REFERENCE: Bowman Evidence pp. 6-7

PREAMBLE:

(Bowman evidence pp. 6-7) "Finally, it is noted that the response to PUB/Centra I-9(c) highlights the specific situation of offseason loads (such as grain dryers) and how these loads would play into calculations of coincident peak demand levels. The response indicates that "to the extent that seasonal loads do not contribute to the historical coincident peak demand of the class, their loads is effectively not included in the determination of their class coincident peak demand." […]

"The appropriate way to deal with this unavoidable form of load diversity within a class is through rate design, not through changing COS methods which are otherwise founded in cost causation."

QUESTION:

Would an alternative to attempting to address load diversity from customers such as grain dryers be to establish a new customer class that reflects the seasonal nature of their consumption and with demand allocations commensurate with the class's contribution to the peak day? Please provide the advantages and disadvantages of establishing such a seasonal customer class.

ANSWER:

It may be possible, though probably not advisable given there are easier and more appropriate solutions available in the rate design process.

A new rate class should reflect a material group of customers (in number or usage) whose characteristics differ significantly from any of the classes that presently exist, where this can be done consistent with other rate design criteria, such as:

1) Understandability of the rate structure
2) Ease of administration and interpretation
3) Encouraging justified uses of energy while discouraging uneconomic uses.

There may be challenges with designing a new rate class if it becomes difficult to create a group of customers that have relatively similar load profiles, which are also distinct from the existing rate class. There could be many users part way in between The existing rate class and the proposed new rate class (for example, a summer-focused recreational lodge that uses significant gas for water heating during peak tourist, but still uses a modest or low amount of gas in the winter when the recreational buildings are not in use but other facilities must be kept warm).

The advantages of creating a new class for cost of service are few, given a good rate design can solve all of the noted problems.

The disadvantages are described above, namely:

- The users are unlikely, as a group, to be large enough to justify their own rate class.
- The definition of the class members may be difficult, and/or exclusionary (for example, if the class was “grain dryers” because they use power mostly outside heating season, why wouldn’t a summer seasonal restaurant qualify?)
- The class characteristics may be difficult to collect, or be unstable, if the class if quite small.
- There may be considerable edge participants (for example, if the class consists of customers who mostly use gas outside heating season – how does one specifically define “mostly”)?

As for equally effective but much more readily implemented alternatives, it is true there are users of gas who have primarily summer season loads, such as seasonal restaurants, grain dryers, etc. However, because these loads do not add to peak, they do not drive new cost allocations to their existing SGS class for peak-related components. Since they do not use gas at peak, they would not contribution to the CP.

As a result, there is no real need to create a class for these customers – they are readily able to reside within a class but have their unique characteristics recognized by a good rate design. This could be analogous to what occurs with the Manitoba Hydro Limited Use of Billing Demand customers, for example (or other service offerings, like seasonal rates, or >200 amp residential service) – their class for cost of service purposes is more consolidated (typically Small General Service), but once the rates are designed, they are in a more refined portion of the rate structure, which can pay or less than the typical customer in the class.

To take an example of the Grain Dryers – if they reside in the SGS class but do not contribute to attracting CP-allocated costs, then the rates that they pay can be designed to be lower on average than other SGS customers to reflect this difference in consumption behavior. This can be done in at least two ways:

4) Charge rates for distribution services to all customers in the class that vary between summer use and winter use (with summer use less on a per unit basis than winter use). For example, the winter charge can be higher than the summer charge. Alternatively, the CP-related charges can be based on a ratcheted usage in winter months (for example, the number of units charged each summer month for bill purposes can be based on the greater of actual usage or 90% (or some other percentage) of the maximum monthly amount used in the previous December, January, and February. in this way more units (and dollars) would be billed to those who have a high winter use and less to those who do not. This approach may be adopted without adding a new rate offering within the class.
5) Design a rate offering, similar to the electric LUBD, that the summer-focused customers can opt into within the SGS class.

Given the above rate design alternative, there is no need to create a new rate class within the cost of service study.

