

## INTRODUCTION AND RELIEF REQUESTED

In the 17 years that FRPO has been represented in deferral disposition proceedings, discovery has included interrogatories followed by technical conferences and/or settlement conferences, with some extending to oral hearings and submissions in some years of significant disputes. This current deferral disposition proceeding was truncated to one round of interrogatory responses followed by submissions. We had anticipated that there would be a technical conference and/or a settlement conference. Our initial review of the interrogatory responses left us with a number of unanswered questions, but we did not know the significance of the issue until further research.

In this submission, FRPO could have asked EGI to provide background evidence in support of its numbers however this evidence would be inappropriate for reply argument and would not be able to be tested by intervenors and the Board. Without the ability to clarify the responses provided to our interrogatories, we have initiated research to strive to understand current responses by using prior responses provided by Enbridge Gas Distribution Inc. (EGDI) and Union Gas Ltd. (UGL) from past proceedings and available market information.

As a result of this effort, we urge the Board to make findings on upstream optimization on an interim basis to allow further discovery at a subsequent proceeding – ideally in the 2025 disposition proceeding which should be initiated in a matter of months. The following analysis demonstrates our concern that we do not have the ability or requisite information to understand completely how Enbridge arrived at the resulting proposed dispositions. Respectfully, we do not believe the Board has sufficient evidence to make a final determination and would be assisted by further discovery including potentially an oral hearing as a result of discovery that could be part of the 2025 disposition proceeding that included the Upstream Optimization results from the 2024 year.

In addition, we submit that the spending in the Enhanced Distribution Integrity Management Program (EDIMP) should be deferred until after EGI files evidence of the efficacy of the investments based upon the Settlement Proposal in phase 1 of the rebasing proceeding.

## PEAK ASSET PLANNING RESULTS IN UNDERUTILIZED CAPACITY

The primary design criterion for transportation capacity is the demand on the Peak (or Design) day for the geographical region for which the utility has planned. As a result, there is unutilized capacity for that region on non-peak days. Historically utilities have been incented to reduce the cost of the unutilized capacity. This effort is usually

accomplished by either releasing the capacity for another party to utilize it or using the capacity to exchange gas for a third party with the utility being compensated for the transactions. Given the respective regulatory evolutions for each of the EGDI and UGL legacy utilities, the companies operated under different accounting approaches to strive for the cost of mitigation.

In pursuit of understanding their determinations, we asked for “an explanation and the calculation of net revenue for January 2024 for both EGD and UGL assets.”<sup>1</sup> We asked for January as due to gas demand, the market is active seeking gas to meet the demand and the utility often has surplus capacity given that few days are actually Peak or Design Days. While the response provided a very brief generic listing of categories of expenses deemed to be incremental, there was little specificity and no calculation provided to create understanding. One of the key categories is tolls which depending on how these expenses have been delineated as incremental, there may be a risk of incremental recovery. There is little specific evidence in this proceeding of the methodologies used in utility transactions for mitigation and the answer in FRPO-4 is, in our view, woefully deficient.

### **EGI has NOT Reconciled Removal of UDC Charges from QRAM**

In the case of UGL, the utility plan for unabsorbed demand charges (UDC) and incorporate recovery of those costs in delivery rates. However, the cost of the transport is recovered through gas commodity transport rates which are reconciled in the QRAM process. Given the fact that the amount of EDC and the amount of capacity that could be released varies, UGL places the fall transportation demand charge in its rates and provides a compensating adjustment under 179-108 for the monthly amount of cost.

In FRPO-6, we asked EGI to “show how those costs were removed from the PGVA to eliminate the risk of double counting.” EGI provided the “net UDC costs” as defined by the embedded footnote. To understand the total net UDC for a month, we aggregated the individual paths across the three UGL rate zones for July 2024 resulting in a total of \$2.22M. Comparing the QRAM filing for Q1 of 2025<sup>2</sup> to ensure complete year-end accounting, one can see that Enbridge booked \$0.975M for the month of July. It is possible that the definition of net UDC is incorrect in the footnote but clearly the numbers do not demonstrate that all of the costs have been removed through the QRAM process. This difference is but one example of numbers that have not been reconciled as requested and ought to be explained before final clearing.

---

<sup>1</sup> Exhibit I.FRPO-4

<sup>2</sup> EB-2025-0078, Exhibit E, Tab 1, Schedule 2, Page 1 (included as Attachment 1 for the convenience of the reader).

**EGI Transacted 2024 Capacity Releases Without QRAM Adjustment**

EGI does not report on capacity release for its respective delivery areas in the EGD rate zone. However, that does not mean that capacity to the EGD rate zone is not released by the utility. To assess the significance of these releases, we accessed the contract demand energy reports from TCPL<sup>3</sup>. TCPL posts a monthly report showing the temporary assignments (capacity released on a temporary basis) by each shipper on a monthly basis. We have aggregated the total capacity held by EGI from Parkway to its respective EDA rate zones and monthly assignments by the utility to third parties in 2024 in the following table.

