CENTRA GAS 2021 COST OF SERVICE METHODOLOGY REVIEW APPLICATION

INTERVENER EVIDENCE INFORMATION REQUESTS

CAC (D. RAINKIE, K. DERKSEN)

JUNE 23, 2022

PUB/CAC-1 **Reference:** Derksen-Rainkie Evidence p.16

Preamble:

(Derksen-Rainkie Evidence p. 16, lines 28-31) "Centra's COS proposals that adopt a narrow definition of cost causation, on a piece-meal basis for the few in-scope issues, will result in a COSM that lacks overall cohesion, with a mix of different definitions of cost causation. The Centra COS proposals do not result in a natural gas COSM that is more consistent with the electric COSM, as is erroneously asserted by Centra."

Request:

Please provide specific examples of the inconsistencies between the proposed gas COSM and the approved electric COSM, specifically with reference to analogous assets or costs.

Response to PUB/CAC 1:

On an overall basis, Manitoba Hydro electric COS and Centra's current COS are conceptually consistent and aligned. The effect of Centra's proposals is to move in a direction of inconsistency, overall, with electric COS.

More specifically, electric and natural gas broad assets/services are analogous. MH electric generation, which includes Bipoles, and US Transmission are analogous with a gas production, upstream transportation (TCPL) and storage and related pipeline. Similarly, electric and natural gas transmission and distribution infrastructure are analogous.

MH's generation (including Bipoles) and U.S. interconnection assets are classified on the basis of system load factor (the split between demand and energy is nearly equivalent), with the demand related costs allocated on the top 50 CP winter hours which are then averaged over many years. Energy is allocated on an unweighted basis.

Currently, Centra allocates production costs on the basis of unweighted energy and all upstream capacity costs (TCPL, storage and related pipeline) are classified on PAVG, the peak component determined on the basis of 1-LF which is allocated on the basis of CP (averaged over the past 3 years, with the exception of the Power Stations). The energy component is allocated on unweighted annual energy.

It is evident that the utilities COS practices related to generation, production, and storage and pipeline are not only consistent in terms of the load factor classification approach that explicitly separates between demand and energy, but also broad-based recognizing the dual demand and energy cost drivers. A narrower view of cost causation could conclude that the large fixed hydroelectric costs should be classified entirely (but for minor variable costs) as demand. Similarly, the MH Bipoles are clearly transmission assets, the cost of which, if viewed narrowly, are driven only by the size of conductors to meet peak conditions. However, as recognized by the PUB in Order 164/16, Bipoles are viewed from the broader role these assets serve, that is, as an extension of generation. Hence, Bipoles are functionalized as generation and classified and allocated on this basis. Similarly, U.S. interconnections are classified and allocated consistent with generation.

Centra's current COS methodology treats upstream capacity (both related to TCPL and Storage and Related Pipeline) on the basis of the PAVG allocator. Like MH COS, these assets are recognized for the broader roles in providing service recognizing the dual demand and energy cost drivers. Further, like MH, these investments are treated on an aggregate basis given the integrated nature of upstream TCPL and storage and related pipeline.

As part of Centra's current COS Application, Centra is proposing to disaggregate upstream TCPL capacity from Storage and Related Pipeline and proposing two separate treatments. For upstream TCPL, Centra is proposing to classify the capacity portion of these costs on the basis of 100% demand to be allocated on a single maximum design day CP allocator. Conversely, Centra is proposing a weighted energy allocator (Winter in Excess of Summer Demand) for the allocation of Storage and Related Pipeline costs. Centra is proposing a CP allocator for upstream TCPL capacity costs on the basis that it is only capacity requirements under maximum design day/hour conditions that drive these costs, resulting in a very narrow view of cost causation. On the other hand, Centra's Storage and Related Pipeline costs incurred to meet the totality of its customers peak upstream requirements, are proposed to be allocated very broadly on a weighted energy allocator basis (Winter in Excess of Summer Demand). This disaggregated COS treatment is questionable recognizing the integrated nature of Centra's gas supply portfolio; it also conflicts with the broader MH COS treatment related to generation and U.S. interconnections. It begs the question of why a broader allocation for MH generation and U.S. interconnection is appropriate for billions of dollars of investment costs, but inappropriate for Centra's upstream capacity? Thus, the rationale for Centra's proposals is highly questionable, recognizing how similar investment is treated for electric COS.

From a downstream perspective, MH classifies its transmission investment on the basis of 100% demand, as does Centra. However, MH allocates transmission investment on the basis of the top 50 winter CP hours. Centra currently allocates transmission based on PAVG, which weights demand by 1-LF and energy by LF. Centra is proposing to move to allocating transmission on the basis of a single maximum design day/hour allocator that weights 100% of transmission cost allocation to this single hour. While there are some differences between MH and Centra current treatment of transmission, what is consistent is the spirit and intent of the current allocators that recognize the broader view of cost causation and the dual demand and energy cost factors. This conflicts with

Centra's proposal that is as narrow a view of cost causation that can be taken. Again, it is exceedingly difficult to rationalize the conflicting conceptual difference between MH and that proposed for Centra given that transmission for electric operations is also a winter peaking utility with transmission investment costs multiples higher than that of Centra.

Finally, it is noted that while radial taps are directly assigned to the GSL>100 class, that class is also allocated a full share of all transmission cost throughout Manitoba.

PUB/CAC-2 **Reference:** Derksen-Rainkie Evidence pp. 22 and 24; Application p. 30 of 40;

Preamble:

(Derksen-Rainkie Evidence p. 22, lines 26-28) "The issues associated with the Interruptible Class from Centra's proposals are minimized by retaining the peak and average methodology for the allocation of demand-related upstream and downstream costs."

(Derksen-Rainkie Evidence p. 24, lines 19-21) "Its system has evolved overtime such that the Interruptible Class is now firm for downstream purposes, and thus there are allocation methods other than PAVG that can be used while still ensuring cost recovery from all users of the system"

(Centra Application p. 30 of 40, lines 10-16) "The Interruptible Class can be included in the calculation of the Coincident Peak allocator for two reasons. First, the Interruptible Customers use Centra's distribution system to receive Alternate Supply even while being curtailed for upstream capacity factors. Second, Centra includes the Interruptible Class capacity requirements in its downstream capacity planning criteria. This ensures all customers that use the system pay for a portion of the system and is more closely aligned with cost causation than a Peak and Average allocator."

Request:

a) In light of the Interruptible class not being subject to interruptions due to downstream limitations of Centra's system on account of planning to meet Interruptible load on a firm basis, please explain what issues remain with the Interruptible class from a cost allocation perspective.

b) If the Board finds that Peak and Average should continue to be used to allocate the demand portion of transmission and distribution costs, should the Interruptible class's contribution to the coincident peak be included in the calculations to determine the peak portion of the Peak and Average allocator? Please explain why or why not.

