BOARD STAFF INTERROGATORY #1

INTERROGATORY

Ref: A1/T5/S1/para4

At paragraph 4 the evidence states:

> "However, if the Base Pressure Gas and LUF costs are treated on a fully allocated cost basis, then all storage capital costs should be treated on a fully allocated cost basis in order to be consistent and equitable. The cost consequence of using a fully allocated approach to all storage capital would be an increase in utility regulated rate base of approximately $32M to $49M, with an associated increase in revenue requirement for the regulated utility which would more than offset the reduction set out in the following table."

a/ Please explain why regulated rate base would increase under the fully allocated cost approach described above, when it would seem intuitive that rate base should decrease because all the capital costs are spread over all storage assets, both regulated and unregulated.

b/ Please compare and contrast the existing Enbridge allocation approach with the methodology in use today for Union's non-utility storage cost allocations.

c/ Staff is interested in understanding the theory of incremental versus fully allocated costing in the context of separating utility from non-utility businesses. Please discuss the theoretical underpinnings of using an incremental versus a fully allocated costing methodology in creating a fair separation of utility and non-utility storage to avoid, to the greatest extent possible, cross-subsidization between the 2 businesses. Please include a discussion of the advantages and disadvantages of each approach.

RESPONSES

a) Under a fully allocated cost sharing method, all customers would be allocated a portion of the total storage capital based upon their relative shares of the total storage capacity or deliverability available. Because the relative investment in Enbridge's unregulated storage is larger than its share of the overall storage capacity and deliverability, a fully-allocated approach would reduce the allocation of capital costs to the unregulated line of business and increase the allocation to regulated storage.

On page 15 of its 2012 cost allocation study, Black & Veatch described the range of cost sharing outcomes that would have resulted from the use of full cost allocation of

Enbridge's storage capital, at that time. Despite the fact that Enbridge had booked some $84 million dollars of additional plant as it built the capacities for its unregulated storage business, only about $32 to $49 million of the total storage plant would have been allocated to the unregulated storage business under a fully allocated cost sharing methodology. The implication of this is that the remaining portion of that $84 million would have been allocated to utility storage. The utility, and its customers, would have had to carry a higher amount of rate base than it would have if the unregulated storage development had not occurred.

Under the Incremental cost sharing model, all of the $84 million is allocated to the unregulated storage business, with no impact for the utility customers.

b) Enbridge is not familiar with how Union Gas allocates its storage costs today.

c) Enbridge has described the nature of incremental and fully allocated costing in its pre-filed evidence (Exhibit A1, Tab 5, Schedule 1) and in response to VECC Interrogatory #1 at Exhibit I.A1.EGDI.VECC.1.

As explained, Enbridge believes that it not appropriate to use both of these two separate and distinct cost allocation methodologies for costs of a similar nature within its integrated storage facility. Enbridge's current allocation of its unregulated storage capital, under the incremental methodology, respects this principle. The use of incremental costing for some elements of capital costs, and full allocation for others would depart from this principle.

As explained above, in response (a), if Enbridge were to use fully allocated costing for all storage capital expenditures, then there would be more capital costs allocated to the regulated storage operation, and less allocated to the unregulated line of business. This is because the unregulated line of business has made disproportionately larger investments in recent years on capital expenditures to modernize and renew and expand the integrated storage operation. Therefore, to the extent that there is cross-subsidization, it could be said that the regulated storage operation is the beneficiary. As explained in evidence and in response to SEC Interrogatory #2 at Exhibit I.A1.EGDI.SEC.1, any change to fully allocated costing for all storage capital expenditures is appropriately addressed at rebasing.

Witness: B. Black

BOARD STAFF INTERROGATORY #5

INTERROGATORY

Ref: D1/T2/S1/para 12

Paragraph 12 speaks to the main changes in the gas supply plan for 2016. For example it says:

> "The completion of the GTA Project enables the Company to make a number of changes in the Enbridge CDA. The primary change that occurs is an increase in the contracted M12 capacity for transport between Dawn and Parkway that the Company has with Union Gas. This amounts to an increase in Union M12 capacity of 400,000 GJs per day. Coinciding with the increase in available transport from Union Gas, the Company was able to de-contract 266,000 GJs per day of long haul TCPL capacity from Empress to the Enbridge CDA."

What is the net cost impact (or benefit) to the transportation portfolio associated with the changes in Union's M12 contracted capacity and the de-contracting with TCPL?

RESPONSE

Enbridge addressed the gas supply cost benefits associated with the GTA Project in the Leave to Construct Application (EB-2012-0451). The annual average expected gas supply benefits for Enbridge's ratepayers from the GTA Project were set out in response to Exhibit J6.X in that proceeding. As seen in that document (see pages 2-4), these benefits (for the CDA) were estimated to be as much as $109 million per year, depending on the Empress-Dawn basis. A copy of Exhibit J6.X is included as an Attachment to this response.

In response to Board Staff Interrogatory #3 at Exhibit I.D1.EGDI.STAFF.3, Enbridge has explained that Segment A of the GTA Project will now be in service in March 2015. The gas supply impacts (cost benefits) to ratepayers from the GTA Project will begin as of that time.

Witness: D. Small

UNDERTAKING J6.X

UNDERTAKING

On Hearing Day 2 (September 13, 2013)[1] and Hearing Day 3 (September 16, 2013)[2], the Joint Panel committed to provide an indicative impact of the Settlement Term Sheet with TransCanada. On Hearing Day 4 (September 17, 2013)[3], Union committed to provide the impact through Undertaking J4.5 and Enbridge committed to respond to the same request on Hearing Day 6 (September 26, 2013)[4], however no separate undertaking number was assigned. The following response is provided on behalf of Enbridge.

This is an update to the October 10, 2013 undertaking and is based on information from the Settlement Agreement filed on October 31, 2013.

RESPONSE

This response provides the impact of the Settlement Agreement with TransCanada. Impacts of the Settlement Agreement include an increase in transportation costs as a result of higher TransCanada tolls and a decrease in transportation costs as a result of access to short haul transport to the Enbridge EDA, made possible as a result of the Settlement Agreement.

The toll impacts of the Settlement Agreement provided by TransCanada are a 55% increase in short haul tolls to the Enbridge Franchise and a 19% increase in long haul tolls to the Enbridge Franchise. The tolls contained in the Settlement Agreement are within the ranges Enbridge provided in its original response to J6.X.

The impact on tolls stemming from the Settlement Agreement relative to compliance tolls and the tolls provided in the original response to J6.X for transportation service utilized by Enbridge are as follows:

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[1] Refer to Hearing Day 2 (September 13, 2013) transcript at page 120, line 28 to page 121, line 7.
[2] Refer to Hearing Day 3 (September 16, 2013) transcript at page 127, lines 4 to 16.
[3] Refer to Hearing Day 4 (September 17, 2013) transcript at page 54, line 22 to page 55, line 21.
[4] Refer to Hearing Day 6 (September 26, 2013) transcript at page 63, lines 10 to 17.

Witnesses: J. Denomy
M. Giridhar

$/GJ	Compliance Filing Toll	13% Increase in Long Haul & 45% Increase in Short Haul	20% Increase in Long Haul & 55% Increase in Short Haul	Settlement Agreement Toll
Empress to Enbridge CDA	1.57	1.77	1.88	1.86
Empress to Enbridge EDA	1.62	1.83	1.94	1.92
Dawn to Enbridge CDA	0.24	0.34	0.37	0.37
Dawn to Enbridge EDA	0.44	0.63	0.68	0.68
Dawn to Iroquois	0.42	0.61	0.65	0.65
Parkway to Enbridge CDA	0.12	0.18	0.19	0.20
STS to Enbridge CDA	0.12	0.18	0.19	0.20
STS to Enbridge EDA	0.32	0.47	0.50	0.50
Parkway to Enbridge CDA SN	0.13	0.19	0.20	0.20

The annual increase in gas costs resulting from the Settlement Agreement tolls provided above relative to the compliance tolls and using the October 2013 QRAM gas supply portfolio is approximately $66.4 million. This calculation is provided in the table below. The bridging contribution accounts for approximately 1/3rd of the impact on gas costs with the remaining impact accounting for cost recovery of the Eastern Ontario Triangle.

$ Millions	Total TCPL Transportation Costs October 2013 QRAM	Total TCPL Transportation Costs Settlement Agreement Tolls
	234.7	301.0
Difference Relative to October 2013 QRAM		66.4

The average annual decrease in gas supply costs resulting from the ability to displace 170,000 GJ/d of long haul transport to the Enbridge EDA with short haul transport in 2016 is estimated to be approximately $49 million per year. This expected benefit was calculated using TCPL Compliance Filing Tolls, an average Empress to Dawn basis differential of $0.51 /GJ and 100% utilization of long haul capacity.