2024 EGI PARKWAY-EDA CAPACITY RELEASES from TCPL CDE REPORTS

TOTAL (GJ/D)	184,765 *	408,725
MONTH	PARKWAY-UNION EDA (GJ/D)	PARKWAY-EGD EDA (GJ/D)
JANUARY	1,262	0
FEBRUARY	1,262	0
MARCH	1,262	0
APRIL	1,262	187,570
MAY	1,262	187,570
JUNE	1,262	229,772
JULY	1,262	229,772
AUGUST	1,262	229,772
SEPTEMBER	1,262	187,570
OCTOBER	1,262	187,570
NOVEMBER	1,262	0
DECEMBER	1,262	0
*INCLUDES STS & EMB		

While EGI does not report on its EGD rate zone assignments, it is abundantly clear that for the non-heating months, EGI releases significant quantities of capacity. Yet, there is no compensating PGVA adjustment in the QRAM filing<sup>4</sup> for the months where when EGI has assigned about half of its Parkway to EGD EDA capacity.

<sup>3</sup> <https://www.tccustomerexpress.com/3531.html> provides TCPL postings of monthly assignments by all shippers.

<sup>4</sup> EB-2025-0078, Exhibit C, Tab 1, Schedule 1, Page 1 (included as Attachment 2 for the convenience of the reader).

Since there is very little on the record to explain how EGI ensures that net margins are calculated appropriately for this capacity, we went back to the last significant proceeding on the issue of exchanges and assignments. In the 2012 Deferral Disposition proceedings, intervenors were very concerned how the utilities were managing and accounting for transportation capacity. This concern was heightened given what was learned about UGL's accounting for "Return on Purchased Assets" which was denied by the Board given that the subject "assets" were actually storage contracts that were already expensed.<sup>5</sup> In the 2012 Disposition proceeding, CME asked questions about EGI's accounting of transactional services.<sup>6</sup> We make two important observations when comparing those responses and the current record in this proceeding:

- The detail provided in the response ought to have been provided in support of our inquiry in FRPO-4. Since the evidentiary portion of the proceeding is over, FRPO would seek similar specific evidence in a subsequent proceeding.
- If the accounting that is described in the response to CME interrogatories, specifically in Schedule 6 c), is still in place, there is insufficient evidence to understand how ratepayers are kept whole.

Given that in FRPO-4 EGI included tolls in their generic description of the determination of net revenue, further evidence is required to ensure the appropriate allocations are made between ratepayer and shareholder for the costs of this transportation.

### **EGI's Evidence Capacity Releases does NOT Match TCPL Assignments**

An additional area of reconciliation that is disconcerting is the lack of alignment between EGI's reported capacity releases for the UGL rate zone and TCPL's posting of assignments. TCPL reports that EGI assigned 1,292 GJ/d of Parkway to Union EDA capacity for each month of 2024. This assignment does not show up in the UDC Volume occurred in FRPO-6 and there is insufficient UDC shown in January and February of 2024 in the QRAM filing<sup>7</sup> to account for this assignment. Clarity on this issue should be achieved with additional discovery to ensure appropriate responsibility for the transportation costs.

---

<sup>5</sup> EB-2011-0038, dec\_order\_Union\_20120120, pg. 27-30

<sup>6</sup> EB-2013-0046, Exhibit I, Tab 5, Schedules 4-6

<sup>7</sup> EB-2024-0326, Exhibit E, Tab 1, Schedule 2, Page 1, column (h)

## EDIMP DISPOSITIONS OUGHT TO AWAIT BENEFITS EVIDENCED

During the first phase of rebasing, EGI and ratepayer representatives agreed to a \$12.5M budget for EDIMP. This higher than the EGI-proposed figure was premised based upon specific expectations of showing value in Asset Life Extension as described in the Settlement Proposal<sup>8</sup> approved by the Board:

*Enbridge Gas will provide annual reporting on actual DIMP/EDIMP spending, setting out the work done (and associated costs), listing the projects/facilities where work was done, describing what facilities work was deferred or avoided or otherwise impacted as a result and discussing the cost/benefit analysis of the DIMP/EDIMP work done during the past year.*

However, the evidence presented does not inform what facilities work was deferred or avoided nor does the evidence examine the cost/benefit analysis of the work undertaken. In our view, it does not even address what incremental work was driven by the goal of Asset Life Extension. EGI states that the evaluation of alternatives would be done by the end of 2025 so we do not understand why there is not better evidence on the value of the work that could have been provided.<sup>9</sup> In our view, the dispositions from this account ought to be deferred until the value of these costs are evidenced aligned with the Settlement Proposal.

ALL OF WHICH IS RESPECTFULLY SUBMITTED ON BEHALF OF FRPO,



Dwayne R. Quinn

Principal

DR QUINN & ASSOCIATES LTD.

Attach.