Response to PUB/CAC 2a:

<u>From a downstream perspective</u>:

The issues with respect to the Interruptible class, are lesser but not eliminated as suggested by Centra, in light of the fact that Centra is now planning as if Interruptible customers are firm. The outstanding issues include:

1) Centra has elected to firm up Interruptible customers, which means Centra has elected to incur additional investment in capacity to support these customers. The cost of this additional investment is unknown and has been funded by all customers. Given the reduced rate afforded to Interruptible customers despite being provided firm service, all customers have been overfunding this cost. On a go forward basis once a new COS has been prepared, all customers will continue to pay for having firmed up interruptible customers. There has been no analysis or justification provided to demonstrate that the benefits that interruptible customers have provided to the system no longer exist and the cost to firm up Interruptible customers is lesser than the discounted rate provided;

   As such, it is recommended that Centra undertake a value of interruptible analysis. Centra has not provided the economic case to justify the firming up of customers and it remains unclear whether firm customers are now having to contribute to higher costs and rates compared to the alternate of not firming up Interruptible customers and continuing to provide a discounted cost.

Further, from an upstream perspective, Centra has concluded either explicitly or implicitly that it is less costly to serve its upstream portfolio by excluding Interruptible customers at the peak (i.e. the cost to serve Centra's upstream portfolio including Interruptible customers would increase by having to secure additional capacity from TCPL and/or storage). It is unclear, as no evidence has been advanced, why Centra concludes it continues to be the least cost alternate to only hold enough capacity upstream to serve firm customers, while from a downstream perspective, the least cost alternate of serving capacity needs of all customers is to firm up Interruptible customers and do away with the discounted cost currently provided. This results in a conflicted view that Centra holds upstream compared to the view held for downstream purposes. A value of interruptible report should consider the economics both upstream and downstream to justify this dichotomy.

2) Since 1990, from a downstream perspective, Interruptible customers have rarely been curtailed, which is, in part, driven by system planning design that considers both a maximum design hour and the overbuilding of Centra's system (for future purposes). This means that Centra is planning its system on a single hour that may only occur once every 25 or 30 years. It also means that cost is incurred based on planned for loads and not the loads that actually occur afterwards. While it is true that Interruptible customers could elect firm service per Centra's Terms and Conditions of Service, such service was only provided if sufficient capacity was available;

   Thus, it is unclear what has actually changed such that the benefit provided to the system by virtue of holding curtailable load no longer exists.

3) The load, customer, and service characteristics of the Interruptible customers are such that the continuation of an Interruptible class has not been justified, and class consolidations, which may be necessary, have implications to allocated costs of all customers through the COS;

4) It remains unclear what contract demand obligations Centra holds for Interruptible customers, if any, and the implications to COS; and

5) That Alternative Service rates includes the allocation of cost of downstream demand and requires review.

<u>From an upstream perspective</u>:

All COS issues with respect to the Interruptible class continue to exist. Centra continues to invest in upstream assets, both TCPL pipeline and storage, on the basis that Interruptible customers are not served at the peak, and it is unclear how Centra defines, for upstream purposes, peak. Given the level of upstream curtailment, it is likely that Centra's definition of peak for upstream purposes is less than under maximum design hour (day) used for downstream planning purposes.

Centra proposes to exclude Interruptible customers from an allocation of TCPL-related capacity costs on the basis that capacity is not procured for Interruptible customers at the peak (how ever defined), despite Interruptible customers benefiting from this service much of the year. On the other hand, Centra proposes to allocate storage and related pipeline costs to Interruptible customers because they "use" the service, which reflects a broader definition of cost causation. On this basis Centra is proposing a COS methodology that considers TCPL and storage as separate portfolios, which they are not, they are integrated and commingled. For example, in the absence of storage, Centra would have to procure greater levels of TCPL capacity. Further, in the absence of the curtailability of Interruptible customers, Centra would have to procure additional TCPL and/or storage capacity to meet the additional peak requirements.

Given all these issues, the continued use of the PAVG methodology is reasonable, is simple, well understood, is viewed as reasonably cost causal, and is the basis of rates determined to be fair and equitable by the PUB for decades.

Response to PUB/CAC 2b:

Yes. It is Centra's evidence that Interruptible customers are being served on a firm basis for downstream purposes. This means that Centra is investing in greater levels of transmission and distribution infrastructure to meet all peak requirements, including Interruptible customers. In this case, Interruptible customers should be treated no different, for downstream purposes, than firm customers and likewise should be responsible for downstream capacity that it is currently being excluded from in the PAVG allocator.

PUB/CAC-3 Reference: Derksen-Rainkie Evidence p.25; Exhibit CAC-8 from 2019/20 Centra GRA (Derksen-Rainkie Evidence) p. 109; Collins Evidence (2021 Centra COSSMR Proceeding) p. 5

Preamble:

(Derksen-Rainkie Evidence p. 25, liners 15-22) "The portion of utility facilities and related expenses required to serve the average load is allocated on the basis of each class's average demand (that is, annual volumes averaged over either 365 days or 8760 hours). Average use, as a proportion of peak load, is by definition load factor and hence, average demand (average volumes) are weighted by system load factor. The remaining demand related costs are allocated to each class based on excess or unused demand (i.e. 1-LF). As is the case with the Average and Excess method, PAVG has the effect of allocating a portion of the utility's demand-related costs on a commodity-related (throughput) basis."

(Exhibit CAC-8 from 2019/20 Centra GRA, p. 109, lines 9-14) "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."

(Collins Evidence p. 5 lines 19-24) "Furthermore, a major flaw in the P&A method is its double count of average demand in the cost allocation process: once in the average allocator, and again in the peak allocator, since average demand is a subset of peak demand. This penalizes high load factor classes. Unlike the P&A method, other allocators such as the Design Day Demand allocator, as well as the Average & Excess allocator, do not suffer from this flaw since average demand is considered once in the allocation process."

Request:

a) Please provide additional explanation for why system load factor is an appropriate factor to apportion the demand and volumetric costs in the PAVG allocator.

b) Please explain what changes in the system configuration (pipe or station sizes or capacities, pressures) would be driven or influenced by the annual volumes as opposed to the peak demands.

c) In his evidence from this proceeding, Collins explains why using the system load factor penalizes high load customer classes by allocating them a greater share of costs, despite their more efficient usage of Centra's plant. Please explain why higher load factor customer classes should attract a greater allocation of the costs related to Centra's plant.

