the long-standing MH accounting policy was to capitalize these costs (capitalized and amortized for rate-setting purposes) and the long-standing Centra accounting policy was to expense these costs (included in revenue requirement for rate-setting when expended). It was understood by all parties to the hearing that these accounting policies would be required to be harmonized when the transition to IFRS occurred.

Centra's position on the meter exchange labour issue at the 2013/14 GRA was that it was reviewing which of the alternate accounting treatments that it would adopt upon transition to IFRS and that it did not want to make any changes to accounting policies that would require a retrospective adjustment in advance of the transition to IFRS which was expected to occur in 2015/16 with restatements to 2014/15.

In Order 85/13, the PUB made the following findings with respect to potential accounting policy changes and IFRS on pages 17 and 29, respectively, as follows:

> "…The **Board will direct Centra to file** an **International Financial Reporting Standards status update** at the **next General Rate Application**. **Until such time**, the Board expects **Centra not** to **make any further accounting changes** for **rate-setting purposes**. With respect to **meter exchange costs**, the **Board will not direct a change in accounting policy at this time**. The **Board will expect Centra** to **put forward a proposal** on harmonizing this accounting policy with Manitoba Hydro **in its IFRS status update report** directed in this Order." (Emphasis added)

> "The Board notes that given the direction in the Regulatory Deferral Accounts exposure draft, Centra may not have to write of its rate-regulated assets. The **Board will expect Centra to keep the Board apprised on developments on this issue** as they evolve and the **implications on ratepayers**. The Board understands the underpinning for accounting policy changes related to rate-regulated assets and depreciation rates depend on the outcome of this issue. **Centra is not to make any further accounting changes** related to **International Financial Reporting Standards without seeking the Board's approval**…" (Emphasis added)

In Order 85/13, the PUB provided the following directive to Centra with respect to IFRS on page 7 as follows:

> "**3. That Centra file** with the Board an **International Financial Reporting Standards status update report prior** to the **next General Rate Application** that will provide the Board with **options available for rate-setting purposes**." (Emphasis added)

**Gas Meter Exchange Accounting Policy – 2019/20 GRA**

In the 2019/20 GRA filing, pages 6 to 7 of Tab 13, Centra indicated that in response to the above noted PUB directive, MH filed an IFRS Status Update Report with the PUB as Appendix 5.4 of the MH 2014/15 & 2015/16 Electric GRA.

Centra also noted that it filed a letter dated March 10, 2016 seeking the PUB's confirmation of its proposed accounting treatment of certain matters related to gas operations and that on April 4, 2016 the PUB informed Centra that it intended to make a final ruling on the proposed accounting changes at the next Gas GRA. Centra also indicated that with the filing of information in the 2019/20 GRA related to the transition to IFRS and proposed accounting changes, it is seeking confirmation from the PUB that the directive is now closed.

The IFRS status report that was provided with the MH 2014/15 & 2015/16 GRA, contains a very short paragraph on harmonization of accounting policies at page 49 and does disclose that the capitalization of gas meter exchange costs was expected to increase consolidated net income by approximately $5 million in 2015/16. This report did not address the portion of the PUB directive to provide rate-setting options for Centra to the PUB.

In its March 10, 2016 letter to the PUB (provided in Attachment 1 of the response to CAC/Centra I-16 (a)), Centra indicated that on transition to IFRS it intended to harmonize the accounting treatment for gas meter exchange labour with that of electric operations, which is to capitalize these costs. Centra also indicated that:

> "**Centra intends** to **apply this change in policy on a prospective basis** commencing in the **2015/16 fiscal year** (with **restatement of the 2014/15 fiscal year** for comparative reporting purposes) and is **requesting the PUB's confirmation** that **this approach** is **appropriate** for **rate-setting purposes**."

In the PUB's response letter of April 4, 2016, it stated that:

> "In the **Board's view**, **whether each of the accounting changes proposed by Centra** in its March 10, 2016 correspondence **should be implemented for rate-setting purposes** will be **examined in the next Centra General Rate Application** and does not warrant an interim proceeding at this time. It is the **Board's intention to examine and make a final ruling** with **respect to each of these issues for rate-setting purposes** at the hearing of the **next General Rate Application in 2017**." (Emphasis added)

In section 5.3 of Tab 5 and Appendix 3.4 of the 2019/20 GRA filing, Centra provided an overview of its transition to IFRS and associated accounting changes, including new regulatory deferral accounts and amortization periods for these accounts for which Centra is seeking PUB endorsement as part of this application.

Appendix 3.4 contains a lengthy list of new regulatory deferral accounts that Centra established on the transition to IFRS effective April 1, 2014 (2014/15 fiscal year which with the restatement is the effective year of transition to IFRS) for which it is now requesting endorsement from the PUB for rate-setting purposes. In Appendix 5.9, Centra indicates that it is commencing the capitalization of gas meter exchange labour costs for Centra for financial reporting and rate-setting purposes beginning in the 2019/20 Test Year.

Appendix 3.4 and Appendix 5.9 of the 2019/20 GRA filing are silent with respect to the impacts of capitalization of gas meter exchange labour costs for financial reporting and rate-setting purposes for the five-year period from the effective date of transition to IFRS, in the 2014/15 fiscal year to the 2018/19 fiscal year. This material is also silent with respect to any options that the PUB has with respect to the rate-setting treatment of these impacts for that five-year period.

**Recommended Rate-Setting Treatment for Gas Meter Exchange Labour - Cumulative Profit Adjustment**

In the response to CAC/Centra I-6 (a), Centra clarified that the profit adjustment related to the harmonization of the accounting policy of meter exchange costs (profit adjustment) has been recorded in the Eliminations column of MH's consolidated financial statements since that transition to IFRS, effective in the 2014/15 fiscal year. The profit adjustment in the Eliminations Column is made up of the lower O&A costs as a result of the capitalization of these costs and is partly offset by the depreciation of the capitalized costs with the net impact being an increase in MH's consolidated net income (and retained earnings) each year since 2014/15.

For the five-year period between 2014/15 and 2018/19, the cumulative net impact on MH's consolidated income statement and balance sheet can be summarized as follows (from the response to CAC/Centra I-6 (b)):

- Consolidated Balance Sheet: increase in Property, Plant & Equipment of $21.2 million offset by $5.9 million of Accumulated Depreciation – for Net Plant of $15.3 million; and
- Consolidated Income Statement: reduction of O&A expense of $21.2 million offset by $5.9 million of Depreciation Expense – for a Net Profit/Retained Earnings increase of $15.3 million.

The cumulative impact of this profit adjustment of $15.3 million has currently been recorded in the Eliminations column of MH's consolidated financial statements and has not been attributed to Gas operations for purposes of evaluating the sufficiency of Centra's financial reserves (retained earnings) for rate-setting purposes.

In the response to CAC/Centra I-6 (c), Centra confirmed that Gas customers have been funding the costs of the gas meter exchange program in rates between 2014/15 and 2018/19 given that these costs were included in the 2013/14 revenue requirement, as an approved O&A expense.

When requested in information request CAC/Centra I-6 (d), to explain why it was not proposing to transfer the cumulative profit adjustment for this five-year period to the Gas operations effective April 1, 2019, so that Gas customers who have paid for the meter exchange costs in gas rates could benefit from this profit adjustment, Centra did not provide a rationale and simply referred back to the response to part (a) of this information request which outlines the accounting treatment for the last five-year period.

The key observations from a rate-setting perspective based on the forgoing information are as follows:

1. Centra has captured the impact of a number of accounting changes related to the transition to IFRS in deferral accounts between the 2014/15 and 2018/19 period for review and disposition for rate-setting purposes at the 2019/20 GRA;

2. Most of these IFRS accounting changes would have resulted in a reduction in Centra's net income/increase in expenses if not captured in deferral accounts for rate-setting purposes. These increased expenses were not built into Centra's rates that were approved in 2013/14;
3. The change in the gas meter exchange accounting treatment has the impact of increasing net income/reducing expenses and the associated revenue requirements. However, Centra's customers have been paying rates that were set back in 2013/14 that include the higher level of costs associated with meter exchange cost being expensed in O&A;
4. It was clearly the intent of Centra back in 2016 to credit customers with the favourable reduction in O&A expenses related to the harmonization/capitalization of the gas meter exchange costs for rate-setting purposes, as evidenced by its request to the PUB in its March 10, 2016 letter to confirm that this change was appropriate for rate-setting purposes;
5. It appears that the PUB did not want to make decisions on the impacts of IFRS accounting changes for rate-setting purposes on an interim basis and outside of a comprehensive GRA, that was at the time of the writing of its April 4, 2016 reply to Centra's letter, expected to occur early in 2017;
6. The recording of the profit adjustment related to gas meter exchange costs in the Eliminations column of MH's consolidated financial statements can be viewed as an interim measure to record the impacts for financial reporting purposes until the comprehensive review for rate-setting purposes occurred at the current GRA. This is no different in substance than the recording of other IFRS adjustments in deferral accounts pending endorsement/approval by the PUB for rate-setting purposes; and
7. The current 2019/20 GRA is the first GRA since the implementation of IFRS for Centra and as such is the expected regulatory proceeding to determine the appropriate rate-setting treatment of all IFRS accounting changes for Centra, including the gas meter exchange cumulative profit adjustment.

It is recommended that the PUB direct Centra to include the cumulative profit adjustment of $15.3 Million related to the capitalization of Gas meter exchange labour from 2014/15 to 2018/19 to be part of the financial reserves for rate-setting purposes. It is also appropriate to include the plant, accumulated depreciation and depreciation expense for rate-setting purposes.

It is fair that customers receive both the costs and benefits associated with all of the IFRS accounting changes including the gas meter exchange accounting change. Gas customers have continued to fund gas meter exchange costs between 2014/15 and 2018/19 (in the rates that were approved in the 2013/14 GRA) and as such should enjoy the associated benefit of the cumulative profit adjustment in the consideration of financial reserves for rate-setting purposes.

MH's business is a largely regulated electric and gas operations with a few smaller unregulated subsidiaries. As a public and regulated entity, it is reasonable that all of MH's consolidated retained earnings are considered in the evaluation of the financial position of all of it various lines of business. Currently, the gas meter exchange profit adjustment is not attributed to any of MH's lines of business. The gas meter exchange profit adjustment is not associated with its unregulated subsidiaries or electric operations. As such, it is a fair and reasonable rate-setting treatment to attribute the cumulative profit adjustment to gas operations (Centra) for the purposes of evaluating the financial reserves of Centra for rate-setting.

There may be options to implement the recommendation to attribute the cumulative profit adjustment to Centra's financial reserves.

The preferred option is that Centra adjust its financial statements and financial reporting to include the cumulative retained earnings, property, plant and equipment and accumulated depreciation associated with the gas meter exchange accounting policy change (modeled in the financial scenarios provided in the response to PUB/Centra II-7 (c)). In this option the impact of the accounting change would form a normal part of Centra's financial reporting and GRA filings. This would be consistent with having "one-set of books" for both financial reporting and rate-setting purposes.

As alternative, the net impact of the cumulative profit adjustment could be included in Centra's financial statements as a regulated asset with a corresponding increase to retained earnings with the regulated asset being amortized over time (modeled in the financial scenarios provided in the response to PUB/Centra II- 7 (d)). However, if this option is implemented, care would have to be taken in determining the amortization period for rate-setting purposes. If the amortization period for the regulated asset is shorter than the depreciation period for property, plant and equipment (10 years), then this accounting treatment would artificially increase non-gas revenue requirements (amortization would be higher than depreciation) and exacerbate projected indicative rate increases.

If the preferred option(s) are not possible for financial reporting purposes, then a second option may be for MH to continue to record the impacts of the accounting change in the Elimination column of the consolidated financial statements but for the PUB to consider the cumulative profit adjustment for rate-setting purposes as part of regulatory proceedings and GRA filings. While it is highly desirable that Centra be able to keep "one-set of books" if this is possible, appropriate rate-setting treatments do not have to follow IFRS for financial reporting purposes.

Regardless of the ultimate financial reporting treatment of this cumulative profit adjustment, it should be attributed to Centra/gas operations for rate-setting purposes.

### 5.5 Centra's Level of Projected Financial Reserves for 2019/20 For Rate-Setting Purposes Are $96 million When the Cumulative Profit Adjustment for Meter Exchange Costs are Included

The attribution of the cumulative profit adjustment to Centra/gas operations will improved the level of Centra's financial reserves in the 2019/20 Test Year.

When requested in information request CAC/Centra I-6 (e), to provide a CGM18 financial scenario that incorporated the favourable impact of this increase in financial reserves to 2019/20 non-gas revenue requirements and future projected indicative rate increases, Centra declined to provide a response indicating that it was unsure what the “two-sided” journal entry would be to develop this scenario. This financial scenario was subsequently requested in information request CAC/Centra II-127 (a) and was ultimately provided in the response to PUB/Centra II-7 (c) (i), although the projected indicative rate increases were not adjusted as requested in this response.

For simplicity in running the financial scenario in the response to PUB/Centra II-7 (c) (i), Centra was requested to assume the transfer of the cumulative profit adjustment effective April 1, 2019. As a result, the impact of attributing the cumulative profit adjustment to Centra is not included in the 2018/19 fiscal year in the financial scenario. As the Equity ratio calculation for 2019/20 averages the ending 2018/19 balance (March 31, 2019) with the ending 2019/20 balance (March 31, 2020), the impact of the profit adjustment will be understated by 50% in the financial scenario, as the adjustment is not assumed to be made until April 1, 2019.

However, in reality, the cumulative profit adjustment relates to all fiscal years back to 2014/15, so the attribution of the profit adjustment for the purposes of rate-setting should consider the opening and closing balance of the adjustment for both the 2018/19 and 2019/20 Test Years that are under review in the regulatory proceeding.

Figure 7 adjusts for this circumstance and summarizes the impact of including the cumulative profit adjustment for both the 2018/19 and 2019/20 Test Years (based on the information provided on page 4 of 6 of the response to PUB/Centra II-7 (a)-(e), which includes the cumulative profit adjustment by year and the depreciation of the unamortized balance of the meter exchange capitalized amounts by year):

| Figure 7 - Meter Exchange Profit Adjustment Fully Included in 2019 & 2020 | | | | |
|---|---|---|---|---|
| | **2019** | | **2020** | |
| | **$** | **%** | **$** | **%** |
| **Average Equity:** | | | | |
| Opening Retained Earnings | 76 | | 80 | |
| Opening Meter Exchange Adjustment | 14 | | 15 | |
| **Adjusted Opening Retained Earnings** | **90** | | **95** | |
| | | | | |
| Closing Retained Earnings | 80 | | 83 | |
| Closing Meter Exchange Adjustment | 15 | | 13 | |
| **Adjusted Closing Retained Earnings** | **95** | | **96** | |
| | | | | |
| Average Retained Earnings | 93 | | 96 | |
| Average Share Capital | 121 | | 121 | |
| **Average Equity** | **214** | | **217** | |
| | | | | |
| **Capital Structure:** | | | | |
| Long-Term Debt | 370 | 58.7% | 383 | 58.7% |
| Short-Term Debt | 46 | 7.3% | 53 | 8.1% |
| Average Equtiy | 214 | 34.0% | 217 | 33.2% |
| **Total Capitlization** | **630** | **100.0%** | **653** | **100.0%** |
| | | | | |
| **Sources:** | | | | |
| Opening/Closing Retained Earnings - PUB/Centra I-49 b | | | | |
| Meter Exchange Profit Adjustments - PUB/Centra II-7 b-e, page 4 | | | | |
| Average Share Capital & Debt - PUB/Centra I-49 a | | | | |

The key observations with respect to Figure 7 are as follows:

1. The projected adjusted closing retained earnings for 2018/19 including the meter exchange profit adjustment are $95 million;
2. The projected adjusted closing retained earnings for 2019/20 including the meter exchange profit adjustment are $96 million; and
3. The projected Equity ratios including the meter exchange profit adjustment for 2018/19 and 2019/20 are 34% and 33%, respectively, or 2% higher than the 32% and 31% included in the financial scenario provided in the response to PUB/Centra II-7 (c).

In summary, after the appropriate rate-setting adjustments to properly attribute the cumulative gas meter exchange profit adjustment to Centra, its projected financial reserves are $96 million, and the projected Equity ratio is 32% in the 2019/20 Test Year. This level of financial reserves is the higher under MH's ownership.

## 6.0 It is Recommended that Centra's 2019/20 Non-Gas Revenue Requirement be Adjusted Downward by $5 million for Rate-Setting Purposes

In its application, Centra indicates that it is not applying for a general rate increase for 2019/20 related to non-gas costs and that based on the revenues currently being generated by existing rates, it expects to generate a net income (contribution to financial reserves) of approximately $2.9 million in the 2019/20 Test Year (within the PUB's previously approved level of net income of $3 million).

This section of the Evidence reviews various elements of the 2019/20 non-gas revenue requirement (O&A Expense and Property Tax Expense) where there are issues related to the reliability of Centra's forecasts for rate-setting purposes and it is ultimately recommended that the PUB should approve downward rate-setting adjustments of $5 million related to Centra's 2019/20 O&A expense targets. The $5 million reduction is equivalent to an overall rate reduction of approximately 1.6% based on current revenues of $308 million, including gas costs. It is also recommended that the PUB obtain further information on the impacts of the 2018 re-assessment before approving Centra's 2019/20 property taxes into rates.

This section also recommends that the PUB direct that additional information and analysis be provided at future Centra GRA's with respect to the integrated cost allocation methodology, debt management strategies and the application of debt policy guidelines and that the PUB provide further clarification, directives or recommendations with respect to the disposition or use of the $17 million of excess Furnace Replacement Program funding collected from SGS customers since 2007/08.

### 6.1 Centra's Application Indicates that at the Projected Net Income of $2.9 million there is No Non-Gas Revenue Requirement Increase Required for 2019/20

In Tab 2 of Centra application, it indicates that it is not applying for a general rate increase for 2019/20 related to non-gas costs. Centra is also requesting approval to discontinue funding the Furnace Replacement Program (FRP) and to remove the associate costs from the rates of SCG customers.

In information request CAC/Centra II-124 (b), CAC requested Centra to reconcile different figures that were provided between the application and information requests with respect to the requested non-gas cost revenue requirement and non-gas revenues at existing rates. In that information request, Centra clarified that:

- Its requested non-gas cost revenue requirement for the 2019/20 Test Year is $149.1 (as updated on March 22, 2019) which includes $0.545 million of FRP funding that was included in its approved budget to August 1, 2019 (the then anticipated implementation date of new rates);
- The non-gas revenue requirement for the 2019/20 Test Year excluding the FRP funding is $148.5 million;
- Non-gas costs of $148.5 million have been included in the Cost Allocation Study which excludes the FRP funding of $0.545 million, as Centra is requesting this funding be discontinued upon the implementation of new rates; and
- The non-gas revenues at existing rates (excluding the FRP funding) are $148.5 million and as such there is no non-gas revenue deficiency or sufficiency/increase requested for 2019/20, at the projected net income of $2.9 million.

Figure 8 provides a comparison of the approved non-gas revenue requirement for the two last test years, 2010/11 and 2013/14 as well as the 2019/20 requested non-gas revenue requirements.

| Figure 8 - Comparison of Approved and Requested Revenue Requirements | | | | |
|---|---|---|---|---|
| | | | | 2019/20 |
| | 2010/11 | 2013/14 | 2019/20 | vs. |
| | Approved | Approved | Request | 2013/14 |
| Operating & Administrative | 60,343 | 68,800 | 60,550 | (8,250) |
| Depreciation & Amortization | 27,367 | 30,091 | 32,350 | 2,259 |
| Capital & Other Taxes | 23,940 | 18,750 | 20,312 | 1,562 |
| Finance Expense | 19,105 | 16,945 | 21,603 | 4,658 |
| Furnace Replacement Program | 3,800 | 3,800 | 545 | (3,255) |
| Corporate Allocation | 12,000 | 12,000 | 12,000 | - |
| Other Income | (2,026) | (1,866) | (1,190) | 676 |
| Net Income | 2,505 | 2,506 | 2,894 | 388 |
| **Total Non-Gas Revenue Requirement** | **147,034** | **151,026** | **149,064** | (1,962) |
| Less: Furnace Replacement Program | (3,800) | (3,800) | (545) | 3,255 |
| **Net Non-Gas Revenue Requirement** | **143,234** | **147,226** | **148,519** | **1,293** |
| Revenue at Existing Rates (Exclud FRP) | | 144,146 | 148,519 | 4,373 |
| **Revenue Sufficiency (Deficiency)** | | (3,080) | **-** | **3,080** |
| | | | | |
| **Sources:** | | | | |
| 2010//11 Approved - CAC/Centra I-3a attachment, page 112 | | | | |
| 2013//14 Approved - CAC/Centra I-3a attachment, pages 112 & 114 | | | | |
| 2019/20 Requested - CAC/Centra II-124 b | | | | |

The key observations with respect to Figure 8 are as follows:

1. The approved non-gas revenue requirement for 2013/14 totaled $151.0 million including the FPR funding. The approved 2013/14 non-gas revenue requirement excluding the FRP funding was $147.2 million. This resulted in an approved revenue deficiency of $3.1 million (general revenue increase of approximately 1.0%) based on the revenue at existing rates excluding the FRP funding of $144.1 million;
2. The requested non-gas revenue requirement for 2019/20 totals $149.1 million including $0.545 million of FRP funding. The requested non-gas revenue requirement for 2019/20 excluding the FRP funding is $148.5 million, an increase of $1.3 million from the level approved at the 2013/14 GRA. This increase results primarily from higher depreciation & amortization, finance expense and capital & other taxes offset by decreases in O&A expenses; and

3. The projected revenue at existing rates excluding the FRP funding is $149.5 million which is $4.4 million higher than the $144.1 million for the 2013/14 GRA. It is also noted that on August 1, 2017 (Order 79/17), the PUB directed that the non-gas components embedded in Centra's rates revert back to the levels approved in 2010 flowing from the 2009/10 and 2010/11 GRA, effectively reversing the approved revenue deficiency/1.0% general revenue increase from the 2013/14 GRA.

In summary, Centra's calculations of non-gas revenue requirements indicate that it is not seeking a non-gas or general revenue increase in 2019/20 at an expected net income of $2.9 million.

## 6.2 There are Significant Concerns with Respect to the Reliability of Centra's O&A Forecasts for Rate-Setting for the 2019/20 Test Year

In its application, Centra is projecting O&A costs of $63.315 million for 2018/19 and is requesting approval of 2019/20 non-gas costs that include O&A costs of $61.250 million (Appendix 5.13, Figure 5.9).

The last time that Centra's detailed O&A budgets were reviewed by the PUB in a comprehensive hearing process was part of the 2013/14 GRA, about six years ago. For 2019/20, O&A costs represent approximately 41% ($61/$149) of the non-gas revenue requirement and 20% ($61/$308) of the total revenues including gas costs. O&A expenses are by far the highest component of non-gas revenue requirements.

### MH O&A Targets & PUB O&A Findings Order 69/19

In the recent MH 2019/20 Rate Application, independent expert evidence on behalf of the Consumers Coalition outlined a number of concerns with respect to the reliability of MH's O&A budgets for rate-setting purposes. These concerns can be summarized as follows:

- The O&A targets for 2018/19 and 2019/20 were outdated, being approximately two years old and were developed by MH before the VDP transition began;
- Unallocated contingency amounts appeared to be used as plugs to maintain the level of previously developed O&A targets in the MH16 forecast, despite the fact that there were no actual or planned expenditures related to these continency amounts;
- Estimates of Labour savings from the VDP and sourcing savings from the Supply Chain Initiative were being revised downward from the prior GRA;
- The reversion to a prior MH budgeting practice of assuming 2% escalation of O&A costs was offsetting about 35% of the VDP and Supply Chain savings in the space of two fiscal years with a 100% offset occurring in approximately 6 years;

- The offsetting of the VDP and Supply Chain savings was occurring despite the implications of Manitoba's public sector wage freeze legislation (Public Services Sustainability Act) and cost saving measures in the Manitoba public sector in general; and
- The offsetting of the VDP and Supply Chain savings was occurring despite the findings and recommendations from the PUB in Order 59/18 (pages 141 to 142 and 264) flowing from MH's 2017/18 & 2018/19 GRA that there was an opportunity for MH to find areas to reduce O&A costs during a time of restructuring and transition and that MH should continue its cost containment efforts, both in terms of staff reductions and supply chair management after the VDP concludes.

In the MH 2019/20 Rate Application, the evidence that was filed on behalf of the Consumers Coalition recommended that:

1. The PUB re-emphasize its O&A rate-setting findings from Order 59/18, that MH continue to actively manage its O&A costs by including a provision for O&A productivity for rate-setting in 2019/20;
2. The PUB make a normalization adjustment for rate-setting purposes to remove a one-time and non-recurring increase in collection costs from 2017/18 that was the starting point for the development of targets for 2018/19 and 2019/20;
3. The PUB adjust the O&A targets for rate-setting purposes to remove a provision for unallocated transitional contingency funds as there were no planned costs related to these contingencies;
4. The PUB adjust the O&A targets for rate-setting purposes to incorporate an escalation assumption of 1% that had been utilized by MH between the MH13 and MH15 forecasts to reflect an assumption for productivity; and
5. The PUB make total downward adjustments to the 2018/19 and 2019/20 O&A targets of $22 million for rate-setting purposes.

In Order 69/19, dated May 28, 2019, at pages 23 and 24, the PUB accepted the recommendations of the Consumers Coalition and made the following findings with respect to O&A costs for rate-setting purposes:

> "The **Board findings** that **Manitoba Hydro's 2019/20 O&A target** is **not acceptable** for **rate setting purposes**. **First**, the **target is premised on a high-level target calculation from early 2017 for the 2017/18 year**, and **includes two prior non-recurring costs** that **should be normalized in establishing a target for rate-setting purposes**…The Board finds that the 2019/20 O&A target should be reduced by $8.1 million. This is the amount of a one-time increase for collection costs in 2017/18…The **Board does not accept** that the **2019/20 test year O&A target** should **include this $8.1 million for rate-setting purposes**,

as it is **a one-time occurrence**…**Similarly, the Board finds** that the **2019/20 O&A target should be reduced by a further $7.3 million** – the amount included in the 2019/20 O&A budget to support transitional business requirements arising from the Voluntary Departure Program…These **expenses were not incurred in 2018/19** and **Manitoba Hydro is not planning for these costs in 2019/20**…For these reasons, the **test year O&A target should also not include this $7.3 million expense for rate setting** purposes…**Second**, the **panel finds** that, **in developing the 2019/20 target for rate-setting purposes**, an **escalation factor of 1%** above the 2018/19 Financial Outlook **is to be used**…**Manitoba Hydro's** evidence **did not establish that a 2% escalation factor should be used**. Moreover, the **Board is concerned** that the **use of a rate of escalation of 2% will erode all of the O&A savings** achieved by Manitoba Hydro through the **Voluntary Departure Program** and **supply chain management** within the early years of Keeyask entering service. This **offsetting of savings** would be **inconsistent with the intent of the Voluntary Departure Program** and **contrary to the need for Manitoba Hydro to find savings in controllable costs** during a period of major capital expansion and related rate pressures…In the **absence of evidence demonstrating the appropriateness of a 2% escalation number**, the **Board finds that a 1% rate of escalation** is to be **used for rate setting purposes**. This is **consistent with Manitoba Hydro's prior commitment** dating **back to 2013** to **limit operating cost increases to 1% per year**. As the **Board stated in Order 59/18**, the Board **expects Manitoba Hydro continue its efforts to reduce O&A costs, both in terms of staff reductions and supply chain management**. The **Board reiterates that cost control should be on-going**, and that it **should continue in the post-voluntary Departure Program years**…Reducing the escalation rate to 1% further **reduces the O&A target to $489 million**, or $22 million less than Manitoba Hydro's $511 million target. This is **equivalent to a 1.3% rate decrease for ratepayers** in 2019/20 and will **have enduring benefits for ratepayers over time.**" (Emphasis added)

**Centra's 2018/19 & 2019/20 O&A Targets**

In information request CAC/Centra I-12 (c), CAC requested Centra to provide a table similar to the response to Coalition/MH I-13 (b) and (c) from the Manitoba Hydro 2019/20 Rate Application proceeding that summarizes the Centra O&A forecasts for 2018/19 and 2019/20 in two columns by (i) starting with Centra's 2017/18 actual O&A (ii) adding the impact of projected wage increases, merit & progression on labour costs (iii) adding the impact of escalation on non-labour & benefit costs (iv) deducting Centra's allocated portion of labour savings from the VDP (v) deducting Centra's allocated portion of sourcing savings from the Supply Chain initiative (vi) adding any contingency/provision for restructuring costs (vii) adding the increase in meter reading costs from MHUS (viii) adding/deducting the net amount of any other miscellaneous changes to O&A (ix) deducting the amount of meter exchange costs that are being capitalized in 2019/20 (x) resulting in 2018/19 and 2019/20 forecast O&A costs.