REFERENCE: Bowman Evidence p. 7

PREAMBLE:

(Bowman evidence p. 7) "However, CGM's description of the development of the allocator indicates that it will "be developed in conjunction with the approved load forecast". While the load forecast should be one input to the peak design day allocation, it is important that the allocator reflect the actual risk-adjusted peak load that CGM considers necessary for system planning and investment. For example, if CGM uses inputs to the design process that include safety margins on temperature, customer coincidence, or load forecast risk, these variables should be part of the allocator. Ultimately, the coincident peak design day allocator should largely reconcile to the design hour actually used by CGM's planning staff, and not necessarily to the load forecast that happens to be used in any given GRA."

QUESTION:

Should the design day peak in the COSS reconcile with the demand billing determinants which are determined by the volume forecast? Please explain why or why not.

ANSWER:

Yes, but not one-to-one.

For example, the design day peak may be intended to address a specified design temperature or wind (which Centra keeps as confidential). The load forecast billing determinants may be based on an average low temperature. So, if the design temperature were, for example -44C, but the load forecast and billing determinants are set at -35C, then each class' billing determinants should be scaled up to -44C loads for the purposes of cost allocation based on their incremental contribution under the design day peak condition. This may mean a relatively small change, for example, in the Special Contract customer, but a relatively large adder to the heating-dominated SGS class.

Similarly, if the system is designed for peak output being produced by the Power Stations, but the load forecast assumes relatively limited usage by the Power Station class at peak times, this load forecast driven billing determinant should be scaled up to the full design capacity for that customer class, as this is the basis of CP which drives system costs.

REFERENCE: Bowman Evidence p. 8; CAC/ATRIUM I-6b

PREAMBLE:

(Bowman p. 8) "In the event a direct allocation of costs in the COS study is not implemented, the alternative precedent is set out for the case of FortisBC, as described by Atrium in CAC/Atrium I-6(b). Under that approach, the customer is not directly allocated costs via the cost of service study, and does not form a "class" in the COS analysis. Instead rates for the unique special contract are established outside the Cost of Service study, and then when the COS study is modelled, the revenues received from the special contract are considered an offset to the costs otherwise included in the COS. Mathematically, the approach would be akin to the treatment of export revenue in the Manitoba Hydro electricity COS study, where the sales are not reported as being part of any "class" (there is no export class in the MH electricity COS study), but instead are reflected only as a revenue which is credited against the overall costs that the utility incurs. Using such an approach would not remove the need for a regulated rate to be developed to serve the Special Contract customer, but that rate could in theory become a direct calculation based solely on assets used by the customer. On balance, the approach proposed by Atrium is preferable, but the export-styled approach would be a more preferable alternative than the status quo, where the service to the Special Contract customer includes excessive assets that can be shown to bear no linkage to the service provided the customer."

QUESTION:

a) Please provide more information regarding the FortisBC example referenced on p. 8 of Mr. Bowman's evidence including how this rate setting methodology alternative could be applied to Centra's cost of service study and the Special Contract class rates. For example, if the FortisBC special contract rates are not cost-based, explain how they are determined.

b) Please discuss whether the proposed alternative to set the Special Contract class rates "*outside the Cost of Service study*" could lead to concerns regarding transparency, justification, and reasonableness for these rates?

ANSWER:

a) and b)

Mr. Bowman is not recommending this alternative and does not have direct experience with the FortisBC Energy example. It is simply noted that Atrium provided this example in CAC/Atrium-I-6a, where “Bypass and Special Contract are revenue credited in the COSS”.

This approach would align well with a common cost of service practice, where revenue from certain utility activities is credited into the Cost of Service study without that party become a “class” of customer. For example, there is no class of customer for pole rental revenues earned by Manitoba Hydro, or exports (off-system sales are often included in a Cost of Service study as a straight revenue).

This view does not preclude the rate being charged to the service in question being regulated or not regulated. The PUB could readily review a highly truncated cost of service style analysis for the Special Contract customer to approve rates focused on the specifically assigned assets in question. Having established that rate, the Cost of Service study could then be run for the entire system with the revenues from that class already locked in.