Response PUB/CAC 3a:

The PAVG demand allocator is a variation of the base, intermediate, peak system design process that is easily understood for electric purposes but that applies equally to natural gas also. The foundation for this allocation approach is associated with the planning process for Centra's gas planning process. It involves designing the appropriate amount of baseload, intermediate load, and peak load facilities to most economically serve the load. Like electricity, baseload capacity for natural gas is characterized by high fixed costs incurred most economically for long-duration needs. Peaking supply is characterized by low fixed costs and high variable costs, the costs of which are most economically incurred for short duration needs. Intermediate falls between these two extremes.

For COS purposes then, baseload is allocated using annual energy requirements, and peak load would be allocated using peak day or multiple top days of energy requirements.

The PAVG methodology simplifies this process by saying there are only two determinants: peak use and annual (average) use. The amount that is used every day of the year is average daily use and all other use, including intermediate, is assigned to the peak category. In proportional terms, base load is the average load over the total load (i.e. load factor) and peak use is the remainder (1-LF%).

In this simplified view, both the cost to serve base load (i.e. energy) and capacity (peak load) is what drives costs and thus is viewed to be cost causal. While capacity matters because of the need to meet the capacity requirements on the peak day, the choice of the technology and/or the size of pipe is also affected by annual usage. From this perspective, the pipeline or its size wouldn't have been chosen if it was only going to be used for a few days of the year, or at the extreme very rarely, if it were only to be put in place to meet a 1 in 20 or 1 in 30-year occurrence. The existence of higher load factor usage makes existing pipeline distribution economically feasible, and therefore annual usage is an implicit factor in determining (and allocating) the total cost of the system.

Thus, PAVG and LF used by Centra which weights more heavily on demand, but also weights based on energy that reflects the pattern of its system usage throughout the year.

Response to PUB/CAC 3b:

As noted above, baseload is viewed as being put in place to serve customers annual volume requirement throughout the year, and capacity above baseload put in place to serve the peak needs of customers. In the electric industry, a utility will choose different resources to serve these different needs most economically. For example, a peaker plant that is relatively cheap to build, but expensive to run, will be put in place to serve the peaking needs of the electric utility. A hydroelectric plant that is very costly to build but relatively cheap to operate will be put in place, to serve load throughout the year because it is most economic to do so. For Manitoba Hydro, which serves its load almost entirely through hydroelectric facilities, provides both the ability to serve energy needs throughout the year, but also provides peaking service. However, with hydroelectric facilities like that at MH, the demarcation between the portion of the plant that serves peak versus that which serves energy is not easily determinable. The same concept is extended and applied to the natural gas industry, often as part of the gas supply planning process, but is applied to transmission and distribution pipelines in practice also. In this case, pipelines are viewed to serve more than one role, that is to serve peak requirements as well as energy requirements. Similar to hydroelectric facilities, the demarcation between the portion of pipeline that serves peak and that which serves energy is not easily determinable and hence, the reliance on LF to provide the demarcation point.

That said, there has been little system configuration changes on Centra's system that would warrant such a fundamental change in COS philosophy. Based on the record and the CAC Consultants understanding, Centra's system configuration is virtually identical to what existed in 1996 and in the years prior to 1996 when the PAVG methodology was implemented (and re-implemented).

The PAVG philosophy is one which reflects that "size matters". In other words, the PAVG is a methodology that assumes a philosophy that the more a customer uses, the more they should have to pay.

The firming up of Interruptible customers, as Centra suggests, should certainly not be viewed as a valid rationale for a fundamental change in philosophy as it effectively would result in the “tail wagging the dog”. Atrium suggests that the only reason for the use of a PAVG methodology would be if Centra was served through several interconnections, which was the same argument raised by some intervenors as part of the 1996 COS proceeding, and which was ultimately implicitly dismissed by the PUB as a valid argument in Order 107/96 when PAVG was re-established.

Response to PUB/CAC 3c:

Please see the response to PUB/CAC 3a and 3b.

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PUB/CAC-4 **Reference:** Derksen-Rainkie Evidence p.25;

Preamble:

(Derksen-Rainkie Evidence p. 25, lines 23-25) "For Centra, the result is as follows:

- Approximately [commercially sensitive information redacted] of demand-related costs are weighted and allocated based on CP; and
- The remaining approximate [commercially sensitive information redacted] are weighted to energy and allocated based on a class's average annual volume."

Request:

Please provide a reference for the redacted figures referenced above, or explain their origin.

Response to PUB/CAC 4:

The origin of the redacted figures in the CAC Evidence was the CAC Consultants longstanding experience with and involvement in Centra's rate-setting proceedings for almost three decades. This information was routinely used and provided in prior Centra rate-setting processes and financial reporting processes for many years.

PUB/CAC-5 **Reference:** Derksen-Rainkie Evidence p.26;

Preamble:

(Derksen-Rainkie Evidence p, 26, lines 11-15) “It is also important that no service should be provided at no cost to customers and, thus, caution must be exercised regarding the potential for free riders in adopting a particular methodology - those who do not use service on-peak or who are able to shift demand and modify behaviour in order to reduce and/or avoid cost responsibility;”

Request:

Please explain whether and why it is preferable to address “free riders” in the cost allocation stage as opposed to the rate design stage of rate-setting.

Response to PUB/CAC 5:

Addressing “free-riders” use of the gas system can be found with the broader definition of cost-causation contained in PUB Orders 107/96 and 164/16 that include consideration of both planning and use of the gas system, as further described in Section 3.1 of the CAC Evidence. As such, consideration of these circumstances is appropriately included in the cost allocation stage of rate-setting.

Additionally, the CAC consultants view, as further described in Section 3.3 of the CAC Evidence, is that, while cost-causation is the primary driver of cost allocation considerations, it is impractical to remove all other ratemaking objectives as they are inherently an important element of developing a cohesive and workable COS framework.

PUB/CAC-6 **Reference:** Derksen-Rainkie Evidence p.27;

Preamble:

(Derksen-Rainkie Evidence p.27, lines 5-8) "Incorporating each class's portion of system average demand is an implicit acknowledgement that average load drives a portion of the demand-related costs owed to base-load resources, in addition to costs incurred to serve peaking requirements;"

(Derksen-Rainkie Evidence p.27, lines 12-15) "Centra determines the load on its transmission and distribution pipeline on the basis of several factors including pressure, customer usage (volumes) related to non-heat dependent baseload, as well as temperature dependent load as inputs."