The table below shows the annual average expected gas supply benefits for Enbridge's ratepayers arising from the GTA Project over the 2015 to 2025 timeframe for a range of basis and utilization scenarios.

Witnesses: J. Denomy
M. Giridhar

Annual Average GTA Project Benefits Calculations for Current Base Case - Basis and Utilization Scenarios @ Compliance Filing Tolls - 2015-2025

$ Millions		Average Empress-Dawn Basis = 0.51 $/GJ	Average Empress-Dawn Basis = 0.92 $/GJ	Average Empress-Dawn Basis = 1.50 $/GJ
Enbridge CDA				
Long Haul Load Factor = 100% (January to December)	System Gas	109	62	(2)
	Direct Purchase	64	39	5
	Total	173	101	3
Long Haul Load Factor = 42% (November to March)	System Gas	138	119	92
	Direct Purchase	64	39	5
	Total	202	158	96
Long Haul Load Factor = 25% (December to February)	System Gas	145	134	118
	Direct Purchase	64	39	5
	Total	210	173	122
Enbridge EDA				
Long Haul Load Factor = 100% (January to December)	System Gas	49	21	(15)
Long Haul Load Factor = 42% (November to March)	System Gas	65	53	38
Long Haul Load Factor = 25% (December to February)	System Gas	69	62	53
Grand Total				
Long Haul Load Factor = 100% (January to December)		222	122	(12)
Long Haul Load Factor = 42% (November to March)		267	211	134
Long Haul Load Factor = 25% (December to February)		279	235	175

Enbridge has not updated the benefits resulting from the GTA Project using the tolls provided in the Settlement Agreement. With other assumptions held constant, the expected gas supply benefits using the tolls in the Settlement Agreement would be higher. However, the reason why Enbridge has not updated the benefits using tolls in the Settlement Agreement is because, while the unit increase in long haul tolls is higher than the unit increase in short haul tolls, these increases are based on a six year surcharge recovery for long haul vs. a sixteen year surcharge recovery for short haul. Over the term of the Settlement Agreement the differential in tolls is expected to be approximately the same as the differential in compliance tolls.

The combined benefits of the GTA Project and the Settlement Agreement are substantial and far exceed the increase in short haul and long haul tolls resulting from the Settlement Agreement under all but the scenario where Enbridge uses all its contracts at a 100% load factor and the basis differential between Alberta and Dawn is $1.50 or more.

As noted in evidence, 100% utilization is an unrealistic assumption given that Enbridge operates its distribution system at approximately 30% utilization factor. In addition, Enbridge has not included upstream arrangements necessary to meet growth in peak demand. The absence of short haul supply will result in ever decreasing utilization of long haul transport increments resulting in a transfer of wealth from Enbridge rate payers to other shippers on the TransCanada system. Enbridge has or is in the process of firming up approximately 360 TJ/d of long haul transport in lieu of previously contracted STFT for 2014. Enbridge would note that while the determination of final

Witnesses: J. Denomy
M. Giridhar

Mainline tolls were based on an average throughput from Alberta they did not explicitly incorporate firming up of Enbridge's 2013 peak day demand or growth in Enbridge's peak day demand over time.

Finally, the basis differentials reflected in the table do not reflect changes in Marcellus basis relative to Alberta. Enbridge notes that at TGP Zone 4 Marcellus, a trading point in the Marcellus formation, gas is currently trading at approximately $2.60 /GJ, a discount of approximately $0.60 /GJ relative to AECO in Alberta. Enbridge's analysis has assumed that Marcellus basis would trade above Alberta basis. In addition, Enbridge would note that current basis differential between AECO and Dawn is approximately $0.45 /GJ.

Witnesses: J. Denomy
M. Giridhar

APPrO INTERROGATORY #1

INTERROGATORY

Reference: i) Exhibit A1 Tab 5 Schedule 1 paragraph 4

Preamble: APPrO would like to better understand Enbridge's position on utility/nonutility cost allocation as well as Enbridge's statement *"that if Base Pressure Gas and LUF are treated on a fully allocated basis, then all capital storage capital costs should be treated on a fully allocated basis in order to be consistent and equitable."*

a) Please confirm that LUF is an operating cost. If not confirmed, please explain.
b) Has Enbridge ever reclassified any LUF as Base Pressure Gas? If so, please explain, and provide the last five years of volumes that have been reclassified.
c) Is it Enbridge's position that if either Base Pressure Gas or LUF is allocated on a fully allocated basis, that all storage capital costs associated with utility and nonutility storage should be allocated on a fully allocated basis? Please explain.
d) Please show how the values in the table in paragraph 4 page 2 of 6 were derived and include all related assumptions.

RESPONSE

a) LUF is a provision for expected losses included in the Company's gas volume budget.

b) No, Enbridge has not reclassified any LUF as Base Gas.

c) Yes. The reasons why all storage capital costs should be allocated on a consistent basis are explained at Exhibit A1, Tab 5, Schedule 1, paragraphs 4 and 6 (b) (v).

   The treatment of LUF is somewhat different in that, as stated in the response to b) above, LUF is not a capital cost. This is explained at paragraph 6 (a) of the evidence at Exhibit A1, Tab 5, schedule 1. Enbridge submits that gas costs associated with the current LUF provision should not be allocated between the utility and unregulated businesses as the provision was determined based upon only the pre-NGEIR utility storage volumes and activity and that has not changed. There is no additional recovery from utility customers for any LUF that has been experienced for the activity associated with the unregulated storage business. The cost of that additional LUF, no matter how great or small will be borne entirely by the shareholder. For this reason, Enbridge does not feel that the allocation of any of the previous amount of LUF should be recovered from the unregulated business.

d) The current book value of Base Gas is $38.9 million. Under the current Incremental Cost Allocation method, all of this is carried by Regulated Storage.

Under a Full Cost Allocation method, and based upon an 85.7% Capacity share, $33.3 million would be carried by Regulated Storage and the balance of $5.6 million (14.3%) would be carried by Unregulated Storage. The Revenue Requirement amount shown is the utility Revenue Requirement reduction that would result from the allocation of the $5.6 million at the 2016 forecast return rate.

The 0.84 Bcf of LUF is the volume of LUF recovered from Regulated Storage customers through a Provision for LUF under the current Incremental Cost Allocation method. Any LUF experienced by the Company in excess of this 0.84 Bcf will be borne by Unregulated Storage or, effectively, the shareholder under the Incremental method.

Under a Full Cost Allocation method, 0.72 Bcf of LUF would be recovered from utility storage customers with the remaining 0.12 Bcf of the estimated 0.84 Bcf being borne by the unregulated storage business, plus any additional LUF resulting from the increased activity caused by the unregulated storage business. The $0.67 million reduction in gas cost is the amount of LUF that would no longer be recovered from utility customers. The calculations for these amounts are shown in footnotes 5 and 6 at page 2 of Exhibit A1, Tab 5, Schedule 1. That amount, plus the cost of any additional LUF caused by the unregulated storage activity, would be recovered from the unregulated business and/or Enbridge shareholders.

APPrO INTERROGATORY #2

INTERROGATORY

Reference: i) Exhibit A1 Paragraph 5

Preamble: Enbridge provides the volumetric drivers of storage; APPrO would like to understand the related deliverability drivers.

a) Please redo the table in paragraph 5 and include the allocation of deliverability between regulated and non-regulated storage.
b) Please provide the aggregate storage deliverability curve over an injection/withdrawal cycle for all storage assets, and also illustrate the respective regulated and non-regulated amounts making up such deliverability curve.

RESPONSE

a) The Volumetric Driver for 'Deliverability' would be added showing 1.94 Bcf/d or 82.9% of deliverability for the utility (includes Union and LINK) and 0.40 Bcf/d or 17.1% for unregulated storage.

b) The table below sets out the Deliverability and Injection entitlements of the various gas storage customer stakeholders. It describes their maximum flow rates and a brief description of when these maximum rates begin to decrease over the Withdrawal or Injection cycle.

