GAS MARKETER GROUP (GMG) (DIRECT ENERGY MARKETING LIMITED,
ONTARIO ENERGY SAVINGS L.P., and
SUPERIOR ENERGY MANAGEMENT GAS L.P.)

Information Request Responses to Ontario Energy Board Staff re: Commodity Pricing, Load Balancing, and Cost Allocation Methodologies for Natural Gas Distributors

Board Staff Interrogatory #1

Interrogatory:

Ref: Gas Marketer Group Evidence Submission (Exhibit E8, E14, E19), page 15

Preamble: The Gas Marketer Group is proposing to move from the current Board approved quarterly rate adjustment mechanism to a monthly rate adjustment mechanism. The evidence states, "With this methodology, the reference price more closely matches the monthly index price, allowing customers to make informed decisions with respect to consumption and service provider."

i. Have the members of the Gas Marketer Group either individually or as a group, undertaken market research studies to assess if Ontario natural gas consumers would be assisted in their decision with respect to consumption and service provider with a monthly rate adjustment mechanism? Please file the supporting studies and the results of the research if available.

ii. Please explain how prices that would fluctuate on a monthly basis would assist customers to evaluate existing longer term supply options such as a 3 or 5 year contract with a retailer at a fixed price.

Response:

i. The GMG has not completed research to determine if natural gas customers will use more frequent price signals yielded from monthly rate changes to adjust their consumption patterns and/ or conservation efforts. However, the GMG respectfully points out that Ontario consumers receive daily price signals with respect to the price of gasoline, and make consumption and conservation choices based on this daily pricing signal. It would follow that customers would make better informed decisions on natural gas consumption if the rate set for natural gas was more reflective of the price of natural gas at the time of consumption.

ii. GMG believes that monthly rate setting by utilities that is reflective of current market prices allows consumers to more easily differentiate between the Default Supply offering made by the utilities, and the competitive offering made by marketers. This is based on utilities offering a variable "default" commodity cost based on a monthly forecasted index, and the Marketers offering fixed rate, long term contracted commodity cost. As customers do not sign contracts to receive service from the utility, and the customer can freely move to a contracted term service, the most basic service, being a monthly floating rate product, should be provided by the utility. If a customer prefers a fixed rate product, a competitive offering would be the solution, and a fixed term contract would be signed. This would make the natural gas price offerings of the utility versus competitive retailers easier to compare and it would be similar to the choice consumers commonly make in the banking market, as described on the bottom of page 3 of the GMG evidence. If no contract is signed, the neutral, open, variable mortgage is the "default choice" in this established "fixed versus variable" choice market.

In addition, cost causation is best served by this distinction because the DSP is best able to match costs to the customers who received the DSP service in the month.

Board Staff Interrogatory #2

Interrogatory:

Ref: Gas Marketer Group Evidence Submission (Exhibit E8, E14, E19), page 4

The evidence states, "…. Furthermore, the long lead time to calculate the QRAM, plus the 3 month nature of the price leads to an exaggerated need of deferral accounts, further distorting the price charged to system customers from the wholesale market price paid by utilities". [Emphasis added]

Please explain how would the proposed monthly rate adjustment mechanism eliminate or reduce the reliance on deferral accounts.

Response:

The proposed monthly rate adjustment mechanism would reduce the reliance on deferral accounts by more closely matching the amount charged to customers to the actual cost of purchases made during the month. By reducing the lag time between the rate filing and the start date of the change in the rate, and reducing the time period covered by the forward curve estimated price, the "unit rate difference" decreases, as illustrated in Figure 5 and Table 8 of the GMG Evidence. This backcast was completed using the actual Union information and methodology, in order to determine what the "unit price difference" would be using the proposed month ahead only reported price from NYMEX as reported on the fifth last business day. This comparison shows how much closer to the actual WACOG the estimate would be based on this proposed methodology. The deferral amounts are exaggerated using the current methodology, as evidenced by the fact that the absolute value of the average QRAM "unit rate difference" is more than twice as large as the MRAM "unit rate difference", as shown in Figure 5 of the GMG Evidence.

Board Staff Interrogatory #3

Interrogatory:

Ref: Gas Marketer Group Evidence Submission (Exhibit E8, E14, E19), page 15

Preamble: The calculation of the Alberta default supply price or Gas Cost Flow-through Rate (GCFR) provided by Direct Energy Regulated Services (DERS) involves a six-step process.

i. In a manner similar to the evidence filed by Enbridge at Exhibit E1, page 41, Table 1, please describe the services offered by DERS to sales and direct purchase customers, where applicable, as it relates to commodity, transportation, and load balancing.

ii. Please indicate whether the GCFR includes the forecast costs of gas acquired for commodity and load balancing.

iii. Please describe the means used by DERS to provide load balancing services to sales and direct purchase customers (if applicable). Does DERS use storage to provide load balancing?

iv. If DERS uses storage for load balancing, please describe the treatment of storage costs from both an accounting and regulatory standpoint.

v. Please describe the daily delivery obligations and the treatment of delivery imbalances (i.e. banked gas account) for direct purchase customers.