Request:

a) Please identify and provide examples of the baseload resources that are in Centra's system. That is, what additional plant is used for baseload purposes that is not already in place and serving the peak?

b) Please identify any incremental costs that Centra incurs that are not already incurred to serve peak demands.

c) Please confirm whether, at least on a conceptual basis if the specific details of Centra's Synergi software are unknown, the volumes related to non-heat dependent loads are added to the temperature-dependent loads to determine the peak loads on the system.

Response to PUB/CAC 6a:

Further to the response to PUB/CAC 3a, in addition to transmission and distribution infrastructure providing both baseload and peaking services, from an upstream perspective, Centra holds both TCPL capacity investment and Storage and Related Pipeline investment that provides both baseload and peaking services.

Response to PUB/CAC 6b:

Conceptually, there are no further costs incurred, at least until that capacity is no longer sufficient to serve load because of load growth and/or new customer attachments. However, this perspective, taken to its logical conclusion, means that only those customers who drive the capacity at the time of construction should pay for all investment costs and everyone else can use the excess capacity for free. Excess capacity occurs for a variety of purposes including: 1) the maximum design day/hour planned for rarely occurs; 2) that load does not materialize as planned for; and/or 3) because Centra, as do all utilities, overbuilds in order to serve load many years into the future. For these reasons, such a narrow view would penalize some customers while others would enjoy the system for free.

Response PUB/CAC 6c:

Yes, this is consistent with the CAC Consultants understanding that volumes related to heat and non-heat dependant loads are reflected as part of Centra’s gas planning, consistent with its practice in 1996, when the PAVG methodology was re-established.

PUB/CAC-7 **Reference:** Derksen-Rainkie Evidence p.28;

Preamble:

(Derksen-Rainkie Evidence p.28 lines 7-8) "PAVG recognizes the benefits of the excess summer capacity made available by low load factor customers in order to optimize the total cost to serve all customers;"

Request:

a) Please explain whether the "benefit" of excess summer capacity is truly a benefit, considering it exists because of customer classes with low load factors, which in turn causes Centra to incur additional costs to serve the peak demand, in particular costs for storage and pipeline transportation to access the storage.

b) If PAVG allocates less cost to customer classes with low load factors (compared to Coincident Peak) for the benefit of excess summer capacity, please explain whether that means PAVG allocates more costs to high load factor customer classes, which do not provide the benefit of excess summer capacity.

Response to PUB/CAC 7a:

The premise of the question is not confirmed. It is noted that the costs incurred for storage and related pipeline costs are not only incurred to serve low load factor customers, but all customers (excluding T-Service). Further, the cost of storage and related pipeline is incurred to avoid further investment in capacity along TCPL. In other words, it is the combination (integration) of TCPL pipeline capacity as well as storage and pipeline capacity that enables Centra to meet its peak requirements. As such, if excess transmission capacity in Manitoba was unavailable (fully used), Centra would require additional capacity upstream (TCPL), in which Centra concludes from a gas supply portfolio perspective, is either more costly and/or lessens or eliminates use and other operational benefits associated with storage.

Response to PUB/CAC 7b:

Yes, this can be viewed as one of benefits of the PAVG methodology which relies on the philosophy that size matters and the more used, the more a customer pays. As noted in the responses to PUB/CAC 3a and 3b, the PAVG methodology is intended to reflect the cost associated with providing baseload and peaking service to customers. This is done by weighting energy (i.e. baseload) on the basis of load factor and weighting demand by 1-LF, as baseload and peaking service associated with pipeline service is integrated, similar to what is done for electric operations for both generation and transmission.

PUB/CAC-8 **Reference:** Derksen-Rainkie Evidence p.31; PUB Order 164/16 p. 27

Preamble:

(Derksen-Rainkie Evidence p.31, lines 21-26) “Based on Centra's CP proposal for Year-Round (TCPL) Pipeline capacity, it should be noted that the Interruptible Class will avoid all demand-related TCPL costs despite using and benefiting from the capacity paid for by firm customers for a significant portion of the year, each and every year. The total upstream capacity costs of Centra are nearly $60.0 million annually which Interruptible customers will avoid with a move to Centra's proposed allocation methodology;”

(PUB Order 164/16 p.27) “The Board finds that Manitoba Hydro's ratemaking principles and goals of rate stability and gradualism, fairness and equity, efficiency, simplicity, and competitiveness of rates should be considered in a General Rate Application ("GRA") and not in the cost of service methodology.”

Request:

If the situation of Interruptible customers using and benefiting from TCPL capacity (except at times of system peak demand) is ultimately considered unfair, please explain the advantages and disadvantages of addressing this perceived unfairness at the rate design stage (instead of in the COSS), consistent with the PUB’s finding in Order 164/16 that questions of fairness be addressed at a general rate application.

Response to PUB/CAC 8:

Consistent with the assessment that was outlined in the response to PUB/CAC 5 with respect to the issue of “free-riders”, the issues surrounding the Interruptible Class can be found with the broader definition of cost-causation contained in PUB Orders 107/96 and 164/16 that include consideration of both planning and use of the gas system, and as such, consideration of these circumstances is appropriately included in the cost allocation stage of rates-setting.

Additionally, it is impractical to remove all other ratemaking objectives as they are inherently an important element of developing a cohesive and workable COS framework.

PUB/CAC-9 Reference: Derksen-Rainkie Evidence p.31; Centra COSMR Application p. 34 of 40; Tab 8 of the 2019/20 Centra GRA pp. 12-13

Preamble:

(2019/20 GRA Tab 8, p. 12 of 52, lines 20-21, and p. 13 of 52, lines 1-2) "Centra transports gas withdrawn from storage on ANR, GLGT and the TCPL Mainline to supply the Manitoba market during winter months.

At the beginning of winter, under the assumption of a normal weather year, Primary Gas, U.S. Supplies, Storage, and SGDS are used to meet both Firm and Interruptible requirements. As the winter progresses, Centra monitors the extent to which weather has varied from normal and the resulting storage inventory levels. If storage withdrawals are greater than planned, Centra may offer Alternate Supply Service to Interruptible customers (or physically curtail them as required) to conserve storage gas for the firm market. Alternate Supply Service or physical curtailment of Interruptible customers may also be required to ensure that the firm load is met during colder than normal weather on any particular day."

Put another way, Centra's storage and U.S. pipeline arrangements are used to meet the winter seasonal demand in aggregate as well as contribute to meeting the peak day requirements.

(Application p. 34, lines 16-27) "1) Atrium recommends that Centra consider evaluating an alternative allocation approach to upstream contracted pipeline and storage capacity resources. We suggest a seasonal resource stack-based analysis of each pipeline and storage capacity resource's contribution to the seasonal and peak day demands of its customers. The analysis should include modeling the use of pipeline capacity for serving the seasonal customer demands vis-a-vis storage injections as well as peak day.