		Deliverability (MMcfd)		Injection (MMcfd)	
	Maximum Inventory (Bcf)	Maximum Deliverability Rate	Lowest Flow Rate with Ratchets	Maximum Injection Rate	Lowest Flow Rate with Ratchets
EGD's Bundle Rate Payers	91.25	1,740 MMcfd until remaining inventory falls below 43.8% of Maximum Inventory	Deliverability is reduced from 1,740 MMcfd toward 430 MMcfd as remaining inventory approaches zero.	772 MMcfd until storage balance reaches 75% of Maximum Inventory	Injection Rate is reduced from 772 MMcfd toward 274 MMcfd as storage balance increases from 75% of the Maximum Inventory to 100%.
Union Gas (Dow Moore)	5.72	100 MMcfd until remaining inventory falls below 25% of Maximum Inventory	Deliverability is ratcheted from 100 MMcfd to 86 MMcfd at 25% of Maximum and then to 57 MMcfd as remaining inventory falls below 20% of Maximum.	57 MMcfd until storage balance reaches 100% of Maximum Inventory	
Union Gas (Black Creek)	1.00	10 MMcfd until remaining inventory falls below 85% of Maximum Inventory	Deliverability is ratched down from 10 MMcfd to 8.5 MMcfd at 25% of Maximum Inventory and then to 5 MMcfd as remaining inventory falls below 20% of Maximum.	10 MMcfd until storage balance reaches 80% of Maximum Inventory	Injection Rate is ratcheted from 10 MMcfd to 5 MMcfd as storage balance increases from 80% of the Maximum Inventory to 100%.
Niagara Gas Transmission (LINK)	0.00	86 MMcfd throughout the year	NA	86 MMcfd throughout the year	NA
Aggregated Unregulated Storage	16.33	400 MMcfd	The Unregulated contracts have a number of different ratchet points; some based on inventory and others on time of year. These reduce the overall deliverability rates for Unregulated Storage towasrd about 200 MMcfd.	300 MMcfd	The Unregulated contracts have different ratchet points, some based upon remaining inventory and others on time of year. These reduce the overall contracted injection rate for Unregulated Storage toward about 150 MMcfd.

Witnesses: B. Black
D. Small

APPrO INTERROGATORY #3

INTERROGATORY

Reference: i) Exhibit A1 Schedule 1 paragraph 6

Preamble: Enbridge supports the use of continuation of an incremental cost allocation for LUF during the IRM.

a) Please provide the annual volumes injected and withdrawn from storage for each of the last five years separately showing the volumes for the regulated, unregulated and total volumes. Please include the percentages that the regulated and unregulated represent of the total annual volumes.

RESPONSE

a) The table below shows the injection and withdrawal activity for both regulated and unregulated storage since 2010.

	Total Storage		Regulated Storage		Unregulated Storage		Unregulated Storage	
	Injection 10^3m^3	Withdrawal 10^3m^3	Injection 10^3m^3	Withdrawal 10^3m^3	Injection 10^3m^3	Withdrawal 10^3m^3	Injection % of Total	Withdrawal % of Total
2010	2,247,658	2,328,378	2,045,098	2,166,093	202,560	162,285	9.0%	7.0%
2011	2,582,015	2,285,815	2,298,816	2,145,618	283,199	140,196	11.0%	6.1%
2012	2,305,493	2,404,300	2,070,073	2,241,945	235,420	162,355	10.2%	6.8%
2013	2,548,157	2,900,288	2,298,291	2,543,087	249,866	357,201	9.8%	12.3%
2014	3,046,575	2,359,847	2,588,753	2,033,987	457,822	325,861	15.0%	13.8%

Assumes 37.7 Mj/m^3

Witness: B. Black

BOMA INTERROGATORY #1

INTERROGATORY

Ref: Exhibit A, Tab 3, Schedule 1, Appendix B

Please provide revised line 2 incorporating Board's new cost of capital policy, released October 15, 2015.

RESPONSE

Please refer to the response to VECC Interrogatory #8 found at Exhibit I.E1.EGDI.VECC.8, which provides updated cost of capital, allowed revenue and deficiency calculations incorporating an ROE of 9.19% (as compared to the forecast of 9.13% included within the pre-filed evidence), as determined in the Ontario Energy Board's *Cost of Capital Parameter Updates for 2016 Applications* published October 15, 2015.

Witnesses: K. Culbert
R. Small

BOMA INTERROGATORY #2

INTERROGATORY

Ref: Exhibit A, Tab 5, Schedule 1, Page 3

Does LUF gas only arise in respect of storage? Is there any LUF in respect of gas that does not enter storage but flows directly to customers? How does this differ from the Unbilled and Unaccounted for Gas discussed at Exhibit D1, Tab 2, Schedule 3? Are the two accounts additive; is there double counting?

RESPONSE

LUF or 'Lost and Unaccounted For' Gas is a term that has been used to describe apparent gas losses only from within the storage activity. There is no LUF resulting from any activity other than from the gas that flows into and out of the storage system.

The Unbilled and Unaccounted for Gas or UUF relates to apparent gas losses that occur from within Enbridge's gas distribution activity. Provisions for UUF and LUF are separate and are not additive nor double counted.

Witnesses: B. Black
M. Suarez

BOMA INTERROGATORY #3

INTERROGATORY

Ref: Exhibit A, Tab 5, Schedule 1, Page 3

Is the revenue EGD earns from managing Dawn Moore and Black Creek storage pools a credit to EGD cost of service? What is the revenue over the last several years? Please provide reference.

RESPONSE

Enbridge recovers the cost to operate Union Gas's 22% share of the Dow Moore Pool, through a direct charge to Union. The amount recovered is credited against the costs used to calculate the cost of storage services and, ultimately, storage rates. The amount recovered from Union for each year from 2012 through 2014 has been $252,900. All other costs associated with operating these two pools are recovered from storage customers, including Union Gas, through Storage, Transmission and Compression rates.

Witnesses: B. Black
R. Small

BOMA INTERROGATORY #4

INTERROGATORY

Ref: Exhibit A, Tab 5, Schedule 1, Page 3

Please explain fully what is meant by "storage turnover rate"?

RESPONSE

The term ‘storage turnover rate’ is used in the Black & Veatch report simply to compare the levels of injection and withdrawal activity of various customers, or customer groups, as a function of their storage capacity.

The storage turnover rate exhibited by Enbridge has traditionally been lower than for unregulated storage which is consistent with Enbridge’s use of storage as an annual load balancing tool. Essentially, Enbridge injects and withdraws its stored gas volumes once a year. Conversely, it is expected that short term, unregulated storage customers would likely cycle their gas more than once a year and that would translate to a higher level of injection and withdrawal activity relative to their contracted storage capacity. This would appear as a higher storage turnover rate.

Witness: B. Black

BOMA INTERROGATORY #5

INTERROGATORY

Ref: Exhibit A, Tab 5, Schedule 1, Page 2

Please explain the derivation of the 14.3% used to determine the $5.6 million for the unregulated storage business's share of the cost of the Base Pressure case; and the same for LUF.

RESPONSE

The 14.3% is the proportion of unregulated storage capacity (16.33 Bcf) compared to the total storage capacity (114.29 Bcf). The total is made up of the 97.96 Bcf of regulated storage capacity and the 16.33 Bcf of unregulated capacity.

Witness: B. Black

BOMA INTERROGATORY #6

INTERROGATORY

Ref: Exhibit A, Tab 5, Schedule 1, Page 2

What is the derivation of the Base Pressure Gas cost of $38.9 million? How was the amount of Base Pressure Gas determined? Please provide EGD's definition of Base Pressure Gas, and the history of its use, including the determination of Base Pressure Gas amounts.

RESPONSE

The cost of Base Pressure Gas is the accumulated figure in the Company's asset accounts for gas purchased to be used as Base Pressure Gas. It reflects the historical cost of the Base Pressure Gas.

Base Pressure Gas is the quantity of gas required to achieve a targeted minimum Base Pressure for each of the storage reservoirs. The volume of Base Pressure Gas is set based upon a number of considerations including Enbridge's understanding of the reservoirs, and overall system design, safety and operational considerations.

Witness: B. Black

BOMA INTERROGATORY #7

INTERROGATORY

Ref: Exhibit A, Tab 5, Schedule 1, Page 2

Does each of EGD's pools have the same level of Base Pressure Gas relative to its capacity? Please provide amounts of Base Pressure Gas for each pool, and an explanation for any differences. Please show the annual amount of Base Pressure Gas in place over the last five years, both for EGD storage as a whole and for each pool.

RESPONSE

Most of Enbridge's storage pools have been operated to the same Base Pressure of 350 psig until this year's reduction in Base Pressure in some pools. The table below shows the Base Pressure Gas volumes and pressures, by pool, both before and current.