This might also take a form more similar to the Surplus Energy Program (SEP) for Manitoba Hydro. In that case, the SEP rates are set by their own regulated process. SEP is notionally a “class” in the Cost of Service study, but it only functions as a means to credit the revenues back to the remainder of the system. No SEP rates are set through the Cost of Service study, and any SEP customer who wanted to understand or influence their rate would have no need to be involved in any Hydro Cost of Service analysis, since the rate is not set as a consequence of that study. SEP rates are regulated and by that measure, transparent and reasonable.

REFERENCE: Bowman Evidence pp. 9-10; 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. […]"

(Bowman Evidence pp. 9-10) "The final set of recommendations from Atrium relate to upstream capacity resources. Atrium provides a recommendation that these upstream contracted pipeline and storage capacity resources should be allocated

> using a “seasonal resource stack-based analysis of each pipeline and storage capacity resource’s contribution to the seasonal and peak day demands” of customers. Alternatively, Atrium recommends use of winter season demand in excess of summer season demand. Both methods are consistent with the concept that storage requirements arise due to variations in a customer’s (and the overall system’s) seasonal load, and costs incurred for this purpose should track that seasonal load contribution.”

QUESTION:

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?

ANSWER:

a) and b)

It is Mr. Bowman’s understanding that the primary cost driver of the storage and US pipeline costs are the seasonal volumes needing to be stored, not the peak day. If this is not correct, it may be appropriate to include a small peak day allocator into the cost allocation for these components, but similar to the winter excess allocator, it should be winter peak in excess of non-winter peak (i.e., the peak that drives storage costs versus the peak that does not drive any need for storage and related US pipeline capacity).

This would only be appropriate for those costs incurred to meet peak day over and above what is already needed to meet broad winter supply obligations.

REFERENCE: Bowman Evidence p. 18; PUB MFR 10-Attachment; PUB/Atrium I-8

PREAMBLE:

(Bowman Evidence, p. 18) "In terms of approach to updating the study, CGM's previous approach was to allocate the UFG percentages to each of the customer classes. It appears **this approach may under-recognize the different characteristics of the distribution and transmission systems, and the much greater UFG that is expected to arise on the distribution system and for customers connected to the distribution system**. For example, such items as theft or seized meters, factors that can be present and go unnoticed for a time on distribution systems, are not a factor on transmission systems. On a transmission system there is simply less quantity of conveyances to leak, less points to be affected by outside factors like auto collisions, less places for bad meters to arise. **Atrium submits that "establishing a class-level allocation is unnecessary." This is generally true**, but in the alternative establishing a distinct allocation of UFG associated with customers who make extensive use of the distribution system, versus customer who mainly or solely make use of the transmission system, is necessary to achieve accuracy and fairness." [emphasis added]

(PUB MFR 10-Attachment, p.8 of 14, lines 20-22) "The physical escape of gas from the utility system is a relatively small contributor to overall UFG. Overall, it is estimated that between 5% and 10% of total UFG can be attributed to physical loss factors."

(PUB MFR 10-Attachment, p.9 of 14, lines 26-31) "It is estimated that the volume of gas lost through fugitive and vented emissions and the establishment of line pack is approximately [commercially sensitive information redacted] 103 m3 on an annual basis. This amount of loss was first split between transmission and distribution, and then distributed between customer classes by use of capacity allocators that exist in the current cost allocation model. The results are reported in the table below."

(PUB MFR 10-Attachment, pp.2 of 14, lines 19+) "Large volume customers in the High Volume Firm, Interruptible, Main Line and Power Station classes are served either through positive displacement rotary meters or through inferential turbine meters. In all cases, these meters are equipped with sophisticated on-site flow computers that correct for absolute gas pressure and flowing gas temperatures in real time. These units are also connected via telemetry to Centra's gas control facility, where operating conditions and meter readings can be obtained on a daily basis.