2) In place of the aforementioned analysis, as an alternative approach for storage and related pipeline injection and redelivery capacity, Centra should use the winter season demand in excess of summer season demand. […]"

(Derksen-Rainkie Evidence p.31, lines 30-33) "This is because the procurement of upstream Storage & Related Pipeline costs are largely incurred on the basis of the capacity requirement to serve Centra's customers regardless of the fact that Interruptibles "make use" of these services for large portion of the year."

Request:

a) Does the Winter Season Demand in Excess of Summer Season Demand (Winter Excess) allocator address the fact that some of the storage and U.S. pipeline costs are incurred to meet the peak day requirements? Are costs of the storage and U.S. pipelines related to meeting peak day requirements reflected in the Winter Excess allocator?

b) If not, how could the Winter Excess approach be adjusted to address the costs of the storage and U.S. pipelines that are incurred to meet the peak day?

Responses to PUB/CAC 9a and 9b:

It is noted that a similar Winter Season Demand in Excess of Summer Season Demand allocator was advanced by Intervenors as part of the 1996 COS Review and ultimately dismissed by the PUB in Order 107/96. Based on the current record, there is no evidence to suggest a fundamentally different system gas supply portfolio to warrant a change in methodology the PUB previously rejected in favor of the current PAVG.

To be responsive to the question posed, however, as discussed in PUB/CAC 7a, Centra's gas supply investments are based on a portfolio approach such that the selection of the mix of TCPL and storage (and related pipeline) must meet the peak requirements of customers and as such, should not be viewed as separate portfolios. Thus, yes, storage and related pipeline costs are incurred to supplement or peak shave investment in TCPL capacity to ensure peak loads of all Centra's customers are met.

The proposed Winter in Excess of Summer Demand is a methodology that allocates cost based on weighted volumes and implicit in that allocator is some weighting of demand, although the weighting is unknown. This proposed treatment is consistent with the electric weighted energy allocator used previously for purposes of generation and bipoles allocation (which includes generation storage and transport service), which the PUB dismissed more recently in Order 164/16.

In contrast, the existing PAVG methodology explicitly weights demand based on 1-LF and a lesser weighting of volume based on LF and comports well with Centra's operations for at least several reasons: 1) provides a heavier weighting based on demand, which is the primary purpose of storage and related pipeline given that in the absence of this investment, a larger investment in TCPL capacity would be required 2) provides a lighter weighting based on volumes which considers the broader benefits of this resource; and 3) is simple and understandable.

PUB/CAC-10 **Reference:** Derksen-Rainkie Evidence pp.33-34; CAC/Atrium I-6a; PUB/Centra I-18b

Preamble:

(Derksen-Rainkie Evidence p.33, lines 13-15) “It is recommended that the PUB retain the diameter-length distribution classification study as a means to estimate the weighting of customer and demand for distribution plant as this methodology is the most commonly used.”

(Derksen-Rainkie Evidence p.34, lines 8-11) “The two most common methods for the classification of distribution plant including the Zero Intercept Study and the Minimum System Study. Centra's current COS methodology for classification of distribution plant is based on a diameter-length study, which is a variation closely related to the minimum system study referred to in Centra's Application.”

In response to CAC/Atrium I-6a, Atrium provides a table showing the distribution classification approaches of five Canadian gas utilities. Two utilities base the classification on a settlement, while the remaining three base the classification on a minimum system study.

PUB/Centra I-18b adds another comparator, specifically Heritage Gas Ltd’s distribution mains classification approach which is to use a diameter-length study.

Request:

a) Please explain whether Centra’s diameter-length study is considered to be a variation of a minimum system study and thus is counted among the minimum system studies used at other Canadian gas utilities.

b) If not, please provide data that show that diameter-length studies are the most common approach to classifying distribution mains.

c) Explain the similarities and the differences between a diameter-length study and a minimum system study.

Response to PUB/CAC 10a and 10b:

Yes, the Diameter-Length study is a variant of the Minimum plant study that are conceptually consistent in that both view that the cost of distribution plant is driven by demand as well as the number of customers, and both are intended to derive the minimum cost incurred in connecting to and serving customers and thus is a surrogate for distance.

To be clear, CAC's Consultants are not certain that the diameter-length study is a common approach used in industry practice today. Our comments were intended to convey that the philosophy of viewing distribution plant driven by the cost incurred to meet customer capacity requirements as well as being sufficiently long enough to attach customers (distance) is a commonly held view and that the diameter-length is a methodology that accomplishes this concept.

Response to PUB/CAC 10c:

The minimum system method assigns customer costs on the basis of the ratio of the cost of the minimum system divided by the total investment in distribution plant. An analysis is undertaken to assess the minimum sized pipe and then a cost is applied to it. This method is viewed to be relatively simple and tends to be based on data available to the utility and derives an actual minimum value rather than a theoretical value. As mentioned in the CAC Evidence, the drawback of this method is that conceptually, even a minimum sized distribution pipeline is viewed to provide some capacity.

The diameter-length study calculates the size of each distribution pipe by multiplying the total length of each size of pipe by the diameter. The diameter-length equivalent for the smallest size pipe is calculated for each pipe but the largest sized distribution pipe is excluded in the calculation. A ratio of the total diameter-length to the actual diameter-length determines the customer component. The benefit of this method is that it relies on the physical measurements of number and length and excludes any application of cost as debate can occur about the appropriate cost (historical, depreciated, current, etc.). The drawback for this method is that a minimum sized pipe is assumed to be able to deliver some capacity requirement to customers and that diameter may not be viewed to sufficiently represent the internal area of a pipe.

PUB/CAC-11 **Reference:** Derksen-Rainkie Evidence pp.36-38; PUB/CENTRA I-3a-f; PUB/ATRIUM I-9a-b; CAC/CENTRA I-7b; Appendix 3 (p. 30 of 32) of Centra's COSSMR Application

Preamble:

(Derksen-Rainkie Evidence p. 36, lines 15-19) "It is recommended that gas DSM be treated conceptually consistent with electric DSM, functionalized as transmission and allocated based on the peak and average allocator given that the investment benefits not only the participating classes, but also provides broader system and societal benefits and is consistent with the PUB's COS policy of a broader definition of cost causation."

(Derksen-Rainkie Evidence p. 38) "For these reasons, it is recommended that gas DSM investment be viewed as a system resource, functionalized as transmission and allocated based on PAVG which allocates these costs on both a demand and volumetric basis. This treatment recognizes that benefits are obtained by both non-participants as well as participants through the lowering of commodity costs and capacity investment in the long term. It also allocates DSM costs to all Centra customers and thus, recognizes the overall societal benefits provided. To functionalize DSM on the basis of production and allocated on the basis of energy, as Centra suggests, results in T-service and Direct Purchase customers avoiding cost responsibility for an investment that provides broad societal benefits and which conflicts with the spirit of DSM investment."