In the response to CAC/Centra I-12 (c), Centra stated the following:

> "**Centra's operations are integrated** within the **organizational structure of Manitoba Hydro** with **costs being allocated to Centra** through the **Integrated Cost Allocation Methodology** ("ICAM")…**Centra does not have employees**, as such **employee time is allocated to Centra through an activity charge** (activity rate x hours worked) **or through a cost driver for common or governance functions**. **Activity charges represent close to 70% of the overall allocations to Centra**…The change in activity charges can be impacted by wage settlements, other activity rate cost components, sick and vacation time, variability of work requirements, as well as other factors. **Given the method under which cost are allocated, Centra cannot isolate the impact of general wage increases, merit, etc. on O&A and is unable to provide a table comparison as requested**." (Emphasis added)

Given that MH and Centra operations are fully integrated and that Centra's costs are allocated from the larger consolidated operations, Centra's O&A targets/forecasts for 2018/19 and 2019/20 have been reviewed for the same concerns and issues that were raised by the Consumers Coalition and accepted by the PUB in Order 69/19 related to the MH 2019/20 Rate Application.

It was also confirmed by Centra in the responses to CAC/Centra II-125 (a) (b), that there were no changes to the overall level of the O&A targets between CGM16 and CGM18, with the exception of an increase in the O&A target by $3 million in 2018/19 as a result of deferring the commencement of the capitalization of gas meter exchange labour to 2019/20 in CGM18.

It appears that the same issue is present with the Centra O&A targets, as was the case for the MH O&A targets, in that they were finalized in April of 2017 before the VDP transition began and are over two-years old. There is also a similar concern that unallocated contingencies are being added into the Centra O&A budget to force the total target back to the outdated amounts from CGM16.

### 6.3 It Is Recommended That The $61 million O&A Budget for 2019/20 Be Reduced for Rate Setting Purposes by $5 million to $56 million

A review of allocated VDP and supply chain savings, unallocated contingencies and escalation assumptions related to Centra's O&A targets and the associated rate-setting recommendations are provided below.

**VDP & Supply Chain Initiative Savings Allocation to Centra**

In the response to CAC/Centra I-12 (d) (e), Centra provided estimates of the VDP and supply chain savings that were allocated to gas operations that can be summarized as follows:

- Total savings of $0.9 million for 2017/18;
- Total savings of $2.4 million for 2018/19;
- Total savings of $2.7 million for 2019/20; and
- The allocation of these total cost savings to Centra was estimated at 4% of the total consolidated savings, equivalent to the Total Assets cost driver which is representative of the relative size of the electric and gas utility.

In information request, CAC/Centra II-133 (c), CAC noted the following excerpts from the record of this proceeding with respect to the allocation of costs between MH and Centra:

- In the response to PUB/Centra I-28 (a), Centra indicated that the split of total O&A between gas and electric operations has been approximately 11%/89% between 2015/16 and 2019/20;
- In the response to PUB/Centra I-28 (b), Centra indicated that (i) the Total Asset cost driver of 4% gas/96% electric is a general driver that represents the relative size of the electric and gas utility and (ii) the Activity Charges cost driver of 8% gas/92% electric is a general driver that represents the relative amount of activity charges by staff to each of the utilities;
- In the response to PUB/Centra I-20 (d), Centra indicated that the Corporate Activity cost driver represents the relative amount of labour activity in each of the utilities; and
- In the response to PUB/Centra I-25, Centra indicated that staff approved under the VDP worked in all functions of the business.

In that information request, CAC requested that Centra explain that given the broad nature of the VDP and supply chair savings, why have they been assumed to be allocated to gas operations O&A based on the relative size of the gas utility (4%) versus either (i) the relative amount of labour/activity charges (8%) to gas operations or (ii) the relative split of total O&A costs (11%) to gas operations. Centra provided the following response to a similar information request (PUB/Centra II-11 (a)(b)) as follows:

> "The **total assets driver** is a **general driver** used **to allocate costs and savings to Centra** that **represents the relative size of the electric and gas utility**. The VDP was a corporate wide offering to all Manitoba Hydro staff, regardless of their age, jurisdiction, years of service etc. As such, **without knowing the full impact of the VDP**, a **general driver based upon the size of each utility** was **determined to be the most appropriate** for this **initiative**." (Emphasis added)

In the response to PUB/Centra II-11 (c), Centra provided an analysis that indicated that approximately 85% of labour and benefits are allocated to Centra based on direct activity charges while the remaining 15% are allocated using other allocation processes. As noted above, in the response to CAC/Centra I-12 (c), Centra indicated that activity charges represent close to 70% of the overall allocations to Centra. Also, based on a review of the responses to PUB/Centra II-23 (a) to (f) it appears that there is only a vary small amount ($1.3 million in 2019/20) of costs allocated to Centra using the corporate asset driver that relate to corporate governance, corporate services and public relations. The other cost drivers noted in this information request are allocating costs to Centra in a proportion that significantly exceed the 4% corporate asset driver (Number of customers is 33%, Activity charges is 8%, Management Estimates is 24%), with 4% being the lowest allocation to Centra (Corporate Assets driver).

Based on this analysis and given the broad nature of the VDP/supply chain savings (which are not limited to corporate governance programs or activities), it is concluded that the Corporate Asset cost driver (4%) is not the appropriate cost driver to use to allocate the savings to Centra. On the face of it, it would be expected that the allocation of these savings to Centra would be much higher given Centra's own evidence at this proceeding that gas operations are allocated about 11% of total O&A costs and Activity charges (8% allocated to Centra) represent about 70% of the overall allocations of O&A costs to Centra.

It is not clear from the record of this proceeding, why Centra believes that a 4% allocation of VDP/supply chain savings to gas operations is appropriate. The causal relationship between the broadly based VDP/supply chain savings and the relative amount of corporate assets between MH and Centra appears to be weak.

The information in this proceeding indicates that an allocation of at least 8% of the VDP/supply chain savings would be more reasonable given the broad nature of the underlying savings and the better causal relationship between these savings and the relative amounts of activity charges between MH and Centra.

Using the Company's estimate of $2.7 million of savings based on a 4% allocation, a more appropriate allocation of 8% of the savings to Centra for rate-setting purposes would be estimated at $5.4 million ($2.7 million * 8% / 4%) or double the savings that have been allocated to Centra. As such, an appropriate downward adjustment to Centra's O&A target for 2019/20 would be quantified at $2.7 million ($5.4 million - $2.7 million) of additional savings.

**Escalation Assumptions for Centra**

As note in Section 6.2 of the Evidence, in the response to CAC/Centra I-12 (c), Centra stated that due to the method that is used to allocate costs to gas operations, it was unable to isolate the dollar impact of escalation factors such as general wage increases and merit for 2018/19 and 2019/20.

In the response to CAC/Centra I-12 (h), Centra indicated that the CGM18 escalation assumption for the O&A forecast was 2% per year from 2018/19 to 2027/28, which at O&A levels around the $61 million level would result in annual escalation in the order of $1.2 million on an annual basis.

At a rate of 2% escalation per annum, the cumulative impact of around $2.4 million from 2018/19 to 2019/20 would offset about 89% of the VDP and supply chain savings ($2.7 million) allocated to Centra, in just two fiscal years.

While there are other impacts on the O&A forecasts, (such as a decrease in meter program activities as a result of lower requirements to meet Measurement Canada standards), this high-level calculation is confirmed by the fact that 2019/20 O&A would be at the level of $64 million ($61 + $3) absent the accounting change to capitalize gas meter exchange labour which is only slightly down from the $65 million pre-VDP O&A levels in 2016/17.

Even at the recommended adjusted level of savings allocated to Centra of $5.4 million calculated above, annual escalation of $1.2 million would totally erode the savings in approximately 4 to 5 years ($5.4/$1.2 = 4.5 years).

Centra confirmed in the response to CAC/Centra II-133 (g) that it did not explicitly incorporate a productivity factor in establishing its O&A targets for 2018/19 and 2019/20.

As was the case in the MH 2019/20 Rate Application proceeding, Centra has not supported the 2% escalation factor with any evidence, it is simply the return to a previous budgeting practice that MH used before 2013.

The return to a 2% escalation factor represents a passive approach to cost control. Given the rate pressures that Centra is facing (reviewed in Section 8.0), more active cost control is required to manage the rate increases projected in the 10-year forecast and preserve the savings from the VDP and supply chair initiative for a longer period of time.

Consistent with the PUB findings in Order 69/19 and recognizing that gas operations O&A is an allocation from the larger consolidated MH operations, it is recommended that the PUB utilize a 1% escalation factor for Centra for rate-setting purposes in 2018/19 and 2019/20. The 1% escalation factor was used by MH in its forecasts between MH13 and MH15.

This recommendation is also consistent with the rate-setting policy signal being provided to MH in Orders 59/18 and 69/19 that it must prudently and actively control costs to the full extent possible before it seeks rate increases from customers and recognizes that Centra is not a stand-alone entity, but rather, its O&A costs are allocated from MH consolidated O&A costs. It is also consistent with the current provincial governments approach to managing costs in the public sector in Manitoba.

This recommendation would reduce annual escalation from $1.2 million to $0.6 million. This would result in cumulative escalation for the two test years of $1.2 million or a $1.2 million downward rate-setting adjustment from the cumulative $2.4 million inherent in the Centra O&A targets.

The adjusted $1.2 million cumulative escalation for 2018/19 and 2019/20 would represent about 22% ($1.2/$5.4) of the recommended $5.4 million savings allocation to Centra. The combination of the two recommendations to increase the VDP/supply chain savings to Centra to $5.4 million and reduce the annual escalation to 1% or $0.6 million, would have the impact of preserving the benefits of these savings for Centra's customers to 9 years ($5.4/$0.6 = 9 years).

**Unallocated Contingencies for Centra**

In responses to information requests CAC/Centra I-12 (f) and CAC/Centra II-133 (f), Centra confirmed that:

- The contingency forecast of $1.887 million (PUB/Centra I-38) for 2018/19 was for funds held to assist management in the restructuring process;
- For the nine-months ended December 31, 2018 there were no restructuring costs and there were no restructuring costs forecast in 2019/20; and
- The contingency forecast of $1.059 million (PUB/Centra I-38) for 2019/20 represents the difference between the target and the detailed budgets or a reserve for cost increases and program changes that have not yet been incorporated into detailed plans.

Consistent with the issues that were noted in the MH 2019/20 Rate Application, these contingency amounts appear to be plugs to make the detailed budgets match the previously developed targets from CGM16 and do not have any planned expenditures associated with them. As such, they have not been justified for rate-setting purposes.

It is recommended that the $1.059 million contingency for 2019/20 be adjusted for rate-setting purposes by making a corresponding downward reduction to approved O&A expenses for 2019/20.

**Total Recommended Reductions to 2019/20 O&A for Rate-Setting Purposes**

Based on the record of this proceeding and considering the foregoing analysis, it is recommended that the PUB to make the following adjustments to Centra's 2019/20 O&A target for rate-setting purposes:

1. Adjust the allocation of the VDP and supply chain savings to Centra upward by $2.7 million for a total of $5.4 million to 2019/20 based on an 8% allocation, which would result in a downward adjustment to O&A of $2.7 million;
2. Adjust the escalation assumptions in the 2018/19 and 2019/20 O&A targets to 1% to reflect the assumption of a productivity factor and be consistent with Order 69/19. This

would reduce escalation from $1.2 million in each fiscal year to $0.6 million, with a cumulative downward adjustment to 2019/20 O&A of $1.2 million; and

3. Adjust the 2019/20 O&A target for the unallocated general contingency of $1.1 million as this contingency has no planned expenditures and has not been justified for rate-setting purposes.

The recommended adjustment for 2019/20 for rate-setting purposes is a total of $5.0 million ($2.7+$1.2+$1.1) which would reduce the 2019/20 O&A target to $56.3 million ($61.3 - $5.0) from the $61.3 million requested by Centra in its application. The $5 million reduction is equivalent to an overall rate reduction of approximately 1.6% based on current revenues of $308 million, including gas costs.

Figure 9 provides a high-level illustrative calculation of the cumulative impacts of the recommended rate-setting adjustments on Centra's O&A forecast for the period to the end of CGM18 (2027/28):

**Figure 9 - Impacts to O&A Forecast of Recommended Rate-Setting Adjustments**

| | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 |
|---|---|---|---|---|---|---|---|---|---|
| O&A @ 2% Esclation | 61.3 | 62.5 | 63.8 | 65.1 | 66.4 | 67.7 | 69.1 | 70.5 | 71.9 |
| O&A @ 1% Escalation<br>(including rate-settting adjustments) | 56.3 | 56.9 | 57.5 | 58.1 | 58.7 | 59.3 | 59.9 | 60.5 | 61.1 |
| **Decrease in O&A Forecast** | **(5.0)** | **(5.6)** | **(6.3)** | **(7.0)** | **(7.7)** | **(8.4)** | **(9.2)** | **(10.0)** | **(10.8)** |

The key observations from Figure 9 are as follows:

1. Figure 9 uses Centra's 2019/20 O&A forecast of $61.3 million as the starting point and escalates this amount at 2% in the top row to illustrate the O&A trajectory to 2027/28. In the second row, the 2019/20 O&A net of the recommended $5.0 million of rate-setting adjustments of $56.3 million is escalated at the 1% recommended out to 2027/28. The third row is the decrease to O&A targets as a result of the rate-setting adjustments and a 1% escalation factor;
2. Based on the total O&A rate-setting adjustments for 2019/20 and a 1% escalation factor, total O&A would grow to $58 million by 2022/23, a reduction of $7 million from trajectory

in CGM18 (which represents about a 2.3% rate reduction ($7/$308) based on current Gas revenues including gas costs of about $308 million); and

3. By the end of the CGM18 forecast period in 2027/28, the rate-setting reductions and 1% escalation factor would reduce the O&A trajectory by about $11 million to $61 million (which represents about a 3.6% rate reduction ($11/$308) based on current Gas revenues including gas costs of about $308 million).

As was the case in Order 69/19 from the MH 2019/20 Rate Application, the recommended rate-setting adjustments and 1% escalation factor represent enduring benefits to Centra's customers in the future.

### 6.4 It is Recommended that the PUB Direct Centra to Develop an Integrated Cost Allocation Methodology (ICAM) Report That Can Be Used to Support the Allocation of Consolidated Operating Costs and Shared Costs Between Centra and MH at Future Rate Setting Proceedings

MH's uses an Integrated Cost Allocation Methodology (ICAM) to allocate all O&A costs and the portion of finance expense, depreciation and taxes related to common assets (common administrative buildings, communication equipment, information technology systems and work equipment shared by the electric and gas lines of business) between Centra and MH.

Page 7 of Appendix 5.10 of the application indicates that for the year ended March 31, 2016, approximately $86 million or 58% of Centra's non-gas expenses of $148 million, were allocated to Centra using the ICAM.

In Order 99/07 (pages 107 and 108), the PUB directed that an independent review of the ICAM by undertaken as a result of organizational and operational changes that had taken place since the last formal review of the methodology in the 2002 Status Update Hearing. The PUB found that it was important to achieve acceptance of the current ICAM by all parties and that an independent review, outside the GRA process, should accomplish the goal of gaining intervenor acceptance of the validity of the approach, which is in the public interest.

As a result of the delays and uncertainties associated with Centra's implementation of IFRS, the response to this directive was significantly delayed and at the 2013/14 GRA, Centra proposed that it implement IFRS first, simplify the ICAM second and review the methodology in a forum outside of a GRA, such as a workshop or other collaborative approach involving Centra, PUB staff and intervenors. On page 63 of Order 85/13, the PUB found that concurrent with the implementation of IFRS, Centra should propose a process to review and simplify the ICAM.

In Order 108/15 (page 35) the PUB directed that it expected Centra to file a terms of reference for a study of the ICAM on or before June 30, 2016. Subsequent to the issuance of that directive, Centra sought and received the PUB's endorsement (on August 8, 2016) of a proposal to work with PUB staff and intervenors to develop an agenda for a technical conference with an objective of enhancing all parties understanding of the current ICAM. An ICAM technical conference was held at MH's offices on November 30, 2016 and was attended by PUB members, PUB staff and advisors and representatives of CAC.

In the 2019/20 GRA filing, Centra filed a short description of the ICAM in section 3.0 of Appendix 5.9 of the application and a copy of the presentation delivered at the technical conference in Appendix 5.10 of the application. On pages 12 to 13 of Tab 13, Centra indicated that is awaiting determination by the PUB as to whether an independent study of the ICAM is still required following the technical conference that was hosted by Centra on November 30, 2016.

The two main information requests related to the ICAM in this proceeding were;

- the response to PUB/Centra I-33 (a) that provided a general overview and examples of the costs components that are allocated (O&A and finance, depreciation and taxes on common assets), the allocation processes (timecarding of labour related expenditures such as wages & benefits, motor vehicles, small tools, safety clothing and travel, common overhead cost allocation of corporate governance, infrastructure services, departmental support and operational management and material handling overhead, procurement costs processes including materials, supplies and external services and system postings of bad debts, finance, depreciation and taxes on common assets), the allocation methods (allocation of 100% natural gas costs and shared costs through the cost drivers of number of customers, corporate assets, corporate activity charges and management estimates); and
- the response to PUB/Centra II-23 (a) to (f) that provided summary tables of the total costs allocated to Centra based on number of customers, corporate assets, corporate activity charges and management estimates.

The information from the ICAM technical conference and the overview and examples provided in the responses to PUB/Centra I-33(a) and PUB/Centra II-23 (a) to (f) were helpful to understand the overall functioning of the ICAM, how it had been changed/simplified after the implementation of IFRS and the overall level of costs allocated by each of the cost drivers. It can be concluded that progress has been made in understanding the basic functioning of the ICAM such that it can be relied upon for the purposes of setting Centra rates for 2019/20.

However, the information provided on the record of this proceeding is not sufficient to recommend to the PUB that the ICAM directive from Order 99/07 has been fully satisfied. An external review of the ICAM would be much more comprehensive than an overview of the functioning of the methodology, examples of the allocations and high-level summarises of the output of the shared cost drivers that is on the record of this proceeding.

It is expected that an external review would fully document the overall consolidated costs that are allocated to MH and Centra through the ICAM, gain a detailed understand of the basis for the cost drivers used and alternative cost drivers, perform detailed tests of the resulting allocations and systems that are used (including system postings and overhead allocations) as well as document issues noted or anticipated future issues and make recommendations where necessary for improvement.

In these ways, an external review would provide a much higher level of assurance to the PUB that the ICAM was appropriate and reliable for rate-setting purposes, for both the Centra GRA hearings and MH GRA hearings. As such, it is difficult to conclude that the level of information gained through a single technical conference and the information request process as part of the Centra 2019/20 GRA, satisfies the original intent of the PUB directive.

At the same time, there appears to be a willingness among the various parties to the Centra regulatory process to work collaboratively to satisfy the intent of the ICAM directive and there are concerns about the significant costs of an independent external review. It would be advantageous to continue the momentum that has been gained on the ICAM review.

Based on the foregoing analysis there are no recommendations for rate-setting adjustments as a result of the information on the record associated with the ICAM, with the exception of the issues and recommendations noted in Section 6.3 with respect to O&A. However, there are a number of recommendations with respect to the ICAM review for future Centra GRA's:

1. The PUB should direct Centra to develop a comprehensive ICAM report that can be used to support the allocation of consolidated operating costs and shared costs between Centra and MH, at future gas and electric rate-setting proceedings. This report would document the overall consolidated costs that are allocated to MH and Centra, the detailed basis for costs drivers used, discuss emerging issues and alternative cost drivers considered, with any resulting recommendations for changes to the PUB for rate-setting purposes;
2. The initial ICAM report could be reviewed through a collaborative process of workshops/technical conferences that occur before the next MH or Centra GRA, including PUB staff and advisors and intervenor representatives, with the goal of obtain sufficient information and assurance that the ICAM is an appropriate methodology for a fair allocation of O&A and shared costs;
3. Once the initial ICAM report is accepted as satisfying the intent of the PUB directive, this report should be maintained on an annual basis (much like a Cost of Service Study) and filed with each Centra and MH GRA to support the allocation of O&A and common costs; and
4. If for any reason, Centra is unwilling or unable to develop the ICAM report and continue to pursue this issue through a collaborative process, then the PUB should proceed to once again direct Centra to file a terms of reference for an independent external review, including circulation to intervenors for comments.

**6.5 It is Recommended that the PUB Obtain Further Information on The Impacts of the 2018 Province Wide Reassessment on the 2019/20 Property Tax Forecast Before Approving This Forecast Into Rates**

In information request, CAC/Centra I-13 (a) to (e), CAC noted that in the variance analysis for the 2012/13 and 2016/17 fiscal years, property taxes had declined as a result of the 2012 and 2016 province-wide reassessment of property values and requested that Centra to provide information on the escalation assumptions and actual results related to these two reassessments.

In the response to these information requests (CAC/Centra I-13 (b), Centra indicated that:

- For the 2012 re-assessment the escalation assumption used in the property tax forecast was 3% and for the 2012/13 fiscal year Centra's property taxes decreased by $0.9 million or 7.6%; and
- For the 2016 re-assessment the escalation assumption used in the property tax forecast was similar to 2012 at 3% and for the 2016/17 fiscal year Centra's property taxes decreased by $0.2 million or 1.7%.

In information request CAC/Centra II-134 (a) (b), CAC sought clarification of the assumptions with respect to the 2018 re-assessment and the impact on projected property taxes in the 2018/19 and 2019/20 Test Years and if the potential for over-statement of these forecasts exists given this occurred in the last two provincial re-assessments. In the responses, Centra provided the following information with respect to the 2018 re-assessment:

- The March 22, 2019 update of the 2019/20 property tax forecast reflected updated information as a significant portion of the annual property tax bills had been received and a 3% increase was included for those properties where the actual tax bill had not been received;
- The 2019/20 approved budget was based on a 3% increase when compared to the 2018/19 outlook; and
- The current outlook for property taxes for 2018/19 is an increase of $0.595 million or 5.0% for 2018/19 and the forecast for 2019/20 is an increase of $0.350 million or 2.8%.

From the information that is currently on the record of this proceeding, it is unclear of the exact timing of the impact of the 2018 re-assessment and if the property tax forecast for the 2019/20 Test Year has the potential to be over-stated as was the case for the 2012 and 2016 re-assessments, considering that a similar 3% increase has been utilized in the forecast.

It is recommended that the PUB obtain further information on the impact of the 2018 re-assessment and the potential for over-statement of the 2019/20 Test Year property tax forecast at the oral hearing, before approving Centra's forecast into rates.

Depending on the further information, there is a potential for a further rate-setting adjustment to property taxes, but this adjustment can not be quantified based on the record at this time.

**6.6 It is Recommended that the PUB Direct Centra to Provide Information on Centra's Debt Management as Part of Future Minimum Filing Requirements and to Review and Report Back on Select Issues Concerning the Application of Debt Policy Guidelines at the Next GRA**

In Order 85/13, the PUB made the following findings at page 22 with respect to Centra's debt management policies:

> "The **Board notes that Centra's policy** of **not having more than 15% of its debt maturing within a fiscal year** does **not address the concentration of debt maturing** in a **narrow time frame that straddles fiscal years**. The **Board believes Centra must amend the debt concentration policy** after **considering the recommendations of CAC to limit concentration in any 12-month period**. The **Board will require Centra to report its debt concentration policy** at the **next General Rate Application**." (Emphasis added)

The PUB made the following directive on Centra's debt management policies at page 8 of Order 85/13:

> "**5. That Centra further articulate** its **debt concentration policy** including **consideration of limiting the concentration of debt maturing in any particular 12-month period** and **report back to the Board** at the **next General Rate Application.**" (Emphasis added)

In response to the above noted directive from Order 85/13, Centra provided a summary MH's interest risk policy and guidelines on its existing debt portfolio (that had been amended in October of 2014) in section 3.5 of Tab 3 of the application, which can be summarized as follows:

- To limit the aggregate of (i) floating rate debt (ii) short term debt and (3) fixed rate long term debt to be refinanced with the subsequent 12- month period – to a maximum of 35% of the total debt portfolio;
- To maintain an aggregate of floating rate debt and short term debt within 15% to 25% of the total debt portfolio; and
- To limit fixed rate long term debt to be refinanced within a 12-month period to be less than 15%.

Centra is requesting that the PUB confirm that directive #5 from Order 85/13 has been satisfied.

Centra indicated that during the past few years, the interest rate risk had been mitigated by rebalancing the percentage of short term debt, floating rate long term debt and fixed rate long term debt within the debt portfolio to closely align the aggregate of short term/floating rate debt within 15% to 25% of the total debt portfolio. In addition, debt maturities for new debt issuances had been selected to smooth the debt maturity schedule and to manage the concentration risk and since 2006/07, Centra had sought to reduce the interest rate risk by extending the weighted average term to maturity (WATM) by approximately 7 years to 16 years at March 31, 2018.

Centra also indicated that it will continue to transition its debt portfolio to apply the principles of MH's debt management strategy, including those to manage the interest rate risk within the debt portfolio.

Centra elaborated on its debt management strategy and practices in the response to PUB/Centra I-47 (b) including how treasury operations are managed on a consolidated basis for MH and how consolidated debt issuances are assigned to Centra by MH to meet Centra's long-term debt requirements.

