REFERENCE:

CAC Evidence pdf page 38 – DSM allocation

PREAMBLE TO IR:

PDF p.38 of CAC Evidence state that "under this alternative, the costs of gas DSM could be allocated as a system benefit. Centra states that if such a perspective is taken, the appropriate allocation would be to functionalize the costs as production and allocate the costs based on forecasted annual energy by class.

CAC recommends that Gas DSM be treated conceptually consistent with electric DSM and be functionalized as transmission and allocated based on the peak and average allocator.

QUESTION:

(a) Given that Centra customers have the option of purchasing their own gas supplies and arranging for customer-paid transportation to Manitoba (in the case of T-Service customers), how does CAC reconcile the differences between the electric and natural gas systems in respect of DSM allocation, where in the electric system, all customer classes are required to obtain their commodity energy volumes and transportation services from supply (i.e. generation) through to delivery of the volumes to the AC transmission from Manitoba Hydro.?

(b) Given that the gas DSM benefits derived from participation by LGS and SGS customers are largely related to production (gas purchases, transportation to Manitoba, storage), with at most limited benefits derived from transmission and distribution system deferrals, how does CAC reconcile the allocation of DSM costs purely through transmission allocators related entirely to PAVG, which allocates these costs on both a demand and volumetric basis. Why would it be appropriate in Centra's case to allocate DSM to Transmission, which is not the production/supply function?

(c) Given that T-Service and Mainline customers, who are largely T-Service participants, do not contribute materially to production costs, transportation costs, storage costs, or distribution costs, how does CAC reconcile the statement that the current allocation method applicable to DSM costs, "*results in T-Service and Direct Purchase customers avoiding cost responsibility for an investment broad societal benefits and which conflicts with the spirit of DSM investment.*"?

(d) Please confirm that reduced use by one customer due to DSM also reduces the revenue received from that customer to be able to pay for the system. Given that system costs are largely fixed, is not the presence of a DSM program already an upward rate driver on other customers (the non-participants)? If this is the case, why also make those other customers pay for the DSM program cost that benefits the participant?

Response to IGU/CAC 1a:

It is the CAC Consultants understanding that Centra's current COS treatment recovers the costs associated with DSM from both T-Service and Direct Purchase customers and thus, the CAC Consultants proposal is directionally consistent with Centra's current COS treatment in this regard.

Further to the response to PUB/CAC 11a and 11b, in the CAC Consultants view, the supplier of transportation and commodity/energy is not a determining factor, particularly recognizing the strong public policy underpinning gas DSM including environmental and other societal benefits provided.

Response to IGU/CAC 1b – 1d:

Please refer to the response to PUB/CAC 11a and 11b

REFERENCE:
CAC Evidence, pdf page 7 Special Contract3

PREAMBLE TO IR:

CAC indicates the Special Contract customer should not be direct assigned assets because these assets are part of the broader Brandon/Southwest Area System.

QUESTION:

(a) Please confirm that the Special Contract customer class does not use, and can in no way be served, by assets in other locations, such as the North of Winnipeg system.

(b) Please confirm that the Special Contract customer cannot be supplied by odorized gas, and as such the Brandon/Southwest Area System is of no use in delivering supplies to the Special Contract customer since it only supplies odorized gas.

Response to IGU/CAC 2a & b:

Not confirmed. It is unclear what "assets in other locations" means in terms of the broader Centra system. As Centra outlines on pages 31 and 32 of its COSMR Application, gas pipeline infrastructure systems, such as the one serving the City of Brandon, are highly interconnected and the pipelines that serve the Special Contract class predominately (but not solely) have a one-way relationship with the rest of the system, under normal operating conditions.

Under postage stamp ratemaking, if the criteria for a direct assignment are not abundantly clear, then a particular customer class is assigned a proportion of the broader system costs, regardless of the specific geographic location of the customer or which specific assets they use or don't use. As outlined in Section 8.3 of the CAC Evidence, the Brandon/Southwest Area system has clearly been a highly integrated system for many decades, the cost of which has been funded by all customers.