	Prior to 2015		Current 2015	
	Base Pressure at Wellhead (psig)	Base Pressure Volume (Bcf)	Base Pressure at Wellhead (psig)	Base Pressure Volume (Bcf)
Black Creek	350	0.331	350	0.331
Corunna	350	2.310	350	2.310
Coveny	350	1.936	312	1.811
Dow Moore	350	7.883	350	7.883
East Kimball	350	2.590	350	2.590
Ladysmith	350	1.926	350	1.926
Mid-Kimball Colinville	350	8.390	312	7.466
Seckerton	350	6.454	350	6.454
South Kimball Colinville	350	5.727	312	5.168
Wilkesport	350	2.858	312	2.537
Chatham D	500	1.129	500	1.129
Total		41.534		39.605

Witness: B. Black

BOMA INTERROGATORY #8

INTERROGATORY

Ref: Exhibit A, Tab 5, Schedule 1, Page 2

Please confirm the Base Pressure Gas is a rate base item.

RESPONSE

The Company confirms that Base Pressure Gas is a capital asset included within utility rate base.

Witnesses: B. Black
R. Small

BOMA INTERROGATORY #9

INTERROGATORY

Ref: Exhibit A, Tab 5, Schedule 1, Page 2

Please explain the role of Tecumseh Gas Storage. Is it a separate corporation, a division of EGD, or some other entity? Are its accounts part of the regulated utility's accounts? Does it hold all of EGD's regulated and unregulated storage assets? Please explain fully.

RESPONSE

Tecumseh Gas Storage Ltd. is the name by which Enbridge's Gas Storage operations were conducted from inception in the early 1960s through until wind-down into Consumers' Gas in the early 1990s. Since that time, Gas Storage Operations have been part of Enbridge Gas Distribution. The accounts associated with the unregulated storage business are segregated within a separate non-utility line of business.

Witnesses: B. Black
R. Small

BOMA INTERROGATORY #10

INTERROGATORY

Ref: Exhibit A, Tab 5, Schedule 1, Page 2

(a) Please explain fully the sale of 1.93 Bcf of Base Pressure Gas in the storage facility in 2015 (see footnote 7).

(b) What is the total volume of Base Pressure Gas before and after the sale of 1.93 Bcf?

(c) Why was the decision made to reduce the amount of Base Pressure Gas in 2015? Was the sole reason to create more unregulated storage capacity? Have other changes to the level of Base Pressure Gas been made over the last ten years? What are the impacts of the reduction(s) on storage operations and costs?

(d) What were the proceeds of the sale? How were the proceeds accounted for? Were the proceeds credited to the revenue requirement, or retained by the shareholder?

RESPONSE

(a) In the spring of 2015, Enbridge sold 1.93 Bcf of Base Gas from within its Gas Storage facility. As a result of this sale, Enbridge reduced the Base Gas volume in four of its ten storage reservoirs, which resulted in a reduction to the targeted minimum or ‘base’ pressure for the respective pools and an offsetting increase in the storage volumes of the unregulated storage business.

(b) Prior to the sale of Base Gas in 2015, Enbridge held 41.53 Bcf of Base Pressure Gas. After the sale the volume was reduced to 39.60 Bcf.

(c) Enbridge decided to reduce the volume of Base Gas in order to increase Working Gas capacity in the pools and create more Unregulated storage capacity.

There have not been any other acquisitions or dispositions of Base Gas in the last ten years.

Witnesses: B. Black
R. Small

These reductions in Base Gas will not add to the regulated storage operations costs. In fact, the costs will be reduced in the future as the space allocator for operating costs to Unregulated storage will increase, and the utility rate base value for Base Gas will be smaller at rebasing. These benefits will be reflected within the earnings sharing results starting in 2015.

(d) The profit from the sale of the Base Gas (proceeds less book value) was $5.8 million. This amount will be included as part of Enbridge Gas Distribution's corporate financial results for 2015.

Witnesses: B. Black
R. Small

CCC INTERROGATORY #1

INTERROGATORY

Reference: Ex.A1/T5/S1/p. 5

The evidence states that the ongoing use of the current Enbridge methodology was endorsed by an independent review by Black & Veatch, who agreed that it was appropriate for the storage assets that existed at the time of the NGEIR decision to be allocated to the utility operations, with any incremental assets to be allocated to the business unit that requires those assets. Under this approach, pre-existing assets (which include Base Pressure Gas) are allocated to regulated storage.

Was Black & Veatch asked to update its study undertaken in 2012 in light of the Board's Decision in the EB-2012-0459 proceeding directing Enbridge to file evidence regarding the allocation of base pressure gas and lost and unaccounted for gas to non- utility storage on a fully allocated basis? If so, please provide the updated study. If not, why not?

RESPONSE

Enbridge did not ask Black & Veatch to update its study following the Direction given in the Board's EB-2012-0459 Decision. Enbridge does not interpret the Board's direction (see pages 75 to 76 of the EB-2012-0459 Decision) as requiring or directing an update to the Black & Veatch study. Enbridge has provided the information required by the Board and has provided additional evidence to support its position.

Witness: B. Black

CCC INTERROGATORY #2

INTERROGATORY

Reference: Ex.A1/T5/S1/p. 5

The estimated cost consequence of the use of a fully allocated approach to all storage capital contained in the 2012 Black & Veatch Study would be an increase in utility rate base of approximately $32 to $49 million. What is the current estimate based on existing assets?

RESPONSE

Enbridge has identified the net plant balances for both regulated and unregulated storage at the end of the second quarter in 2015. They are $245 million and $77 million, respectively (a total of $322 million). The unregulated storage business currently uses 14.3% of total storage capacity and 17.1% of total storage deliverability. Based upon these, a fully allocated approach would result in asset values of $46 million to $55 million for unregulated storage which is between $22 million to $31 million less than the current level using incremental costing.

The implication of this is that utility rate base would increase by between $22 million and $31 million based upon the 2015 numbers.

Witness: B. Black

FRPO INTERROGATORY #1

INTERROGATORY

REF: Exhibit A1, Tab 5, Schedule 1, Page 3

How is LUF cost allocated to rate classes?

RESPONSE

The cost of LUF is allocated to the customer classes using the space allocation factor.

The space allocator represents the average winter demand in excess of the average annual demand for each customer class. In other words, the space allocator represents the difference between the average winter day consumption and the average daily consumption for each customer class.

Witnesses: A. Kacicnik
M. Kirk

SEC INTERROGATORY #1

INTERROGATORY

Ref: [A1/2/1/p.3]

Preamble: Enbridge has requested that its 2016 rates be effective as of January 1, 2016, and has requested interim rates if new rates cannot be in place by January 1, 2016. In EB-2012-0459 the Board ordered Enbridge to file full evidence with respect to the allocation of base pressure gas and LUF gas in either its 2015 or 2016 rate application, so that the Board could determine whether to reallocate those costs on a fully-allocated basis for ratemaking purposes. That evidence was filed for the first time in this proceeding on September 30, 2015.

Please explain why Enbridge did not file this evidence earlier, so that the Board would have time to make a determination with respect to this allocation prior to January 1, 2016. Please provide details of any factors outside of the control of Enbridge that prevented Enbridge from filing this evidence in a more timely manner.

RESPONSE

Within Enbridge's Custom IR application (the EB-2012-0459 proceeding), Enbridge's evidence indicated that annual rate adjustment applications for each of the years 2015 through 2018 of the five year customized incentive plan term would be filed in September of the fiscal year prior to the rate year application. As explained at Exhibit A2, Tab 2, Schedule 1, paragraphs 21 to 23 in the EB-2012-0459 proceeding, this approach would allow for the supporting evidence to be the most up-to-date as possible for the following year's rates. Also, as explained, this approach is the same as was used in Enbridge's first generation IR plan.

No party objected to Enbridge's proposed timing for rate adjustment proceedings, and the Board's Final Rate Order in the EB-2012-0459 proceeding did not require any change to the indicated timeline. The Board's Decision in the EB-2012-0459 proceeding stated that Enbridge was to file necessary evidence and a proposal related to the Allocation of LUF and Base Gas Costs to Non-Utility Storage in time for a 2015 or 2016 rate application. The Board's Decision did not indicate any requirement to file such evidence on a different timeline from the balance of the relevant rate adjustment application.