In information request CAC/Centra I-9 (a) to (k), CAC noted that Centra did not provide any analysis of the cost and rate-setting implications of rebalancing the Centra debt portfolio or of applying the debt management strategy and interest rate policy guidelines of MH to gas operations and requested Centra to provide (i) a more detailed explanation of how the MH policy guidelines are being applied to Centra and how the Centra debt portfolio has been rebalanced over the last few years (ii) an assessment of the appropriateness of applying the MH guidelines to gas operations considering the different operational circumstances of the two lines of business (iii) to provide detailed calculations of Centra's projected performance for 2018/19 and 2019/20 as compared to the policy guidelines (which were noted above) and (iv) to update a number of charts and analysis from the 2013/14 GRA there were helpful to understand how the debt portfolio has and is projected to be rebalanced to be within the policy guidelines.

Centra provided a very comprehensive and useful response to CAC/Centra I-9 (a) to (k), which allowed the follow up information requests to focus on the following issues in CAC/Centra II-130 (a) to (e), which can be summarized as follows:

1. In CAC/Centra I-9(a), Centra indicated that it projects the total of short-term debt and floating rate debt to be approximately 15% as at March 31, 2019 and March 31, 2020. The follow up issue in CAC/Centra II-130 (a) was to request Centra to explain the policy considerations of maintaining this total at the lower end (15%) of the policy range versus the middle (20%) or higher end (25%) of the range;
2. Based on the variability of Centra's quarterly debt structure as outlined in the response to CAC/Centra I-9 (g) and (h), the follow up issue in CAC/Centra II-130 (b) was to ask Centra to explain how it manages the aggregate of short term and floating rate debt, in terms of year-end, quarterly or moving averages or some other metric;
3. In order to understand the potential benefits and risks of pursing a more aggressive debt portfolio, the follow up issue in CAC/Centra II-130 (c), was to request Centra to provide a schedule of finance expense for the 10-year forecast period of CGM18, that targeted an

aggregate of short term/floating rate debt of 20% and 25% and discusses the benefits/risks of managing to the middle or higher end of the policy range;

4. In CAC/Centra I-9(a), Centra indicated that it projects the total of short-term debt, floating rate debt and new borrowings within 12 months to be approximately 26% as at March 31, 2019 and 25% as at March 31, 2020 which is 9% to 10% lower than the policy guideline of a maximum of 35%. The follow up issue in CAC/Centra II-130 (d) was to request Centra to explain the policy considerations of maintaining this total at about 10% lower than the maximum policy of 35%; and
5. In CAC/Centra I-9(f), Centra indicated that it projects the WATM of the Centra debt portfolio to decline from 19.5 years at March 31, 2013 to 14.6 years at March 31, 2020 and the percentage of debt maturing over 20 years to decline from 61.0% at March 31, 2013 to 13.1% as at March 31, 2020. The follow up issue in CAC/Centra II-130 (e) was to request Centra to explain if it has plans to increase the WATM of the Centra debt portfolio and increasing the proportion of the debt portfolio maturing in over 20 years or allocating some of the MH ultra-long debt issues to Centra to be more consistent with the projected WATM of MH's debt portfolio of 17.0 years at March 31, 2020.

Centra's positions on the above noted issues can be summarized as follows:

1. Centra is concerned that managing the aggregate of short term debt/floating rate debt at 20% or 25% at year-end or managing the total of short term debt/floating rate debt/new borrowings within 12 months closer to the 35% maximum under the policy would result in a rolling average that would be close to or exceed the top end of the policy ranges on a rolling-average quarterly basis. This concern is based on the fact that Centra has temporary seasonal borrowing requirements arising primarily from its gas storage inventory with the lowest balance for the year generally seen at the end of the fiscal year;
2. Centra is concerned that while the scenarios that target 20% and 25% of short term/floating rate debt provide modest savings in finance expense these savings could be more than offset if variable interest rates increase by 0.50% throughout the forecast period in CGM18; and
3. The smaller size and infrequency of requirements for Centra's debt issues impact the ability to align Centra's WATM to MH's and for the most recent debt issues Centra has required floating rate debt which tends to be shorter dated and reduce the WATM. Centra also indicated that it will look at all possibilities available in the market around the time of the planned $50 million debt issuance in 2019/20, including ultra-long debt to maintain compliance with the policy guidelines and more closely align its WATM with MH's.

The remaining issues or concerns based on the review of the above noted information are as follows:

1. Of the projected increase in non-gas revenue requirements in CGM18 of $36 million to 2027/28, approximately $10 million or 28% relates to increased finance expense (please see Section 8.0 of the Evidence for additional analysis). It is expected that the projected increase is mainly due to projected capital expenditures and forecast changes in interest rates;
2. The information/analysis provided in the information request process was reasonably comprehensive and useful in understanding the underlying issues. In the future, if this information could be provided as a regular part of the Centra minimum filing requirements this would allow for a more comprehensive review of the issues and a greater ability to develop conclusions and recommendations on the issues rather than just raising outstanding issues;
3. The stated purpose of the short-term debt advances is to "fund seasonal working capital requirements and to bridge the timing between long term debt issues" (PUB/Centra I-47 (b)). These seasonal increases in working capital requirements are by Centra's own admission temporary in nature and as such it is an open question for further consideration if these temporary fluctuations in short-term debt should be considered in the overall financing strategy/approach to managing the aggregate of variable rate debt and targeting the appropriate or optimal positioning in the 15% to 25% policy guideline;
4. The only information on the benefit/risk of a more aggressive use of variable rate debt was a simple financial scenario provided in second round information requests. As such, there was no ability to understand and test this scenario or develop other scenarios that would allow for a holistic review of the optimum level of variable rate debt within Centra's policy guidelines; and
5. The size and infrequency of Centra debt issues are noted as valid considerations, however, the fairness of the allocation of the benefits of MH's consolidated debt portfolio to both gas and electric customers (including ultra-long debt issues at favourable interest rates) and the concern over the lower proportion of Centra's debt portfolio that matures in over 20 years also bears continuing review and management by Centra.

Based on the foregoing analysis there are no recommendations for rate-setting adjustments to Centra's projected finance expense for 2019/20. However, there are a number of recommendations with respect to these issues for future Centra GRA's:

1. The PUB should direct Centra to provide information on its debt management, policies and forecasts of related debt metrics (similar to those that was provide in the information responses noted above) as part of Centra's minimum filing requirements at future GRA's;
2. The PUB should direct Centra to further review the potential benefits/risks of more aggressive use of variable rate debt and the appropriate application of its interest rate

risk guidelines as it relates to seasonal working capital requirements and report back at the next Centra GRA; and

3. The PUB should direct Centra to consider the issues raised with respect to increasing the proportion of the Company's debt portfolio that matures in over 20 years and the potential allocation of MH ultra-long debt issues to Centra and report back at the next Centra GRA.

These recommendations would allow for a more efficient and holistic review of these issues at future GRA's, especially considering the projected increases in finance expense in CGM18.

### 6.7 It is Recommended that the PUB Provide Further Clarification, Directives or Recommendations With Respect to the Disposition or Alternate Use of the $17 million of Excess Furnace Replacement Program Funding Collected from SGS Customers

In its application, Centra is requesting approval from the PUB to discontinue funding the Furnace Replacement Program (FRP) and to remove the associated costs from rates of the SGS class upon implementation of the new rates flowing from the 2019/20 GRA.

In section 3.1.2 of the application, Centra indicated the following with respect to the FRP:

- In 2007/08, Centra allocated $2.3 million of revenues collected from the SGS customer class to fund the FRP program with an additional $3.8 million allocate to the program each year since that time;
- The cumulative balance in the FRP was projected to grow to around $30 million by August of 2019, with the expectation that approximately $13 million of the fund will be required from 2019/20 to 2027/28 to replace the remaining eligible furnaces and boilers under the program; and
- Centra is projecting that approximately $17 million of the cumulative funding will be excess to the requirements of the program and that the timing of any planned dispositions or allocations from the fund of the excess, will be subject to the review and approval by Centra's Board of Directors and PUB approval will be sought in a future Centra regulatory proceeding.

In information request, CAC/Centra I-5 (b)(c), CAC requested Centra to confirm that the FRP program was directed by an Order of the PUB and explain why Centra assumes that the disposition of the FRP excess balance is subject to the authority of its Board of Directors versus the PUB. CAC also requested Centra to explain why the excess funding could not be used in the current regulatory proceeding to reduce the rates of SGS customers that have contributed to the FRP balance in order to reduce the intergenerational inequity for those customers that have contributed to the excess.

In the response to these information requests, Centra confirmed that the FRP was established by Order of the PUB and that the intent was to seek approval of the PUB in a future regulatory proceeding with respect to any planned disposition or other allocations from the fund. With respect to the question on why the excess funds could not be disposed of in the current regulatory process, Centra referenced the response to PUB/Centra I-102 (a), which indicated that it was Centra's intension to seek stakeholder input on the potential alternatives to be assessed, with some possible alternatives including:

- Return the excess funding to ratepayers through a rate rider (analysis provided in PUB/Centra I-102 (b) indicated a one, two and three-year rate rider would be projected to reduce the typical residential customers bill by $55/8.0%, $28/4.0% and $11/1.6%, respectively);
- Allocate the excess funding to support natural gas DSM programs through Efficiency Manitoba; and
- Allocate the excess funding to fund bill affordability initiatives.

In the response to CAC/Centra II-126, Centra also indicated that on June 10, 2019, the Province of Manitoba released a consultation draft of a proposed regulation for The Efficiency Manitoba Act which would see the balance of the FRP Account transferred to Efficiency Manitoba "to be used to offset the cost of natural gas demand-side management initiatives set out in an approved efficiency plan."

While the implications and timing of the consultation draft of the proposed regulation for Efficiency Manitoba are not known, it is recommended that in the current regulatory proceeding, the PUB:

1. Clarify the jurisdiction with respect to the disposition/use of the FRP excess funding for interest parties given that the FRP was originally established by Order of the PUB in Order 99/07 and funded exclusively by SGS customers;
2. Provide interest parties with the opportunity to provide recommendations with respect to the disposition or alternate use of the excess FRP funding as part of closing submissions; and
3. Make any further directives or recommendations (to Centra or the Province of Manitoba), necessary in the decision flowing from this regulatory proceeding, based on the clarification and information from recommendations #1 and #2.

## 7.0 Centra Has Not Adequately Responded to the PUB's Findings from Orders 85/13 & 108/15 to Provide Additional Information on Its Strategic Direction, Risk Assessment and Management Structure at the Next GRA

In Order 85/13, the PUB expressed concern that Centra's overall strategic vision is lacking and that the MH Corporate Strategic Plan (CSP) does not respond to the PUB concerns with respect to the corporate direction of gas operations and requested that Centra provide a more articulated vision at the next GRA. In Order 108/15, the PUB recommended that Centra review its management structure and that it expected to review the Company's management structure, strategic plan, risk analysis and capital expenditure plan at the next GRA.

This section of the evidence briefly reviews Centra's responses to these concerns in the 2019/20 GRA and concludes that Centra has not adequately responded to the PUB findings from Orders 85/13 and 108/15. This section concludes by recommending that the PUB direct Centra to consider these topic areas more fully as part of the comprehensive strategic, operational and financial review that is currently being undertaken by the Manitoba-Hydro Electric Board (MHEB) and Centra's Board of Directors and provide more fulsome responses to the PUB's concerns at the next Centra GRA.

### 7.1 Information Provided on Centra's Strategic Direction is High Level and Does Not Address the PUB's Concerns that Centra's Overall Strategic Direction is Lacking

The PUB made the following findings with respect to Centra's strategic plan/corporate direction in Order 85/13, at Page 69, which can be summarized as follows:

> "The **Board is interested in knowing Centra's strategic direction**, including where Centra will be investing ratepayer dollars in the coming years, and also what Centra's customers can expect on Centra in terms of improved service levels…the **Board finds Centra's overall strategic vision lacking**. The **Corporate Strategic Plan** provides **targets and goals** at a **high level**, but **does not answer the Board's question** of the **corporate direction Centra is headed**… The **Board requests that Centra consider these questions** and **provide** the Board with a **more articulated vision** in its **next rate application**" (Emphasis added)

At transcript pages 1185 to 1192 of the Centra 2013/14 GRA, the PUB Chair commented that based on the information filed by Centra in that proceeding:

- It was difficult to understand the corporate direction of Centra and as gas operations are a small portion of overall scope of MH's consolidated operations, it tends to get lost in the overall scheme of things;

- There was very little mention of the risks that are facing Centra and that understanding these risks and quantification of the risks would be helpful to the PUB in setting the appropriate retained earnings levels for the Company for rate-setting purposes; and
- It would support rate requests if the PUB had a better understanding of the kinds of investments that the utility intends to make, the issues that are facing the utility on a go-forward basis and the improved or broader level of service that customers are receiving for these investments.

The PUB Chair comments from the 2013/14 GRA appear to directly relate and provide additional context to the ultimate findings noted above (from Order 85/13) and in Section 4.3 below (from Order 108/15) with respect to the expectations of the PUB to review Centra's strategic plan, utility risk analysis and capital expenditure plan further at the next GRA.

In information request CAC/Centra I-2 (b)(d)(e), CAC noted that Centra had filed a high-level Corporate Strategic Framework in Tab 2 of the Application with only a mission statement for MH consolidated operations and no vision statement for electric or gas operations, that the 2018/19 Annual Business Plan filed with the Minister of Crown Services was not intended to replace the CSP and that MH commenced the completion of a new CSP in 2018/19.

In those information requests, CAC requested Centra to explain (1) if the new CSP would contain more detailed goals and strategies related to gas operations (2) if there were plans to develop a vision statement for gas operations (3) if there were any plans to improve customers service levels given the projected indicative rate increases in CGM18 (4) if there were plans to pursue further optimization of integrated planning between electric operations and gas operations and (5) if there were plans to expand natural gas into unserved areas of Manitoba. CAC also asked Centra to provide a summary of strategic business plans/initiatives of the divisions/departments that provide service to gas operations to respond to the PUB's concerns from Order 85/13.

In the response to these information requests, Centra indicated that MH was in the process of developing a long term (20 year) strategic plan for both electric and gas operations that began in the spring of 2019, that the content of the plan with respect to the items noted in the questions have not yet been decided and provided a reference back to some of the operational initiatives that were outlined in various tabs of the GRA filing.

While it is apparent that Centra put some effort into outlining a number of operational initiatives that relate to gas operations, on an overall basis the assessment of the material on the record of this proceeding with respect to corporate direction is that it is high-level and mainly relates to electric operations and as such, does not adequately respond to the PUB findings from Orders 85/13 and 108/15. Whether or not the MH/Centra strategic planning initiative that is currently underway will produce more meaningful and detailed information related to gas operations is an open question.

**7.2 Information Provided on Centra's Risk Assessment is Incomplete and Does Not Provided Sufficient Information for a Comprehensive Review of the Appropriate Level of Financial Reserves for Rate-Setting Purposes**

Risk assessment is an integral part of developing a corporate strategic plan and assessing the required financial reserves of the gas utility, especially in a Modified Cost of Service rate-setting framework for a publicly owned monopoly utility, where the purpose of financial reserves is to promote rate stability for customers.

In information request CAC/Centra I-2 (h)(i), CAC noted that Centra had filed the MH Corporate Risk Management Report from the fall of 2018 (Attachment 1 of the completeness filing) which was largely focused on risks that impact electricity operations (with only 3 risk profiles that are specific to gas operations) and that Centra does not provide any Key Variable Sensitivity analysis in the Gas IFF (CGM18) similar to that which is commonly provided with electric rate applications. In these information requests, CAC requested Centra to provide (1) Centra's perspectives on risk trends and changes, highest priority risks, other areas of concern and high consequence risks that are specific or most significantly impact gas operations and (2) a table of sensitivity analysis for key variables that can impact the gas operations financial outlook (interest rates etc.) as well as sensitivities related to potential variances to spending targets for Gas O&A, Business Operations Capital (BOC) and Demand Side Management (DSM) spending.

In the response to these information requests, Centra provided the following with respect to key risk considerations and key variable sensitivities:

- Risk Trends & Changes – changing environmental requirements and legislation including the impacts on Centra and its customers of the carbon tax and a Government of Canada initiative to develop a Clean Fuel Standard including a potential objective to reduce the carbon intensity of the gas delivered by gas distribution companies by between 5 and 10%;
- Highest Priority Risks – Centra has not identified any major risks as being critical and requiring specific attention over the next 12 months or longer;
- Other Areas of Concern – those items noted included the potential requirement for additional capital investment as a result of the (1) the implementation of an asset management system over the next two to three years and (2) the potential implementation of an Advanced Metering Infrastructure (AMI) program;
- High Consequence Risks – many communities supplied by natural gas rely on a single natural gas supply and are vulnerable to a single failure causing an outage; and
- Key Variable Sensitivities – Centra provided the impacts to retained earnings of warmer/colder than normal weather, higher/no customer growth and a +/- 0.5% change to interest rates for the 2019/20 Test Year only and declined to provide any sensitivities related to its controllable costs of O&A, BOC and DSM based on the assertion that the levels of these expenditures have been set in order to provide for an on-going safe and

> reliable supply of natural gas or the direction by the Government of Manitoba to maintain a continuation of current DSM programs while responsibility transitions to Efficiency Manitoba. In information request CAC/Centra II-123 (d), CAC reiterated its request for CGM18 financial scenarios assuming +/- $5 million of Gas BOC for each of the 10 years of CGM18, which was ultimately provided by Centra.

While the limited information on risk assessment/quantification in the information requests is directionally better than the information in the application, the overall assessment is that it is incomplete and does not provide sufficient information for a comprehensive review of the appropriate level of financial reserves for rate-setting purposes. This topic will be further discussed in Section 9.0 of the Evidence with respect to the appropriate financial targets for Centra for rate-setting purposes.

### 7.3 Information Provided on Centra's Management Structure Does Not Address the PUB Concerns from Order 108/15

The PUB made the following findings with respect to Centra's management structure in Order 108/15, at Page 26, which can be summarized as follows:

> "**Previously, Centra had a division manager of gas supply**; a **position that is currently vacant**. Furthermore …. **responsibility for gas operations** appears to have been **combined with several other duties assigned to senior managers** of Manitoba Hydro. The Board therefore **recommends that Centra review its managerial structure** to ensure that its **operational decision makers** … have **clear lines of responsibility** to a senior manager. The **Board expects** to **review Centra's management structure further** at the **next General Rate Application**. **At that hearing**, the **Board also expects** to **review Centra's strategic plan**, including the **utility risk analysis** and capital expenditure plan." (Emphasis added)

In the original application in Tab 2, Centra provided a high-level organizational structure chart of MH's executive and senior management and a generic description of the MH business units as it has in past GRA's. It does not appear that Centra attempted to directly address the PUB's concerns from Order 108/15 with respect to Centra's management structure in the GRA filing.

In information requests CAC/Centra I-2 (f)(g) and CAC/Centra II-123 (a)(b), CAC requested Centra to provide (1) a more detailed organizational chart which provides information down to the departmental level and delineates between those departments that are dedicated only to gas operations and those departments that provide integrated services to gas and electric operations and (2) to explain if there were any further plans to review the gas management structure now that the Voluntary Departure Program (VDP) is completed.

In the response to these information requests, Centra provided the following information:

- There are four departments in the MH/Centra organizational structure that provide services to gas operations only – Gas Supply Department (reports to Director of Customer Care), Gas Engineering & Construction Department (reports to Director of Engineering & Construction), Gas Apparatus Maintenance & Control and Winnipeg East Department (both report to Acting Director of Customer Service Operations – Winnipeg);
- The vacant Director of Gas Supply position was eliminated and reporting within Gas Supply was consolidated under the Manager of Gas Supply; and
- As part of the VDP, MH executives responsible for the gas management structure reviewed and aligned the organizational structure as part of an overall effort to streamline operations and management including the consolidation of all gas operational and customers service functions under the VP of Marketing & Customer Service. There are no specific plans for changes to this management structure in 2019/20.

While there have been changes to the overall organizational structure as a result of MH's restructuring and downsizing efforts (further consolidation of a number of roles), there does not appear to be any changes that directly respond to or address the PUB's concerns from Order 108/15, as those managers that have specific responsibility for gas operations continue to report to senior managers with broad areas of responsibilities in the MH consolidated organization.

**7.4 It is Recommended that the PUB Direct Centra to Address Its Concerns on Strategic Direction, Risk Assessment and Management Structure as Part of the Current Centra Board of Directors Review and Provide the Results at the Next Centra GRA**

The overall assessment from this section of the evidence is that Centra has not adequately responded to the PUB's findings from Orders 85/13 & 108/15 to provide additional information on its strategic direction, risk assessment and management structure at this GRA, for rate-setting purposes.

The PUB's concerns from the two prior regulatory proceedings are still outstanding and information on these topic areas in the current GRA remain at a high-level, concentrated mainly on electric operations with very little information specific to gas operations to assist the PUB in carrying out its rate-setting mandate for Centra.

It is recommended that the PUB direct Centra to consider these topic areas more fully as part of the comprehensive strategic, operational and financial review that is currently being undertaken by the MHEB and Centra's Board of Directors and provide more fulsome responses to the PUB concerns at the next Centra GRA.

## 8.0 The Level of Projected Indicative Rate Increases in the Next Eight Years of Centra's Financial Forecast Demonstrate the Need for Regular Regulatory Reviews by the PUB

Centra's 2019/20 GRA is based upon its most current financial outlook which is referred to as CGM18. CGM18 provides a financial outlook of its income statement, balance sheet, cash flow statement and projected/indicative non-gas rate increases for eight years past the 2019/20 Test Year to its 2027/28 fiscal year.

CGM18 projects the requirement for cumulative rate increases of 9.63% over the eight-year period between 2020/21 and 2027/28 based on projections of non-gas revenue requirements that are expected to increase 24% between 2020/21 and 2027/28. This level of rate increases is significantly higher than the previous Centra financial forecasts and the general rate increases approved in the past 20 years by the PUB.

This section of the evidence reviews the drivers of the projected increases in Centra's non-gas revenue requirement over the eight-year period as well as the implications for Centra's management of costs and the PUB's regulation of Centra in the short to medium timeframe. This section concludes by recommending that the PUB reiterate an earlier directive from 2003 that regular regulatory reviews of Centra occur at least once every three years.

### 8.1 CGM18 Projects Indicative Rate Increases In the Order of 10% for the Eight Years Between 2021 and 2028 (Compared to 9% Approved Rate Increases Between 2000 and 2020)

In section 3.1 of the application, Centra states the following with respect to the indicative rate increases projected in CGM18, after the 2019/20 Test Year:

> "CGM18 was approved by Centra's Board of Directors on October 26, 2018…**For 2020/21 and beyond**, **CGM18 projects that moderate general revenue increases will be required** in order **to provide sufficient funds** for ongoing capital investments and **maintain a 30% capitalization rate.** As these **financial projections are subject to change** in subsequent forecasts for updated in assumptions and circumstances, they are **only provided to the PUB for informational purpose at this time**. **Rate applications made in future years** will **depend** upon the **outlook and circumstances at that time** and will be subject to the review and approval of the Centra Board of Directors." (Emphasis added)

Figure 10 provides a summary of the key financial parameters contained in CGM18:

**Figure 10 - Summary of CGM18 Financial Outlook**

| | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 |
|---|---|---|---|---|---|---|---|---|
| Rate Increase | 2.25% | 1.00% | 1.00% | 1.00% | 1.00% | 1.00% | 1.00% | 1.00% |
| Cumulative Rate Increase | 2.25% | 3.27% | 4.31% | 5.35% | 6.40% | 7.47% | 8.54% | **9.63%** |
| Cumulative Additional Revenue | 6 | 10 | 14 | 17 | 21 | 24 | 28 | 32 |
| Annual Additional Revenue | 6 | 4 | 4 | 3 | 4 | 3 | 4 | 4 |
| Net Income | 5 | 7 | 7 | 7 | 7 | 8 | 7 | 7 |
| Retained Earnings | 86 | 93 | 99 | 106 | 113 | 120 | 127 | 134 |
| Equity Ratio | 29% | 29% | 29% | 29% | 29% | 29% | 29% | 29% |
| | | | | | | | | |
| Net Plant in Service | 603 | 626 | 646 | 666 | 686 | 707 | 727 | 747 |
| Net Regulated Assets | 109 | 112 | 114 | 117 | 119 | 122 | 124 | 127 |
| Other Assets | 107 | 105 | 105 | 105 | 105 | 105 | 105 | 105 |
| **Total Assets** | **819** | **843** | **865** | **888** | **910** | **934** | **956** | **979** |

**Source: Appendix 3.1**

The key observations from Figure 10 are as follows:

1. CGM18 has been prepared by Centra based on a goal-seek to maintain the equity ratio at a level of 29%, which is close to the level that has been determined by the PUB in past regulatory decisions to be acceptable (30%);
2. In CGM18, Centra is projecting that its total assets will increase from $819 million in 2020/21 to $979 million in 2027/28, an increase of $160 million or 20%. Over that time frame Centra's net plant in service is projected to increase from $603 million to $747 million, an increase of $144 million or 24%;
3. The assumption of a 29% equity ratio drives the projection of the requirement to increase the level of allowed net income from $3 million to $7 million as a result of the growth of Centra's total assets over the period of CGM18;
4. Indicative rate increases are projected at 2.25% for 2020/21 and 1.0% for each subsequent year in the forecast out to 2027/28;
5. For the period from 2020/21 to 2027/28, Centra is projecting cumulative rate increases of 9.63% related to non-gas costs and net income requirements. This accumulates to projected additional revenues of $32 million by 2027/28; and
6. Retained earnings are projected to increase from $86 million to $134 million, an increase of $48 million or 56% over the period to 2027/28.

The issues concerning the assumption of a 29% equity ratio by Centra in CGM18 will be reviewed in Section 9.0 of the Evidence.

In accordance with the information provided in the response to PUB/Centra I-1 (a) from the 2013/14 GRA, the general rate increases approved by the PUB since MH acquired Centra are as follows:

- 2003/04 = 1.9% general rate increase;
- 2005/06 = 2.0% general rate increase;
- 2006/07 = 1.0% general rate increase;
- 2007/08 = 2.0% general rate increase;
- 2008/09 = 1.0% general rate increase;
- 2010/11 = 0.8% general rate increase;
- Cumulative general rate increase to 2012/13 = 9.0%

The 1.0% general rate increase approved for 2013/14 in Order 85/13, was subsequently rolled-back by the PUB in Order 79/17, dated July 28, 2017. As such, the approved general rate increases since MH acquired Centra in 1999, nearly 20 years ago are in the order of 9%.

In contrast, Centra is now projecting close to 10% general rate increases in the eight-year period between 2020/21 and 2027/28 (1.25% = 10%/8 years), which is more than double the rate of actual general rate increases experienced over the last 20 years (0.45% = 9%/20 years).

While Centra characterizes these indicative rate increases as “moderate”, it should be remembered that the overall rate increases are calculated based on the overall level of Centra’s revenue requirements including gas costs. As gas costs represent somewhere in the range of 50% of the total revenues in CGM18, a 10% general rate increase is around a 20% or more increase in non-gas costs. Projected changes in non-gas revenue requirements will be further reviewed in Section 8.2 of the Evidence.