(PUB/Centra I-3c) "If Centra was directed to treat DSM as a system resource, the most appropriate treatment would be to functionalize the costs as Production, classify them as Energy and allocate them based on volumes."

(PUB/Centra I-3d) "Allocating DSM costs as a system resource may increase controversy during the regulatory review of the EM plan as each customer class will share the cost of DSM for all other customer classes. Accordingly, intervenor groups will be inclined to scrutinize the economics of programs offered to other classes, which may result in a reduction in programs for hard-to-reach customers in the income qualified and Indigenous customer segments if this results in DSM programming being selected purely on an economic basis.

As an upside, treating DSM as a system resource is administratively simpler and even if it is not justified on the basis of cost causation, the approach achieves broad allocation of costs across all customer classes, which is consistent with socializing the cost of DSM on a policy basis to recognize the non-energy supplemental benefits such as GHG reduction and socio-economic benefits."

Request:

a) Please explain why functionalization as Transmission is appropriate for DSM costs if they are to be treated as a system resource.

b) Please explain why allocation of DSM costs by PAVG is appropriate, given the current allocation is based on annual volumes.

c) Please provide CAC's experts' position on Centra's statement in PUB/Centra I-3d that "*Allocating DSM costs as a system resource may increase controversy during the regulatory review of the EM plan […] which may result in a reduction in programs for hard-to-reach customers in the income qualified and Indigenous customer segments if this results in DSM programming being selected purely on an economic basis.*"

Response to PUB/CAC 11a and 11b:

The understanding of the CAC Consultants is that the current allocation of DSM costs is based on direct assignment based on a forecast of class participation provided by Efficiency Manitoba and is not based on class annual volumes as stated in PUB/CAC 11b. Once the costs are directly assigned to a class, they are classified on the basis of energy (volumes) such that within the class, the costs are recovered from each customer on a volumetric basis.

The spirit of the CAC Consultants proposal is that the cost of gas DSM be allocated on a broader basis, than the current direct assignment approach. A broader allocation is more consistent with the strong public policy intent behind gas DSM to lower greenhouse gas emissions and which provides other societal benefits in addition to the lowering of energy costs and reduction in the investment in system capacity requirements over the longer term. This approach would also be consistent with electric COS.

Centra's current direct assignment approach allocates the cost of DSM based on forecasted class participation. Within the class, however, all customers, regardless of participation pay for DSM, presumably on the basis that non-participants within a class benefit from those who do participate and thus, any perceived notion that direct assignment is superior from a cost causation perspective is debatable.

The CAC Consultants proposed allocation based on PAVG is intended to recognize the broader cost reductions and benefits provided to society as a whole and as well as the potential for both energy and investment in capacity reductions over time. In the view of the CAC Consultants, this would be more consistent with the intent of gas DSM that provides benefits to all customers, regardless of whether they participate. That said, upon further reflection, the proposal to functionalize DSM to transmission may stop short of reflecting the spirit of this intention. On this basis, a broader functionalization than transmission may better capture that intention.

Response to PUB/CAC 11c:

As noted in the response to PUB/CAC 11a and 11b, there are non-participants within a class already who pay for programs for which they do not participate in. Further, the programs are pooled such that there will be some programs that are not economically justifiable on their own but are pooled with programs that more than meet the economic threshold such that overall, the portfolio is deemed to meet the economic feasibility. On this basis, any representation that the current direct assignment approach slavishly adheres to cost causation is misleading and it is doubtful that a broader view of cost causation proposed by the CAC Consultants would produce the outcome articulated by Centra. Further it is Centra that is responsible for the appropriate allocation of gas DSM, and not Efficiency Manitoba.

PUB/CAC-12 Reference: Derksen-Rainkie Evidence p.37; PUB/Centra I-3a-f

Preamble:

(Derksen-Rainkie Evidence p.37, lines 11-17)

"1. Centra asserts that gas DSM primarily provides economic benefits to the participating customers and only minimal incremental economic benefits to the overall system; and

2. Centra asserts that a methodology consistent with electric operations may not be cost causal given that gas DSM is less cost effective as gas operations are unable to benefit by the deferral of more costly generation investment or increases in export revenues (by freeing up energy to be sold extra-provincially that would otherwise be consumed by domestic customers)."

Request:

a) Do CAC's experts agree with Centra's assessment that allocating DSM as a system resource may not be cost causal, as explained by Centra in item 2 in Section 7.2 on page 37? Does section 7.3 of CAC's evidence provide CAC's cost of service experts' complete perspective on the cost causal nature of DSM as a system resource? If not, please provide additional information in support of the cost causality of allocating DSM as a system resource.

b) Please explain how the benefits of DSM to gas ratepayers differ from the benefits to electric ratepayers.

Response to PUB/CAC 12a and 12b:

Please refer to the responses to PUB/CAC 11a and 11b. Further, as noted in CAC Evidence, page 37, while the economic case and the deferral of plant is readily understood and quantified for electric operations, it is expected that at least some of those benefits, such as reduced transmission, distribution and upstream capacity must also exist for gas DSM. Gas customers have exhibited a declining use per customer due to the improved efficiency of homes and businesses and lowers the design day requirements compared to the design day requirements at the time when the original plant was designed and installed to serve customer loads and thus, serves to lower overall revenue requirement for all customers. As such, the costs of gas DSM are driven to reduce usage, for socio economic and environmental benefits such as the reduction of greenhouse gases, and result in the reduction of system costs.

PUB/CAC-13 **Reference:** Derksen-Rainkie Evidence p.38; 2016 Manitoba Hydro Electric COSS Review, May 13, 2016 Workshop, page 645;

Preamble:

(Derksen-Rainkie Evidence p.38 lines 6-12) "The PUB COS policy is that cost causation requires consideration of all of the uses of an investment to recognize that the primary and secondary benefits influence the planning and justification of assets. When gas DSM is analyzed within this policy framework, it is reasonable to consider that it benefits not only the participating classes, but also broader societal imperatives. Additionally, this broader view of cost causation aligns with Centra's corporate decarbonization direction and allows for alignment in the treatment of DSM cost allocation between electric and gas operations."