---

<sup>8</sup> EB-2022-0200, Exhibit O1, Tab 1, Schedule 1, Page 56

<sup>9</sup> Exhibit G, Tab 4, Schedule 1, Page 12

**EB-2025-0155**  
**EGI 2024 Deferral and Variance Account**  
**Dispositions**

**ATTACHMENT 1**  
**to**  
**FRPO Submissions**

**GRAM Filing Showing Monthly Commodity Adjustments for**  
**UGL Rate Zones**

Union Rate Zones  
 Summary of Gas Supply Deferral Accounts

Line No.	Particulars	Union North West PGVA (179-147) (\$000's) (1) (a)	Union North East PGVA (179-148) (\$000's) (2) (b)	Union North West Tolls & Fuel (179-145) (\$000's) (3) (c)	Union North East Tolls & Fuel (179-146) (\$000's) (4) (d)	South PGVA (179-106) (\$000's) (5) (e)	Inventory Revaluation (179-109) (\$000's) (6) (f)	Load Balancing & Spot Gas Purchases (179-107) (\$000's) (7) (g)	Unabsorbed Demand Costs (179-108) (\$000's) (8) (h)	Total (\$000's) (i)=sum of (a) to (h)
1	April, 2024	\$ (2,308)	\$ (279)	\$ 249	\$ (420)	\$ (5,931)	\$ 26,334	\$ -	\$ 3,009	\$ 20,654
2	May	\$ (1,929)	\$ 208	\$ (36)	\$ (623)	\$ (1,294)	\$ 133	\$ -	\$ 2,003	\$ (1,538)
3	June	\$ (791)	\$ 565	\$ (225)	\$ (334)	\$ (6,253)	\$ 120	\$ -	\$ 1,085	\$ (5,833)
4	July, 2024	\$ (823)	\$ 551	\$ (515)	\$ (574)	\$ (2,991)	\$ (18,533)	\$ -	\$ 975	\$ (21,911)
5	August	\$ (863)	\$ (1,148)	\$ (551)	\$ (685)	\$ (7,169)	\$ 33	\$ -	\$ 634	\$ (9,749)
6	September	\$ (1,381)	\$ (676)	\$ (401)	\$ (135)	\$ (12,164)	\$ 39	\$ -	\$ 104	\$ (14,615)
7	October, 2024	\$ (2,407)	\$ 137	\$ 140	\$ (290)	\$ (4,306)	\$ 8,665	\$ -	\$ 567	\$ 2,506
8	November	\$ (1,187)	\$ 478	\$ 522	\$ (139)	\$ (488)	\$ 61	\$ -	\$ 377	\$ (377)
9	December	\$ 6,247	\$ (4,252)	\$ 2,028	\$ 3,566	\$ 16,266	\$ 56	\$ -	\$ 341	\$ 24,251
10	January, 2025	\$ (2,620)	\$ 3,185	\$ 375	\$ (243)	\$ 19,106	\$ (11,708)	\$ -	\$ 362	\$ 8,458
11	February	\$ (722)	\$ 3,808	\$ 1	\$ (53)	\$ 20,441	\$ 38	\$ -	\$ -	\$ 23,512
12	March	\$ 430	\$ 6,191	\$ 58	\$ (15)	\$ 24,490	\$ 38	\$ -	\$ -	\$ 31,192
13	Total (Lines 1 to 12)	\$ (8,354)	\$ 8,767	\$ 1,644	\$ 54	\$ 39,708	\$ 5,275	\$ -	\$ 9,457	\$ 56,550
<b>Current QRAM Period</b>										
14	April, 2025	\$ (881)	\$ 1,386	\$ (18)	\$ (372)	\$ (442)	\$ (24,146)	\$ -	\$ -	\$ (24,472)
15	May	\$ (1,126)	\$ 1,074	\$ (14)	\$ (385)	\$ (2,180)	\$ -	\$ -	\$ -	\$ (2,631)
16	June	\$ (1,013)	\$ 1,133	\$ (9)	\$ (371)	\$ (1,041)	\$ -	\$ -	\$ -	\$ (1,301)
17	July, 2025	\$ (901)	\$ 1,401	\$ (8)	\$ (383)	\$ 2,192	\$ -	\$ -	\$ -	\$ 2,301
18	August	\$ (826)	\$ 1,301	\$ (7)	\$ (381)	\$ 2,303	\$ -	\$ -	\$ -	\$ 2,389
19	September	\$ (418)	\$ 611	\$ (9)	\$ (370)	\$ (1,655)	\$ -	\$ -	\$ -	\$ (1,841)
20	October, 2025	\$ (327)	\$ 451	\$ (9)	\$ (380)	\$ (1,899)	\$ -	\$ -	\$ -	\$ (2,164)
21	November	\$ 480	\$ 944	\$ 6	\$ (110)	\$ 5,577	\$ -	\$ -	\$ -	\$ 6,898
22	December	\$ 1,258	\$ 2,989	\$ 22	\$ (84)	\$ 17,035	\$ -	\$ -	\$ -	\$ 21,221
23	January, 2026	\$ 1,541	\$ 4,017	\$ 31	\$ (65)	\$ 24,462	\$ -	\$ -	\$ -	\$ 29,986
24	February	\$ 1,335	\$ 2,832	\$ 23	\$ (71)	\$ 18,324	\$ -	\$ -	\$ -	\$ 22,442
25	March	\$ 887	\$ 1,842	\$ 7	\$ (78)	\$ 6,900	\$ -	\$ -	\$ -	\$ 9,558
26	Total (Lines 14 to 25)	\$ 9	\$ 19,980	\$ 15	\$ (3,048)	\$ 69,577	\$ (24,146)	\$ -	\$ -	\$ 62,386

\* Reflects actual information.  
 Notes:

- (1) See page 2.
- (2) See page 3.
- (3) See page 4.
- (4) See page 4.
- (5) See page 5.
- (6) See page 6.
- (7) See page 7.
- (8) Union is not proposing to recover the deferral balance for the Unabsorbed Demand Charge (Account No. 179-108) deferral account in the current QRAM.