## 8.2 Centra is Projecting That Non-Gas Revenue Requirements Will Increase By 24% Between 2021 and 2028

Figure 11 provides a summary of the components of projected non-gas revenue requirements from 2020/21 to 2027/28, with a comparison of the base year in the analysis of 2019/20:

| Figure 11 - CGM18 Non-Gas Revenue Requirement | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | **2020** | **2021** | **2022** | **2023** | **2024** | **2025** | **2026** | **2027** | **2028** |
| Operating & Administrative | 61 | 62 | 63 | 64 | 65 | 66 | 68 | 69 | 70 |
| Finance Expense | 23 | 25 | 26 | 27 | 29 | 30 | 30 | 32 | 33 |
| Depreciation & Amortization | 25 | 27 | 28 | 29 | 31 | 31 | 32 | 33 | 34 |
| Capital & Other Taxes | 17 | 18 | 18 | 19 | 19 | 20 | 20 | 21 | 21 |
| Corporate Allocation | 12 | 12 | 12 | 12 | 12 | 12 | 12 | 12 | 12 |
| Other Expenses/Net Movement | 10 | 10 | 9 | 9 | 9 | 10 | 9 | 9 | 9 |
| Less: Other Incone | (2) | (2) | (2) | (2) | (2) | (2) | (2) | (2) | (2) |
| **Net Non-Gas Expeneses** | **146** | **152** | **154** | **158** | **163** | **167** | **169** | **174** | **177** |
| Net Income | 2 | 5 | 7 | 7 | 7 | 7 | 8 | 7 | 7 |
| **Total Non-Gas Revenue Requirement** | **148** | **157** | **161** | **165** | **170** | **174** | **177** | **181** | **184** |
| | | | | | | | | | |
| **Source: Appendix 3.1** | | | | | | | | | |

Figure 12 provides an analysis of the year over year and cumulative increases in the components of projected non-gas revenue requirements, using 2019/20 as a base year:

| Figure 12 - CGM18 Non-Gas Revenue Requirement Changes | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | **2021** | **2022** | **2023** | **2024** | **2025** | **2026** | **2027** | **2028** | **Increase 2028 vs. 2020** | **Average Annual Increase** |
| Operating & Administrative | 1 | 1 | 1 | 1 | 1 | 2 | 1 | 1 | 9 | 1.1 |
| Finance Expense | 2 | 1 | 1 | 2 | 1 | 0 | 2 | 1 | 10 | 1.3 |
| Depreciation & Amortization | 2 | 1 | 1 | 2 | 0 | 1 | 1 | 1 | 9 | 1.1 |
| Capital & Other Taxes | 1 | 0 | 1 | 0 | 1 | 0 | 1 | 0 | 4 | 0.5 |
| Corporate Allocation | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Other Expenses/Net Movement | 0 | (1) | 0 | 0 | 1 | (1) | 0 | 0 | (1) | (0) |
| Less: Other Incone | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Net Non-Gas Expeneses** | **6** | **2** | **4** | **5** | **4** | **2** | **5** | **3** | **31** | **3.9** |
| Net Income | 3 | 2 | 0 | 0 | 0 | 1 | -1 | 0 | 5 | 0.6 |
| **Total Non-Gas Revenue Requirement** | **9** | **4** | **4** | **5** | **4** | **3** | **4** | **3** | **36** | **4.5** |
| | | | | | | | | | | |
| **Percentage Increase:** | | | | | | | | | | |
| Net Non-Gas Expeneses | 4.1% | 1.3% | 2.6% | 3.2% | 2.5% | 1.2% | 3.0% | 1.7% | **21.2%** | 2.7% |
| Total Non-Gas Revenue Requirement | 6.1% | 2.6% | 2.5% | 3.0% | 2.4% | 1.7% | 2.3% | 1.7% | **24.3%** | 3.0% |

The key observations from Figure 11 and Figure 12 are as follows:

1. Non-gas expenses (excluding net income) are expected to increase from $146 million in 2019/20 to $177 million in 2027/28, an increase of $31 million or 21%. This equates to an average annual increase of approximately $3.9 million or 2.7% year;

2. Non-gas revenue requirements (including net income) are expected to increase from $148 million in 2019/20 to $184 million in 2027/28, an increase of $36 million or 24%. This equates to an average annual increase of approximately $4.5 million or 3.0% per year;
3. O&A is projected to increase by $9 million or $1.1 million per year, which is primarily a function of the assumption of 2% escalation in CGM18;
4. Finance Expense is projected to increase $10 million or $1.3 million per year, Depreciation & Amortization (D&A) is projected to increase $9 million or $1.1 million per year and Capital & Other Taxes is projected to increase $4 million or $0.5 million per year. These three expense categories increase on average about $2.9 million per year with the primary driver being the increase in projected net plant as a result of planned capital expenditures. It is noted that there are other drivers of these expense categories such as changes in forecast interest rates and property taxes, but it expected that the primary driver is growth in plant assets;
5. Net income is projected to increase by $5 million to the $7 million level (based on the assumption of a 29% equity ratio) which equates to about a $0.6 million increase per year on average; and
6. In total all of the categories of non-gas revenue requirements are increasing at an average rate of about $4.5 million per year which based on overall revenues of about $308 million (including gas costs) result in projected indicative general rate increase of about 1.5% per year.

In summary, the projected rate of growth of non-gas revenue requirement in CGM18 of $36 million or 24% (average annual rate of increase of $4.5 million or 3.0%) is significantly higher that the projected rate of growth from CGM12 with RRA of $18 million or 12% (average annual rate of increase of $3.0 million or 2.0%) as outlined in Section 4.1 of the Evidence.

### 8.3 Active Management/Prioritization of Operating Costs & Capital Expenditures Combined with the Review of Financial Reserve Levels is Required to Alleviate Future Projected Rate Pressures on Consumers

As noted in Section 4.3 of the Evidence, it is unlikely that the offsets to cost/rate pressures that have occurred in the last six years will occur to the same extent in the next 5 to 10 Years. The magnitude of future cost/rate pressures will require careful and active management by Centra and regular regulatory reviews by the PUB and participation by interested parties in order to protect the public interest.

The analysis in Section 8.2 demonstrates the primary drivers of future rate increases and reinforces the following conclusions with respect to management of costs and regulatory review requirements:

1. O&A costs need to be actively managed and Centra/MH needs to pursue further cost containment measures during a time of organizational change in order to reduce the rate of growth/escalation of costs and associated rate pressures. Escalation of O&A at 2% is driving about $9 million or 25% of the increase in non-gas revenue requirements of $36 million;
2. Centra should consider expediting the implementation of its Capital Planning and Asset Management initiatives to improve the pacing and prioritization of its capital expenditures which are driving close to $23 million or 64% of the increase in non-gas revenue requirements of $36 million. It is concerning that in the response to CAC/Centra II-123 (c) (i), Centra takes the position that Asset Management is a considered an area of concern but not a high priority risk. The PUB should closely monitor Centra's progress on Capital planning and Asset Management and provide the necessary regulatory direction to ensure that these initiatives are implemented appropriately and on a timely basis;
3. The largest contributor to the $23 million or 64% of the increase related to capital expenditures is finance expense which comprises $10 million or 28% of the increase. Centra and the PUB should carefully manage and monitor debt management strategies, policy guidelines and debt portfolio metrics to ensure the optimal debt portfolio and interest rate risk management to assist with prudently minimizing rate increases to customers; and
4. Centra and the PUB should carefully consider the appropriate financial targets and level of financial reserves required for gas operations. The assumption of moving from an allowed net income of $3 million to $7 million in order to maintain a 29% equity ratio (and grow retained earning levels to $134 million) is driving about $4 million or 11% of the increase in non-gas revenue requirements of $36 million.

Additionally, it is noted that the PUB made a number of findings and directives with respect to BOC spending levels in CEF16 on pages 110 to 113 and 264, which can be summarized as follows:

> "The **Board finds** that, while in **a period of major capital spending** on Keeyask and Bipole III, **Manitoba Hydro should find savings in Business Operations Capital**…The **Board does not accept the Business Operations Capital Spending forecast in Capital Expenditure Forecast CEF16**..The **Board finds that Business Operations Capital Spending can be safely decreased by $160 million** based on Manitoba Hydro's evidence that it can defer $160 million of spending in the Test Year…**The Board accepts the METSCO's evidence that Manitoba Hydro cannot demonstrate the proposed spending is necessary or has been optimized to any extent**…it does recognize the cost pressures that result from the capital program that includes Bipole III, Keeyask, and a new interconnection with the U.S. Those

**cost pressures mean** that **Manitoba Hydro can no longer continue to fund Business Operations Capital at its historic levels** unless and until it can demonstrate through mature asset management processes that those investments are necessary." (Emphasis added)

The PUB made the following recommendations to MH with respect to BOC in Order 59/18 on page 264, which are as follows:

> "**1. Defer $160 million of Business Operations Capital spending** to a future period beyond 2018/19…**2. Continue to find reductions in Business Operations Capital spending during the current period of record spending on major capital projects** such as Keeyask and Bipole III."

While the findings and directives from Order 59/18, focus on the rate pressures related to the MH major capital projects, the analysis in Section 8.2 demonstrates that there are also significant rate pressures as a result of Centra's projected capital expenditures. Just as it was the case in the MH circumstances, the PUB should direct Centra to demonstrate that the current and future levels of BOC spending are necessary through mature capital planning and asset management processes and recommend that they find reductions in order to ease pressures on gas rates.

In MH GRA regulatory processes there is considerable review of Electric IFF's and alternate financial scenarios as the Modified Cost of Service rate-setting approach that has been historically used in the past to set electric rates, "looks past" the test year(s) under review by using the long-term IFF and allowing the PUB to make informed judgements on how proposed rate increases in the test year(s) impact the longer-term financial outlook and rate trajectory for MH.

Long-term Gas IFF's (10 years) have been provided in Centra GRA regulatory processes for about the last 15 years, but there is not the same focus on examining and understanding the longer-term outlook and alternate financial scenarios for Centra. This is likely because gas rates are still set on a shorter-term focus on the test year(s) based on the current level of non-gas revenue requirements as well as a corporate allocation and a $3 million level of net income.

Although more limited in comparison to Electric GRA's, there are a few financial scenarios on the record of this proceeding as well as analysis contained in this Evidence, which can be used to illustrate the conclusions noted above, including the following:

- The analysis of the differences between Centra's O&A forecasts and forecasts assuming the recommended rate-setting adjustments and 1% escalation levels from Section 6.3 of Evidence;
- The financial scenario in the response to CAC/Centra II-123 (d), which provides a CGM18 sensitivity of the non-gas revenue requirements to a +/- $5 million reduction in BOC spending each year; and

- The CGM18 financial scenario in the response to PUB/Centra I-2 (b), which assumes an allowed net income of $3 million throughout the forecast period to 2027/28.

**Shorter-Term Indicative Rate Increases to 2021/22**

In CGM18, Centra is projecting indicative general rate increases of 2.25% in 2020/21 and 1.00% in 2021/22 for a cumulative increase of 3.27% and a cumulative additional revenue requirement of $10 million by 2021/22.

By 2021/22, the combined impact of the recommended rate-setting adjustments to O&A ($6 million reduction), maintaining the allowed net income of $3 million ($4 million reduction) and lower BOC spending of $5 million annually ($2 million reduction) would directionally appear to offset the requirement for the near term rate increases of 3.27%.

**Longer-Term Indicative Rate Increases to 2027/28**

In CGM18, Centra is projecting cumulative indicative rate increases of 9.63% and a cumulative additional revenue requirement of $32 million by 2027/28.

By 2027/28, the combined impact of the recommended rate-setting adjustments to O&A ($11 million reduction), maintaining the allowed net income of $3 million ($4 million reduction) and lower BOC spending of $5 million annually ($4 million reduction) would directionally appear to offset approximately $19 million of the additional revenue requirements. In 2027/28, the $13 million of remaining additional revenue requirements would result in cumulative rate increases of 4.13% ($13/$315) compared to 9.63% projected in CGM18.

While these alternate scenarios are based on high-level and illustrative calculations, they do demonstrate how active management of costs and regular regulatory reviews can assist in minimizing rate increases and protecting the interests of customers.

**8.4 It Is Recommended that the PUB Reiterate the Directive from Order 118/03 that Centra Establish Regular GRA Reviews Every Three Years Given the Rate Pressures Forecast in CGM18**

The last Centra GRA under private ownership was the 1998 GRA with a public hearing that occurred in 1998.

After the acquisition of the Company by MH, Centra filed a 2001/02 Distribution Rates Application with the PUB early in 2001 based on a Cost of Service rate-setting methodology that requested approval of distribution rates effective April 1, 2001. In March of 2001, the application was subsequently withdrawn by Centra.

In December of 2002, Centra filed a gas GRA based on a rate/base rate of return rate-setting methodology for its 2003/04 fiscal year, requesting rates be approved effective April 1, 2003 with respect to all gas consumer on and after August 1, 2003.

In Order 118/03, dated July 29, 2003, the PUB made the following findings with respect to regular regulatory reviews at pages 24 and 84, respectively:

> "**Since the last approved Rate Base is based on a 1998 Test Year**, this **application contains six years of Rate Base components** including plant additions, plant deletions, contributions in aid of construction, depreciation and working capital allowance changes. The **Board is required to review and decide** on the **prudence of all these components** to properly **discharge its obligations**. The **task is made more onerous and time consuming** that it would otherwise have been **because of the long passage of time since the last GRA** filing." (Emphasis added)

> "The **Board recognizes** that **parties expressed frustration with Centra's absence** from the **public review since 1998**. As previously mentioned, the **Board's job was made more onerous** due to the **long passage of time between the last GRA held in 1998**. Therefore, the **Board will require Centra establish** a **more regular schedule**, **not to exceed three years, for periodic reviews.** This **regular schedule** should **improve** the **efficiency**, **effectiveness** and **timeliness** of the **regulatory process**, **even if no rate changes are requested."** (Emphasis added)

In Order 118/03, the PUB made the following directive with respect to regular regulatory reviews at page 102:

> "**23. Centra establish** a more **regular schedule** for **periodic rate reviews**, **not exceeding three years** between general rate applications." (Emphasis added)

Centra did not include this directive in the status of on-going directives from Order 118/03 that was provided on page 14 of Tab 13 or in Appendix 13.4 of the Application (Centra's comments on all on-going directives). When CAC questioned whether the Company views this directive to be satisfied or rescinded by the PUB, Centra responded in CAC/Centra I-16 (d), that it views this directive to be on-going.

While much time has passed since the 2003/04 Centra GRA, there appears to be similarities in the situation that currently exists with the passage of six years since the last Centra GRA in 2013/14. Notably, the Centra filing contains nine years of revenue requirement, rate base and financial information consisting of seven years of actual information and two years of forecast information. Additionally, (1) there is a plethora of information on the transition to IFRS that occurred in 2015/16 and the request for approval of updated depreciation rates/accounts and a significant number of regulatory deferral accounts/amortization periods (2) four years has elapsed since Centra's last Cost of Gas Application which has necessitated the filing by Centra of five years of gas cost information for review and finalization (3) for larger volume customers there are significant non-gas cost rate increases that result from cumulative impacts of capital investment and shifts in the pattern of the underlying costs that result from the passage of time since the last GRA, which at the same time is expected to have delayed the corresponding rate reductions for the smaller volume customers (4) there are significant decreases in forecast non-primary gas costs and overall refunds of gas cost deferral accounts that have delayed being implemented in rates for customers and (5) there are close to 30 interim Orders (Appendix 13.1) that need to be finalized by the PUB at the current regulatory proceeding.

While the PUB could not have anticipated the events and circumstances that have brought us to the current situation some 16 years ago in 2003, the PUB's directive from Order 118/03 that regular regulatory reviews every three years would improve the efficiency, effectiveness and timeliness of the regulatory process is as valid now as it was back in 2003.

The PUB also has recognized the benefits of moving MH back to a regular regulatory cycle in the findings on pages 171 to 174 of Order 59/18.

Based on the foregoing analysis, it is recommended that the PUB reiterate the directive from Order 118/03 that Centra establish a regular regulatory schedule including periodic regulatory reviews not to exceed three years.

Regular regulatory reviews will assist the PUB to monitor Centra's progress on cost control, implementation of capital planning and asset management enhancements and management of Centra's debt portfolio, and will assist in ensuring that rate pressures that are built up over time or refunds that are due to customers (as well as the finalization of interim Orders) are dealt with on a timely basis.

## 9.0 The Basis For Determining Centra's Financial Reserves for Rate-Setting Purposes Should Be Transitioned to a Minimum Retained Earnings Test Based on a Comprehensive Risk Analysis

When Centra was under private ownership, gas rates were set for decades based on a rate base/rate of return (RBROR) rate-setting framework with a capital structure not to exceed 40% Equity.

Under MH's ownership (and since 2005), gas rates have been set based on a modified form of RBROR (MRBROR) where MH's return on its investment in Centra has been limited to the pre-acquisition earnings ($14 t0 $16 million) and gas rates have included a $12 million corporate allocation and an allowed net income of $3 million.  During this period, the PUB found that the appropriate stand-alone Equity ratio for Centra was 30%, but gas rates have never been set based on this factor.

Since the acquisition of Centra, MH's policy has been that it does not require a return on investment from Centra and it has proposed rate increases to maintain a reasonable level of financial reserves to promote rate stability for customers (consistent with a Modified Cost of Service (MCOS) rate-setting framework). Centra did not propose actual rate increases or forecast indicative rate increases based on a 30% Equity ratio.

Centra appears to have adopted targeting close to a 30% Equity ratio (29%) as the basis for its most recent financial forecasts (CGM16 & CGM18) and indicative rate increase projections. It is unclear why Centra has adopted this change in policy or approach and concerning that it has increased its emphasis on the RBROR calculations that continue to be provided in the GRA filings.

This section of the evidence reviews the appropriate basis on which Centra's financial reserves should be determined for rate-setting purposes. The section concludes by recommending that the basis for determining Centra's financial reserves for rate-setting purposes should be transitioned to a Minimum Retained Earnings Target based on a comprehensive risk analysis, adapted to Centra's circumstances based on the direction that is being pursued by the PUB with respect to rate-setting for MH, in Orders 59/18 and 69/19. It is also recommended, that in the interim period of this transition, if there is a need for a general rate increase, a $3 million net income and the consolidated MH target of 25% equity be used for gas rate-setting.

### 9.1 Under Private Ownership Centra's Rates Were Set for Decades Based on a Rate Base/Rate of Return Rate-Setting Framework with a Capital Structure of Around 40% Equity

Historically, for decades when Centra was under private ownership, its rates were set based on a Rate Base/Rate of Return (RBROR) rate-setting framework. The RBROR rate-setting framework is formulaic in nature and is used in many jurisdictions to determine revenue requirements and set rates based primarily on consideration of the financial forecasts of a single test-year and is designed to allow the utility the opportunity to earn an approved return on equity (ROE/net income) based on an approved capital structure (debt to equity ratio). The RBROR can be referred to as a "vertical" rate-setting approach in that it looks specifically at the test-year revenues and expenses to make rate-setting determinations based on a formula.

Under RBROR, there are a number of factors to consider in determining the appropriate capital structure of the company, including business, regulatory and financial risks and the ability to access the capital markets for equity and debt.

While there are decades of jurisprudence and regulatory precedent that support the determination of an fair and reasonable ROE, there are two basic principles with respect to a fair ROE (1) the opportunity cost principle, that the owner of a public utility should be provided the opportunity to earn a ROE that is similar to other investments with the same level of risk and (2) the capital attraction principle, that the owner of a public utility should be provided the flexibility to access the capital markets and attract capital on reasonable terms.

In practical terms when Centra was a privately owned company, the setting of a fair ROE and capital structure also considered the ability to maintain bond ratings and meet debt covenants (interest coverage and percentage of debt capitalization) in order for it to be able to access the capital markets to issue debt at reasonable cost and terms, as the need arose.

Centra's approved capital structure for rate-setting purposes was historically not to exceed a 40% Equity ratio, which typically was at the higher end of the industry range of 35% to 40%. The risk premium that was inherent in the approved Centra ROE recognized the PUB assessment that Centra's risks are on balance, below the average risks of Canadian gas local distribution companies (Order 8/94, page 42) and that the company's capital structure was at the higher end of the industry range and as such its ROE would be reduced by 25 basis points (Order 8/94, page 51).

## 9.2 Under MH Ownership Centra's Rates Have Been Set Based on a Modified Rate Base/Rate of Return Rate-Setting Framework with a Focus on Limiting MH Returns to the Pre-acquisition Earnings of $14 to $16 Million

After the transition to ownership by MH, gas rates were set using what could be referred to as a modified RBROR approach (MRBROR). The allowed net income for Centra was not derived by applying an approved rate of return on equity to an approved rate base as is the case in a traditional RBROR approach. Under the MRBROR approach, gas rates were set by adding a corporate allocation and net income to the other cost of service expenses (O&A, deprecation, interest etc.) to generate a specific financial outcome – namely a net income of $3 million.

The $3 million of allowed net income was based on the consideration that the pre-acquisition earnings of Centra when it was an investor owned utility were in the range of $14 million to $16 million and that the total return to MH would be limited to a $12 million corporate allocation plus a $3 million net income (total of $15 million or mid-point of pre-acquisition range) to ensure that there was "no harm" to gas customers rates as a result of the purchase of Centra by MH.

While the approach to set gas rates under MH ownership has been referred to as a Modified Cost of Service (MCOS) Rate-Setting framework, this is in many ways a misnomer.

As explained in Section 8.3 of the Evidence, the MCOS that has been historically used to set electricity rates in Manitoba "looks past" the test year(s) under review by using the long-term IFF and allowing the PUB to make informed judgements on how proposed rate increases in the test year(s) impact the longer-term financial outlook and rate trajectory for MH. The focus of a MCOS approach is to allow for sufficient financial reserves (retained earnings) to promote rate stability for customers and to act as a buffer for negative financial events. The MCOS can be referred to as a "horizontal" rate-setting approach in that it looks over the longer-term planning horizon to make rate-setting determinations in the current test year(s) and considers a number of alternate financial scenarios/rate paths.

In contrast, the approach to set gas rates under MH ownership has retained many elements of the former RBROR approach to setting rates including the primary focus on the revenue requirements of the specific test year(s), reference to pre-acquisition earnings determined under the RBOR approach as a limit on the total return to MH and more limited review and analysis of the forward looking financial forecasts to inform the rate-setting determinations in the current test year(s). This is why this approach is referred to as a MRBROR approach in this evidence to distinguish it from the MCOS that has been historically used to set electricity rates for MH.

While the standalone Equity ratio for Centra under private ownership had historically been in the 40% range, in Order 99/07 (2007/08 & 2008/09 GRA) the PUB made a finding at page 109 that "…the Board accepts Mr. Matwichuk's advice and finds that given Centra's borrowings are guaranteed by the Province, with the fee for the guarantee allowed in costs for rate setting, a 70:30 ratio is adequate, rather than the 60:40 model that would be acceptable if there were no provincial guarantee."

Centra did not accept the PUB's determination of a 30% Equity ratio for rate-setting purposes, taking the position at the GRA's subsequent to the issuance of Order 99/07 that the proper application of the "standalone" regulatory principle would result in a 40% Equity ratio, that share capital should not be considered part of the Equity ratio calculation as it was backed by debt in the consolidated financial statements, that it was fully integrated into the operations of MH and financed through MH (i.e, Centra was no longer a standalone entity) and that evidence and process to come to the 30% Equity ratio determination was lacking (the 30% stand alone Equity ratio determination was not based on capital structure evidence or comprehensive risk analysis provided by Centra and Intervenors but rather a short reply to a cross examination question by a CAC/MSOS witness).

Despite the PUB findings of a 30% Equity ratio, gas rates in subsequent GRA's were actually set based on the allowed net income of $3 million to ensure that there was no harm to the gas customers as a result of the acquisition of Centra by MH, and not based on a 30% equity ratio. During these years, Centra's Equity ratio (calculated based on what is referred to as the "PUB methodology" which includes MH share capital as part of Equity) was above the 30% level (see the response to PUB/Centra I-58, column G).

The only time it appears that the 30% Equity ratio was used as a factor to set or adjust gas rates was in Orders 108/15 and 79/17, when the PUB noted that Centra's Equity ratio had increased to 35% and directed that Centra file a GRA for a review of non-gas revenue requirement by January 20 of 2017 or the non-gas components embedded in rates were to revert back to the levels last approved on an interim basis in Order 66/11 (2010/11 Test Year), which essentially reversed the general rate increase approved for the 2013/14 Test Year.

### 9.3 MH has Never Set Separate Formal Financial Targets for Centra but its Previous Policy Was Proposing Rate Increases to Maintain a Reasonable Level of Retained Earnings to Promote Rate Stability For Customers

As has been noted by Centra at the past GRA's, there are no formal financial targets that have been set for Centra and the established MH financial targets (debt to equity, interest coverage and capital coverage) are for consolidated operations only (as an example, see the response to PUB/Centra I-2 (a) from the 2013/14 GRA for the wording of this note).

For the most part, since the PUB's determination of a $3 million net income for rate-setting purposes, Centra's Gas IFF's have been based on a $3 million net income. The notable exception being CGM12 in which Centra's Board had approved a forecast with a higher level of net income to rebuild retained earnings from a deficit position as a result of the expectation that $77 of rate-regulated assets would have to be written-off upon transition to IFRS (discussed in Section 5.2 of the Evidence).

It was not the policy of Centra or its Board of Directors to forecast proposed and indicative rate increases to obtain or maintain a 30% Equity ratio or to earn a full return on investment like a private shareholder. As noted above, there were no formal financial targets set for Centra by its Board and the focus of proposing rate increases was on maintaining a reasonable level of financial reserves to promote rate stability for customers. The Centra policy was summarized by the PUB in Order 103/05 at page 32, Order 135/05 at page 67 and Order 128/09, at page 89 as follows:

> "**Centra indicated** at the hearing that Cost of Service was the **method used** by its **Board of Directors** and senior management, **to determine the revenue requirement of Centra and MH**…Accordingly, **Centra indicated and argued** that **Cost of Service was its preferred approach to setting revenue requirement and rates** and should be the way by which it is regulated…In support of that position, it was **pledged** at the hearing that **MH will never seek a return on its investment in Centra other than**:
>
> (a) **full recovery of its costs**, including the sharing with Centra financing costs and other costs associated with the acquisition of Centra; and
>
> (b) the **development of sufficient retained earnings in Centra** from natural gas distribution operations to **provide** for a **prudent financial foundation for natural gas operations.**" (Emphasis added)

> "The **Board notes the assurances provided at the hearing**…that **MH seeks only the return of its costs related to Centra** together with such **reasonable net income** as the Board determines to **ensure Centra's financial position is adequate** for **consumer protection**." (Emphasis Added)

"**Centra indicated** that while a 75:25 debt to equity ratio target is MH's overall corporate target, it is not relevant in the context of Centra as a stand-alone utility, and that **there is no reason for Centra having any particular debt to equity ratio** as long **as the Utility** has a **sufficient level of retained earnings** to **meet its operational and financial risks**." (Emphasis added)

This rate-setting policy and the projections of indicative rate increases to generate net income in the range of $3 million on average on an annual basis was maintained by Centra until CGM15 was approved by its Board in December of 2015.