Witness: K.Culbert

Enbridge's proposal and supporting evidence in relation to Allocation of LUF and Base Gas Costs to Non-Utility Storage was filed in September 2015, along with the rest of the evidence for the 2016 rate adjustment application. Enbridge believes that issues around allocation of the LUF and Base Gas costs can be resolved at the same time as any other issues in this proceeding, in time for implementation effective January 2016. However, if the Board feels it necessary to opine separately on the Allocation of LUF and Base Gas Costs to Non-Utility Storage on a different timeline from the other elements of the application, Enbridge believes that the remaining evidence supports the approval of interim rates which could be implemented in January 2016. Any outstanding impact of the Cost Allocation element could be included into final rates if necessary at a later time following a subsequent Final Board Decision. In this regard, it may be relevant to note (as explained at Exhibit A1, Tab 5, Schedule 1, paragraph 4) that the 2016 revenue requirement impact of adopting a different Cost Allocation approach for LUF and Base Gas is around $1 million, which is a relatively minor amount in relation to the Company's proposed 2016 Allowed Revenue of $2,919 million.

SEC INTERROGATORY #2

INTERROGATORY

Ref: [A1/5/1, p. 6]

Preamble: Enbridge has proposed that any review of the cost allocation methodology for storage costs be done at the time of its next rebasing application. In EB-2012-0459, the Board ordered Enbridge to file the appropriate evidence for this review in its 2015 or 2016 rate application, rather than in its rebasing application.

Please provide full details of any changes in circumstances, or other such factors, since the EB-2012-0459 proceeding, that form the basis to defer this review further, until the next rebasing application. If there are no such changes in circumstances, please explain why the Board should alter the conclusion it reached in the EB-2012-0459 proceeding that this application would be the appropriate timing for this review.

RESPONSE

The Company has provided the information requested in the Board's Direction EB-2012-0459. Enbridge is not suggesting that the review of that information be deferred until rebasing. However, as explained in evidence, Enbridge's position is that if any storage capital expenditures are subject to a fully allocated cost methodology then that should apply to all storage capital expenditures. That change would require a wider review than what is being undertaking in this case and is an item better suited to a rebasing application.

Witness: B. Black

VECC INTERROGATORY #1

INTERROGATORY

Reference: A1/T5/S1/pg.1-2

a) Please explain why it is inconsistent (rather than simply not being the same) to fully allocate Base Pressure Gas and LUF costs on a fully allocated basis and all other costs on an incremental basis.
b) Please define what EGD understands as the meaning of fully allocated and incremental costing in terms of storage assets. Please explain why incremental costing is better suited as the methodology to be applied in this case.

RESPONSE

a) Please see response to APPrO interrogatory #1(c) at Exhibit I.A1.EGDI.APPrO.1. Discussion of Enbridge's position about appropriate cost allocation is set out in the prefiled evidence (Exhibit A1, Tab 5, Schedule 1) and in response to Board Staff Interrogatory #1 at Exhibit I.A1.EGDI.STAFF.1.

b) Incremental costing will allocate any additional costs incurred by the Unregulated storage business to that line of business. Pre-existing costs already being incurred by the Regulated storage business will continue to be borne by that line of business.

   Fully allocated costing will allocate a portion of all storage costs to each of Unregulated and Regulated storage based on appropriate allocation factors.

   Enbridge has explained why incremental costing is appropriate for Base Gas and LUF in response to APPrO Interrogatory #1(c) at Exhibit I.A1.EGDI.APPrO.1.

Witness: B. Black

VECC INTERROGATORY #2

INTERROGATORY

Reference: A1/T5/S1/pg.2 & D2/T5/S1/pg.15

a) Please provide the derivation of the $32 to $49 million estimated increase in revenue requirement if fully allocated costing were applied to all storage capital.

RESPONSE

a) This reference is incorrect. The ‘D2’ reference should be to the Black & Veatch report that is found at Exhibit A1, Tab 5, Schedule 1, Attachment.

The indicated numbers do not describe a change in the revenue requirement but instead the level of capital that would be carried by the unregulated storage business under a fully allocated costing approach. Please note that the evidence at Exhibit A1, Tab 5, Schedule 1, paragraph 4 (top of page 2) is incorrect in the way that it describes the impact of a change to fully allocated costing for capital expenditures. The evidence should indicate that the consequence of using fully allocated costing at the time of the Black & Veatch report would have been to reduce the level of capital allocated to the Unregulated business to $32 to $49 million. Under the Incremental cost allocation methodology the Unregulated storage business carried around $84 million in storage capital at that point in time. Using a fully allocated costing approach there would be a reduction of between $35 million and $52 million in the storage capital allocated to the Unregulated business. That amount would be added to the Utility rate base under a fully allocated approach.

The derivation of the $32 to $49 million is based on utilization of Space and Deliverability as allocation factors for the total cost of capital of all storage capital, both regulated and Unregulated.

Total Capital: ($MM, Reference Table 1 & Table 2 for 2011, Black & Veatch report, pages 16 and 17)

$203.5 (Regulated) + $84.4 (Unregulated) = $287.9 (Total Storage Capital 2011)

The lower range number is calculated using a Space allocation factor, which is the ratio of the Unregulated to total storage space available.

98 Bcf (Regulated) + 12.20 Bcf (Unregulated) = 110.2 Bcf (Total Storage space)

Witness: B. Black

11.07% = 12.20 / 110.2 - Unregulated Space allocator

11.07% x $287.9 (Total Storage Capital) = $31.9 (~$32)

The higher range number is calculated using a Deliverability allocation factor, which is the ratio of the Unregulated Deliverability to the total storage Deliverability available.

1.94 Bcf/d (Regulated) + 0.4 Bcf/d (Unregulated) = 2.34 (Total storage deliverability)

17.09% = 0.4 / 2.34- Unregulated Deliverability allocation factor

17.09% x $287.9 = $49.2 (~$49)

This demonstrates that under an incremental methodology, the Unregulated business carried $84.4 million in capital for 2011, but under a fully allocated methodology the Unregulated business would carry between $32 million and $49 million depending the allocation factor chosen to allocate the capital.

VECC INTERROGATORY #3

INTERROGATORY

Reference: D2/T5/S1/pg.23

a) Please confirm that Tables 3 and 4 shown the OM&A costs allocated on an incremental cost basis.
b) Please confirm that the total storage costs are the summation of the “Total” of each of Table 3 and Table 4 (i.e. total storage costs in 2007 are $8,494,180 + $236,803).
c) Please provide the OM&A storage related costs on a fully allocated basis (or if the tables show fully allocated then on an incremental basis).

RESPONSE

Reference should be Exhibit A1, Tab 5, Schedule 1, Attachment, page.23.

a) No, these amounts reflect the cost as allocated under a Full Cost Allocation method.

b) Yes they are.

c) The OM&A costs shown are based on a fully allocated approach. Because of the nature of the OM&A activities it is not possible to show the OM&A for the indicated years on an incremental basis. Enbridge expects that the incremental OM&A that is being incurred for the unregulated business is less than the amounts of O&M that are allocated to the unregulated business using a full cost allocation method.

Witness: B. Black

APPrO INTERROGATORY #4

INTERROGATORY

Reference: i) Exhibit B1 Tab 1 Schedule 1

Preamble: Enbridge has used its placeholder rate base project cost estimates. APPrO is interested in understanding the status of major projects.

a) Please provide the status of the GTA Reinforcement Project and any other major project included in the 2016 rate base.

b) For each project noted in a) above, please provide the original capital budget, by year and the current forecasted completion costs.

RESPONSE

a) Status of The GTA and Other Major Projects

There are two major projects included in rate base for 2016.

GTA Project

The GTA Project is expected to be put into service in multiple phases, with the Eastern segment (Segement B) in service December 2015 and the Western segment (Segment A) in service March 2016, later than the originally planned October 31, 2015. The latest cost estimate for the project is $932 million. The incremental cost to the OEB approved LTC amount can largely be attributed to increased construction complexity associated with the final design, in many cases driven by permitting agencies, as well as costs associated with the approximate five month schedule extension. The construction delays have been a result of protracted approval times from a number of permitting agencies and landowners relative to the original project schedule; in addition, the schedule extension is a result of more complex, deep road bore crossings that have taken longer than estimated in the original schedule.