**EB-2025-0155**  
**EGI 2024 Deferral and Variance Account**  
**Dispositions**

**ATTACHMENT 2**  
**to**  
**FRPO Submissions**

**QRAM Filing Showing Transportation Costs for**  
**EGD Rate Zones**

Union Rate Zones  
 Summary of Gas Supply Deferral Accounts

Line No.	Particulars	Union North West PGVA (179-147) (\$000's) (1) (a)	Union North East PGVA (179-148) (\$000's) (2) (b)	Union North West Tolls & Fuel (179-145) (\$000's) (3) (c)	Union North East Tolls & Fuel (179-146) (\$000's) (4) (d)	South PGVA (179-106) (\$000's) (5) (e)	Inventory Revaluation (179-109) (\$000's) (6) (f)	Load Balancing & Spot Gas Purchases (179-107) (\$000's) (7) (g)	Unabsorbed Demand Costs (179-108) (\$000's) (8) (h)	Total (\$000's) (i)=sum of (a) to (h)
1	April, 2024 *	\$ (2,308)	\$ (279)	\$ 249	\$ (420)	\$ (5,931)	\$ 26,334	\$ -	\$ 3,009	\$ 20,654
2	May *	\$ (1,929)	\$ 208	\$ (36)	\$ (623)	\$ (1,294)	\$ 133	\$ -	\$ 2,003	\$ (1,538)
3	June *	\$ (791)	\$ 565	\$ (225)	\$ (334)	\$ (6,253)	\$ 120	\$ -	\$ 1,085	\$ (5,833)
4	July, 2024 *	\$ (823)	\$ 551	\$ (515)	\$ (574)	\$ (2,991)	\$ (18,533)	\$ -	\$ 975	\$ (21,911)
5	August *	\$ (863)	\$ (1,148)	\$ (551)	\$ (685)	\$ (7,169)	\$ 33	\$ -	\$ 634	\$ (9,749)
6	September *	\$ (1,381)	\$ (676)	\$ (401)	\$ (135)	\$ (12,164)	\$ 39	\$ -	\$ 104	\$ (14,615)
7	October, 2024 *	\$ (2,407)	\$ 137	\$ 140	\$ (290)	\$ (4,306)	\$ 8,665	\$ -	\$ 567	\$ 2,506
8	November *	\$ (1,187)	\$ 478	\$ 522	\$ (139)	\$ (488)	\$ 61	\$ -	\$ 377	\$ (377)
9	December *	\$ 6,247	\$ (4,252)	\$ 2,028	\$ 3,566	\$ 16,266	\$ 56	\$ -	\$ 341	\$ 24,251
10	January, 2025	\$ (2,620)	\$ 3,185	\$ 375	\$ (243)	\$ 19,106	\$ (11,708)	\$ -	\$ 362	\$ 8,458
11	February	\$ (722)	\$ 3,808	\$ 1	\$ (53)	\$ 20,441	\$ 38	\$ -	\$ -	\$ 23,512
12	March	\$ 430	\$ 6,191	\$ 58	\$ (15)	\$ 24,490	\$ 38	\$ -	\$ -	\$ 31,192
13	Total (Lines 1 to 12)	\$ (8,354)	\$ 8,767	\$ 1,644	\$ 54	\$ 39,708	\$ 5,275	\$ -	\$ 9,457	\$ 56,550
<b>Current QRAM Period</b>										
14	April, 2025	\$ (881)	\$ 1,386	\$ (18)	\$ (372)	\$ (442)	\$ (24,146)	\$ -	\$ -	\$ (24,472)
15	May	\$ (1,126)	\$ 1,074	\$ (14)	\$ (385)	\$ (2,180)	\$ -	\$ -	\$ -	\$ (2,631)
16	June	\$ (1,013)	\$ 1,133	\$ (9)	\$ (371)	\$ (1,041)	\$ -	\$ -	\$ -	\$ (1,301)
17	July, 2025	\$ (901)	\$ 1,401	\$ (8)	\$ (383)	\$ 2,192	\$ -	\$ -	\$ -	\$ 2,301
18	August	\$ (826)	\$ 1,301	\$ (7)	\$ (381)	\$ 2,303	\$ -	\$ -	\$ -	\$ 2,389
19	September	\$ (418)	\$ 611	\$ (9)	\$ (370)	\$ (1,655)	\$ -	\$ -	\$ -	\$ (1,841)
20	October, 2025	\$ (327)	\$ 451	\$ (9)	\$ (380)	\$ (1,899)	\$ -	\$ -	\$ -	\$ (2,164)
21	November	\$ 480	\$ 944	\$ 6	\$ (110)	\$ 5,577	\$ -	\$ -	\$ -	\$ 6,898
22	December	\$ 1,258	\$ 2,989	\$ 22	\$ (84)	\$ 17,035	\$ -	\$ -	\$ -	\$ 21,221
23	January, 2026	\$ 1,541	\$ 4,017	\$ 31	\$ (65)	\$ 24,462	\$ -	\$ -	\$ -	\$ 29,986
24	February	\$ 1,335	\$ 2,832	\$ 23	\$ (71)	\$ 18,324	\$ -	\$ -	\$ -	\$ 22,442
25	March	\$ 887	\$ 1,842	\$ 7	\$ (78)	\$ 6,900	\$ -	\$ -	\$ -	\$ 9,558
26	Total (Lines 14 to 25)	\$ 9	\$ 19,980	\$ 15	\$ (3,048)	\$ 69,577	\$ (24,146)	\$ -	\$ -	\$ 62,386

\* Reflects actual information.

Notes:

- (1) See page 2.
- (2) See page 3.
- (3) See page 4.
- (4) See page 4.
- (5) See page 5.
- (6) See page 6.
- (7) See page 7.
- (8) Union is not proposing to recover the deferral balance for the Unabsorbed Demand Charge (Account No. 179-108) deferral account in the current QRAM.