### 9.4 Centra Appears to Have Adopted a 30% Equity Ratio as the Basis for Its More Recent Financial Forecasts (CGM16 & CGM18) and Indicative Rate Increase Projections

In contrast to Centra's policy/approach to forecasting gas rate increases in the past, the more recent financial forecasts (CGM16 and CGM18) show a shift in focus away from projecting indicative rate increases based on a $3 million net income to slowly build financial reserves, to a focus on goal-seeking net income requirements and indicative rate increases to maintain an Equity ratio close to 30% (CGM16 and CGM18 both target 29% Equity ratio over the longer term forecast).

Figure 13 provides a summary of the key financial parameters contained in CGM16 for the period 2019/20 to 2026/27:

**Figure 13 - Summary of CGM16 Financial Outlook**

| | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 |
|---|---|---|---|---|---|---|---|---|
| Rate Increase | | 1.00% | | 1.50% | 1.25% | 1.00% | | 1.75% |
| Cumulative Rate Increase | -1.00% | -0.01% | -0.01% | 1.49% | 2.76% | 3.79% | 3.79% | **5.60%** |
| Cumulative Additional Revenue | 0 | 3 | 4 | 8 | 13 | 17 | 18 | 23 |
| Annual Additional Revenue | 0 | 3 | 1 | 4 | 5 | 4 | 1 | 5 |
| Net Income | 4 | 4 | 2 | 3 | 3 | 3 | 2 | 3 |
| Retained Earnings | 70 | 74 | 76 | 79 | 82 | 85 | 87 | 90 |
| Equity Ratio | 30% | 30% | 30% | 29% | 29% | 29% | 29% | 29% |
| | | | | | | | | |
| Net Plant in Service | 567 | 581 | 596 | 612 | 626 | 645 | 662 | 679 |
| Net Regulated Assets | 98 | 99 | 97 | 95 | 92 | 88 | 86 | 83 |
| Other Assets | 87 | 86 | 86 | 86 | 86 | 86 | 86 | 86 |
| **Total Assets** | **752** | **766** | **779** | **793** | **804** | **819** | **834** | **848** |

**Source: CAC/Centra II-125 b**

The key observations from Figure 13 are as follows:

1. Net income was projected to average around $3 million over the timeframe of the CGM16 forecast;
2. The Equity ratio was projected to be 30% from 2019/20 to 2021/22 and then be steady at 29% from 2022/23 to 2026/27;
3. Indicative rate increases were forecast at 1.00% (2020/21), 1.50% (2022/23), 1.25% (2023/24), 1.00% (2024/25) and 1.75% (2026/27) and for cumulative indicative rate increases of 5.60%, including the 1.00% rate-rollback in the 2017/18 fiscal year;
4. Total assets were forecast to grow from $752 million in 2019/20 to $84 in 2026/27, an increase of $96 million or 13%. Net plant was forecast to grow from $567 million in 2019/20 to $679 million in 2026/27, an increase of $112 million or 20%; and
5. Retained earnings were forecast to grow from $70 million in 2019/20 to $90 million by the end of the forecast (2026/27), an increase of $20 million or 29%.

It is unclear if Centra was targeting/goal-seeking an Equity ratio of close to 30% in CGM16 (for the first time) in order to forecast the indicative rate increases noted above or if non-gas cost changes were such that a net income of around $3 million was adequate to maintain the Equity ratio between 29% and 30% over the forecast period.

What is clear is that in CGM18, Centra, for the first time is targeting/goal-seeking an Equity ratio of close to 30% in order to forecast the indicative rate increases and that this approach is resulting in net income increasing to the $7 million level and retained earnings increasing to $127 million by 2026/27 (the last common year of CGM16 and CGM18) in CGM18, which represents a $37 million ($127-$90) or 41% increase in retained earnings for that fiscal year. Total assets for 2026/27 are also forecast to increase by $108 million ($956-$848) and net plant is forecast to increase $48 million ($727-$679).

The cumulative indicative rate increases are increasing from 5.60% in CGM16 to 9.63% in CGM18. A summary of the CGM18 financial parameters was provided in Figure 10, Section 8.1 of the Evidence.

In information requests CAC/Centra I-11 (m) and CAC/Centra II-129 (a)(b), CAC requested Centra to explain why there was this apparent change in policy or approach. In the responses to these information requests Centra indicated that:

- the indicative rate increases in CGM18 beyond the 2019/20 fiscal year were for "Informational purposes only and subject to the review and approval of Centra's Board of Directors…the $3 million net income level and 70:30 debt-to-equity ratio are mutually exclusive in that restricting net income to $3 million annually results in a steady decline in the equity ratio to 26% capitalization by the end of the forecast period"; and

- CGM18 “has used the 30% equity ratio as a guideline in determining the projected indicative rate increases over the forecast period. This was not a change in policy but rather meant to be illustrative”.

Centra has provided no rationale for the change in approach in what was understood to be an official forecast approved by the Centra Board and not simply an illustrative financial scenario.

As was noted above, the total projected assets in 2026/27 in CGM18 are now projected at $956 million, which represents a $108 million or 13% increase over the $848 million forecast in CGM16. It is a simple mathematical relationship that as the size of a utilities asset base grows, the use of Equity ratio goal-seek will result in higher required levels of retained earnings, net income and ultimately higher rate increases.

The increase in the level of projected indicative rate increases and retained earning levels between CGM16 and CGM18 would appear to be in large part a function of the 29% to 30% Equity goal-seek and a higher level of projected total assets. Centra has not indicated any change in its operations or risk assessments that would justify this significantly higher (41%) level of retained earnings projected in CGM18.

It is concerning that while Centra’s Equity ratio has been above the 30% level since at least 2002/03, it never has requested that its rates be decreased to maintain the 30% level. Now that Centra is projecting that its Equity ratio will be below 30% based on the planned level of capital investments, it is shifting its focus to project indicative rate increases to maintain a 30% Equity level.

Another concern that is noted is the increased emphasis of the RBROR calculations in Centra’s application. Since the acquisition of Centra by MH, the PUB has directed Centra to continue to provide RBROR calculations (in addition to MRBROR calculations used to set rates) in order to satisfy historic legislative requirements (for the PUB to set a rate base and return on equity or ROE) and as a measure of “no harm” to customers based on the maximum allowed return that would be generated by a RBROR approach to rate setting.

In its application, Centra has undertaken significant efforts to update the rate base calculations for the multitude of new regulatory deferral accounts and the transition to IFRS, updated the lead/lag study related to working capital requirements and filed expert testimony from Drazen Consulting Group Inc. (DCGI) with respect to capital structure and ROE matters. While a portion of this effort can be attributed to compliance with regulatory directives (update of the ROE for feasibility test purposes in accordance with Order 85/13), there appears to be a renewed focus on RBROR revenue requirements calculations that has not occurred since Centra’s rates were set based on a RBROR approach in the 2003/04 Test Year.

There is more emphasis in Tab 3 of the 2019/20 GRA filing with respect to the maximum revenue requirements that would be indicated by a RBROR approach including what is described as a $3.1 million "shortfall" in revenue requirements net income for 2019/20 (Tab 3, page 6 and page 10 of the March 22, 2019 supplement to the application).

Centra is also requesting that the PUB approve the addition of $31 million of new regulatory deferral accounts into rate base for 2019/20, to recognize the transition to IFRS, which increase the overall return on rate base by $1.8 million and ROE by $0.820 million (responses to CAC/Centra I-11 (c) and CAC/Centra II-132 (a)). Centra is also resolute that its cumulative expenditures for DSM that average $54 million for 2019/20 continue to be including in the working capital component of rate base despite the transition of Gas DSM activities to Efficiency Manitoba. The inclusion of DSM in rate base results in an overall return on rate base of $3.2 million and ROE of $1.4 million (responses to CAC/Centra I- 11 (h) and CAC/Centra II-132 (b)). The inclusion of $85 million of regulatory deferrals/DSM deferrals in rate base result in $2.2 million of ROE/net income requirements in the RBROR calculations and upwards of $26 million ($86 * 30%) in equity to maintain to maintain a 30% Equity ratio.

These positions by Centra are reminiscent of the requests that were made by Centra in the 1997, 1998 and 2003/04 GRA's to align the overall rate of return and return on rate base to consider the financing of regulatory deferral accounts when gas rates were actually set on using a RBROR approach. These requests were denied by the PUB in Orders 8/97, 79/98 and 118/03, respectively.

It is also curious to note that while Centra is requesting approval of the addition of numerous regulatory deferral accounts to rate base, its understanding of the current regulatory framework in the response to PUB/Centra II-41 (d) appears to be that Centra does not request approval of the PUB for the inclusion of capital expenditures in rate base. According to Schedule 6.0.0 updated, net plant makes up about 88% ($567/$646) of the requested rate base and $31 million of additional regulatory deferral accounts would comprise about 5% ($31/$646) of rate base.

There have historically been issues with the appropriateness of including regulatory deferral accounts in rate base (especially the earning of a full rate of return on these accounts) and whether these accounts meet the definition of an element of rate base under the PUB Act. Given that RBROR calculations are a remnant of the past ownership structure of Centra and historic legislative requirements, the primary focus/concern in this evidence is the direction of gas rate setting at future GRA's under a MCOS approach and not the RBROR calculations.

What is not clear is if Centra is signalling a change in approach to increase and use the maximum allowed revenue requirements under RBROR to justify a higher approved level of net income/rates in the future or if the renewed emphasis on RBROR is a defensive strategy to respond to the PUB's concerns from Order 108/15 (page 17) that Centra has been over-earning on a weather normalized basis and may be in excess of what is required to assure the financial health of the utility, or both.

## 9.5 DCGI's ROE and Capital Structure Recommendations are Not Appropriate for a Modified Cost of Service Rate-Setting Framework

Centra filed the expert evidence of Drazen Consulting Group Inc. (DCGI) as Appendix 3.5 to its 2019/20 GRA filing. The purpose of the DCGI evidence was to address the appropriate ROE and level of net earnings for Centra, both prospectively and retrospectively. DCGI's key findings in its evidence are summarized as follows:

- Centra's actual net earnings have averaged about $3 million over the long run, and Centra's Equity ratio has been close to the 30% target that the PUB had found to be appropriate, so there should be no concern about Centra over-earning historically;
- As a result of Centra's growing business, $3 million of net earnings will not enable Centra to maintain the 30% Equity ratio; and
- Based on comparable utility data and a goal of a 30% Equity ratio, a reasonable and effective approach over the next 5-10 years for rate-setting, is to base net earnings on a deemed 30% Equity ratio and a return on equity (ROE) in the range of 8.3% to 8.5%.

In information request CAC/Centra I-7 (k), CAC requested DCGI to explain if it was relying solely on the one-year benchmarking of the approved ROE's of other Canadian Gas Distributors (from Table 2 of the DCGI evidence) to come to the conclusion with respect to a ROE of 8.3% to 8.5% at a deemed Equity ratio of 30%, or if DCGI had performed any of the traditional cost of capital regulatory tests (CAPM, Risk Premium, DCF, Comparable Earnings) that are commonly used by cost of capital experts to recommend the appropriate range of ROE's to regulatory tribunals. In the response, DCGI stated:

> "The **primary basis** for **recommending a ROE of 8.3%-8.5%** was that a ROE in this range will enable Centra to **maintain a 30% equity ratio**…The initial step of checking returns of all other Canadian LDC's was to identify the range of results found appropriate for all other Canadian local distribution companies. Note that this explicitly represents a "comparable earnings" test." (Emphasis added)

In information request PUB/Centra I-51 (a), DCGI was asked to explain the relationships that support requiring a 8.3% to 8.5% ROE to compensate for a 30% equity level. In the response, DCGI stated:

> "An **8.3%-8.5% return on equity** ("ROE") will **produce the dollar returns sufficient** to **maintain a 30% equity ratio**. This was determined by analyzing the equity ratios that result from maintaining a constant ROE's in the range of 8.3%-8.7%. Thus, the range of 8.3%-8.5% is the result of maintaining the target equity ratio given Centra's expected capital expenditures over the next decade." (Emphasis added)

In information request CAC/Centra I-7 (j), DCGI was requested to explain the evidence upon which it was forming the opinion that Centra has higher risk than SaskEnergy and explain if it had undertaken a comprehensive review of the relative risks of Centra and SaskEnergy, as is commonly used by cost of capital experts to make recommendations to regulatory tribunals with respect to ROE and capital structure. DCGI was also requested if it was aware that the last full decision on cost of capital and capital structure of the PUB found that Centra's risks are on balance, below the average risks of Canadian gas LDC's (Order 8/94, page 42). In the response DCGI stated:

> "The basis was explained in the evidence. The observation in Order 8/94 that Centra's risks are below the average of other Canadian LDC's does not mean that Centra should have a ROE lower than the lowest other LDC."

In information request CAC/Centra I-7 (m), DCGI was requested to explain if it had conducted any comparative risk analysis to reconcile a recommendation of a 30% Equity ratio for Centra with MH's consolidated Equity ratio target of 25%. In the response, DCGI stated that "No. The focus was on Centra's needs."

The review of DCGI's evidence, information responses and the clarification in the response to CAC/Centra I-7 (k), that the "primary basis" for recommending a ROE of 8.3% to 8.5% was that a ROE in this range will enable Centra to maintain a 30% Equity ratio, results in the following assessments:

1. DCGI's evidence is not traditional cost of capital expert evidence that relies on a number of accepted ROE methods/tests and a comprehensive risk analysis to develop opinions with respect to the appropriate ROE and capital structure of a regulated utility;
2. While DCGI indicated that its ROE analysis represents a comparable earnings test, this ROE methodology has been presented by ROE experts at prior Centra GRA's and is much more involved in terms of analysis of multiple years of data and adjustments for risk differentials, than DCGI's review of a one-year list of approved ROE's for other Canadian Gas LDC's. As well, in the past, given the issues associated with this method, the PUB has given the comparable earnings method little weight in determining the fair ROE (Order 8/94, page 44);
3. DCGI's risk analysis was limited to one aspect of Centra's risks, a high-level review of weather variability between Centra and SaskEnergy and did not recognize or deal with the previous findings of the PUB that Centra's risks are on balance, below the average risks of Canadian gas LDC's (Order 8/94, page 42);
4. The PUB has denied the use of use of a deemed Equity ratio (using a deemed or notional capital structure versus an actual capital structure for rate-setting) in the past, most recently in Order 118/03 (page 70); and

5. DCGI's evidence is not an independent review of the appropriate capital structure and ROE for Centra that is derived from traditional regulatory tests or a comprehensive risk assessment, but rather can be more properly characterized as a benchmarking exercise or a reasonability check of an appropriate ROE based on an assumed capital structure/equity ratio of 30%.

In summary, much like the indicative rate increases in CGM18 are a goal-seeking exercise derived from the assumption of an 29% to 30% Equity ratio, the DCGI recommended ROE range of 8.3% to 8.5% is based on a goal-seeking exercise assuming the same 30% Equity ratio – which is then subsequently back-checked for reasonability by reviewing the allowed ROE's of other Canadian LDC's.

The lower end of the DCGI recommended ROE range of 8.3% is likely acceptable for the purposes of updating the ROE that is used in the feasibility test (at least until the planned review of the feasibility test methodology by the PUB) and continuing a high-level calculation of revenue requirements under a RBROR approach, to the extent these calculations re determined to be necessary on an on-going basis.

If the PUB were to accept DCGI's recommendations, then gas rates would be set directly using this methodology, rather than the current approach where historically awarded levels of pre-acquisition return are used as a check on "no harm" to customers. If rates were to be set either directly by generating a ROE for Centra to maintain a 30% Equity ratio in its IFF (as recommended by DCGI) or indirectly by increasing the maximum allowed ROE in the MRBROR calculations, or both, then more rigour (in terms of comparative risk assessments and detailed review of the ROE formula's and generic cost of capital proceedings in other jurisdictions) would be required, than has been undertaken in the DCGI benchmarking exercise.

However, the use of the 8.3% ROE and a deemed 30% Equity ratio to actually set gas rates as recommended by DCGI is not appropriate.

As summarized in Section 9.3 of the Evidence, the intent and policy underlying MH's purchase of Centra was that (1) MH did not require a return on investment like an investor owned utility, but rather a contribution to financial reserves to promote rate stability and (2) that customers should enjoy lower rates under public ownership. This approach of a government business enterprise like MH or Centra is contrast with the requirement of investor owned utilities to earn a fair ROE in order to attract investor equity and issue debt.

Acceptance of the DCGI recommendations amounts to importing investor owned utility RBROR concepts (Equity ratios and ROE's) into the MCOS rate-setting of a government business enterprise, as well as artificially increasing rates through higher net income levels, without any justification in terms of risk.

Additionally, if MH changes its approach and requests future rate increases that are closely aligned with the maximum revenue requirements calculated under the RBROR approach (in the extreme case requesting a revenue requirement that is $1 less than RBROR), then it is not in substance following a MCOS approach, but for all intents and purposes, a RBROR approach.

The DCGI recommended approach or an approach that uses the maximum requirements from a RBROR approach, would not be consistent with the intent when MH purchased Centra and a MCOS rate-setting framework, and are not recommended to the PUB.

The Sections of the Evidence that follow will review the evolving policy framework with respect to setting MH's electricity rates and make recommendations in terms of its applicability to Centra.

**9.6 The PUB has Questioned the Relevance of the Equity Ratio for a Crown Owned Utility Like MH and Has Directed Consideration of a Minimum Retained Earnings Test (MRET) for the Purposes of Setting MH's Rates**

The MCOS rate-setting approach has been used for decades to set MH rates and the MRBROR approach has been used to set Centra rates for the last 15 years.

The decisions from the 2017/18 & 2018/19 MH GRA (Order 59/18) and 2019/20 MH Rate Application (Order 69/19), represent a significant shift in rate-setting policy in terms of the framework and target that is used to set rates for MH, as well as how risks of the utility should be factored into rate-setting.

On pages 61 to 63 of Order 59/18, the PUB outlined its findings with respect to MH's new financial plan and financial ratios:

> "…the **Board finds** that a **particular equity level target and pace to achieve that target should not determine the rate increases approved in this GRA**…the **Board's assessment must include consideration of the circumstances of Manitoba Hydro's operations**…it has historically undertaken large investments such as generating stations and transmission lines that have initial large surpluses of capacity for the needs of Manitobans. These assets have **large upfront construction costs** but **relatively low annual operating costs** that extend through a **very long expected useful life**…With Manitoba Hydro's investments currently underway in Keeyask and Bipole III, the situation today is no different.
>
> An **important question from a rate-setting perspective is how these large investments should be funded**…The concern is to find the **right balance between** the **rate increases** and the **level of debt** to fund large capital projects.
>
> In making this determination, the **Board is guided by two considerations**. The **first** is: **what "reserves" should Manitoba Hydro hold** to manage risk and **which risks should it**

> **take into account**…The **second** is to **place concerns** about the **amount of debt** and **retained earnings** in a **different perspective by also considering cash flow**, using two long-standing financial metrics used by Manitoba Hydro: **interest coverage ratio** and the **capital coverage ratio**.
>
> The **Board accepts** Morrison Park Advisors' evidence that **debt-to-equity is a questionable metric** for a **vertically integrated monopoly Crown utility** with a **debt guarantee from the provincial government**…The equity level target does not have the prominence suggested by Manitoba Hydro given the context in which the utility operates." (Emphasis added)

The PUB made a number of findings with respect to how MH's risks should be considered for rate-setting purposes in Order 59/18, pages 63 to 66, which can be summarized as follows:

> "…as the Board has demonstrated in past decisions – including in years of drought where the Board awarded rates in excess of those sought by the Utility – it will consider all of the facts and circumstances which confront Manitoba Hydro at that point in time in determining the appropriate rate relief…The **Board is prepared to take regulatory action** – whether through a rate rider, an interim rate increase, or a general rate increase – **as required in times when emergent situations face Manitoba Hydro**…The **Board agrees** with the evidence of Morrison Park Advisors **that Retained Earnings should be used to manage drought risk in combination with regulatory action by the Board**. The **Board further agrees** that **interest rate** and **export price risks over the long term** should **be addressed with rate increases as and when those risks materialize**. **Rates should not be set to increase Retained Earnings to manage those longer-term risks**…the **Board is prepared to consider regulatory action when required to address emerging risks facing Manitoba Hydro**…the Board finds that the 7.9% requested and projected rate plan is not the appropriate balanced plan for meeting the risks and challenges that confront the utility…However, the **Board concludes that there is merit to gaining a better understanding of the financial reserves required for Manitoba Hydro under various circumstances**. This would include **consideration of risk tolerances**, **what risks should be protected by reserves** and the **circumstances which would guide the need for more aggressive rate increases** to **continue full cost recovery** for Manitoba Hydro…Consideration of the appropriate level of financial reserves for example a minimum retained earnings test, is best done through a collaborative approach with stakeholders…The **Board directs** Manitoba Hydro to participate in **a technical conference**…for the **consideration of the establishment** of a minimum retained earnings test or similar **test to provide guidance in the setting of consumer rates for use in rule-based regulation**. The test or rule is to be based on **maintaining appropriate** or minimum **levels of retained earnings** and **meeting other financial metrics** in the **face of potential risks to the Utility**." (Emphasis added)

The PUB directed (Directive #9) on Page 267 of Order 59/18, that a technical conference be held to consider the establishment of a minimum retained earnings or similar test to provide guidance in the setting of consumer rates for use in rule-based regulation. Subsequently, on its own initiative the PUB set aside Directive 9 based on concerns that the technical conference had become an adversarial process with greater cost and complexity than had been contemplated at the time of the directive and that the potential delay in the filing of MH's next GRA until the technical conference was concluded, would be contrary to its aim of assisting MH in achieving a regular regulatory cycle (Order 126/18). The PUB made it clear however, that parties were free to explore this alternate rate-setting framework at the next MH GRA.

The issues with respect to the appropriate framework, test and considerations of risks in rate-setting were also subsequently reviewed in detail during the MH 2019/20 Rate Application process that culminated with an oral hearing in April/May of 2019 and PUB Order 69/19.

The issue of proposing rate increases based on the goal-seeking of a particular Equity ratio was also extensively canvassed during this regulatory proceeding.

Evidence provided on behalf of the Consumers Coalition indicated that the PUB findings on the questionable use of the Equity ratio as a rate-setting target combined with the consideration of a Minimum Retained Earnings target and clarification of how risks will be considered in rate setting, represented the PUB signalling a significant shift in the policy framework and target that is used to set electric rates in Manitoba. The implications of this policy shift were that rate increases would no longer be based on goal-seeking the achievement of an Equity ratio in a prescribed timeframe and building up financial reserves to cover all possible financial risks and that the PUB was prepared to take regulatory action when and if emergent risks occurred.

It was also recommended that a risk analysis tool (referred to by MH as its Uncertainty Analysis) could be enhanced to provide a quantitative tool to guide the incorporation of risk and financial reserve considerations into rate-setting and as part of consideration of a rule-based regulatory framework and Minimum Retained Earnings target for future MH GRA's.

Evidence provided on behalf of the Manitoba Industrial Power Users Group (MIPUG) indicated that (1) it was increasingly an item of debate as to whether MH's financial reserves have reached a sufficiently high level that they could be maintained at a stable level, rather than simply perpetually increasing through additional net income and that (2) the policy focus regarding building up reserves had began to change – from the past policy focus on attainment of an Equity ratio that mathematically forces retained earnings to build up based on growth in the asset base – to what might be required in the future in terms of reserves to ensure rate stability for customers.

In Order 69/19, on pages 28 to 30, the PUB indicated that its findings on the issues of financial metrics, the consideration of risks in rate-setting and reserves remained the same as in Order 59/18 and the PUB reiterated the findings from Order 59/18. The PUB also re-issued the following findings at page 30 of Order 69/19 (which can be also found as directive #9 on page 47 of that Order):

> "The **Board finds** there is **merit in a collaborative process** as **envisioned by the Board in Order 59/18**. The **Board directs Manitoba Hydro** to **participate in a technical conference** hosted by Board staff or an external consultant appointed by the Board **for the consideration of the use of rule-based regulation** to provide guidance in the setting of consumer rates and of the **question of the role and sufficiency of reserves** in Manitoba Hydro's operations and the **Board's rate regulation of the utility**." (Emphasis added)

The implications of this new policy direction and findings by the PUB with respect to Centra's rate-setting framework is reviewed in the next section of the Evidence.

### 9.7 It is Recommended that the PUB Direct the Consideration of the Establishment of a Minimum Retained Earnings Test for a Future Centra GRA's for Rate-Setting Purposes

The rate pressures that are facing MH are primarily a function of the major capital investment plan and to a lesser extent the requirement to replace aging infrastructure.

As outlined in Section 8.2 of the Evidence, there are also significant rate pressures that are projected for Centra, with non-gas revenue requirements projected to increase at a rate of 3% per year. Not unlike MH, these rate pressures are to a large extent driven by projections of capital expenditures and the requirements to replace aging infrastructure.

The MRBROR rate-setting approach that has been used to set gas rates for the last 15 years has served the purposes that it was intended. It was an approach that allowed for the transition of Centra's rate-setting from private to public ownership, allowed for the consideration of "no-harm" to ratepayers in the early years after the integration of MH and Centra and despite there being many opposing positions from Centra and Intervenors in the early years of its development, has been for the most part accepted by all parties as a workable approach. While Centra's asset base has grown over that period of time, interest rates and allowed ROE's in the regulated utility industry fell and as such, the maximum of $15 million of pre-acquisition earnings under the MRBROR was sufficient.

However, Centra has now been fully integrated into the operations of MH for nearly 20 years and its financial reserves are now approaching the $100 million level, when appropriately adjusted for IFRS accounting changes (gas meter exchange accounting policy change). Not dissimilar to the issues surrounding the measurement of synergies between MH and Centra within a number of years after the integration, the ability to measure "no-harm" to customers through a RBROR calculation, 20 years after the integration, is theoretical at best.

The size of Centra's balance sheet has and is projected to increase significantly, interest rates and allowed ROE's are gradually increasing and at some point in the near future if the focus on the RBROR concepts of Equity ratio and ROE are continued for rate-setting purposes, it will drive the request by Centra for reconsideration of the $3 million net income level and increasing levels of retained earnings (to maintain a desired Equity ratio). Essentially, Centra's illustrative CGM18, with net income levels of $7 million is a "heads up" or "trial balloon" to the PUB of this concern (that a $3 million net income will not support a 30% Equity ratio given projected levels of capital expenditures).

The request for higher levels of net income/retained earnings would simply be a function of a mathematical relationship between the total assets and Equity ratio (the higher the net assets of Centra, the higher the retained earnings to maintain a 30% Equity ratio) rather than a change in risk assessment or required reserve levels to promote rate stability.

This situation raises the same issues for Centra as MIPUG outlined in its evidence related to the 2019/20 MH Rate Application. Namely, have Centra's levels of financial reserves increased to the level where they could be maintained at a relatively stable level and still be sufficient to promote rate stability for customers - rather than simply perpetually increasing reserve levels to maintain an Equity ratio as a result of a growing asset base.

Centra is not a "stand-alone" utility. Centra is a corporate shell that contains the gas assets but has no employees. Centra is fully integrated into the operations of MH and obtains its management oversight, labour force and financing through MH. Like MH, Centra's debt is guaranteed by the province of Manitoba.