WAMS

The WAMS Program is currently in the Construct Phase. The Construct Phase has been sub-divided into five build group packages, with the last build group scheduled for

Witnesses: T. Knight
R. Small

completion by the end of December 2015. The program will then conduct system integration testing, user acceptance testing, business readiness, training development and training delivery. The planned go-live date is Q2 2016.

b) Original Budget and Current Forecasted Costs

	Prefiled Evidence EB-2012-0459 Exhibits B2-1-1- Page 4 and M1-1-1 (in Millions)						Status at October 2015 (In Millions)					
	2013 Board Approved Budget	2014 Forecast	2015 Forecast	2016 Forecast	Total		Pre 2014	2014 Actual	2015 Forecast	2016 Forecast	2017 Forecast	Total
GTA Reinforcement	25.4	226.3	434.8	-	686.5		24.5	173.5	619.5	100.7	13.7	931.9
WAMS	0.5	36.3	25.7	8.1	70.6		-	19.9	29.6	28.6		78.1
Total Major Projects	**25.9**	**262.6**	**460.5**	**8.1**	**757.1**		**24.5**	**193.4**	**649.1**	**129.3**	**13.7**	**1,010.0**

Witnesses: T. Knight
R. Small

BOMA INTERROGATORY #11

INTERROGATORY

Ref: Exhibit B, Tab 1, Schedule 3, Page 1

Please explain column 6, which shows the volume of the gas in storage (monthly) corresponding to the 2016 gas in storage Rate Base Placeholder of $276.3 million, found at Exhibit B, Tab 1, Schedule 2, Page 1. Please explain the difference in each month's gas in storage number, from the same month's placeholder number. Please explain the basis for each month's difference. Please explain to what extent the difference was caused by the changes to the gas supply plan and describe in detail the impact on a monthly basis.

RESPONSE

Column 6 of Exhibit B1, Tab 1, Schedule 3 provides the monthly gas in storage balances expressed in $ 000's and the average of average balance ($391.1 million) forecasted for 2016.

As discussed in response to FRPO Interrogatory #2 found at ExhibitI.B1.EGDI.FRPO.2, the 2016 Rate Base Placeholder of $276.3 million was based upon the adjusted April 2013 QRAM Reference Price of $183.599/10^{3}m^3. The 2016 Updated Utility Forecast of $391.1 million was based upon the adjusted July 2015 QRAM Reference Price of $196.253/10^{3}m^3. The increase in unit rate, combined with the change in the gas supply planning criteria to maintain higher gas in storage balances, are the primary drivers for the difference.

The explanation for the individual monthly differences would be the same as the explanation above.

Witnesses: D. Small
R. Small

ENERGY PROBE INTERROGATORY #1

INTERROGATORY

Ref: Exhibit B1, Tab 1, Schedule 3, page 2

Please explain the following changes in the calculation of the working cash allowance in the 2016 updated forecast relative to the figures used in the 2015 updated forecast provide in Exhibit B1, Tab 1, Schedule 3, page 2 of EB-2014-0276:

a) Net lag-days of (10.9) versus (11.1) in line 8;
b) Net lag-days of 58.4 versus 60.4 in line 10;
c) Net lag-days of 22.9 versus 23.1 in line 11; and
d) Harmonized sales tax of (1.2) versus 7.0;
e) Please explain any changes in methodology and/or inputs that result in the HST change noted in part (d).

RESPONSE

Applying net lag days to the forecasted level of 2016 expenses determines the overall working cash requirement for the test year. Net lag days are equal to the revenue lag minus the appropriate expense lag and, therefore, have a positive relationship with the revenue lag and negative relationship with the expense lag. For example, a decrease in net lag day could be the result of a decrease to the revenue lag, an increase to expense lag, or some combination of the two.

For 2016, the revenue lag is equal to 40.7 days, a slight decrease of 0.2 days from 40.9 days in 2015. In 2016 the revenue lag day decreased slightly by (0.2) due to a decrease in the billing lag in 2016 as compared to 2015.

Please note that some of the expenditures forecast referenced in the response below were approved by the Board as part of the Custom IR decision. Therefore, the change in year-over-year expenditures referenced reflects the change in year-over-year expenditures forecasts as approved by the Board previously.

a) The change in the net lag day from (11.1) to (10.9) is due to a year-over-year increase in O&M expenditures offset by the decrease in the revenue lag day.

Witnesses: A. Kacicnik
M. Kirk
R. Small

b) The decrease in the net lag day from 60.4 to 58.4 is due to an increase in storage O&M expenditures and a decrease in the revenue lag day.

Note that the Storage operation expense lag days are the same as those established in the Custom IR proceeding. The Company did not make any changes / updates to this expense lag day for 2016. Therefore, the change in net lag days is completely driven by the change in expenditures.

c) The change in the net lag day from 23.1 to 22.9 is due to the decrease in the revenue lag day.

Note that the Storage municipal and capital taxes lag days are the same as those established in the Custom IR proceeding. The Company did not make any changes / updates to this expense lag day for 2016.

d) The change in the HST working cash requirement is mostly due to a decrease in forecast capital expenditures in 2016 as compared to 2015 offset by an increase in total Enbridge revenues in 2016 as compared to 2015.

e) Refer to part (d) above.

Witnesses: A. Kacicnik
M. Kirk
R. Small

FRPO INTERROGATORY #2

INTERROGATORY

REF: Exhibit B1, Tab 1, Schedule 1, Pages 1-2

Please provide the specific respective QRAM prices from April 1, 2013 and July 1, 2015.

a) Please demonstrate how those prices equated to a 40% increase in the value of gas in storage.

RESPONSE

The 2016 Rate Base Placeholder of $276.3 million was based upon the adjusted April 2013 QRAM Reference Price of $183.599/10^3 m^3. The 2016 Updated Utility Forecast of $391.1 million was based upon the adjusted July 2015 QRAM Reference Price of $196.253/10^3 m^3. The increase in unit rate, combined with the change in the gas supply planning criteria to maintain higher gas in storage balances, are the primary drivers for the difference.

Witnesses D. Small
R. Small

APPrO INTERROGATORY #5

INTERROGATORY

Reference: i) Exhibit C1 Tab 2 Schedule 1 Appendix A page 5

Preamble: Enbridge provides a comparison of the actual normalized consumption to Board approved normalized consumption for contract customers.

a) In addition to the Board approved normalized consumption for contract customers for 2015, please provide the forecast normalized consumption for contract customers for 2015 prior to any adjustments made to that forecast during settlement, and please provide the year-to-date best available information on how actual normalized consumption for contract customers for 2015 is tracking against both the Board approved and pre-settlement forecasts for 2015.
b) The Board approved consumption for 2015 included an adjustment made during the settlement process. Was an equivalent adjustment applied to the forecast for 2016 consumption? If no, why not?

RESPONSE

a) Table 1 below shows the summary of the normalized forecast consumption of contract market customers for 2015. The volumes adjustment applied to the contract market during the settlement was an increase of 74.1 10^6m^3.

Table 1
Summary of Contract Market Volumes
(Volumes in 10^6m^3)

	2015 Proposed Budget	2015 Board Approved Budget	Variance
Contract Market Volumes	1,842.1	1,916.2	74.1

Witnesses: H. Sayyan
M. Suarez

The methodology for forecasting volumes and all inputs to the volumetric determination utilizes the last full year of actual data at the time that forecasts are developed for the rate application. This approach has been applied consistently for ratemaking purposes. For the 2016 forecast, actual data up to and including 2014 were utilized. From that standpoint, it is the Company's position that partial year information is not indicative of full year results, and is therefore not appropriately used to inform test year expectations.

b) Please see a description of the Contract Market Volume Forecast Methodology at Exhibit C1, Tab 2, Schedule 1 that starts in paragraph 9 at page 3. Consistent with the described approach, Account Executives reviewed the current 2015 Approved budget from the settlement and actual consumption with contract customers as part of the development of the 2016 volumes forecast. Given the expectations for economic, industry, and weather conditions, individual 2016 volumes projections were developed with each customer.

From that standpoint, the 2015 Approved Budget from the settlement was the starting point of the budget process. However, an "equivalent adjustment" was not incrementally applied as the adjustment was specific to the settlement agreement for 2015 and not part of the methodology employed.

Witnesses: H. Sayyan
M. Suarez

BOMA INTERROGATORY #12

INTERROGATORY

Ref: Exhibit C1, Tab 2, Schedule 1, Page 1

Please provide actual volumes (year to date), and estimate for Tables 1 and 2, and Table 3 at Page 6.

RESPONSE

The methodology for forecasting volumes and all inputs to the volumetric determination utilizes the last full year of actual data at the time that forecasts are developed for the rate application. This approach has been applied consistently for ratemaking purposes.
For the 2016 forecast, actual data up to and including 2014 were utilized. From that standpoint, it is the Company's position that partial year information is not indicative of full year results, and is therefore not appropriately used to inform test year expectations.

Witnesses: H. Sayyan
M. Suarez

BOMA INTERROGATORY #13

INTERROGATORY

Ref: Exhibit C1, Tab 2, Schedule 1, Page 1

How is large non-contract customers' gas consumption forecast? How many customers does EGD have who are eligible for contract rates, but elect to remain on general service (by rate)? What value of gas purchase do they represent?