In the first workshop for the 2016 Manitoba Hydro COSS review, Ms. Derksen, a witness appearing on behalf of Manitoba Hydro, explained Manitoba Hydro's approach to allocating DSM expenditures at that time:

(Manitoba Hydro Electric COSS Review, May 13, 2016 Workshop, page 645, lines 2-8) "We allocate DSM expenditures on the basis of class participation because it's, from our view, the most cost causal approach. It aligns the cost of the programs with the classes that participate in -- in those programs. And it places cost responsibility with those who cause it and can influence it."

Request:

Please reconcile Ms. Derksen's views of the appropriate allocation of DSM expenditures when explaining Manitoba Hydro's then-current approach to allocating DSM expenditures (which is the same as the current Centra approach) at the 2016 electric COSS review with her views at page 38 of CAC's evidence.

Response PUB/CAC 13:

As noted in the preamble to this information request, the views provided as part of the MH COSS Review was the historic position of Manitoba Hydro on the cost allocation of Electric DSM in 2016.

The CAC Consultants views at the current proceeding are informed by analyzing Gas DSM within the policy framework of the PUB COS policy that cost causation requires consideration of all of the uses of an investment to recognize that the primary and secondary benefits influence the planning and justification of assets. In addition to the policy considerations that flow from Order 164/16, the CAC Consultants views were informed by a number of complimentary considerations, including corporate adoption of decarbonization, consideration for alignment of the treatment of DSM cost allocation between electric and gas operations and the enactment of the Efficiency Manitoba Act in January of 2018, that further underscores the broader primary and secondary benefits of gas DSM. Accordingly, the CAC Consultants came to the view that the prior MH position on DSM costs represented too narrow a view of cost-causation and that a broader view of cost-causation would support a recommendation that gas DSM be allocated more broadly based on PAVG.

CENTRA GAS 2021 COST OF SERVICE METHODOLOGY REVIEW APPLICATION

INTERVENER EVIDENCE INFORMATION REQUESTS

CAC (D. RAINKIE, K. DERKSEN)

JUNE 23, 2022

PUB/CAC-14 Reference: Derksen-Rainkie Evidence p.43

Preamble:

(Derksen-Rainkie Evidence p.43 lines 10-15) "The Brandon/Southwest area system, clearly for many decades has been an integrated asset that has been funded by all customers. It is also important to recognize that the SC load growth for the last 25 years have been met either through available transmission capacity provided by the Brandon/Southwest area system or through the addition of capacity, without the requirements of a customer contribution from the SC customer, and the costs were rolled into rates funded by all customers."

Request:

a) Please confirm whether it is possible for Centra to construct main extensions to serve customers without any customer contribution, so long as the revenues from the new customer(s) are sufficient to meet the thresholds approved by the PUB of the feasibility test.

b) Please explain wither it is possible that the increased revenues from an expansion to serve a Special Contract customer are sufficient to cover the costs of the expansion facilities and thus pass the feasibility test without any contribution from the Special Contract customer.

Response to PUB/CAC 14a and 14b:

Two of the central points of the CAC Consultants evidence with respect to Centra's proposed direct assignment of transmission plant to the Special Contract and Power Stations – is that utility assets are generally fungible and can serve different purposes and customers over time and utility assets are integrated and commingled and all customers benefit from and pay for the integrated nature and scale and scope of Centra's system.

Utility systems such as Centra's are complex, serve a wide variety of customers, over a wide variety of uses and are changed over time for a wide variety of reasons. This is why the CAC Consultants agree with the PUB COS policy determinations in Orders 107/96 and 164/16 and advocate selecting cost allocation methods by considering a broad range of benefits and uses of the utility assets and investments, over a range of years and conditions - and not one-off hypothetical situations, such as those posed in the questions, that may or may not have occurred.

It is also the CAC Consultants view that COS methods should be durable for the numerous circumstances encountered in a utilities day to day operations and should not be selected on accidents of geography in terms of where a customer resides or accidents of timing when capacity happens to be available as a result of previous system betterment upgrades.

In terms of whether main extensions can be provided without a customer contribution so long as revenues are sufficient to support that extension, that can happen. However, in the case of the Special Contract customer, its increased loads/capacity was provided through available capacity from the Brandon/Southwest area or through system betterment upgrades that were funded by all customers. In these cases, a feasibility test would not be conducted.

It is the CAC Consultants understanding that no feasibility test was conducted related to the Special Contract increase load growth since 1996.

PUB/CAC-15 **Reference:** Derksen-Rainkie Evidence pp.43-44; Centra COSMR Application p.32 of 40; Appendix 1 (Atrium Report) p. 18 (Figure 1); PUB/Centra I-2

Preamble:

(Centra Application p.32 of 40) “Additionally, the pipelines that serve this customer class predominantly have a one-way relationship with the rest of the system. That is to say that the remainder of the transmission system can receive pressure and capacity support from the pipelines that serve the Special Contract Class, but the rest of the Brandon system, with the exception of the facilities serving the Brandon Power Station, cannot generally be used to serve the load requirements of the Special Contract Class. Similarly, the facilities that serve the Power Station in Brandon do not serve any other customers under normal operating conditions."

(Derksen-Rainkie Evidence p.43, lines 19-22) “As can be seen in the above Brandon/Southwest area schematic, both the SC and PS are connected to the larger system. While some engineering changes have been made to optimize the system, the costs of which have been funded by all customers, this does not result in a situation where it is abundantly clear that the facilities are dedicated to only those customers.”

(Derksen-Rainkie Evidence p.44 lines 1-3) “Based on this broader definition, it is appropriate to consider the long-standing integrated nature of the Brandon/Southwest area system and operating conditions that extend beyond normal operating conditions assumed in a test year.”

Request:

a) If Centra’s other customers derive a benefit from the ability of the Koch and Manitoba Hydro power station pipelines to provide service (in an emergency) to Brandon and the southwest, but Koch and the power station are unable to derive a benefit from being notionally connected to the odourized Brandon/SW system (even in an emergency), please explain why should the Special Contract and the Power Station classes be allocated more cost (i.e. the allocated full share of common costs) instead of a reduced assignment of the costs related to the specific pipelines and facilities serving them.

b) Considering the Power Station customer and the Special Contract customer in Brandon are unable to use odorized gas, and it is not possible for Centra to deliver unodourized gas to these customers except through the pipelines Centra has earmarked for direct assignment, even in emergencies, please explain why these pipelines should still be considered as part of an integrated system in the Brandon/SW area.