Centra shares many of the same operational characteristics of MH (capital intensive with long asset lives and provincial debt guarantee) with the main difference being that MH's asset base is much larger than Centra's given the investment in hydro-electric generating stations and large transmission lines.

Despite the asset differential and legislative remnants (rate base and ROE) from the time that Centra was an investor owned utility, there are no appreciable reasons why the PUB's change in rate-setting policy and the rate-setting framework/principles that are outlined in Orders 59/18 and 69/19 for MH (consideration of a Minimum Retained Earnings Test), should not be applied to Centra, as well.

For the reasons note above and considering the significant rate-setting developments for its parent company, MH, it is appropriate that the reality of Centra's integrated nature be recognised for rate-setting purposes and that the focus for rate-setting be moved to considering the appropriate level of financial reserves to promote rate stability for customers - versus the maintenance of an equity ratio/earning of a level of ROE (on a stand-alone basis).

It is recommended that PUB direct the consideration of the establishment of a Minimum Retained Earnings Test for future Centra GRA's for rate-setting purposes, based on a comprehensive assessment of risk and required reserve levels. The approach that is recommended is to use the principles and analysis that are developed for MH and apply and adapt that to Centra's circumstances, as necessary. This would include the development of an Uncertainty Analysis model for Centra that would be used as a quantitative tool to guide the consideration of the appropriate level of financial reserves for gas operations, for rate-setting purposes.

**9.8 It is Recommended that In the Interim Period Until the Development of a Minimum Retained Earnings Test for Centra that a $3 million Net Income and the Consolidated MH Target of 25% Equity Be Used for Rate-Setting Purposes**

As was noted in Section 9.1 of the Evidence, the determination of an appropriate capital structure is primarily based on the assessment of risks. One of the issues that is raised by Centra's shift in focus to a 30% Equity ratio is why would the Equity ratio of Centra be stronger than the 25% Equity ratio target for MH.

On the face of it, it would appear that there are no differences in the operations or risks of Centra and MH, that would justify a stronger capital structure/Equity ratio for Centra than MH. In fact, a strong argument could be made that based on MH's/Centra's own risk assessment report, Centra's risks are assessed to be lower than MH's. This assessment is supported by a review of the Corporate Risk Management Report (Attachment 1 of Centra's completeness filing). All of the high consequence and high priority risks as well as other areas of concern in the report, are either solely or mainly related to electric operations.

If it is the PUB's direction to continue to use an Equity ratio as a guideline for Centra's rate-setting, then the evidence on the record of this proceeding, would indicate that it would be more appropriate to use the MH 25% consolidated Equity target.

It is recognized that a rules-based rate-setting framework for MH and a Minimum Retained Earnings or similar test is under consideration and will take some time to develop and apply to an actual MH GRA. It is also recognized that Centra does not have an Uncertainty Analysis financial model like MH, and that it would take time to develop this tool.

CGM18 has identified the potential requirement for a general rate increase as early as Centra's 2020/21 fiscal year. As such, there is a practical issue that a general rate increase may be requested before a Minimum Retained Earnings Test and a gas Uncertainty Analysis could be developed for Centra.

As a potential solution to this issue, it is recommended that in the interim period during the development of a Minimum Retained Earnings Test for Centra , the PUB could use the allowed $3 million of net income combined with the MH consolidated 25% Equity ratio as a basis to set/evaluate gas rates.

It is noted that Centra provided a CGM18 financial scenario assuming a $3 million net income in the response to PUB/Centra I-2 (a)(b). Figure 14 provides a summary of the financial parameters of that scenario:

| Figure 14 - Summary of CGM18 Financial Outlook (with $3 Million Net Income) | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | **2021** | **2022** | **2023** | **2024** | **2025** | **2026** | **2027** | **2028** |
| Rate Increase | 1.36% | 0.40% | 1.32% | 0.98% | 1.17% | 0.68% | 1.41% | 0.94% |
| Cumulative Rate Increase | 1.61% | 2.02% | 3.36% | 4.37% | 5.60% | 6.31% | 7.81% | **8.83%** |
| Cumulative Additional Revenue | 5 | 7 | 10 | 14 | 18 | 21 | 25 | 29 |
| Annual Additional Revenue | 4 | 2 | 3 | 4 | 4 | 3 | 4 | 4 |
| Net Income | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 |
| Retained Earnings | 85 | 88 | 91 | 94 | 97 | 100 | 103 | 106 |
| Equity Ratio | 29% | 29% | 28% | 28% | 27% | 27% | 26% | 26% |
| **Source: CAC/Centra I-2 ab** | | | | | | | | |

The key observations from Figure 14 are:

1. Continuing the $3 million allowed net income is projected to result in a slight deterioration in Centra's Equity ratio to the 28% to 29% level for the first four years of the forecast period between 2020/21 and 2023/24;
2. The maintenance of an allowed $3 million net income results in projected cumulative indicative rate increases of 2.02% by 2021/22, which compares to 3.27% projected cumulative indicative rates increases in CGM18, with net income levels increasing to $7 million;
3. At the end of the forecast period in 2027/28, Centra's Equity ratio is projected to be 26% or above the consolidated MH target of 25%; and
4. Retained earnings levels would continue to be strong in the $85 million to $94 million range between 2020/21 and 2023/24 (before attribution of the cumulative profit adjustment related to gas meter exchange accounting policy change).

In summary, in the event that a general rate increase is requested before a Minimum Retained Earnings test for gas operations could be developed, the current approach of allowing a $3 million net income in Centra rates could be continued for a number of years in the interim, while maintaining a strong financial structure and level of financial reserves to protect gas customers from rate instability.

As was noted in Section 8.3, the combination of the allowed $3 million net income, recommended rate setting reductions related to O&A and prioritization of BOC spending to lower levels than currently projected, would also improve the level of financial reserves on a net basis and offset requirements for the indicative rates increases that are outlined in Figure 14 to 2021/22.

## 10.0 The Evaluation of The Results of the 2019/20 Cost Allocation Study Concludes that The Results Are Reasonable and Consistent with Expectations Even if There Are Significant Impacts to Some Customer Classes

Centra filed a General Rate Application November 30, 2018 along with supplementary information March 22, 2019 that resulted in an updated 2019/20 Cost Allocation Study.

Despite Centra representing its 2019/20 General Rate Application as reflecting no general revenue increase, it has become apparent, through the course of the information request process, that its General Rate Application reflects an overall revenue decrease of approximately 1% (or a 3% decrease in non-gas costs) compared with current rates[1]. In addition, Centra's 2019/20 Cost Allocation Study results in some significant bill impacts that range from overall decreases to large increases. Centra's rationalization for the results of the Cost Allocation Study includes:

1. The reflection of no changes in its approach to cost allocation such that the 2019/20 revenue requirement is allocated to customer classes using the cost allocation methods last reviewed and approved by the PUB;
2. The large addition in Transmission Plant investment; and
3. The rollback of rates as directed by the PUB flowing from Order 79/17.

This section of the evidence will evaluate Centra's rationale for the results of the 2019/20 Cost Allocation Study in comparison to the 2010/11 and 2013/14 non-gas costs currently embedded in rates as well as gas costs flowing from the 2015/16 Cost of Gas proceeding.

### 10.1 Centra's Long Standing Cost Allocation Methodology Is Reasonable in Light of the Design and Operations of Its System, Is Principled, and Accepted Industry Practice

The determination of a utility's rates may be viewed in three phases. The first phase focuses on the determination of the overall revenue requirement or the overall rate level of the utility as discussed in the preceding sections. In this first phase consideration is given to the reasonableness of the forecast of customer energy, peak load, the utility's operating and capital costs. The focus is on whether the overall utility costs and forecasts are reasonable, necessary and prudently incurred in the provision of utility service.

[1] CAC/Centra II – 124 (b): ($152.5 - $148.5)/$325 million

In the second phase, the utility's established revenue requirement is allocated to each of its customer classes through the preparation of a cost allocation study. A cost allocation study analyzes which customer or group of customers cause the utility to incur the costs to provide service. It is important to note that cost allocation studies do not look to allocate only the incremental rate increase (or decrease) sought by a utility, but rather, analyze a utility's full revenue requirement and associated capital investments. A cost allocation study is also used in the determination of the third phase of ratemaking, the design of rates of the various customer classes.

While Cost of Service is often described as a basic and necessary tool to be used for purposes of ratemaking, it is also considered the fundamental standard for assessing the just and reasonability of rates by utilities, regulators and stakeholders.

Centra's Cost Allocation Methodology has largely been in place since 1996 through the issuance of Order 107/96. While a number of changes in Centra's operations has prompted changes to Centra's Cost Allocation Study, such as the introduction of WTS in 1999 and the unbundling of rates that ensued, as well as the acquisition of Centra by Manitoba Hydro in 1999 which necessitated a change in expense items on account of the merging of accounting systems, the underlying methodological approach has remained. The key principles/features include:

1. Postage Stamp Ratemaking - The overarching goal of Centra's rates is founded on recovering costs through postage stamp rates. Postage stamp rates are a method of cost allocation where costs are pooled across the service territory and all customers within a rate class are charged the same regardless of their location in the province (or the distances of mains required). This is the accepted approach to ratemaking in most North American jurisdictions. In Manitoba, postage stamp ratemaking has been in place for Centra for several decades; for Manitoba Hydro, postage stamp ratemaking (or uniform rates) are mandated by the Provincial Government through legislation enacted in 2001, although uniform rates were already in place for large energy customer classes prior to that time.

   The underlying premise of postage stamp ratemaking is really one of fairness – allowing access to natural gas service such that all customers benefit at the lowest average costs. This approach to ratemaking provides equal opportunity to service regardless of whether customers are existing or new or where they are located in the system. Postage stamp rates ensure that no one industry or corporation has an advantage over others and that new entrants may compete on an equal basis with existing customers. Postage stamp rates remove economic disincentives that might otherwise exist for new development.

To maintain a reliable gas delivery system, investment must be made from time to time in the repair, improvement or replacement of plant in various locations. Under postage stamp ratemaking, this means that these costs are distributed to all customers and paid for in rates for each customer class. Similarly, when portions of the system reach full operating capacity (associated with load growth) or reach the end of the useful asset life, the upgrade or replacement cost of the facilities are spread among all ratepayers on the system and are not streamed to only those served from those specific portions of the system. Even in cases where assets appear to be put in place to serve only one customer but are fungible, in other words where assets are put in place at a point in time for one purpose or for one customer, that asset can be adapted to attach another customer and thus the cost is often embedded with all costs, allocatable to all customer classes not specifically assigned to a customer.

Postage stamp ratemaking is intended to minimize disputes concerning who will pay for upgraded or new facilities as once in place, the "who pays" question is resolved definitely. This is an important consideration because it avoids a case-by-case modeling approach to cost allocation and avoids the contentious and protracted debate over the modeling and other assumptions used to derive a proposed cost allocation. Regulators long ago recognized that administrative convenience dictated a simple postage stamp convention rather than spending the time and effort to develop detailed allocation methods that could achieve only fictional accuracy.

2. Embedded Costs - Centra's cost allocation methodology is an embedded cost study, the most common approach to cost allocation. Embedded cost studies reflect the costs underpinning revenue requirement which reflect actual recorded historical investments and current operating costs including operating expenses, debt, equity (or in the case of Centra, contributions to reserve), taxes, depreciation, etc. These costs are based on a forecast of a particular year, which is the fiscal 2019/20 year for Centra's current GRA.

   Nearly all gas distribution utilities (and pipelines) in North America use, and their regulators endorse, embedded costing principles for purposes of conducting cost allocation studies and setting interclass and intra-class revenue levels (rates). Marginal/incremental cost of service studies are uncommon, particularly in the natural gas industry. A marginal cost study is forward looking and attempts to quantify the marginal cost of serving an additional customer or serving one unit of additional throughput. While cost analysts and economists generally agree that marginal costing principles based on well-established economic principles are beneficial, the benefits of using marginal costs in natural gas ratemaking are largely lost in the translation from theory to practice.

3. Cost-Based - The theoretical underpinning of Centra's cost allocation methodology is primarily cost-based (those who cause the costs pay for them); it also explicitly includes non-cost causal factors, such as use of the system. To recognize these requirements, Centra adopted a peak and average methodology which has been employed by Centra largely since the 1980's, the principles of which were last reviewed and approved by the PUB in 1996. This methodology focuses on the allocation of demand-related cost to customer classes. The peak and average methodology is a two-part formula that allocates the cost of baseload plant (plant put in place to serve usage that occurs year-round) as well as the cost of plant put in place to serve peak loads. Centra's system load factor provides the weighting between peak and average; approximately 65% of demand-related costs are deemed to be incurred to serve peak day (recognizing how system planners design and build the system) and the remaining 35% based on average usage (energy usage). This methodology thus allocates costs based both on a purely cost causal approach and allocates cost based on how Centra's system is used at times other than on the peak day only.

   This methodology was viewed to be reasonably cost causal, considered use of Centra's system in periods other than peak (a notion of fairness) which was of particular concern for Interruptible and other customers who would otherwise not contribute to any capacity-related costs (associated with transmission, distribution as well as upstream storage and transportation costs) notwithstanding their large use of Centra's system throughout the year, and importantly it is simple enough to be understood and fairly easily executed. It was ultimately approved by the PUB in Order 107/96.

4. Unity - Centra's long-standing practice is to establish revenue requirement by class based on unity. In other words, cost responsibility by class as established through Centra's cost allocation study results is used explicitly to set rates for each customer class. A customer class with revenues equal to their allocated costs would result in an RCC of one or unity. Centra's practice has been in place since 1997, as approved by the PUB in Order 8/97. Centra requested PUB approval to move to unity for all customer classes at the time, despite historically to that point having Revenue to Cost ratios ("RCC") of 3% around unity (that is a Zone of Reasonableness of 97% - 103%).

   A Zone of Reasonableness is often established for utilities because a cost of service study cannot identify for sure the cost of providing service to a class. This occurs because of the existence of significant joint and common costs of a utility which are used by all or nearly all customers and need to be allocated accordingly. This means there is no true cost allocation result but a range of values that could be considered the true value. In this case, cost allocation and its resultant RCC ratios is a tool used when evaluating and setting rates for various customer classes. The translation of cost to serve to pricing should reasonably balance a utility's ratemaking objectives - rate equity is not achieved by using the results of a cost of service study to set rates purely in a mechanistic manner.

In the case of Manitoba Hydro (electric), a ZOR is particularly important because of the dominance of hydraulic (and related HVDC transmission) investment with significant fixed costs and because of the magnitude of export revenue. Manitoba Hydro establishes rates based on a Zone of Reasonableness of 95% - 105% and uses the results of its Cost of Service Study as a guideline to inform rate design and rebalancing proposals (guided by other ratemaking principles). By comparison, for Centra, at least 35%[2] of the cost to serve customers is volumetrically driven, the cost of which is market driven. This means that a large portion of the costs incurred in providing service to customers is known with certainty, or at least little contention exists as to the appropriate cost allocation treatment. This also means that incremental costs and market conditions are explicit factors in the setting of cost-based rates for Centra.

Centra moved to establishing revenue requirement by class based on unity, its proposal of which was driven largely by two factors. First, the movement to a cost of service peak and average methodology approved by the PUB in Order 107/96 which incorporated the concept of fairness at the cost allocation step. As such, Centra advocated that no further concepts of inter-class equity or fairness were required. Secondly, Centra's largest customers were pressing for rates to be explicitly set based on cost (in theory) as represented by an RCC ratio of 1 (unity). The PUB ultimately required that RCC ratios be set at unity. The PUB approved Centra's proposed move to unity on the basis that the peak and average demand allocator reflected an appropriate mix of system capacity cost causation and system operation and thus concepts of customer class equity and fairness have been accommodated at the cost of service phase. The PUB stated that it agreed that further equity and fairness considerations, as reflected by RCC requirements, should be based on recovering 100% of the costs as determined by the cost of service study.

While there is no rule which requires the Board to base rates exclusively on the cost of providing a service, a key consideration is to recognize the rationale that gave rise to the movement to unity. It was recognized that cost allocation is, by its very nature, a matter that calls for the exercise of some judgment, both in terms of the cost allocation methodology itself and in terms of how and where cost allocation principles fit within the broader spectrum

[2] Schedule 10.1.0 (Update): Primary Gas and Supplemental Gas costs as a percentage of the Total Cost to Serve or ($98 million + $13 million + $.85 million)/$325 million

of rate setting principles and the objectives sought. Having established a cost allocation methodology that principally reflected cost causation but also recognized issues of equity and fairness, and in concert with large volume customer considerations, Centra moved to unity. This meant that residential customers whose RCC was at or near 97%, experienced rate increases at the time. For these reasons Centra pursued the move to unity – there was really no compelling reason for a Zone of Reasonableness.

It is also noteworthy that the establishment of revenue requirement by class expressly set at unity is somewhat of a misnomer - it's a point in time snapshot calculation. Given the long absences between the re-setting of rates (and rebalancing to unity), the last of which was 2013/14, even in the absence of an overall change in revenue requirement as Centra suggests in this Application, there can be dramatic changes in class cost responsibility. This can be driven by the time lapse between rate applications with significant changes in cost make-up such as the addition of large transmission plant. Further, the impacts to RCCs in between rate setting processes can be compounded by matters that arise periodically such as the rate rollback flowing from Order 79/17. These matters can be significant - as can be seen in the RCC chart in Section 10.2 below, Centra's current RCCs, prior to class revenue requirement re-balancing flowing from this Application, range from approximately 60% - 150%, and far from unity.

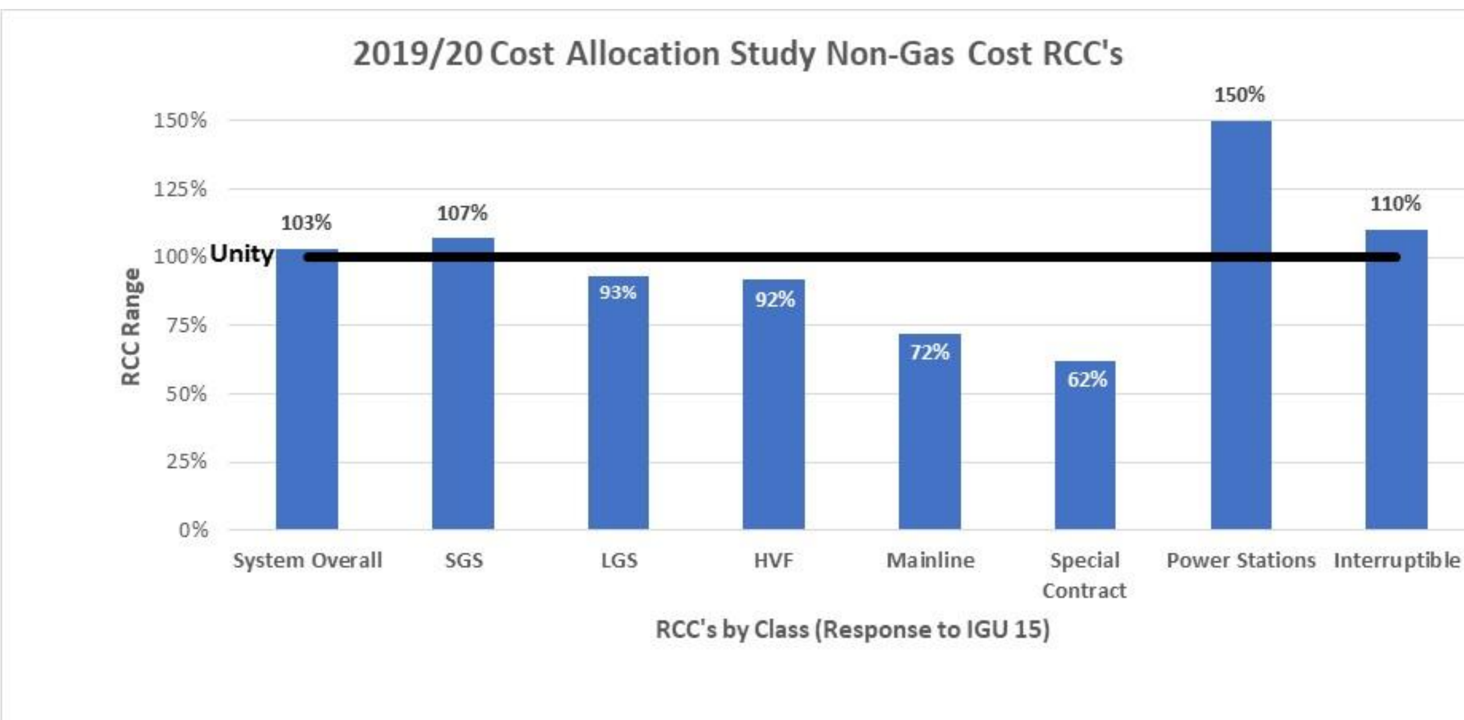
**10.2 The Non-Gas Cost Revenue to Cost Ratios that Range from 60% - 150% flowing from Centra's 2019/20 Cost Allocation Study are Significantly Divergent from Unity. The SGS Class RCC of 107% means that it has been overcontributing to cost in the period since the 2013/14 GRA and subsidizing other Customer Classes**

As previously discussed, Centra's Cost Allocation Study establishes class revenue requirements which is set to equal class revenue (unity). Thus, the Cost Allocation Study is explicitly used to drive rate changes by class; it is also used explicitly in the determination of rate design. The length of time since the last GRA, along with a rate rollback for most customer classes back to 2010/11 directed by the PUB, as well as the significant addition of new transmission plant investment has complicated the evaluation of the 2019/20 results. Additionally, Centra declining to assess the results against costs implicitly reflected in current rates has compounded the evaluation of the 2019/20 results.

The preparation and evaluation of a cost allocation study is not a discretionary exercise. Thus, it is recommended that Centra prepare a Cost Allocation Study at least every 2-3 years even in the absence of a GRA unless sizable changes are anticipated, and in that case more frequently. Based on Centra's capital plans in the next decade, it is critical not only to understand class cost changes, but also to enable a robust evaluation that becomes challenged the longer the time delay.

After having prepared a cost allocation study there are generally several next steps undertaken to assess the reasonability of the results. First, an assessment of the results compared to prior study results to understand why the results changed for a particular class and conversely understanding why results have not changed. Secondly, assessing the cost allocations between classes to understand and explain why costs are higher or lower than a different class. While it may be reasonable to compare the results of revenue requirement to the last approved in 2013/14, it is not reasonable to confine the cost allocation analysis only to 2013/14. This is because Centra rates are a direct result of cost allocation. And current rates reflect a number of different period costs including the 2010/11 GRA non-gas cost rates, the 2013/14 non-gas cost rates (for the Special Contract and Power Station classes), and the 2015/16 cost of gas. While this undoubtedly is complex, but for the rate rollback flowing from Order 79/17, this is routine for cost allocation. There is simply no other way of assessing the reasonability of the proposed cost allocation and rate results in the absence of current rates. Thus, it is not reasonable for Centra to decline requests for data comparisons to the 2010/11 GRA.

The following table provides the revenue to cost coverages flowing from Centra's 2019/20 Cost Allocation Study prior to the re-balancing of class revenue requirement (and rates) to unity:



The key observations from the above table with respect to RCCs are as follows:

1. The resulting non-gas cost revenue to cost range flowing from Centra's 2019/20 Cost Allocation Study is approximately 60% - 150%. Centra's longstanding practice has been to set class revenue requirement (and rates) at unity or 100%.

   It is noted that the revenue at current non-gas cost rates reflect: 1) the 2010/11 non-gas cost rates as a result of the rate rollback flowing from Order 79/17 for the SGS, LGS, HVF, Mainline and Interruptible Classes; and 2) the 2013/14 non-gas cost rates for the Special Contract and Power Stations Classes whose rates were not rolled back flowing from Order 79/17.

2. Overall, Centra's non-gas cost revenue to cost coverage is 103%. This means that current non-gas rates are over-recovering by 3%. This means that Centra is actually seeking an overall general rate reduction of approximately 3% (compared to current non-gas costs) or a 1% general rate reduction (compared to overall total revenue requirement including gas costs of $325 million) – rather than no overall general rate change as Centra contends in its Application.

3. The SGS Class' RCC is 107% (in the absence of a rebalancing of class revenue requirements through rate changes). This means the SGS Class is overcontributing to non-gas costs. In a more extreme case, the Power Stations' RCC is 150%, meaning they too are overcontributing to non-gas costs. Conversely, the Special Contract Class' RCC is 62%, meaning they are under contributing to non-gas costs to a significant degree (compared to unity).

4. The SGS Class (and other classes above unity) have effectively been subsidizing other customer classes in the period since 2013/14.

5. The asymmetrical impact for the Special Contract Class is almost entirely a result of the increase in cost by function which will have a large impact on classes that use relatively more Transmission than average. Additionally, more than 95% of the costs of serving the Special

Contract Class is Transmission related, compared to only 5% of the costs of serving the SGS Class and only 0.4% of the costs to serve the Power Stations. As a result, the significant increase in Transmission investment since the 2013/14 GRA significantly decreases the revenue cost coverage ratio of the Special Contract Class. This matter is discussed further in Section 10.4 below.

6. Given the size of the SGS Class and for whom distribution-related costs are a significant share of their allocated costs, it is not surprising that their RCCs are more rigid in that it takes a fair amount of cost movement to impact their RCCs. The relative size of the SGS Class from a non-gas cost perspective can be seen in the pie chart in Section 10.3 below.

   The total non-gas costs allocated to the SGS Class in this Application are $102.6 million. This is compared to total non-gas costs allocated to the Special Contract Class of $2.3 million and $158,000 for the Power Stations. This can be seen in the bar chart in Section 10.3 below.

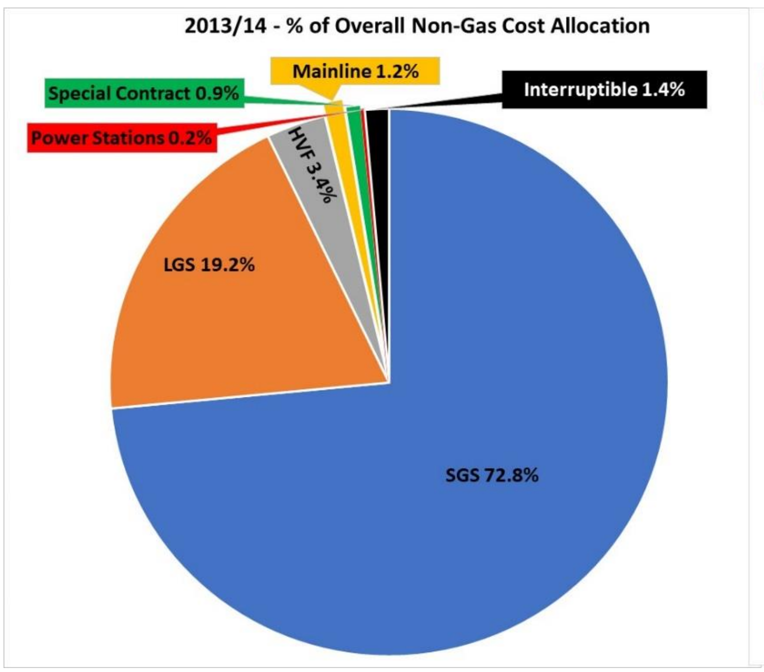
7. The SGS Class' RCC of 107% is primarily attributable to a reduction in the allocation of depreciation and amortization expense (the removal of the costs associated with the Furnace Replacement Program) as well as a reduction in the allocation of Capital and Other Taxes compared with current rates.