RESPONSE

a) The volumetric forecast for large non-contract customers’ volumes within Rate 6 is carried out as part of the General Service average use forecasting methodology described at Exhibit C2, Tab 1, Schedule 3. Regression models for Rate 6 revenue classes are used to generate average use forecasts that are informed by weather, economic conditions, and historical trends. Average use forecasts are applied to the General Service unlocks forecast to generate total volumes for Rate 1 and Rate 6. The development of the Gas Volume Budget is described more fully at Exhibit C1, Tab 2, Schedule 1.

   As noted at page 9 of the latter schedule, migration to Rate 6 over the years has increased the usage per customer over time, although it has flattened out in recent years. There are currently a number of non-contract large volume customers on Rate 6 whose individual annual consumptions greatly exceed the average use determined for the industrial sector, the largest among the Rate 6 sectors. Recognizing that specific changes in operating conditions for large volume non-contract customers could vary considerably from consumption levels being forecast through the average use methodology, Account Executives contact some of the largest Rate 6 customers to assess projected consumption in light of projected economic and industry conditions. This process is identical to that which Account Executives would apply in the development of the grassroots contract volume forecast. Based on the information obtained through this process, the overall Rate 6 consumption is accordingly adjusted.

b) At the time that the 2016 volumes forecast was developed, there were 183 accounts eligible for Contract rates which elected to remain on General Service.

c) In the development of the gas supply plan, gas purchases are determined based on the total volumetric requirements for all customers against the daily supplies to be

Witnesses: H. Sayyan
M. Suarez

received from Direct Purchase customers. Purchases are not made with a particular customer or type of customer in mind. The cost allocation and subsequent rate design process ultimately determine the costs to provide service to the different rate classes.

For the purpose of this response, the following approximate calculation is carried out using Total Purchases amounts in the Summary of Gas Cost to Operations at Exhibit D1 Tab 2 Schedule 4:

$$\text{Portion of Gas Purchase} = \left[\frac{(Volume\ of\ 183\ accounts) \times PGVA\ Price}{Total\ Purchases\ \&\ Receipt}\right]$$

The volume of the 183 accounts represents 2.8% of the Company’s supply and transportation costs.

Witnesses: H. Sayyan
M. Suarez

ENERGY PROBE INTERROGATORY #2

INTERROGATORY

Ref: Exhibit C1, Tab 2, Schedule 1, Appendix A

a) For each of the categories shown in Table 2 (residential, apartment, commercial and industrial) please provide the most recent year-to-date actual normalized average use available for 2015, along with the corresponding figures for the same months in 2014 and the corresponding figures for the same months in the 2015 Board approved column.

b) For each of the rates shown in Table 3 (Rate 1 and Rate 6) please provide the most recent year-to-date actual normalized average use available for 2015, along with the corresponding figures for the same months in 2014 and the corresponding figures for the same months in the 2015 Board approved column.

RESPONSE

a) and b)
The methodology for forecasting volumes and all inputs to the volumetric determination utilizes the last full year of actual data at the time that forecasts are developed for the rate application. This approach has been applied consistently for ratemaking purposes. For the 2016 forecast, actual data up to and including 2014 were utilized. From that standpoint, it is the Company's position that partial year information is not indicative of full year results, and is therefore not appropriately used to inform test year expectations.

Witnesses: H. Sayyan
M. Suarez

ENERGY PROBE INTERROGATORY #3

INTERROGATORY

Ref: Exhibit C1, Tab 2, Schedule 1, Appendix B

a) Please provide an example of the calculation of the total number of general service customers using the enhanced formula shown on page 3 using numbers.

b) Please provide the data and equations and results for the regression equations noted in the general service customer forecast formula on page 3 for both forecast customer additions and forecast monthly change in lock customers. If available, please provide a live Excel spreadsheet with the requested information.

RESPONSE

a) The development of the general service unlocks forecast relies on the same elements that were previously used: year-end customers, new customer additions, monthly change in locked customers, and net transfers. The enhancement being referred to is in the use of monthly regression models to incorporate customer additions and the historical pattern of locked customers in a more dynamic way that relies on historical lags reflected in actual data to objectively model the relationships rather than apply average lags based on only a snapshot of history. In this way, the formula is more of an illustration to describe the same methodology but only accomplished more objectively.

b) Please see tables that start on the next page for the regional regression equations and forecast data for Rate 1 and Rate 6 commercial unlocks. Other Rate 6 sectors could not be modelled adequately given the sporadic nature of customer attachments in these sectors, and instead, the unlocks forecasts relied directly on the customer additions forecasts because lags are generally minimal in these sectors. Output produced by these equations was used to generate monthly percentage changes which were then applied to the 2015 December forecasts for continuity. No live spreadsheet is available with this information.

Witnesses: H. Sayyan
M. Suarez

Table 1 – Rate 1 Regression Equations

Central Region

Variable	Coefficient	t-Statistic	p-Value
C	277.28	2.73	0.01
RES_ADD_CEN	0.99	4.08	0.00
D_FEB	-192.32	-1.95	0.06
D_MAR	-264.36	-2.66	0.01
D_APR	-389.61	-4.12	0.00
D_MAY	-542.16	-6.33	0.00
D_JUN	-854.86	-9.76	0.00
D_JUL	-760.72	-8.49	0.00
D_AUG	-440.48	-5.22	0.00
D_HIGH	459.89	2.92	0.01
AR(2)	-0.49	-5.55	0.00
R-squared	0.86		
Adjusted R-squared	0.83		
S.E. of regression	166.31		
F-statistic	28.03	Prob(F-statistic)	0.00

Eastern Region

Variable	Coefficient	t-Statistic	p-Value
C	62.10	0.48	0.63
RES_ADD_EAS	0.54	3.42	0.00
RES_ADD_EAS(-1)	0.65	3.89	0.00
D_APR	-269.59	-2.15	0.04
D_MAY	-238.36	-1.72	0.09
D_JUN	-900.51	-7.31	0.00
D_JUL	-948.25	-7.90	0.00
D_AUG	-566.64	-4.59	0.00
D_LOW	-1470.74	-5.32	0.00
D_HIGH	1456.42	5.45	0.00
R-squared	0.87		
Adjusted R-squared	0.85		
S.E. of regression	246.20		
F-statistic	37.93	Prob(F-statistic)	0.00

Metro Region

Variable	Coefficient	t-Statistic	p-Value
RES_ADD_MET	2.25	7.89	0.00
D_APR	-443.86	-2.71	0.01
D_MAY	-646.79	-5.75	0.00
D_JUN	-1367.30	-8.05	0.00
D_JUL	-1081.04	-11.85	0.00
D_AUG	-703.23	-2.76	0.01
D_SEP	-515.30	-3.02	0.00
D_LOW	-1120.69	-5.61	0.00
D_HIGH	1395.93	9.91	0.00
D_HIGH_MET	420.70	3.26	0.00
AR(1)	-0.34	-1.77	0.08
R-squared	0.76		
Adjusted R-squared	0.71		
S.E. of regression	416.02		
Log likelihood	-433.44		

Niagara Region

Variable	Coefficient	t-Statistic	p-Value
C	45.71	0.85	0.40
RES_ADD_NIA	0.83	2.67	0.01
RES_ADD_NIA(-1)	0.78	2.44	0.02
D_APR	-161.38	-3.15	0.00
D_MAY	-236.89	-4.32	0.00
D_JUN	-445.63	-8.80	0.00
D_JUL	-454.10	-8.89	0.00
D_AUG	-223.76	-4.32	0.00
D_SEP	-181.14	-3.65	0.00
D_LOW	-418.77	-3.66	0.00
D_HIGH	377.89	3.63	0.00
R-squared	0.85		
Adjusted R-squared	0.82		
S.E. of regression	102.13		
F-statistic	27.32	Prob(F-statistic)	0.00

Northern Region

Variable	Coefficient	t-Statistic	p-Value
C	132.58	0.79	0.43
RES_ADD_NOR	0.78	3.93	0.00
RES_ADD_NOR(-1)	0.53	2.49	0.02
D_APR	-423.25	-2.87	0.01
D_MAY	-523.65	-3.78	0.00
D_JUN	-1108.34	-8.84	0.00
D_JUL	-1314.67	-9.91	0.00
D_AUG	-699.96	-5.78	0.00
D_SEP	-269.79	-2.15	0.04
D_LOW	-2265.21	-8.26	0.00
D_HIGH	1334.15	4.76	0.00
AR(3)	0.48	3.52	0.00
R-squared	0.90		
Adjusted R-squared	0.88		
S.E. of regression	265.02		
F-statistic	37.31	Prob(F-statistic)	0.00