**EB-2025-0155**  
**EGI 2024 Deferral and Variance Account**  
**Dispositions**

**ATTACHMENT 3**  
**to**  
**FRPO Submissions**

**EGDI IRR's to CME in EB-2013-0046 for**  
**EGD Rate Zones**

CME INTERROGATORY #4

INTERROGATORY

Transactional Services Deferral Account ("TSDA")

Ref: Exhibit A, Tab 2, Schedule 1, Appendix A, line 16  
Exhibit C, Tab 1, Schedule 6, pages 1 to 21, Appendices A to D

The Board's Decision and Order in the EB-2012-0055 proceeding indicates that revenues EGD recorded in the TSDA in 2011 included the following:

- Base Exchanges of \$11.8M
  - Capacity Release Exchanges \$3.0M
  - STS-RAM Third Party Exchanges \$0.8M
- For a total of \$15.6M

The information at Exhibit C, Tab 1, Schedule 6, Appendix B, page 1 under the heading "Transportation Optimization" indicates that EGD achieved \$39.4165M of exchange related revenue in 2012. This information suggests that 2012 Base Exchange revenue was in the order of \$20.8148M and up from \$11.8M in 2011. Capacity Release Exchanges appear to have increased more than six fold from about \$3M in 2011 to \$18.6298M in 2012. In connection with this evidence, please provide the following additional information:

- (a) Please describe the changes in circumstances between 2011 and 2012 which operated to produce such a significant increases in Base and Capacity Release Exchanges.
- (b) Please provide the breakdown of the Transportation Optimization revenue recorded by EGD in each of the years 2008, 2009, and 2010 segregated between Base Exchanges, Capacity Release Exchanges, and STS-RAM Third Party Exchanges.
- (c) Please provide the total number of exchange transactions in which EGD engaged in each of the years 2008 to 2012 segregated between Base

Witnesses: K. Culbert  
M. Giridhar  
J. LeBlanc  
D. Small  
R. Small

Exchanges, Capacity Release Exchanges and ST-RAM Third Party Exchanges.

- (d) Are the amounts related to 2012 Capacity Release Exchanges, which EGD has recorded in the TSDA rather than as gas costs reductions, nevertheless, being allocated in the same proportion and to the same rate classes to whom EGD allocates its Upstream Pipeline Transportation costs? If so, then to what classes are these amounts allocated and in what proportions?

## RESPONSE

- a) The increase in 2012 Base Exchange revenue and 2012 Capacity Release Exchange revenue versus the comparable 2011 revenues are a result of two factors – transaction volume and price differential. As discussed in the response to FRPO Interrogatory #12 at Exhibit I, Tab 7, Schedule 12, a determining factor in whether or not a Base Exchange or a Capacity Release Exchange will be entered into is the utilization of STS throughout the winter and subsequent need to accumulate STS credits in the summer. A colder than normal winter in 2011 drove a need for more STS credits in the summer of 2011 while a warmer than normal winter in 2012 resulted in less of a need for STS credits to be accumulated in the summer of 2012 thereby permitting Gas Control to authorize more Base Exchanges and Capacity Releases in 2012. Notwithstanding that EGD was willing to enter into more exchange deals in 2012 the Company still relied upon third parties and their interest in entering into these types of transactions. From a third party perspective what determines whether or not they are interested in entering into a transaction would be based upon the market prices at the pertinent receipt and delivery points.

For example if one were to compare a 2012 Base Exchange and a 2011 Base Exchange transaction one could simply compare the market prices between two points on the day in each year. For example a look at the Iroquois spot price and the Dawn spot price for August 15, 2012 shows US\$3.335/MMBTU at Iroquois and US\$3.005 at Dawn or roughly a US\$0.30 differential. The same two price points on the spot market on August 15, 2011 were US\$4.575/MMBTU at Iroquois and US\$4.470 at Dawn or roughly a US\$0.10 differential of equal volume in 2012 versus 2011 would likely generate 3 times the revenue.

Witnesses: K. Culbert  
M. Giridhar  
J. LeBlanc  
D. Small  
R. Small

- b) and c) Please see the attached table.
- d) Confirmed - amounts are allocated in the same manner through the TSDA as they would be through gas cost reductions. The amount related to 2012 Capacity Release Exchanges is provided in evidence, at Exhibit C, Tab 2, Schedule 2, page 3, Line 1, Column 2. This total is net of the ratepayer guarantee and includes a forecast of interest on the account up to January 1, 2014. The amount is allocated to Sales and Western Transportation Service customers, in Column 2, Lines 1.1 to 1.12, of the Allocation portion of the table, as Sales and Western Transportation Service customers are those who receive Transportation Service from the Company. In this manner, the credit from TS Capacity Release Exchanges is allocated to customers in the same manner as Transportation costs are recovered through rates.