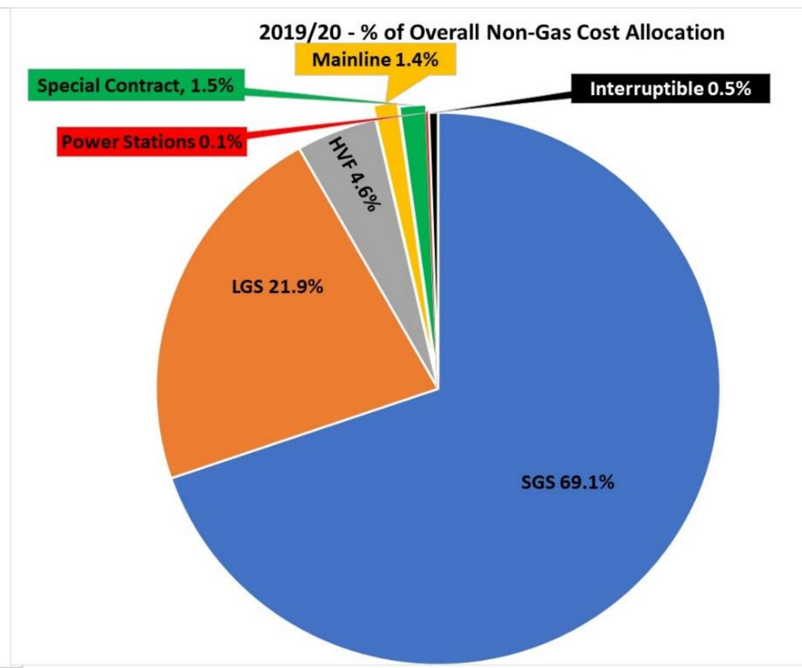
In conclusion, there are several key outcomes of this analysis. First, Centra is currently in an overall non-gas revenue sufficiency position, which means it is actually seeking an overall non-gas decrease of 3.0%. As a percentage of overall costs, including gas costs of approximately $325 million equates to an approximate 1.0% overall decrease, rather than no overall rate change.

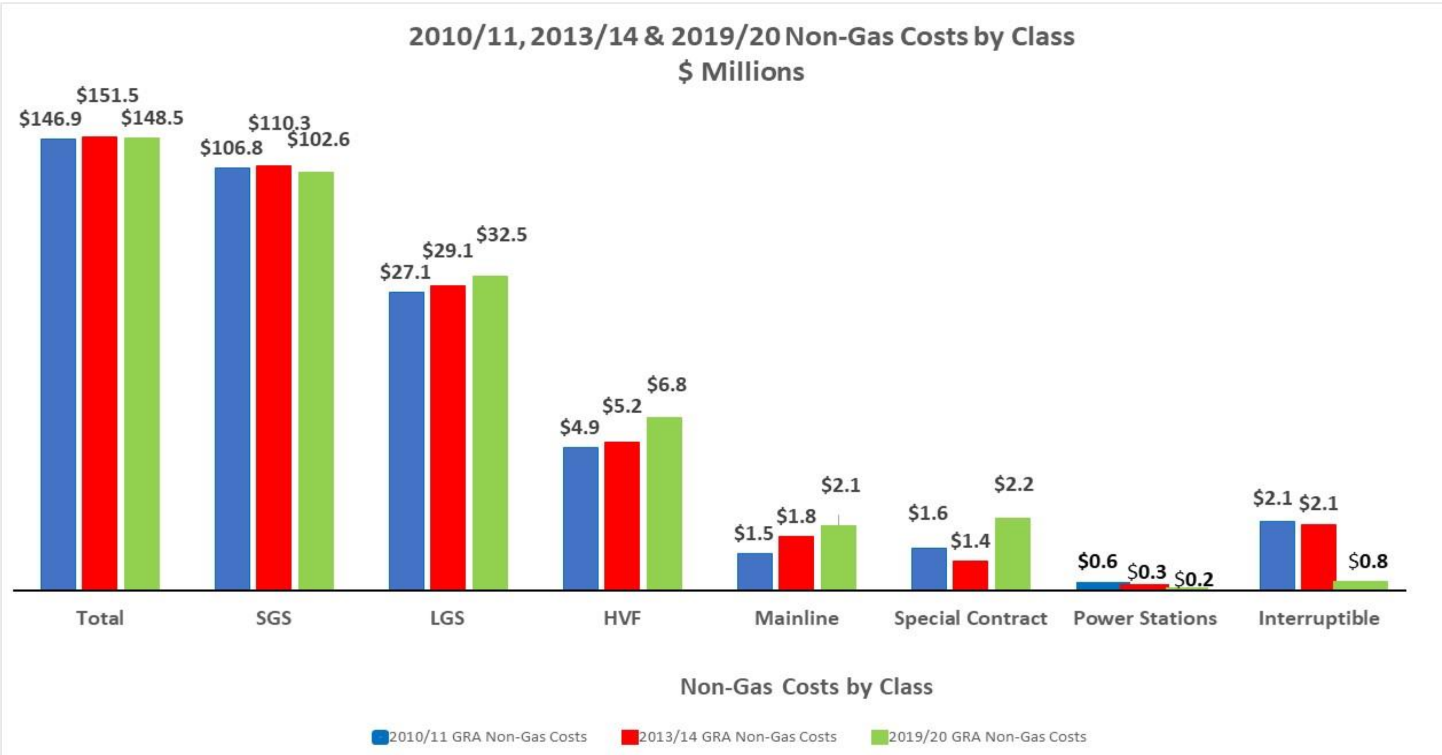
Secondly, the SGS Class have been overcontributing to cost over the last 6-year period and funding other customer classes in the absence of a General Rate Application and Cost Allocation Study. The Interruptible Class with an RCC of 110% has also been overcontributing, largely on behalf of the High-Volume Firm Class on account of the migration of a number of Interruptible customers to the High-Volume Firm Class. The Power Station Class' RCC of 150% is more complex as discussed in Section 10.9 and thus, the same conclusions are not being drawn for this Class.

**10.3 Centra's largest Class – the SGS Class – contribute by far the greatest to Non-Gas Costs Changes despite a decline since the 2013/14 (and 2010/11) Cost Allocation Study. The Power Station Class' contribution to Non-Gas Costs is minimal and has declined by nearly 40% relative to 2013/14, in contrast, the Special Contract Class' contribution to Non-Gas Costs has increased by over 60%**

The following charts depict each class' allocated portion of total non-gas costs flowing from the 2019/20, 2013/14 and 2010/11 Cost Allocation Studies:






The key observations from these charts with respect to class non-gas cost responsibility are as follows:

1. The SGS Class is responsible for the largest portion of the Corporation's non-gas costs. Given the size of the SGS Class, it is not surprising that their RCCs are more rigid in that it takes a fair amount of cost movement to impact their RCCs.

2. The reduction in the SGS Class' allocation of O&M as well as the discontinuance of funding the Furnace Replacement Program more than offsets increased costs associated with Transmission Investment (compared with the 2013/14 Cost Allocation Study).

3. The almost negligible non-gas cost responsibility for the Power Stations is driven by a sizeable reduction in their forecasted load – demand and volumes.

4. While the Special Contract Class' share of overall non-gas costs are very small, their allocated portion is increasing significantly by approximately 60% compared to 2013/14. This is driven

by an increase in Transmission Investment, and which represents more than 95% of their total allocated cost.

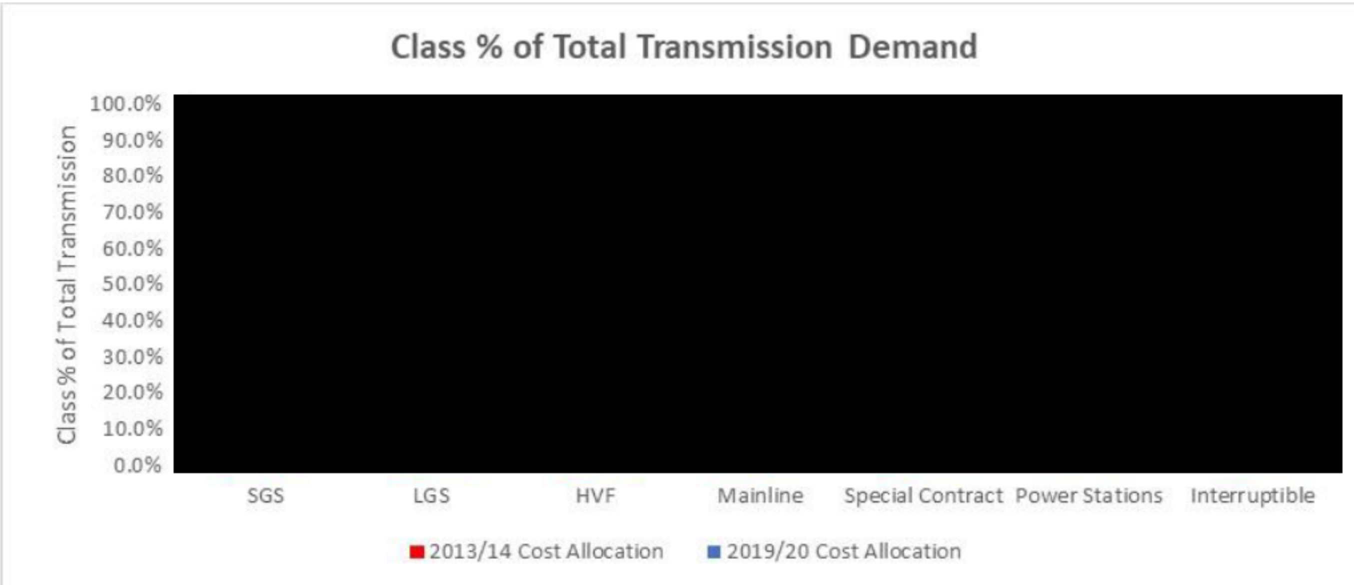
**10.4 Despite a significant increase in Transmission Investment since 2013/14, each Customer Class' allocated portion has not significantly changed. The asymmetrical impact related to the increase in Transmission Investment for some Customer Classes, such as the Special Contract Class, results almost entirely from the fact that Transmission-related costs represents more than 95% of their total cost responsibility**

The 2019/20 Cost Allocation Study results in several significant impacts to some customer classes. These results, in part, are driven by significant investment in transmission plant since Centra's 2013/14 GRA. As shown in the chart below[3], between the 2010/11, 2013/14 and 2019/20 GRA's, investment in transmission plant has increased by approximately 70% which Centra states has not been funded to any great degree through contributions.

| | Total | | | | Total | | | |
|---|---|---|---|---|---|---|---|---|
| | **2019/20** | **2013/14** | **Diff $** | **Diff %** | **2019/20** | **2010/11** | **Diff $** | **Diff %** |
| Transmission | 171,941,304 | 105,875,560 | 66,065,744 | 62.4% | 171,941,304 | 104,375,545 | 67,565,759 | 64.7% |
| | | | | | | | | |
| Accum Depreciation -Trans | (41,188,559) | (29,697,916) | (11,490,643) | 38.7% | (41,188,559) | (26,418,532) | (14,770,027) | 55.9% |
| **Total Transmission** | **130,752,745** | **76,177,644** | **54,575,101** | **72%** | **130,752,745** | **77,957,013** | **52,795,732** | **67.7%** |

It should be noted that while transmission plant cost has increased significantly and each class' allocation portion has therefore increased (but for the Power Stations which is discussed in Section 10.9), there is not a disproportionate impact to any customer class as shown in the following table:

[3] Data sources: Schedules 10.1.4 (Update) 2019/20 GRA; Schedules 11.1.4 (July 31, 2013) 2013/14 GRA per CAC/Centra 3 (a); Schedules 9.2.4 (Revised April 30, 2010) per PUB/Centra II-144 of Centra's 2013/14 GRA

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However, the addition of transmission investment will have significant impacts to cost of service by class, very much consistent with the addition of Bipole III to electric cost to serve. The cost allocation impacts of large transmission investment are driven by several similar issues:

1. First, transmission plant represents an approximate 70% increase in transmission investment compared to an approximate 24% increase in distribution investment since the 2013/14 GRA. This asymmetrical increase in cost by function will have a large impact on classes that have minimal other costs to serve and thus represent a sizable portion of a class' overall bill. For example, approximately [redacted] of the costs of serving the Special Contract Class are Transmission-related (excluding rate riders), compared to [redacted] for the SGS Class and only [redacted] for the Power Station Class[4]. The result is that Special Contract Class (and other T-Service customers) will experience sizeable impacts while other classes whose transmission costs represent a smaller portion of their overall cost to serve will be less pronounced (or offset by other cost reductions). This is shown in the following chart: 1e

[4] Schedule 10.1.3 (Update); The percentages have been calculated including non-primary gas costs and will be slightly higher if non-primary gas costs are excluded.

2019/20 - % of Transmission Demand to Total Class Allocated Costs

[redacted] 1e

Secondly, the addition of new transmission capacity tends to be lumpy in nature, where periods of large investments in transmission are often followed by lengthy periods with relatively little increase in transmission investment. Costs for older assets which are highly depreciated have a diminished impact on total revenue requirement and cost allocation while new assets have a high initial impact as the book value increases significantly - new transmission plant is reflected in revenue requirement and cost allocation at current cost while embedded cost reflects a mix of historical transmission plant vintages, some of which is highly depreciated.

2. New transmission is generally built in large increments, which often include surplus capacity to allow for future increased load. Centra states that the Winnipeg North West Upgrade Project was not only driven by the need for redundancy[5], but to serve anticipated growth as well:

[5] CAC/Centra I – 3c Attachment 2, page 120

*"…will provide transmission capacity to serve the growth just north of Winnipeg for the next 20 years"*[6]

When the costs associated with transmission investment are reflected in the cost allocation study, the costs will be allocated among all customers classes. As load grows into the excess capacity, the increased revenues will be credited to those customer classes with higher loads. This circumstance creates a downward pressure on rates for customer classes contributing to the load growth and an upward pressure with higher rates on other customer classes – there is an impact in the earlier years because of the time needed for customer load growth.

**10.5 Despite the Significant Impacts to the Special Contract Class and other T-Service Customers, Centra's Treatment of Transmission (Capacity) in Cost Allocation is Consistent with its System Design and Operations and Long-Standing Practice, is Reasonable, Principled, and an accepted method of Cost Allocation**

In large part, Centra investment in transmission plant is classified as capacity-related and allocated based on each class' contribution to system peak and average demand ("PAVG). There are a few exceptions including Unaccounted for Gas, and costs associated with DSM. These costs are functionalized to Transmission but classified on the basis of energy and allocated to each customer class based on each class' forecasted annual volumes.

It is the classification and allocation of transmission investment that tends to be contentious. Centra has used the PAVG methodology largely since the 1980's. In 1996, after a brief period using the Modified Partial Plant Methodology, it returned to PAVG subsequent to PUB approval in Order 107/96 flowing from Centra's Cost Allocation and Rate Design Review Application. The methodology was reviewed and endorsed[7] by Centra's consultant, Christensen Associates Energy Consulting in 2012, as part of its review of the Corporation's cost of service methodologies.

The PAVG methodology recognizes both cost causality and non-cost causal factors. In simple terms, the cost of plant that serves the average load[8] is allocated on average demand, and the cost of plant that serves load under peak conditions (in excess of the average load) is allocated on peak demand. The demarcation point between peak day and average day is established using load factor. As a proportion of peak load, average load divided by peak load is, by definition, the load factor (LF). By extension then, the percentage of costs allocated using average load is the

[6] CAC/Centra I – 3c Attachment 2, page 120
[7] Review of Cost of Service Methods of Manitoba Hydro, Christensen Associates, June 8, 2012, page 30
[8] Average load: annual volumes/365

same value as the average load divided by the peak: the Load Factor. The remaining costs to be allocated in proportion to peak load, then, is 1-LF.

Centra elected this methodology, for several reasons:

1. A sound rationale and theoretical basis for allocating costs –the fundamental and underlying philosophy applicable to all cost studies for purposes of allocating costs to customer groups is based on the concept of cost causation. Cost causation seeks to determine which customer or group of customers causes the utility to incur particular types of costs. The peak and average methodology is used in industry and it correlated well with Centra's system operations – a low load factor system (thus more peaking plant and less base load plant). Since the load factor is correspondingly lower, a greater portion of costs are allocated on peak demand and less costs allocated on average demand. The PAVG methodology thus reflected how Centra's system is designed as well as how it is operated.

2. Recognition of cost causality as well as non-cost causal factors - the recognition of average use (annual energy/365 days) in the methodology addressed several concerns for Centra. First, the methodology would address equity (non-cost causal factors) considerations associated with Interruptible customers, grain dryers, asphalt plants that do not use gas during the peak periods and would otherwise not be allocated any transmission cost (or the capacity-related costs associated with distribution investment), even though these customers use natural gas 364 days of the year or at significant portions of the year. For example, Interruptible customers are rarely curtailed on Centra's system. In response to CAC/Centra I-24, Centra states that Interruptible customers have not been curtailed for system reliability reasons over the past 20 years.

   The PAVG methodology would therefore ensure that these customers would pay for a portion of the costs associated with using the system by effectively hardwiring it into the cost study. In the absence of a cost allocation methodology that reflected equity considerations these customers would make no contribution to capacity-related costs (associated with transmission, distribution, and upstream storage and transportation investment) notwithstanding their sizable annual use - in cost allocation and rate design, we often refer to these situations as "free riders".

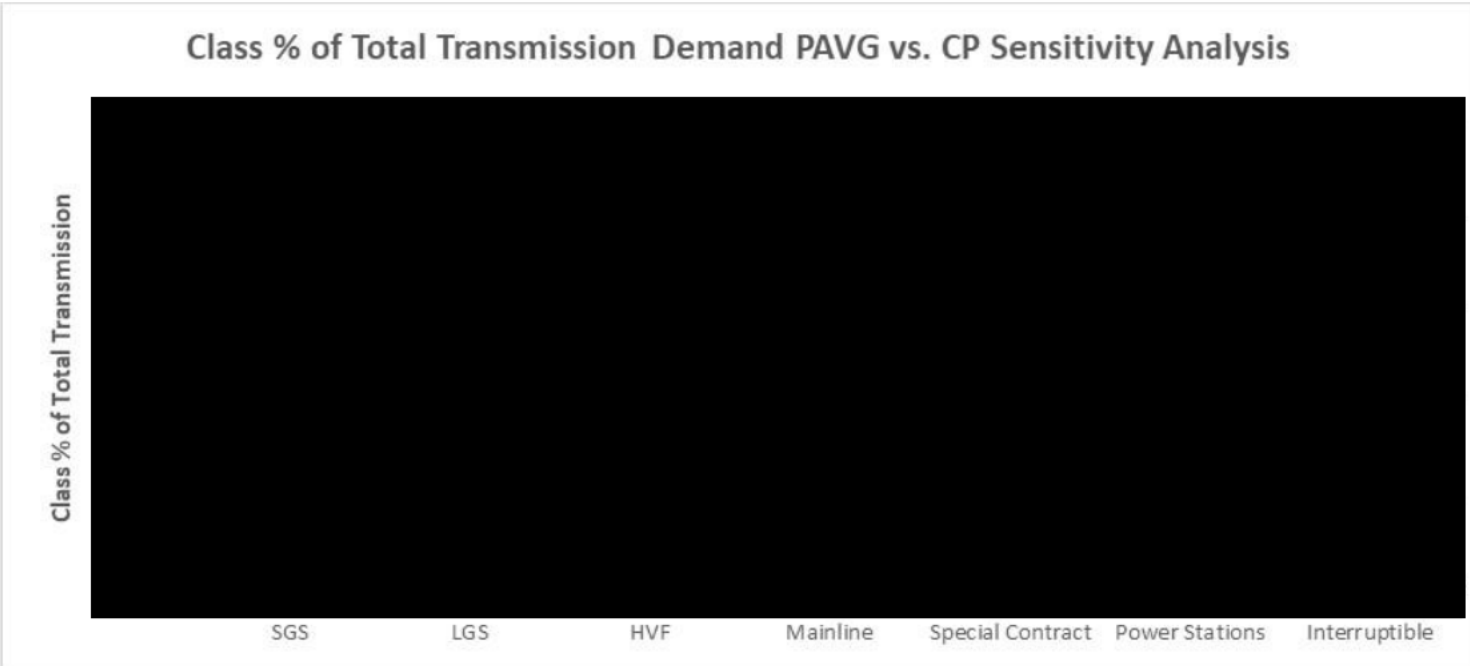
   Centra also recognized that heavy energy usage throughout the year makes pipeline distribution systems economically feasible. The outcome of what this means is that if no customer peaked, the natural gas system would not be built, which intuitively is illogical – in other words, if customers only required service on the peak day, they would be on propane (like home barbeques). Thus, the Interruptible Class, high load factor classes such as the Special Contract and Mainline Classes, would otherwise be receiving the benefit of the use of the system that others are paying for. And is the reason that average load (energy) is recognized to play a sizable role in the costs of the system for Centra.

3. Finally, and importantly, a cost study should not be unduly complicated (relatively speaking), simple enough to be understood, and fairly easily executed. The PAVG methodology meets these requirements.

There are other methodologies employed for allocating capacity-related cost including the following:

i. Coincident Peak allocator - a coincident peak allocator allocates demand-related costs based on each customer class contribution to the design day (highest daily estimated load in a maximum year [redacted] Celsius for Centra)[9]. This is a standard approach used by utilities in the allocation of transmission capacity-related investment which is viewed as the most cost casual because its viewed to conform to the planning and design of transmission investment. In response to IGU/Centra II - 27 I, Centra prepared a sensitivity analysis to directionally provide the results of the 2019/20 Cost Allocation Study assuming the use of a Coincident Peak allocator. The results are provided in the table below:

[9] IGU/Centra 16 (b)

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The key observations are as follows:

1. The results are directionally consistent with the use of a CP allocator. The lower load factor customer classes such as SGS and LGS receive a higher allocation of transmission demand-related costs. Conversely, high load factor (and high usage) customers such as the Special Contract and Mainline Classes would receive a lower allocation of transmission demand-related costs. Interruptible customers would have no demand-related costs allocated as they are assumed to be curtailed at the time of the system peak.
2. It is unclear how Centra has applied the CP allocator – whether it has been applied only to transmission capacity-related costs or all costs classified as capacity-related (for example distribution investment, upstream transportation and storage cost).
3. There are a number of definitions of CP and it is unclear what is meant by "Coincident Design Day" or its derivation.
4. The results are to be considered directional only as there are some other unexplained outcomes related to the Interruptible Class.

While a coincident peak allocator is commonly used in industry to allocate transmission-related capacity costs, it is considered to be more a rigid view of cost causation – it tends to be more of a purist view, resulting in a more aggressive approach to the allocation of capacity-related costs. In terms of the practical task of setting rates, this methodology would require, among other things, the establishment of a Zone of Reasonableness to address issues of fairness and equity which is has its own set of difficulties and contentiousness given the degree of arbitrariness that then results.

Considerations of cost associated with distance from the transmission system are periodically raised. While a distance-based approach to cost allocation may be viewed as theoretically preferable, or intuitively appealing, such an approach is uncommon and not advisable for the following reasons:

i. The distribution system is designed to connect the customer to the transmission system, and in many respects the location of the transmission system is not under anyone's control. The transmission system is sited where it is for a number of valid reasons but whether an individual is close to it or far from it, should not be a basis for how costs are allocated among customers. It's more of happenstance whether a customer is close or far from a primary station. This type of cost allocation approach would result in customers who are close to the TCPL connection to experience a low rate, and customers far removed would experience a high rate.

ii. A distance-based approach to cost allocation also conflicts with well accepted rate-making policies. There tends to be resistance to implementing this type of transmission pricing scheme because the more densely populated areas tend to have a lower cost for transmission service versus the rural areas. Thus, if one were to implement this scheme there would be a cost shift with the urban areas seeing a cost decrease for their transmission service while the rural areas would see a cost increase. This would result in either zonal rates or rates that inhibit economic development.

In summary, Centra's approach is reasonable, principled, and equitable in light of its system design and operations, and an accepted method of cost allocation for natural gas utilities.

**10.6 [redacted] and [redacted] for The Special Contract Class Have Been Largely Met Through Available Transmission Capacity over the past 20 Years without the Requirement of an Incremental Contribution. Rather, all Customers have Paid a Pro-Rata Shared through Embedded Costs** 2d

It is worth noting that over the last couple of decades, load requirements of the Special Contract Class have [redacted] Since 2003, the load associated with this class has [redacted] by 2d approximately [redacted] as shown in the following table.

| Volumes | 2003/04 Actual | 2019/20 Test Year | Change |
|---|---|---|---|
| Special Contract | [redacted] | [redacted] | [redacted] |

2d

There are several key observation's to be made:

1. In addition to the load [redacted] shown in the above table, [redacted] operations in the 1990's and again in the early 2000's that [redacted] load 2d requirements (and cost of [redacted] facilities).

2. Since the 1990's, [redacted] load [redacted] and [redacted] have been largely, if not entirely, met through available transmission capacity. During the 1990's [redacted] load [redacted] was accommodated through a [redacted] facilities [redacted] in 1996 as well as capacity made available [redacted] associated with Southwest Expansion capacity that did not materialize. 2d Similarly, in the early 2000's, [redacted] underwent a [redacted] that was [redacted] available for [redacted] did not incrementally pay through a contribution, rather all customers have paid a pro-rata share through embedded rates.

Transmission-related costs have not been nor should they be viewed as belonging to a particular customer or customer class. While a capital expenditure may be indicated to serve a specific customer or customer classes, the approved long-standing principle in Manitoba and most jurisdictions in North America, is that all customers should pay a pro-rata share of the total system. As Centra states:

*"Growth of an existing system occurs over time due to the addition of new customers through service installation or small new projects or by existing customers increasing gas consumption through the addition of new equipment. While those customers may have been required to make a contribution in aid of construction towards their distribution main and service line costs, at the time there may have been adequate capacity upstream of their connection to serve their new load. However, over time, the accumulation of this normal load growth may result in the acceptable limits to system capacity being reached and a System Betterment project may be initiated to provide additional capacity".*[10] and

*"When identifying the plant assets that "serve" the [redacted] plant, it is important to* 2d *recognize that **gas pipeline infrastructure systems**, like the one serving the City of Brandon, are **highly interconnected** systems consisting of plant assets that are **not** considered to **function independently of each other.** Such systems are managed with the understanding*

[10] IGU/Centra II 16(d)

*that changes to **one aspect of the system will typically impact other aspects of the system with respect to performance or redundancy consideration.**"*[11] Emphasis *Added.*

Thus, the cost associated with the re-build of Centra's primary station in Brandon that connects to TCPL serving much of Brandon, [redacted], and other areas will be 2d rolled into all customer rates.

Unfortunately, and in stark contrast to the above stated perspective, the response to IGU/Centra II-1 went on to quantify "some" of the apparent incremental/standalone cost of serving [redacted] No details were provided by Centra on the derivation or justification of [redacted] portion of the anticipated [redacted] Primary upgrade. And, as previously 2d discussed, it is unclear how or if the capacity growth (including growth associated with plant expansion in past years) that was made available has been considered. Great caution must be exercised, therefore, in interpreting the values, particularly as a point of reference to compare to cost allocation or for purposes of economically justifying bypass of Centra's distribution system.