Response to PUB/CAC 15a and 15b:

As Centra states:

> "Gas **pipeline infrastructure** systems, such as 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 that **changes to** one aspect of the system will typically **impact other aspects of the system** with **respect to performance or redundancy considerations**."[1]

[1] Centra Application, page 31

CENTRA GAS 2021 COST OF SERVICE METHODOLOGY REVIEW APPLICATION

INTERVENER EVIDENCE INFORMATION REQUESTS

CAC (D. RAINKIE, K. DERKSEN)

JUNE 23, 2022

Recognizing the highly interconnected and redundant nature of Centra's system, as Centra states, the CAC Consultants have serious concerns related to Centra's proposal and its conflict with the fundamental tenets of utility ratemaking. The results of Centra's proposal are as follows:

1) Centra's proposal will provide Koch with all the benefits of the integrated system but who will pay for none of the broader system is entirely in conflict with postage stamp ratemaking;

2) The investment made to isolate Koch has been made over many years and has paid for through rates of all Centra's customers;

3) Centra designs its system for a number of years into the future thus it overbuilds its system with enough additional capacity for its future anticipated needs such that it does not have to increase its capacity for incremental changes or load development that occurs annually. On several occasions Koch has sizably increased its operations in which it has not paid for incrementally, but that capacity made available to Koch was paid for by all customers. Further, for the past 20 years, Koch has been receiving the benefit of a reduced cost allocation as a result of the rural expansion contribution adjustment approved by the PUB in Order 118/99;

4) It is Koch's location that makes Centra's treatment plausible. Centra's proposal effectively amounts to a distance-based allocation of cost rather than one based on its overarching postage stamp rate philosophy;

5) Centra's proposal amounts to a change in the rules of the game after the game has started;

6) Centra's proposal will shift in the cost burden and risk to all other customers despite the benefits afforded to Koch by virtue of the integrated system it is attached to as

well as the financial strength of the entire utility to fund the infrastructure investment, which when considering the lower load factor customers, like the SGS class, contribute the vast majority of Centra's revenue requirement; and

7) The fact that Koch and the Power Stations receive unodorized gas is a red herring. Koch and the Power Stations have always received unodorized gas, thus is not a change in circumstance to justify a change in cost allocation to direct assignment or a valid argument for making no cost contribution to the larger Centra network system.

PUB/CAC-16 **Reference:** Derksen-Rainkie Evidence p.39 and 45 (lines 17-19)

Preamble:

(Derksen-Rainkie Evidence p.39 lines 17-20) “It is recommended that no interim rate reduction be provided to the Special Contract customer class as a result of this proceeding, as Centra's customer impact analysis that is relied upon to propose this reduction is incomplete and outdated and such a measure would constitute retroactive ratemaking;”

(Derksen-Rainkie Evidence p.45, lines 15-19)

“iii. By relying on unreliable indicative class impacts, the potential exists that the interim rate reduction would need to be recovered from the SC class at the next GRA; and

iv. Centra's interim rate measure relies on rates prior to the 2019/20 GRA, and based on the 2013/14 GRA, nearly a decade ago, and such a measure would constitute retroactive ratemaking.”

Request:

a) Please provide Mr. Rainkie’s and Ms. Derksen’s views as to whether the approval of an interim rate, followed by variance of the interim rate at a future proceeding, constitute retroactive ratemaking.

b) Please confirm whether the process to finalize the interim rates to the Special Contract and Power Station class will provide the PUB with the opportunity to consider the updated COSS methodology and revenue requirement before finalizing the interim rates charged to the Special Contract and Power Station classes.

c) Please explain why setting a rate to be effective on a future date, such as the PUB may order in response to Centra’s application, constitutes retroactive ratemaking. Are Mr. Rainkie and Ms. Derksen implying that a rate set using historical information amounts to retroactive ratemaking? If so, please provide Mr. Rainkie's and Ms. Derksen's views as to whether the non-gas rate reversion initiated in Order 79/17 amounted to retroactive ratemaking.

d) If the PUB approves changes to the COSS methodology that indicate the rates charged to the Special Contract class are in excess of the costs allocated and assigned to this class, please explain why an approach that provides interim rate relief to this customer, at no impact to Centra's other customer classes except the Power Station class which is populated by Centra's owner, is inappropriate at this time.

Response to PUB/CAC 16a - 16d:

The CAC Consultants concerns with respect to retroactive ratemaking relate to Centra's proposal to go back in time and charge the Special Contract class a level of non-gas rates in effect prior to the 2019/20 GRA. CAC consultants understanding is such that the non-gas rates flowing from the 2019/20 GRA (Order 152/19) were considered just and reasonable by the PUB based on the evidence at that hearing. If the PUB was to approve the Centra interim proposal, it is unclear if going back to the previous non-gas rates would be somehow determining that the rates set flowing from the 2019/20 GRA are in error or not just and reasonable. It appears that this process of going back in time and essentially nullifying the determinations made by the PUB at the 2019/20 GRA would constitute retroactive ratemaking.

The difficulty with moving forward with an interim rate reduction for the Special Customer class to be confirmed or varied at the next GRA, is that the indicative customer impacts that are inherently relied upon by Centra to assess the reasonability of the interim reduction are incomplete, outdated and unreliable – for the reasons described in Section 8.4 of the CAC Evidence. Additionally, while Centra is proposing a short-term swap of the rate reduction for an increase to the Power Station class, it is unknown what the impact might be to other rate classes in the longer term, given the deficiencies in the indicative customer impact information.

It is possible that the non-gas rate reversion initiated in Order 79/17 has elements of retroactive ratemaking. However, it is noted the circumstances surrounding Order 79/17 related to Centra overearning and its non-compliance with the PUB directive on the timing of the next GRA filing and different than those associated with the interim rate reduction proposed as part of this Application

PUB/CAC-17 Reference: Derksen-Rainkie Evidence p.45

Preamble:

(Derksen-Rainkie Evidence p.45, lines 27-30) "Further, if the PUB approves any changes flowing from this proceeding, it is recommended that Centra be directed to file two COS studies at the next GRA, one that reflects all the COS changes as well as the updated revenue requirements, and one that excludes the COS changes such that the impacts as a result of the COS changes can be isolated and tested."

Request:

a) Is Mr. Rainkie's and Ms. Derksen's recommendation for Centra to file two versions of its COSS limited to the situation where the PUB orders a change to the direct assignment of costs to the Special Contract and Power Station classes, or should Centra file two versions if the PUB orders any changes to the COSS methodology?

b) If the PUB does not order changes to the COSS methodology but orders updates to certain studies supporting the COSS, are two versions of Centra's COS studies required?

Response to PUB/CAC 17a and 17b:

The CAC Consultants recommendation that Centra file two versions of its COS at the next GRA is not limited to any particular change in methodology or the updating of any particular special studies that support the COS. Rather, the spirit of the recommendation is that the most effective and efficient way to test changes to either a COS methodology or special studies updates is to isolate these changes/updates from the those that occur as a result of applying the COS to a different future test year.