The metering requirements for the Special Contract Class customer are unique to the Centra system in several ways. This customer consumes almost [commercially sensitive information redacted] of the overall annual system throughput, and its usage pattern is characterized by extremely consistent flow. It requires un-odorized gas directly from the Centra transmission system at transmission line pressure. It is served through a pair of close tolerance auto-correcting turbine meters, that enable Centra to switch from one meter run to another if required. Centra calibrates the pressure and temperature correction apparatus once each month to ensure optimum accuracy. This customer has invested in a redundant check metering facility in series with the Centra metering station. Both metering stations are connected to the Centra SCADA system and are monitored daily. The potential for an out-of-range meter error is fairly low compared to other customer classes."

QUESTION:

a) Is it Mr. Bowman's view that Centra does not differentiate between the expected contributions to UFG from the transmission system compared to the distribution system? If so, please explain in light of PUB MRF 10 - Unaccounted For Gas Review, specifically pages 2, 3, 8, 9 (and others).

b) What additional considerations should Centra apply in order to fully differentiate the contributions to UFG from the transmission and distribution systems?

c) Please reconcile Mr. Bowman's agreement with Atrium's statement: "*establishing a class-level allocation is unnecessary" with his request to "[establish] a distinct allocation of UFG associated with customers who make extensive use of the distribution system, versus customer who mainly or solely make use of the transmission system*".

d) Does Mr. Bowman agree with Atrium's view (in PUB/Centra I-8b) that: "*UFG is a system-wide phenomenon, the cost of which should be recovered in a uniform system-wide fashion, similar to the weighted average commodity cost of gas.*"

ANSWER:

a) Mr. Bowman is not entirely clear on the specific methods used by Centra to allocate UFG, particularly given the document justifying the allocation is now almost 20 years old and the scale of UFG has changed materially on Centra's system since that time (also parts of the document are redacted). It is noted that Centra allocates all UFG at the Transmission level (Appendix 3), though it may allocate larger shares to smaller customers to reflect an implicit recognition of the distribution component of their losses (as suggested at IGU-Centra-6(d))

If a full and up-to-date customer class allocation is performed that, in effect, allocates UFG fairly to each customer class, recognizing that distribution system customers are fully responsible for distribution level UFG, then fair cost allocation has been achieved. It is a concern however that Atrium indicates no customer class based UFG allocation is required – absent this customer class approach to UFG, a transmission versus distribution functionalization will be required.

b) If customer class-specific allocations are not used, measuring should be used to assist with UFG allocation to the respective transmission and distribution systems where possible (e.g., at system transfer points). Analysis of remaining factors should focus on transmission system versus distribution system components.

c) There are two alternative means to allocate UFG. One is to prepare estimates by customer class, and the other is to prepare estimates by functionalized system.

Mr. Bowman understand Centra uses the former and intends to continue using the former. Other than a need to update the inputs and analysis, this approach appears reasonable.

d) If not, then one cannot revert to some simple percentage-based allocation, when different customers use components of the system differently. The UFG would have to be functionalized to the respective transmission versus distribution systems and recovered in each case only from those customers that use that system.UFG is a system-wide phenomenon but does not occur in equal proportions on and across each component or function of the system. Most items in the cost of service study are system-wide phenomenon, but the study still seeks to define which customers use which proportion of the assets that drive the costs to arise.

REFERENCE: Bowman Evidence p. 2; PUB/CENTRA I-3a-f; Derksen-Rainkie Evidence pp.5, and 36-38; PUB/ATRIUM I-9a-b; CAC/CENTRA I-7b; Appendix 3 (p. 30 of 32) of Centra's COSSMR Application

PREAMBLE:

(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."

(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."

QUESTION:

a) Please provide IGU's expert's position on whether Centra should treat demand-side management as a system resource and functionalize, classify, and allocate the DSM costs on this basis.

b) Please provide IGU's expert's position on how Centra should functionalize, classify, and allocate the DSM costs if DSM were to be treated as a system resource.

ANSWER:

a) and b)

No, natural gas DSM is not a system resource or a system cost.

Efficiency Manitoba's filing on this matter was clear –natural gas DSM programs were expected to cost an NPV of $59.827 million[1] but save $74.216 million in NPV of commodity and transportation costs that would largely flow through to those participating customers through reduced usage by the participant or their class.[2] So, on direct costs alone, if the DSM costs were allocated to the participating classes, the customers would still be experiencing savings.