Witnesses: K. Culbert  
M. Giridhar  
J. LeBlanc  
D. Small  
R. Small

Transportation Optimization

	Base Exchanges			STS Ram			Capacity Release			Total		
	Volume	# of Deals	Associated Revenue (\$ millions)	Volume	# of Deals	Associated Revenue (\$ millions)	Volume	# of Deals	Associated Revenue (\$ millions)	Volume	# of Deals	Associated Revenue (\$ millions)
2008	113,452,413	1,401	11.1	1,596,950	29	0.3	0	-	-	115,049,363	1,430	11.4
2009	99,306,548	2,033	9.1	1,768,421	26	0.5	8,055,765	2	0.5	109,130,734	2,061	10.2
2010	73,741,202	1,640	9.7	2,013,808	30	0.5	8,797,390	2	1.3	84,552,400	1,672	11.4
2011	65,013,539	2,590	11.8	1,166,439	19	0.8	8,792,832	2	3.0	74,972,810	2,611	15.6
2012	81,160,158	3,295	19.9	2,144,419	48	0.9	24,460,474	20	18.6	107,765,051	3,363	39.4

(1) excludes any associated incurred/avoided fuel costs

CME INTERROGATORY #5

INTERROGATORY

Transactional Services Deferral Account ("TSDA")

Ref: Exhibit A, Tab 2, Schedule 1, Appendix A, line 16  
Exhibit C, Tab 1, Schedule 6, pages 1 to 21, Appendices A to D

In the evidence at para.20 of Exhibit C, Tab 1, Schedule 6, EGD provides an example of a Base Exchange where a third party has gas available at a particular point (Dawn) and needs the gas at another point (Iroquois) but does not have a way of getting the gas there. In this scenario where EGD has transportation between Dawn and Iroquois which can accommodate the exchange, EGD will provide the point-to-point exchange of the commodity with the pricing of the service linked to the commodity price spread between the two points. In connection with this example, please provide the following information:

- (a) Is the "buyer" of the commodity exchange the person who has commodity at point A and needs commodity at another point B but has no way to get the commodity from point A to point B?
- (b) Is the "seller" of the exchange service the person who holds commodity at point B and the transportation to support the carriage of the exchange buyer's gas from points A to B to replace the exchange seller's gas which has been provided to the buyer at point B?
- (c) Please provide a copy of the contract which EGD enters into to support a Dawn/Iroquois Base Exchange and include the pricing for the service, along with a demonstration of how that pricing is derived from a commodity price spread between Dawn and Iroquois which is realistically representative.
- (d) Similarly, please provide a copy of the contract which EGD would use to support an Empress/Dawn Base Exchange, whereby EGD receives a third party's gas at Empress and delivers an equivalent amount of gas to the third party at Dawn. Include with this representative contract the price which would be charged for the service based on information which is representative of a typical price spread between the two points.

Witnesses: M. Giridhar  
J. LeBlanc  
D. Small

## RESPONSE

- a) and b) In the context described, a third party marketer who has gas at Dawn but would rather sell it at Iroquois because of a price arbitrage would be considered the “buyer” because they require some means to get that gas to Iroquois. EGD has within its TCPL FT contract the ability to deliver gas at a number of points on TransCanada’s system including Iroquois (other examples may include Chippawa, East Hereford). If on the day or days EGD was planning to divert gas on TCPL back to Dawn for the purpose of injection into storage then EGD could act as a “Seller” in the sense that by giving gas to the counterparty at Iroquois and receiving gas back at Dawn on the day can also benefit from that pricing arbitrage.
- c) and d) A copy of a Transactional Services Agreement can be found in Board Staff Interrogatory # 6 (Exhibit I, Tab 1, Schedule 6). As described in response to CME Interrogatory #4 at Exhibit I, Tab 5, Schedule 4 a comparison of the Dawn spot price and the Iroquois spot price on a particular day provides the value of an exchange transaction that would be completed on a particular day. As an alternative EGD may choose to enter into an exchange transaction using NGX which allows counterparties to trade gas between two points using the NGX bulletin board based on the bid and ask prices of two unknown entities ( a NGX trade example is attached as Appendix A).

Capacity Release Exchange deals are also based upon price spreads but rather than the daily spot price used for the purposes of a Base Exchange a comparison of prices for the forward summer period for NYMEX, AECO basis and Dawn basis are used. Also to be taken into consideration is the value of the FT-RAM credit that a counterparty can receive if it were to leave the FT capacity assigned to them by EGD empty and move gas using TCPL Interruptible Transport to the cheapest point which would be Emerson. EGD personnel would complete an analysis as is demonstrated in the attached example, at Appendix B, at a point in time to calculate the value of a capacity release transaction.

The first step in the calculation would be to determine how much gas could be transported from Empress to Emerson by dividing the potential RAM Credit by the applicable tolls – see item k on the example.

The next step is to determine the value of that volume at Empress and at Emerson – see item #'s l and m of the example. This will determine the value a marketer could obtain by buying and selling the gas between Empress and Emerson.

Witnesses: M. Giridhar  
J. LeBlanc  
D. Small

The next step is to determine the value that can be received by selling the volume provided to the counterparty at Empress versus the cost to buy the replacement or exchange volume at Dawn – see item's n and o of the example.

Item r of the attached schedule represents the net proceeds that would be available after buying and selling gas by a marketer at the various points which then is translated into a unit rate – item s.

This would represent the breakeven point or margin a marketer could obtain if they were able to do the transaction themselves – which they cannot because they do not hold the transport.

Recognizing that a marketer would not be willing to do the transaction for nothing the EGD trader is willing to accept an exchange fee for two to three cents below the value that they have calculated.