It is noted that Centra had previously sought approval of the PUB to discretely allocate transmission-related costs associated with the expansion of its system to only the SGS and LGS classes given that these were the only classes that were anticipated to be served by the expansion. In Order 8/97[12], the Board stated:

*"…with respect to the allocation of transmission costs in the rural gas expansion franchise areas…..The Board considers that, up to the present time including the rural expansion projects, **the 'postage stamp· approach** to rates **has been accepted by this jurisdiction.** The Board considers that **the request to allocate costs specifically to the SGS and LGS customer classes is not appropriate**, as customer attachments in classes other than the SGS or LGS class are probable in these areas in the future. Furthermore, **it is possible to isolate other specific geographic areas within the Province which exclude certain classes of customers and to accord such areas similar treatment. The Board does not consider such an approach to be either reasonable or equitable and will therefore not allow this change.**"* Emphasis Added.

In conclusion, in an examination of the rate impact of new transmission investment on customers, the allocation should be clear, predictable and based on sound principles. The

[11] IGU/Centra II 1 (e)

[12] Order 8/97, page 54

allocation must also be consistent with overarching public policy such as postage stamp ratemaking, which has been the long-standing practice in this jurisdiction for decades.

**10.7 It is Not Appropriate to Make One-Off Fundamental Changes to the Centra Cost Allocation Methodology in the Absence of a Full Methodological Review or Phase-In Impacts of new Transmission Investment Through a Zone of Reasonableness**

The significant bill impacts to the Special Contract Class are expected with the large addition in transmission investment. However, in these cases the Applicant would typically consider options to smooth in the rate impacts. Unfortunately, Centra has not provided any options in their evidence in this regard.

Manitoba Hydro (electric) uses several mitigation measures including net income deferral (allowing debt/equity targets to fall), deferral accounts such as the Bipole III deferral, and to a lesser extent the Zone of Reasonableness.

A Zone of Reasonableness for gradually phasing in costs (allowing customer class RCCs below and above unity for a period of time), particularly for those customer classes experiencing significant increases is generally a reasonable approach. As it specifically relates to Centra's 2019/20 GRA, however, it is not advisable to make arbitrary changes to Centra's cost allocation methodology in the absence of a full methodological review that considers the cohesiveness of the full suite of methodologies employed. There are bill mitigation measures that can be employed to address bill impacts and volatility. One-off fundamental changes to address significant bill impacts can lead to unintended consequences.

It is also not reasonable to allow the impacts associated with new transmission investment to be gradually phased in through a Zone of Reasonableness given that the SGS Class has been overcontributing to cost in the period since 2013/14. To gradually implement the rate changes flowing from this Application through a ZOR means that this option would perpetuate the overcontribution/subsidization of the impacted class (s) by the SGS class.

To the extent that the PUB is concerned that the significant bill impacts to larger volume customers warrant an alternate treatment from Centra's rate proposals, a deferral mechanism associated with the impacts of new Transmission investment payable overtime by the participatory classes is an appropriate option that could be considered.

Additionally, as discussed in the following section, another option open to the PUB to mitigate the impacts to the Special Contract customer is to discontinue the allocation of the heating value deferral account to this customer class, recommended as part of the 2012 external review of Centra's cost allocation methodology.

**10.8 Discontinuance of the Allocation of the Heating Value Deferral to the Special Contract Class May be a Consideration to Mitigate Bill Impacts**

Centra purchases natural gas per unit of energy or heat content. The higher the heat content in the supplied natural gas, the richer the gas, and the less natural gas is required to serve load. The converse is also true, the lower the heat content in natural gas, the more volumes of natural gas are required to meet customer load.

Centra has used a standard conversion factor of [redacted] GJ/103m3 for many years. Prior to approximately 2016, the actual heating value, in large part, was lesser than forecast. However, since that time, the heat value has begun to rise. 1d

While Centra appears to be satisfied with the current forecasted level[13], apart from the matter of the Heating Value Deferral discussed below, it is unclear whether there are any other impacts as a result of higher heat content including for example, to Centra's forecast of demand, direct purchase deliveries (and potential under-deliveries) and T-service (potential under-deliveries and impacts on balancing obligations), and whether the cost of any shortfall recorded in a PGVA as a result is being recovered by the appropriate customers.

The Heating Value Deferral Account captures the volume impacts due to the variation in actual gas heating values from a base heat level that is embedded in approved rates. Centra purchases natural gas per unit of energy or heat content but bills customers based on volume, as registered through each customers meter. As noted above, to the extent that the actual heating content of gas per unit of volume is less (or more) than that embedded in rates, customers will use more (or less) natural gas.

Centra's rate structure is largely comprised of volumetric charges for most classes. To the extent that customers use more or less natural gas compared to that forecast and embedded in rates, this will contribute more or less to Centra's gross margin. This deferral mechanism has been in place for several decades and is intended to keep the utility and customer whole from a gross margin perspective as a result of differences between forecasted heat content and actual.

Until more recently, the energy content in the natural gas, on an actual basis, tended to be less than that reflected in rates, which meant, all else equal, that customers would consume more natural gas than forecasted and would otherwise contribute to higher gross margin than forecast. The amount captured in the deferral was then refunded periodically to customers.

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[13] PUB/Centra I-105

Recently, the energy content of the natural gas supplied has tended to be richer than that forecasted in rates resulting in less natural gas consumption and a lower gross margin. This amount has been captured in a deferral account, as done in past years, however, it now has resulted in a positive deferral (that is, owing from customers to Centra), meaning Centra is under-recovering its gross margin. Given that a review of deferrals has not occurred since 2015, this has resulted in an overall amount owing to Centra of approximately $2.5 million[14].

In this Application, Centra has allocated this amount consistent with past practice, based on each class' actual consumption[15]. As shown in the table below, for many customer classes, this does not represent a significant portion of their allocated non-gas or total allocated costs[16]: However, for the Special Contract Class, this represents [redacted] of its allocated costs. 1e

| | Total | SGS | LGS | HVF | Mainline | Interruptible | SC | PS | |
|---|---|---|---|---|---|---|---|---|---|
| Heating Value Deferral | 2,519,879 | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | 2d,1e |
| Total Allocated Costs | 325,784,091 | 134,975,474 | 57,156,395 | 13,751,619 | 2,281,973 | 1,650,883 | [redacted] | [redacted] | 1e |
| Non-Gas Costs | 148,519,256 | 102,632,670 | 32,455,799 | 6,824,301 | 2,057,841 | 769,561 | 2,246,833 | 157,798 | |
| % of Non-Gas Costs | 1.7% | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | 1e |
| % of Total Allocated Costs | 0.8% | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | 1e |

As part of the Christensen Associates Cost of Service Methodology Review, the report of which was prepared in June 2012, it recommended Centra consider allocating the cost of the Heating Value Deferral to only customers with a volumetric rate structure. At page 14 of Manitoba Hydro's Response dated July 19, 2012, it stated:

> *"Centra accepts CA's recommendation with respect to the allocation of the disposition of the heating value deferral. Centra currently assign heating value residuals to all customer classes on the basis of each class' contribution to total annual throughput. Heating value residuals accumulated 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 context 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."*

[14] IGU/Centra II – 12 (c)

[15] IGU/Centra I – 27 (g)

[16] IGU/Centra I - 27; Schedule 10.1.2 (Update)

As part of Manitoba Hydro's Response to the CA Report (page 23), Centra stated that it agreed with CA's recommendation and would implement the change at the next GRA. However, as part of this Application, Centra states that it continues to allocate the Heating Value Deferral based on past practice:

> *"While Centra would agree that a variation in heating value would not have a measurable impact on the monthly margin recovered from the Special Contract class; it has maintained the past practice of allocating the Heating Value Deferral on a volumetric basis"*[17]

> *"…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 collection to date…"*[18] and

> *"Centra proposes to examine the application of the Heating Value Deferral account after the completion of this GRA and would advise the PUB and interveners of any changes that may be proposed on a go-forward basis."*[19]

An option available to the PUB as discussed above to mitigate the bill impact is of the Special Contract Class is to discontinue payment related to the Heating Value Deferral.

By allocating the Heating Value Deferral to all classes with the exception of the Special Contract Class, the following table reflects the approximate allocation by class[20]:

| | Total | SGS | LGS | HVF | Mainline | Interruptible | SC | PS | |
|---|---|---|---|---|---|---|---|---|---|
| Total Allocated Heating Value Deferral | 2,519,879 | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | [redacted] | 1e |

This would result in sizable increases in the allocation of the Heating Value Deferral by Class. However, the impacts are relatively minimal in comparison to Total Allocated Costs by Class (and overall bill) as shown in the following table:

[17] PUB/Centra II-55 (c,d,e)
[18] IGU/Centra II-4 (a)
[19] PUB/Centra II-55 (a-e)
[20] Approximate as a simplifying assumption made to reflect only the 2017/18 actual volumes by class per IGU/Centra 27

| | Total | SGS | LGS | HVF | Mainline | Interruptible | SC | PS |
|---|---|---|---|---|---|---|---|---|
| Total Allocated Heating Value Deferral | 2,519,879 | [redacted] | | | | | | |
| Difference ($) | | [redacted] | | | | | | |
| Difference (%) | | [redacted] | | | | | | |
| % of Total Allocated Costs | | [redacted] | | | | | | |

1e

It is also worth considering the elimination of the Heating Value Deferral entirely, moving forward. The Heating Value Deferral really is a matter pertaining to gross margin, which is impacted by the energy content of natural gas through higher or lower than forecast customer consumption. This treatment was put in place at a time when Centra was a shareholder-owned utility. The intent of the deferral was to protect shareholder earnings from underearning on account of the physical composition of the natural gas, and in return, customers were afforded the same benefit of not over contributing to margin.

While this deferral and Centra's current practice has been in place for years, its discontinuance would be more consistent with Centra's status as a crown-owned regulated utility without the need for rates to be tied explicitly to rate base or a third-party shareholder equity return. As Centra acknowledges, the Heating Value Deferral balances are not significant in relation to its overall annual revenue requirement (a small fraction of 1%).

**10.9 It is Recommended that Centra be directed to Examine the approach to Cost Allocation and Rate Design related to the Power Station Class. Centra discontinued the Application of the Minimum Margin Guarantee notwithstanding the PUB's direction in Order 118/03, that it continue after the Expiration of the Initial 10-Year Contract Term. In the Interim, it is Recommended the Minimum Margin Guarantee of $947,000 payable by the Power Station Class be Re-Implemented and applied as Other Income in Centra's 2019/20 Revenue Requirement to allow for all Customer Classes to benefit from a reduced Revenue Requirement**

The 2019/20 Cost Allocation results with respect to the Power Stations overall appear to be consistent with the intent of the underlying methodology. However, there are a number of concerns identified as discussed below. The allocation of cost to the Power Stations and resultant rates affects the allocation of cost (and rates) to all other classes.

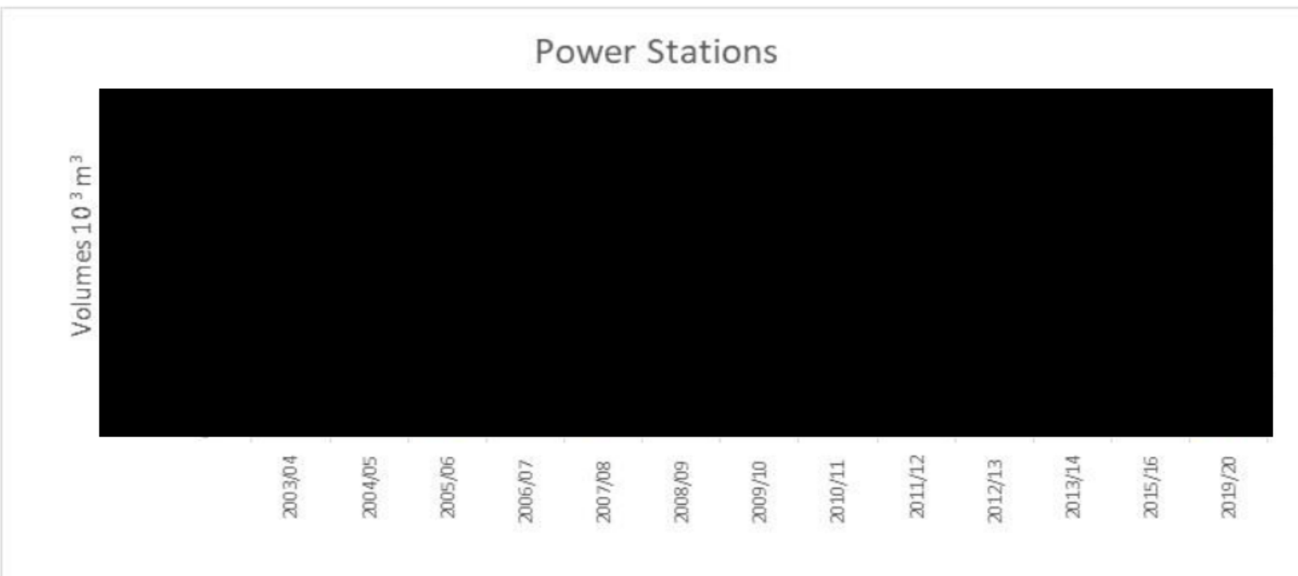
1. Intermittent Load and Load Forecast

The current Centra practice for forecasting Power Stations load is based on a 3-year average of recent historical load. This load (demand and volumes) is used to drive the allocation of cost to this class. It has become apparent that this approach is not effective nor appropriate.

As shown in the table and graph below, the Power Stations load has [redacted] since the last GRA. The Power Stations volume forecast has [redacted] by [redacted] its demand forecast has [redacted] by [redacted] resulting in a load factor of about [redacted]. 2d

| Volumes ($10^3m^3$) | 2003/04 | 2004/05 | 2005/06 | 2006/07 | 2007/08 | 2008/09 | 2009/10 | 2010/11 | 2011/12 | 2012/13 | 2013/14 | 2015/16 | 2019/20 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Actual | Actual | Actual | Actual | Actual | Actual | Actual | Actual | Actual | Forecast | Forecast | Forecast | Forecast |
| Power Stations | [redacted] | | | | | | | | | | | | |

2d




2d

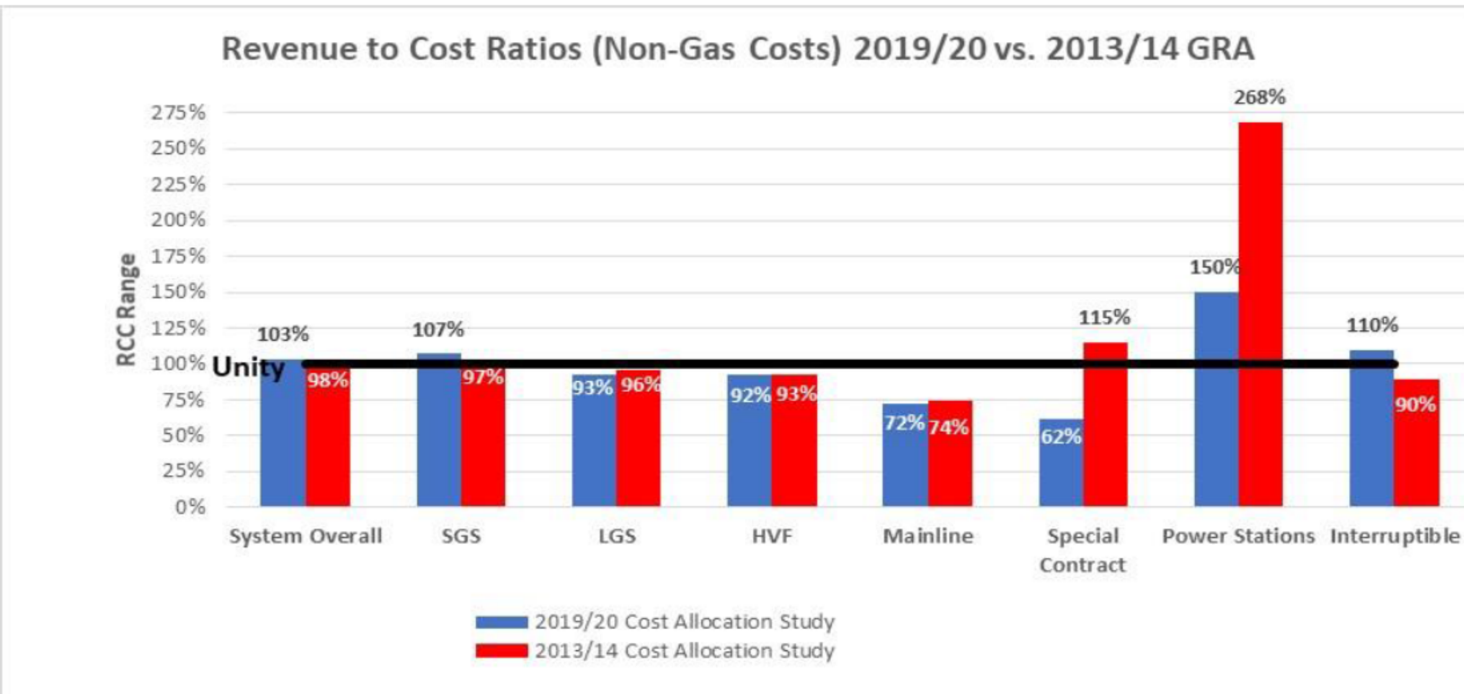
The Key Observations that flow from the Power Station load [redacted] are as follows: 2d

1. As shown in the table below, the Power Stations [redacted] load forecast results in a [redacted] of allocated costs by [redacted] which means, all else equal, other customer classes allocated costs will [redacted] 2d

| | Total System Costs | | | | Power Stations | | | |
|---|---|---|---|---|---|---|---|---|
| | 2019/20 | 2013/14 | Diff $ | Diff % | 2019/20 | 2013/14 | Diff $ | Diff % |
| | | | | | | | | |
| Total Non-Gas Costs | 148,519,256 | 151,520,019 | (3,000,763) | -2.0% | 157,798 | 255,792 | (97,994) | -38.3% |
| Total Costs | 325,784,091 | 351,291,665 | (25,507,574) | -7.3% | [redacted] | 380,533 | [redacted] | [redacted] |

1e

2. The volatility in this class' loads, even assuming a 3-year rolling average of historical usage which was intended to smooth out the revenue stream, results in abrupt changes to this customers' rates and bill, and correspondingly, volatility in allocated costs and impacts to all other customer classes. As shown in the following chart, the RCCs results for the Power Station Class over the past two GRA's have been significant.




3. The [redacted] in the Power Stations load (volume and demand) results in minimal cost responsibility of the overall system costs (approximately $160,000 of $148.5 million of Centra non-gas costs or 0.1%, a tenth of 1%). 2d

This result in of itself is not particularly concerning. The issue is that when the Power Stations are fully operational, particularly if they peak in the winter months for an extended period, the revenues generated would positively impact Centra's net income on an actual basis. This net income is not available, to offset revenue requirement and cost allocation impacts caused in most other years. Thus, the current cost allocation and rate design treatment of the power stations inadequately deals with their very intermittent load causing significant cost responsibility changes to this class and correspondingly to all customer classes.

4. In Order 118/03 flowing from Centra's 2003/04 GRA, the PUB directed that the Power Stations minimum margin guarantee continue for any extended contract terms[21]. In response to PUB/Centra I – 138 (b), Centra advised that the minimum margin has not been extended beyond 2013, the end of the initial 10 years of the contract, which conflicts with the direction of the PUB.

   The minimum margin guarantee was put in place to ensure the level of contribution provided by the Power Stations was protected given the uncertainty that existed regarding the unpredictability of usage and operations. In those years that revenues provided by the Power Stations through rates were insufficient to meet the minimum margin, a top-up of the difference was provided to Centra. The top-up flowed through to Centra's net income on an actual basis and retained earnings. A final feasibility test at the conclusion of the initial 10-year contract term prepared subsequent to August, 2013 would have evaluated the adequacy of the contributions vis a vie the incremental capital investment put in place to serve them. In theory, it could be viewed that in the years during the initial 10-year contract term in which revenues were insufficient to meet the minimum margin, the Power Stations were only funding the minimum contribution and thus, making no contribution to embedded costs.

   While the minimum margin guarantee provided a predictable revenue stream for feasibility test purposes and not for cost allocation purposes, it was not intended to extend beyond the true-up period Rather, the intent was to revisit cost allocation and rate design for the Power Stations after the conclusion of the initial 10-year term of the contract to evaluate its appropriateness and ensure the discontinuance of the minimum margin guarantee would not have an adverse impact on other customer classes.

   There are several issues to be reviewed and considered as follows:

   - The arbitrary 3-year rolling average
   - The potential establishment of a contract demand –24 hours times the maximum hourly flow or historical average coincident peak (removing outliers)
   - the consideration of a minimum monthly demand as a percentage of contract demand

   There may be other alternatives. For these reasons, the current Centra approach requires review. Centra's comments to the contrary as follows are not reasonable:

[21] Order 118/03, page 81

*"Centra prefers a three part rate design for its large volume customers as it provides transparency with regard to the level of customer, demand, and variable costs incurred, and provides a rate structure that is reflective, on a customer by customer basis of the costs they impose on the system.*

*Centra introduced the three-part rate design for large volume customer classes in the 1996 Cost of Service and Rate Design Methodology Review and implemented this rate design in subsequent GRAs.*

*Centra applied for approval of the Power Station class in the 2003/04 GRA, with a three-part rate design consistent with that found in its other large volume customer classes.*
*Centra views that the three-part rate remains appropriate for the Power Station class, as the basic charge and demand charge components enable Centra to recover 100% of the allocated fixed cost for those customers".*[22]

These matters require a detailed review to determine an appropriate approach to cost allocation and rate design designed to provide stability to cost allocation and revenue stream. In the interim, Centra should be required to re-implement the minimum margin guarantee of $947,000[23] payable by the Power Station Class to be reflected as Other Income in Centra's 2019/20 Revenue Requirement and available to reduce the allocation of cost to all customer classes. It is understood that the intent of the minimum margin was for purposes of economic feasibility, and not cost allocation and revenue stability (through rate design). However, in light of the Board's direction in 118/03, and the cost allocation and rate design issues identified above, this can serve to at least moderate some of the cost allocation impacts in the interim while these matters are under review.

**10.10 In addition to the Cost Allocation and Rate Design Issues Discussed in Previous Sections, there a number of other Issues to Be Reviewed. It is Recommended that these matters are best dealt with through a Generic Cost Allocation Methodology Review**

As part of Centra's Application, it states that it is not proposing any substantial changes to Cost Allocation (Tab 10, pages 1,5). Centra states that it views its current cost allocation methodology continues to function in a reasonable manner and that the outputs of that study give appropriate information for the determination of just and reasonable rates".[24] Further, Centra states that it is

[22] CAC/Centra I – 29 (a-b)
[23] PUB/Centra I – 138 (b)
[24] CAC/Centra I – 18 a-d

of the view that there is not a generally accepted length of time or duration between cost allocation reviews.[25]

Centra's last comprehensive public review of cost allocation methodology and rate design occurred in 1996, nearly 25 years ago. In concert with an electric cost allocation methodology review prepared by Christensen Associates in 2012, a brief review of natural gas cost allocation was also undertaken.

A number of issues regarding Centra's Cost Allocation Methodology requiring review have already been identified above, and a sample of other cost allocation matters requiring review are as follows:

Interruptible Class – Centra states that Interruptible customers have not been curtailed for downstream (system reliability) reasons over the past 20 years[26]. Further, Centra states that the large migration of interruptible customers to the HVF Class during the winter of 2013/14 was a result of "Firm service better matches their organization' operational requirements and risk tolerances."[27] It is noted that a large migration of Interruptible customers occurred following the winter of 2013/14 which resulted in sizable costs incurred associated with upstream curtailment.

These matters result in numerous cost allocation-related questions that that require review, a sample of which include the following:

- Is there still a value of an Interruptible Class and does cost allocation reasonably reflect that value? Are Interruptible customers getting the benefit of firm service that firm customers pay for?
- Given Centra's new upstream storage arrangements, are interruptible customers redundant and are the costs reasonably being allocated to this class?
- From an upstream perspective, what rights do Interruptible customers have and are those rights/obligations reasonably reflected in cost allocation?
- What impact does market pricing have on the decision to curtail Interruptible customers (upstream) and is that appropriately reflected in the allocation of costs?
- Are interruptible customers being curtailed upstream in order to shield firm customer from more expensive gas supplies and if so, is that reasonably reflected in cost allocation?
- Does the increased reliance on serving Interruptible customers with the use of alternate supply – how does this comport with cost allocation methodology in terms of capturing costs as caused?

[25] CAC/Centra I – 18 a-d
[26] CAC/Centra I – 24 (a)
[27] IGU/Centra I – 14 (b)

Gas Supply – In response to CAC/Centra 33 a-d, CAC requested Centra to [redacted] In response, Centra provided a listing of the classification factors with no explanation. In response to CAC's question of [redacted] 1a,1c

From a broad perspective, gas supply practice has evolved overtime (with further changes anticipated). The current cost allocation methodology was put in place nearly 25 years ago and there is a significant probability that it no longer conforms with current operations.

For example, storage plant may serve a capacity related function that reduces transmission costs and a commodity function that reduces annual gas commodity costs. The aforementioned Interruptible class issues while focused on that class raise questions more broadly about gas supply cost allocation methodology.

Currently, non-gas costs allocated to the Primary and Supplemental classes are largely classified as volumetrically driven. Given that the non-gas costs associated with the procurement of commodity are largely fixed, it would appear that this treatment requires revisiting.

Further in Order 65/11, the PUB found:

> *"Centra is undertaking a review of the Cost of Service (COS) methodology concurrently with a review of MH's COS methodology. Centra's COS is used to allocate the costs incurred in operating the gas utility to each of the customer classes, and eventually to determine the rates that are charged to each class. Centra's COS was last reviewed by an external consultant in 1996….The Board does not take issue with Centra bearing approximately 35% of the $175,000 cost of the external review of the COS methodology. After 15 years of use, the COS methodology is due for a review."*[28] and

> *"The Board also directs that a review of Centra's rate structure, and specifically the features of Primary Gas and Supplemental Gas, occur in the near future."*[29]

This directive gave rise to the current rate re-bundling review aimed at bill simplification. While bill simplification was specifically identified by PUB direction, the spirit of the above noted review of Centra's rate structure relates to [redacted] and whether the 1a,1c [redacted] may not be in line with

[28] Order 65/11, page 57
[29] Order 65/11, page 4

the original intention of Supplemental Gas – this is a matter requiring review to ensure appropriate cost allocation methodology and a matter that will not be addressed as part of the ongoing rate re-bundling review.

In summary, with the lapse of time since the last review in 1996, changes to Centra's operations, and the issues discussed above and in previous sections that require exploration and review, it is recommended that these matters are best dealt with through a Generic Cost Allocation Methodology Review. The review of Centra's feasibility test as directed by the PUB, is a matter closely connected to cost allocation, and it may be reasonable to consider both these matters jointly.