Accordingly, the clarity that is necessary to direct assign transmission plant to the Special Contract class does not exist and it is appropriate that this class continue to receive an assignment of the broader system costs.

Please also see the response to PUB/CAC 15a and 15b.

REFERENCE: CAC Evidence, redaction

PREAMBLE TO IR:

CAC's evidence includes a number of redacted values

QUESTION:

(a) Please provide all sources, references, calculations, and working papers supporting the development of the values shown as redacted in the CAC evidence.

Response to IGU/CAC 3

Please see the response to PUB/CAC 4.

REFERENCE:

CAC Evidence, pdf page 13. Cost Causation

PREAMBLE TO IR:

CAC indicates that the PUB's Order 164/16 references cost causation as the paramount driver, but also notes that the PUB includes reference to "Cost causation as defined by the Board takes into consideration both how an asset is panned and how that asset is used."

QUESTION:

(a) Please confirm that the reference to "use" as a consideration in the above reference is in the context of cost causation, i.e., if the use of an asset causes costs. It is not referenced as a broad concept that all use generally (regardless as to whether it causes added costs) should be an allocation factor (e.g., the PUB quote does not say users should pay regardless if they cause or drive costs, contrary to cost causation principles).

(b) Please confirm that added use of the Centra gas system at peak times can cause added costs if it drives new investment, or added needs for storage capacity, but that incremental use in, say, August, does not drive new investment in transmission capacity.

(c) Is CAC aware of any classes of customers (e.g., SGS, LGS, Mainline, etc.) who make no use of the system at peak times, such they their CP allocation is zero and they would be allocated no costs for the transmission system?

Response to IGU/CAC 4a and b:

Not confirmed. It is unclear if the stipulations in the questions were intended to narrow or constrain the broad definition of cost causation to only design parameters.

The extracts from PUB Orders 107/96 and 164/16 provided in Section 3.1 of the CAC Evidence, describe a PUB COS policy that considers a broader definition of cost causation in terms of both how a system is designed and how it is operated, primary and secondary uses and benefits of assets, to be assessed over a range of years and a range of operating conditions.

Response to IGU/CAC 4c:

Yes, the Interruptible Class under a CP methodology would not be allocated any capacity related costs. That said, Centra now states that it has firm up, from a downstream perspective, interruptible load such that it should now be reflected in the downstream allocation of capacity costs. From an upstream perspective, based on Centra's CP proposal, the Interruptible Class will avoid all upstream TCPL capacity costs.

Further, as discussed in response to IGU/CAC 7c, there are customers within the larger volume classes such as grain dryers and asphalt plants that avoid demand cost responsibility.

REFERENCE:

CAC evidence pdf page 22 – Practice Manuals

PREAMBLE TO IR:

CAC references two sources for natural gas cost of service, plus a new source for electric cost of service from the "Regulatory Assistance Project".

QUESTION:

(a) Please explain the CAC witness views regarding the relevance or precedence of transmission cost allocation methodologies to natural gas transmission. Are the practices used in electricity directly relevant and transferrable, only somewhat relevant directionally, or not at all relevant? Please provide the same response for distribution assets.

Response to IGU/CAC 5:

It is the CAC Consultant's view that the applicability between gas and electric COS as generally relevant and transferable for all investment but importantly, as with all COS methodology, a solid understanding of the underlying circumstances of the utility including such things as regulatory precedence and institutional practice, load characteristics and operations are required in order to construct a well reasoned, cohesive system of cost allocation. Importantly also, the utility's philosophy on how finely it desires to match to cost behaviour. That is, simplicity and understandability are important goals to be established in COS which will impact how aggregated or disaggregated (i.e. broad or narrow) a framework for COS is established. Investment cost that is aggregated for cost-of-service purposes should result in a unified methodology.