The attached table provides a comparison of 2011 and 2012 summer prices that can be used to determine the value associated with a capacity release exchange deal

Witnesses: M. Giridhar  
J. LeBlanc  
D. Small

Date Time	Clearing Account	Company Name	Trader	Type	Trade In Error	Cash Margin	Cleared	Market	Contract Description	Begin Date	End Date	Buy/Sell	Traded Volume	Total Volume	Price	Currency	Unit	Platf orm	TradeId	Spread Indicato	RFQ
7/9/2013 8:20	Enbridge Gas Distribution Inc.	Enbridge Gas Distribution Inc.	Trevor Mitchell	Normal	No		Yes	NGX Phys. FP Spr (US/MM)	Next Day	10-Jul-13	10-Jul-13	Sell	-10,000	-10,000	\$0.24	USD	MMBtu	ICE	50025969/50025970	Yes	No
7/9/2013 8:20	Enbridge Gas Distribution Inc.	Enbridge Gas Distribution Inc.	Trevor Mitchell	Normal	No		Yes	Union-Dawn/TCP-Iroquois	Next Day	10-Jul-13	10-Jul-13	Buy	10,000	10,000	\$4.15	USD	MMBtu	ICE	50025970	Yes	No
7/9/2013 7:50	Enbridge Gas Distribution Inc.	Enbridge Gas Distribution Inc.	Trevor Mitchell	Normal	No		Yes	Iroquois	Next Day	10-Jul-13	10-Jul-13	Sell	-10,000	-10,000	\$4.39	USD	MMBtu	ICE	50021934	Yes	No

Market	Date Time	TradeId	Reg Type	Cleared	Begin Date	End Date	Traded Volume	Total Volume	Price	Currency
NGX Phys. FP Spr (US/MM), Union-Dawn/TCP-Iroquois	7/9/2013 7:33	50019851/50019852	FUT	Yes	10-Jul-13	10-Jul-13	3,300	3,300	\$0.16	USD
NGX Phys. FP Spr (US/MM), Union-Dawn/TCP-Iroquois	7/9/2013 7:37	50020436/50020437	FUT	Yes	10-Jul-13	10-Jul-13	900	900	\$0.23	USD
NGX Phys. FP Spr (US/MM), Union-Dawn/TCP-Iroquois	7/9/2013 7:35	50020115/50020116	FUT	Yes	10-Jul-13	10-Jul-13	10,000	10,000	\$0.19	USD
NGX Phys. FP Spr (US/MM), Union-Dawn/TCP-Iroquois	7/9/2013 7:37	50020417/50020418	FUT	Yes	10-Jul-13	10-Jul-13	5,000	5,000	\$0.23	USD
NGX Phys. FP Spr (US/MM), Union-Dawn/TCP-Iroquois	7/9/2013 7:43	50021096/50021097	FUT	Yes	10-Jul-13	10-Jul-13	5,000	5,000	\$0.21	USD
NGX Phys. FP Spr (US/MM), Union-Dawn/TCP-Iroquois	7/9/2013 7:43	50021094/50021095	FUT	Yes	10-Jul-13	10-Jul-13	7,100	7,100	\$0.21	USD
NGX Phys. FP Spr (US/MM), Union-Dawn/TCP-Iroquois	7/9/2013 7:50	50021934/50021935	FUT	Yes	10-Jul-13	10-Jul-13	10,000	10,000	\$0.22	USD
NGX Phys. FP Spr (US/MM), Union-Dawn/TCP-Iroquois	7/9/2013 7:56	50022686/50022687	FUT	Yes	10-Jul-13	10-Jul-13	7,500	7,500	\$0.23	USD
NGX Phys. FP Spr (US/MM), Union-Dawn/TCP-Iroquois	7/9/2013 8:03	50023921/50023922	FUT	Yes	10-Jul-13	10-Jul-13	7,200	7,200	\$0.23	USD
NGX Phys. FP Spr (US/MM), Union-Dawn/TCP-Iroquois	7/9/2013 8:14	50025376/50025377	FUT	Yes	10-Jul-13	10-Jul-13	800	800	\$0.23	USD
NGX Phys. FP Spr (US/MM), Union-Dawn/TCP-Iroquois	7/9/2013 8:20	50025969/50025970	FUT	Yes	10-Jul-13	10-Jul-13	10,000	10,000	\$0.24	USD
NGX Phys. FP Spr (US/MM), Union-Dawn/TCP-Iroquois	7/9/2013 8:20	50025967/50025968	FUT	Yes	10-Jul-13	10-Jul-13	2,000	2,000	\$0.23	USD
NGX Phys. FP Spr (US/MM), Union-Dawn/TCP-Iroquois	7/9/2013 7:35	50020105/50020106	FUT	Yes	10-Jul-13	10-Jul-13	10,000	10,000	\$0.19	USD
NGX Phys. FP Spr (US/MM), Union-Dawn/TCP-Iroquois	7/9/2013 8:46	50029074/50029075	FUT	Yes	10-Jul-13	10-Jul-13	3,800	3,800	\$0.26	USD
NGX Phys. FP Spr (US/MM), Union-Dawn/TCP-Iroquois	7/9/2013 9:05	50030941/50030942	FUT	Yes	10-Jul-13	10-Jul-13	3,700	3,700	\$0.38	USD
NGX Phys. FP Spr (US/MM), Union-Dawn/TCP-Iroquois	7/9/2013 7:35	50020136/50020137	FUT	Yes	10-Jul-13	10-Jul-13	5,000	5,000	\$0.22	USD