Natural gas DSM is causing further cost alignment issues, in that these same participating customers will not only save on commodity and transportation, but they will also avoid contributing as much to the fixed costs of Centra's transmission, distribution and other functions. The total bill benefit, inclusive of all components provided these customers will be $143.505 million on an NPV basis.[3] In other words, as a result of the DSM program (even if the programs were free), non-participants would see their bills increase as they were required to make up the amounts that the DSM participants previously contributed to pay for system fixed costs like distribution.

The question that is left is how to best allocate the $59,827 million (NPV) spent to achieve these individual customer and class benefits. It is not a benefit to the system generally – it is a benefit to participants for which they not only captured all the savings, but also managed to cost shift some fixed costs to non-participants.

[1] Efficiency Manitoba 2020-2023 Efficiency Plan, PUB/EM-I-11a-b page 7 of 11.
[2] Efficiency Manitoba 2020-2023 Efficiency Plan, PUB/EM-I-11a-b page 7 of 11, ignoring interactive effects which are an electricity factor, not a natural gas factor.
[3] Efficiency Manitoba 2020-2023 Efficiency Plan, PUB/EM-I-11a-b page 9 of 11.

REFERENCE: Bowman Evidence p. 8; Appendix 1 (Atrium Report) pp. A-8 and A-19

PREAMBLE:

(Bowman Evidence p.8) "Atrium's third recommendation is to directly assign high pressure transmission plant to customers where appropriate, and provide no other allocation of the broader transmission system. This is referenced in regard to the Special Contract customer as well as the Power Stations class. As noted above, this type of approach is entirely consistent with COS principles outlined in the NARUC Gas Distribution manual, and with the concept of customers paying for cost incurrence. […] But direct assignment of costs is a preferred method that increases fairness where the assets or costs can be directly linked to a user or class. […] In the case of the Special Contract customer, direct assignment is not only possible, but also clearly rational as a means to allocate costs […]"

Pages A-8 and A-19 of Atrium's Report (Application Appendix 1, PDF pp. 42 and 53) show a transmission feeding a single Mainline customer in Minnedosa with no service to other customers.

QUESTION:

a) In the above-reference example of a customer situated to be the only customer on a segment of main, would it be appropriate to directly assign the cost of this specific transmission main and related facilities to this customer and exclude other transmission plant allocations?

b) Would such a direct assignment be feasible if this customer remained in the Mainline class, or would a separate special contract class need to be established to effect the direct assignments and unique rates?

ANSWER:

a) and b)

Mr. Bowman is not privy to a number of facts that would aid in making the determination as to whether a direct allocation to this customer is appropriate.

It is noted, however, that the concept of Special Contracts being an alternative to Mainline Firm class for any given customer was identified as a core premise from the outset of that class. Consider the following extract from MFR 7 Attachment, which was the 1996 “Centra’s Position on Rate Design” paper (page 7 of 8):

> Centra has determined that the Main Line class should have very restrictive eligibility requirements. In order to make the rate cost-reflective, and applicable to the specific situation of these handful of customers, it is necessary to restrict the class to those customers that are clearly served directly and exclusively from the transmission system through dedicated or strictly identifiable facilities. For those customers that "almost" qualify for Main Line, or who feel that they would qualify for Main Line service, but for Centra's decision to attach them in a different manner, the option to sign a Special Contract is still available. Centra would consider a Special Contract· with such customers that allows individual circumstances to be reflected. without changing the definition or situation of the tariffed Main Line class. The Board might also achieve greater control over both the Main Line class and these Special Contract customers by having separate mechanisms to define eligibility and cost responsibility.

However, like all major Cost of Service decisions, whether something is appropriate is in part fact-based. For example, it may be relevant whether this customer already paid a major contribution towards the line to be connected, while other customers in their class may not have done the same. It may also be relevant whether the assets dedicated to serving this customer are far more expensive than the average of the transmission-served customers, and whether there is material cross-subsidization within the class as it now exists.

If the situation is not highly unique (size of load, magnitude of assets, etc.), then the customer should be kept in the class to ease ratemaking and likely to improve the stability of rates.