In Manitoba, it is entirely reasonable to view electric generation (including bipoles and US interconnections), transmission and distribution consistent with the overall functions for natural gas including production, upstream transportation and storage, transmission and distribution. In fact, there is desirability to the extent possible to have consistency in cost-of-service methodology between electric and natural gas operations in Manitoba given the utilities are under the same ownership, in order that integration goals can be met and to avoid unintended consequences that may, for example, drive fuel switching in a direction opposite to corporate goals.

For electric COS purposes, generation, bipoles and US transmission, which reflect the most material portion MH's overall rate base and revenue requirement, are generally aggregated in that these costs are all classified based on system load factor, the demand component of which is allocated on the top 50 CP hours averaged over many years and the energy component allocated on annual unweighted energy. This is consistent to Centra's PAVG methodology, although Centra defines its CP based on a 3-year average (10-years for the Power Station Class).

It is true that electric COS classifies its AC networked transmission (i.e. within Manitoba) on the basis of the top 50 CP hours averaged over multiple years. As the Consultants Evidence states, the purpose of capturing so many hours which is then averaged over many years is to reflect a concerted effort to capture some of the wider range of customer use over time (i.e. energy influence) and to avoid circumstances like that identified in IGU/CAC 7c that would either result in an excessive allocation of cost to the streetlighting class or a free-rider circumstance whereby the streetlighting class is allocated no transmission cost.

In contrast to the classification and allocation of electric transmission cost that captures a wide/broad range of operating conditions directionally conceptually consistent with Centra's current PAVG methodology, Centra is proposing to move to a maximum design day CP allocator which 100% weights cost responsibility on the basis of a single occurrence. In the view of the CAC Consultants, this is fundamentally at odds with the spirit and intent of COS methodology for electric operations and the PUB's pronouncements on its view of cost causation in Orders 107/96 and 164/16.

REFERENCE:

CAC Evidence, pdf page 26- Extreme conditions

PREAMBLE TO IR:

CAC indicates that extreme conditions and demands are "rarely experienced" and that cost allocation on the basis of the extreme conditions systems are designed for is "less extreme".

QUESTION:

(a) Is it CAC's witnesses understanding that customers desire to be served by a system during "extreme" conditions that may be uncommon, but are nonetheless within the design parameters of the system?

(b) Does CAC contend that the system should be built only to meet service standards during "normal" weather conditions experienced on a more routine basis?

Response to IGU/CAC 6a and 6b:

Of course, all customers require service under all conditions. The Consultant's Evidence never stated or even implied that customers load should only be met under certain conditions. The Consultant's Evidence is that cost allocation and rate setting must consider perspectives beyond only engineering considerations. In other words, engineering is one of many considerations in the determination of cost allocation and rate setting, however, engineering does not drive cost allocation and rate setting. Economic, accounting, regulatory precedence, legal and other disciplines also influence the establishment of cost allocation methodology and rate setting. And this broader view is consistent with the PUB's direction in Orders 107/96 and 164/16.

REFERENCE:

CAC evidence pdf page 28, bullet 6 – investment for “all conditions”.

PREAMBLE TO IR:

CAC contends that PAVG is an appropriate allocator as it matches Centra’s design approach and investment.

QUESTION:

(a) If Centra were to identify certain asset investments that were only required for low load conditions (e.g., valves or isolation equipment that is needed to ensure system velocities are sufficiently high during low load conditions), would CAC recommend that these costs be allocated on the basis of relative off-season use? Or would these costs be considered to be driven by the users with low load factors who cause infrastructure to be sized larger to meet winter peaks but then fail to make use of the infrastructure during the summer?

(b) Is CAC aware of any material investment that Centra has made that fits the description in (a)?

(c) Manitoba Hydro uses 50 top hours for coincident peak allocation (out of 8760 hours in the year, or less than 1% of hours) to account for load diversity (e.g., of only one hour was selected it may disproportionately impact streetlights, for example, who will be either all-on, or all-off, depending on the year and when the peak hour occurred). The use of 50 top hours provides additional stability to the allocator. Please confirm:

   a. The use of 50 top hours (less than 1% of the year) provides minimal attributes of average annual energy consumed per class and remains a peak allocator.

   b. Confirm whether the CAC witnesses are aware of any load equivalent to the Manitoba Hydro streetlights that could be disproportionately benefitted or harmed by the use of a single peak (e.g., they may randomly exhibit the all-on or all-off binary condition depending on the specific hour/day selected), and if so, provide a detailed description of the type of load.