Avg

\$0.2219

Capacity Release Transaction Analysis - Example

Assume a Capacity Release Exchange of 10,000 GJ

	2012 Summer Prices US\$/Mmbtu	2011 Summer Prices US\$/Mmbtu	
a	FT RAM Credit	2.32342	4,972.1
b	US Exchange rate	0.985	0.973
c	Empress to Emerson transport cost	0.754	0.754
d	Empress Transport	(0.334)	(0.152)
e	NYMEX	3.630	4.000
f	AECO Basis	(0.450)	(0.380)
g	Emerson Basis	0.300	0.270
h	Dawn Basis	0.275	0.330
i = e + f + g	Value of Gas @ Emerson	3.480	3.890
j = e + f + d + fuel	Value of Gas @ Empress	2.861	3.499
k = a / c / 214 days / 1.055056	Volume that can be sold at Emerson	29,205	29,205
l = k X i	Value of gas at Sold at Emerson	21,749.3	24,311.7
m = k X j	Value of gas purchased at Empress	17,879.1	21,870.0
n = 10,000 units X j	Sale of Exchange volume at Empress	5,872.7	7,183.7
o = 10,000 units X (e + h)	Purchase cost of Exchange volume at Dawn	7,920.6	8,782.7
p = l + n	Proceeds of sales	27,622.0	31,495.4
q = m + o	Cost of Replacement gas	25,799.7	30,652.7
r = p - q	Net Proceeds	1,822.3	842.7
s = r / 10,000 GJ's / 214 days	Unit Rate value of transaction - \$/GJ	0.85	0.39

CME INTERROGATORY #6

INTERROGATORY

Transactional Services Deferral Account ("TSDA")

Ref: Exhibit A, Tab 2, Schedule 1, Appendix A, line 16  
Exhibit C, Tab 1, Schedule 6, pages 1 to 21, Appendices A to D

Assume EGD has some excess FT capacity on TransCanada PipeLines ("TCPL") between Empress and Dawn, and proposes to mitigate the costs of that excess capacity by temporarily assigning the FT to a third party. In connection with this scenario, please provide the following information:

- (a) Please provide a copy of all of the documentation which EGD as assignor and the third party as assignee would execute to support the assignment, together with a description of how the pricing for the assigned space would be determined, along with the information which is used to determine that pricing.
- (b) Do the benefits which EGD derives from a stand-alone temporary assignment of FT capacity made to mitigate unabsorbed demand charges get recorded in a gas supply related deferral account, or in the TSDA?
- (c) Assume that the FT capacity is assigned by EGD to the third party for a price equal to 50% of the value of the TCPL FT demand charge. In this scenario, please advise as follows:
  - (i) Is it EGD or the assignee who pays the full demand charge to TCPL during the period that EGD's capacity is held by the assignee?
  - (ii) If the assignee pays the full demand charge, then how does EGD's payment for 50% of the demand charge related to the assigned capacity recorded in EGD's books?
  - (iii) Please provide a step-by-step description of the manner in which the benefit EGD receives from temporarily assigning away FT capacity is determined and then recorded in the deferral account EGD uses for such transactions.

Witnesses: M. Giridhar  
J. LeBlanc  
D. Small

## RESPONSE

- a) The process for the assignment of capacity for a Capacity Release Exchange is the same as any other assignment of TCPL capacity such as for a Direct Purchase Agreement. Using TCPL's "Dovetail" a shipper can assign capacity to another party under TCPL's tariff. Once the assignment has been made TCPL will credit the assignor for 100% of the current approved toll and automatically charge the assignee at 100% of the same toll. In the case of an FT assignment the applicable toll in 2012 was \$2.09/GJ. If the counterparty and EGD make an agreement that capacity is either assigned at a discount or a premium to the toll then it is up to the two parties to bill one another independently.

The response to CME Interrogatory #5 at Exhibit I, Tab 5, Schedule 5, provides for the calculations that would be performed to determine the value of the Capacity Release Exchange and it would be on that basis that EGD and the counter party would agree to the value of the transaction. In the example given the value of the transaction was calculated at \$0.83/GJ. This calculation would provide EGD with a benchmark when negotiating the exchange fee with the third party. If the third party were to offer to do the deal for \$0.80 then that would be acceptable to EGD. If we assume the agreed price was \$0.80/GJ then the third party would bill EGD \$1.29/GJ which would equal the difference between \$2.09/GJ toll that the third party has been billed by TCPL and the agreed to exchange fee of \$0.80/GJ.

Please refer to BOMA Interrogatory #6 at Exhibit I, Tab 2, Schedule 6 for a copy of the TS Agreement.

- b) Unforecast Unabsorbed Demand Charges associated with FT long haul capacity are not included in gas costs and are at risk to the Company. As such, any temporary assignment of capacity to mitigate those costs would be to the shareholder's account and do not go to the TSDA.
- c) As described in part a) if EGD did an assignment of FT capacity then it would receive a credit from TCPL for 100% of the FT toll and the third party would be billed at 100% of the toll by TCPL. In this example the third party would bill EGD the equivalent of 50% of the toll, \$1.045/GJ. If we assume that the assignment was for 10,000 GJ's then EGD would receive a credit from TCPL of \$648,000 (10,000 GJ's X 31 days X \$2.09/GJ). This amount would be credited to the TS Deferral Account. EGD would then receive an invoice from the third party for \$324,000 (10,000 GJ's X 31 days X \$1.045/GJ). This amount would be debited to the TS Deferral Account. The net proceeds of \$324,000 would then be shared 75:25 between the ratepayer and the shareholder.

Witnesses: M. Giridhar  
J. LeBlanc  
D. Small