Were Enbridge to adopt a methodology similar to the GCFR, how does the Gas Marketer Group propose that Enbridge deals with load balancing costs and price variance attributable to direct purchase customers?

Response:

i.

DERS Services

Alberta Marketplace ATCO Gas Territory (90% of Alberta Marketplace)						
Choice of Service	Commodity	Transport	Load Balancing	Storage	Distribution	Comments
DSP (DE Regulated Services)	✓	✓	✓			No storage allowed for DSP
Competitive Retailers (Energy Savings, DE, ENMAX)	✓	✓	✓	✓		
LDC (ATCO Gas)		✓			✓	Owns the infrastructure
All commodity suppliers are responsible for their own customers, from securing supply, to delivering weather sensitive volumes to the city gates.						

Note that DERS transacts and nominates gas on 3 pipelines: Nova Gas Transmission, ATCO Pipelines North and ATCO Pipelines South plus delivery nominations into the two distribution systems, ATCO Gas South and ATCO Gas North. DERS does not own any firm service on any of these pipelines (with a small exception on ATCO Pipeline that was part of the original purchase agreement with ATCO group from an assigned supply contract).

ii. Yes. The Alberta market has evolved to a point where the Default Supply Provider (DSP) is now being treated as any other competitive retailer. The functionality offered by DERS is the same as any other retail provider. The distributor now advises each market participant (incl. the DSP) of their opening balance and each must balance daily to the agreed upon tolerance.

The GCFR forecast includes the cost of gas required to meet normalized weather load requirements for the forecast regulated customer base for the prompt month. This is an estimate of consumption, with the actual consumption trued up in the next monthly GCFR forecast.

iii. DERS does not provide load balancing for direct purchase customers, as Marketers perform this service for their direct purchase customers. For sales customers, DERS daily balances to a forecast of daily consumption as supplied by ATCO Gas, who is the distributor for all DERS customers. By AUC direction storage cannot be used by the regulated service provider, in this case DERS. DERS balances its own account daily, by buying or selling adequate volumes to be in tolerance. The Alberta YD (yesterday gas) and same day instruments are used to transact either (or both) on system ATCO Pipeline or Nova Inventory Transfer (NIT).

iv. As described above, storage is not allowed by the AUC.

v. ATCO Gas (the distributor) provides DERS and all other Marketers with an estimate for the daily flow of gas. DERS delivers this amount within a tolerance of +/- 5% based on previous day deliveries subject to minimums to accommodate smaller retailers. If DERS or any other supplier fails to deliver this amount, ATCO Gas charges penalties on the volumes required to be transacted by the distributor to bring the supplier into tolerance.

vi. There are different alternatives to address load balancing costs, dependent on the market options available. Two approaches to load balancing that would fit with the GCFR process include:

   a. Enable retailers to manage their own load balancing need by allocating their proportionate share of storage assets (and costs), and;
   b. Those retailers not electing proprietary load balancing services would defer back to utility balancing services as currently offered

There would be two types of load balancing costs in this scenario, and the proposed treatment of each is detailed below:

   a. Load balancing costs for not meeting daily required volumes (within a predetermined tolerance) as dictated by Enbridge, would result in the load balancing costs plus penalties to be borne by any Marketer that failed to deliver the appropriate volume on each day. Sales customer volumes would also need to be delivered as determined on each day.

b. "System" load balancing costs would be borne by all distribution customers. This is balancing beyond the volumes dictated by Enbridge in the daily balancing volumes requested in (a.) above. A dedicated load balance deferral account could be established that would encompass system wide operational need.

Board Staff Interrogatory #4

Interrogatory:

Ref: Gas Marketer Group Evidence Submission (Exhibit E8, E14, E19), page 22

Preamble: The evidence states that "It is questionable as to whether customers are aware of this fact, and if so, would they be accepting of a continual over charging of rates that is returned to them months later without the benefit of interest?"

Given that deferral and variance accounts accrue interest at the prescribed short term interest rate, please clarify the above statement?

Response:

The GMG would like to thank Board Staff for pointing out the error in the evidence filed by the GMG, and now recognizes that short term interest rate is paid on PGVA balances. The intent of the statement was to indicate that customers lose access to their capital for periods of time, as a result of the forecasting and disposition methodologies employed by the utilities.

Board Staff Interrogatory #5

Interrogatory:

Ref: Gas Marketer Group Evidence Submission (Exhibit E8, E14, E19), page 15

Preamble: The evidence provides the methodology and supporting schedules used in the calculation of the Alberta default gas supply price or Gas Cost Flow-through Rate as done by Direct Energy Regulated Services.

Please clarify whether in Alberta Direct Energy offers both a regulated and an unregulated natural gas supply service.

Response:

Direct Energy offers both a regulated and unregulated natural gas supply service. The provision of regulated and competitive services is done through separate entities. Direct Energy Regulated Services is a business unit of Direct Energy Marketing Limited, and was established to provide regulated services. Competitive service is provided under the Direct Energy name, through a partnership controlled by Direct Energy Marketing Limited. The relationship between these entities is governed by the Alberta Code of Conduct regulations, established under both the Electric Utilities Act and the Gas Utilities Act.