Response to IGU/CAC 7a:

The proposition advanced does not provide enough detail to allow for a robust response. It is incredibly important to understand the overall COS framework before a determination can be made as to appropriate COS treatment. As discussed in IGU/CAC 6, how detailed a view of COS must be first understood. Such types of investment, if not material, may not warrant a separate treatment, particularly if a broad-based approach is taken for purposes of allocating the most material rate base and revenue requirement costs. In this specific case, it is possible that low load condition infrastructure may not be material and may be put in place to support all load under these conditions.

Response to IGU/CAC 7b:

The CAC Consultants are not aware of any material investment in this regard and, as noted above, it is critically important to first understand how aggregated or disaggregated (broad or narrow) is the established or proposed COS framework. Centra's and Manitoba Hydro's current COS is more broadly based, consistent with Orders 107/96 and 164/16. Centra's proposed overall COS framework lacks cohesiveness, which has resulted in inconsistent proposals of different methodologies at times resulting in a broader allocation, and at other times, an approach that is narrow and disaggregated. Thus, if such an investment is indeed identifiable, it is unclear how Centra would propose to treat this cost for cost allocation purposes.

Response to all parts of IGU/CAC 7c:

This is an excellent example of the challenges with taking too narrow a perspective of cost causation. In this case, the streetlights could become free riders avoiding all cost responsibility related to transmission. Interruptible customers, grain dryers, asphalt plants, and potentially the Power Stations also exhibit these kinds of characteristics and result in the same circumstance. A purist perspective as Centra suggests it wishes to take, however, would view capacity-related cost as only being driven by the peak as established under maximum design day conditions and only those who contribute to that peak should be responsible for its cost. In this extreme, streetlights, Interruptibles, grain dryers, asphalt plants, and potentially the Power Station customers also, should be able to use the system for free. Centra argues that these inequities can be addressed in rate design. Certainly, some of these inequities can be addressed in rate design, but rate design cannot address all inequities, and it can never address a faulty framework for cost allocation. Further, the question becomes on what basis does this inequity get addressed? It can only get addressed by understanding cost responsibility flowing from cost allocation, so one is left in a circularity, having to prepare two cost allocation studies each year (one with and one without the new methodology) and debating the merits of cost allocation in order to arrive at an appropriate determination of RCC, if that can even be done, in each rate application. Given the Centra current approach to limiting information made available in regulatory proceedings, it is doubtful that enough information would be made public to provide meaningful assistance to the regulator.

It is confirmed that MH classifies all AC networked transmission 100% to capacity and allocated on the basis of the top 50 winter hours averaged over many years. It is not appropriate, however, to conclude that the top 50 hours as a percentage of 8760 which equates to less than 1% implies that this methodology is equivalent or close to Centra's proposed CP allocation based on maximum design hour/day. While this is mathematically true, the top 50 hours are intended to represent the highest peaks and the energy influence would be a function of the consumption at these times in relation to total energy. The top 50 hours are further broadened by averaging these hours over many years. The spirit of this methodology is intended to capture the broader use view of cost causation which is directionally consistent with the spirit of the PAVG method, and which fundamentally conflicts with Centra's CP maximum design hour/day proposal. The CAC Consultants agree that the MH top 50-hour allocator is a demand allocator with an implicit energy influence rather than an allocator like PAVG that explicitly separates demand from energy based on load factor. It would have been appropriate for Centra to undertake a load analysis to understand the prevalence of peaks throughout the year on its transmission system such as a 2CP, 4CP, or at the very least, over a number of winter periods, such as done in electric COS which is also a strong winter peaking utility, to consider a broader CP allocator. But, no analysis was undertaken to assess this kind of methodology and would not have addressed capacity allocation associated with distribution or upstream capacity.