Western Region

Variable	Coefficient	t-Statistic	p-Value
RES_ADD_WES	0.62	2.72	0.01
RES_ADD_WES(-1)	0.76	3.45	0.00
D_MAY	-438.38	-3.08	0.00
D_JUN	-744.44	-5.82	0.00
D_JUL	-842.00	-6.44	0.00
D_AUG	-343.11	-2.65	0.01
D_LOW	-1148.85	-3.75	0.00
D_HIGH	909.34	3.15	0.00
R-squared	0.72		
Adjusted R-squared	0.68		
S.E. of regression	270.75		
Log likelihood	-416.91		

Table 2 – Rate 6 Regression Equations

Central Region

Variable	Coefficient	t-Statistic	p-Value
CA_COM_CEN	2.75	7.93	0.00
D_APR	-83.52	-3.82	0.00
D_MAY	-93.67	-4.49	0.00
D_JUN	-144.85	-6.95	0.00
D_JUL	-136.66	-6.52	0.00
D_AUG	-92.47	-4.38	0.00
D_NOV	70.49	3.17	0.00
R-squared	0.81		
Adjusted R-squared	0.78		
S.E. of regression	41.07		
Log likelihood	-247.80		

Eastern Region

Variable	Coefficient	t-Statistic	p-Value
C	35.83	1.81	0.08
CA_COM_EAS	1.23	2.95	0.01
D_APR	-113.15	-4.42	0.00
D_MAY	-118.14	-4.95	0.00
D_JUN	-222.84	-9.06	0.00
D_JUL	-171.68	-7.10	0.00
D_AUG	-144.23	-5.82	0.00
D_SEP	-79.46	-3.40	0.00
D_NOV	99.01	3.86	0.00
D_HIGH_EAS	133.19	5.72	0.00
AR(1)	-0.29	-1.84	0.07
R-squared	0.90		
Adjusted R-squared	0.88		
S.E. of regression	41.84		
F-statistic	35.52	Prob(F-statistic)	0.00

Metro Region

Variable	Coefficient	t-Statistic	p-Value
C	125.79	1.89	0.07
CA_COM_MET	1.80	1.86	0.07
D_MAR	-200.46	-2.20	0.03
D_APR	-294.67	-4.83	0.00
D_MAY	-404.60	-7.15	0.00
D_JUN	-637.03	-12.89	0.00
D_JUL	-503.06	-9.80	0.00
D_AUG	-372.39	-4.93	0.00
D_SEP	-192.58	-3.33	0.00
D_NOV	264.71	2.78	0.01
R-squared	0.87		
Adjusted R-squared	0.84		
S.E. of regression	117.84		
F-statistic	28.96	Prob(F-statistic)	0.00

Niagara Region

Variable	Coefficient	t-Statistic	p-Value
C	24.09	2.10	0.04
CA_COM_NIA	1.98	2.98	0.00
D_APR	-84.27	-6.97	0.00
D_MAY	-103.11	-6.47	0.00
D_JUN	-158.90	-9.31	0.00
D_JUL	-127.15	-10.32	0.00
D_AUG	-83.89	-5.69	0.00
D_SEP	-35.92	-1.84	0.07
D_NOV	62.38	5.61	0.00
R-squared	0.87		
Adjusted R-squared	0.84		
S.E. of regression	30.08		
F-statistic	32.54	Prob(F-statistic)	0.00

Northern Region

Variable	Coefficient	t-Statistic	p-Value
C	132.28	2.57	0.01
CA_COM_NOR	1.87	2.21	0.03
D_APR	-302.12	-5.72	0.00
D_MAY	-432.17	-6.34	0.00
D_JUN	-524.70	-14.27	0.00
D_JUL	-463.25	-9.07	0.00
D_AUG	-438.83	-7.56	0.00
D_SEP	-196.03	-3.52	0.00
D_NOV	229.52	5.89	0.00
R-squared	0.86		
Adjusted R-squared	0.83		
S.E. of regression	113.70		
F-statistic	30.90	Prob(F-statistic)	0.00

Western Region

Variable	Coefficient	t-Statistic	p-Value
C	92.56	2.39	0.02
CA_COM_WES	2.94	3.44	0.00
D_APR	-225.57	-4.39	0.00
D_MAY	-351.67	-7.11	0.00
D_JUN	-534.54	-10.91	0.00
D_JUL	-437.59	-8.72	0.00
D_AUG	-294.43	-6.05	0.00
D_SEP	-196.37	-3.99	0.00
D_NOV	218.48	4.50	0.00
R-squared	0.90		
Adjusted R-squared	0.88		
S.E. of regression	87.65		
F-statistic	45.96	Prob(F-statistic)	0.00

Witnesses: H. Sayyan
M. Suarez

Table 3 - Variable Descriptions

Variable	Description
D(Unlocks_(Region),1)	First difference of unlocks of a particular region
Res_Add_(Region)	Residential customer addition
Res_Add_(Region)(-1)	1 Month Lagged Residential customer addition
Com_Add_Region	Commerical rate 6 customer addition
D_Mth	Dummy of a particular month. Accounts for change in locked customers.
D_High	Dummy for unusually high unlocks
D_Low	Dummy for unusually low unlocks
D_(region)	Dummy for anomoly for a particular region
AR(s)	Autoregressive term of the 's' degree

Table 4 - Rate 1 Unlocks Forecast Data

	Res Cust Add Central	Res Cust Add Eastern	Res Cust Add Metro	Res Cust Add Niagara	Res Cust Add Northern	Res Cust Add Western	D_High	D_Low	D_Met
Jan-16	335	371	242	90	557	276	0	0	0
Feb-16	299	426	210	101	617	326	0	0	0
Mar-16	277	486	190	101	594	405	0	0	0
Apr-16	242	462	180	114	513	398	0	0	0
May-16	284	532	205	102	618	417	0	0	0
Jun-16	397	618	241	103	683	461	0	0	0
Jul-16	389	628	211	111	738	554	0	0	0
Aug-16	411	789	251	138	803	505	0	0	0
Sep-16	429	779	307	138	811	497	0	0	0
Oct-16	918	1003	280	150	893	632	0	0	0
Nov-16	965	1130	399	193	1106	663	0	0	0
Dec-16	778	863	375	165	850	456	0	0	0

Table 5 - Rate 6 Commerical Unlocks Forecast Data

	Com Cust Add Central	Com Cust Add Eastern	Com Cust Add Metro	Com Cust Add Niagara	Com Cust Add Northern	Com Cust Add Western	D_Eas
Jan-16	41	53	67	11	80	54	0
Feb-16	27	31	39	9	48	29	0
Mar-16	37	34	59	8	46	36	0
Apr-16	32	28	32	11	43	22	0
May-16	16	29	28	7	29	31	0
Jun-16	13	29	37	6	41	30	0
Jul-16	22	30	31	5	43	29	0
Aug-16	28	27	29	6	40	29	0
Sep-16	25	40	49	7	55	27	0
Oct-16	67	58	57	14	67	48	0
Nov-16	85	50	78	14	87	58	0
Dec-16	79	88	68	14	64	78	0

Witnesses: H. Sayyan
M. Suarez

VECC INTERROGATORY #4

INTERROGATORY

Reference: C1/T2/S1/Appendix B pg.5

a) Please revise Table 3 to show General Service separately from Contract Market Customers.

RESPONSE

Table 3 below shows the revised table at Exhibit C1, Tab 2, Schedule 1, Appendix B, page 5 to show General Service separately from Contract Market Customers as indicated.

		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6
	Test Year	Actual General Service Customers	Actual Contract Customers	Actual Total Customers (1+2)	Board Approved Customers	Variance Customers (3-4)	%Variance Customers (5/4)*100
FISCAL YEAR	1996	1,260,554	2,736	1,263,290	1,262,815	475	0.0%
	1997	1,309,653	2,781	1,312,434	1,309,752	2,682	0.2%
	1998	1,361,573	2,777	1,364,350	1,353,178	11,172	0.8%
	1999	1,412,071	2,717	1,414,788	1,417,832	(3,044)	-0.2%
	2000	1,462,001	2,737	1,464,738	1,468,915	(4,177)	-0.3%
	2001	1,516,282	2,757	1,519,039	1,514,710	4,329	0.3%
	2002	1,563,921	2,789	1,566,710	1,565,017	1,693	0.1%
	2003	1,619,295	2,721	1,622,016	1,615,037	6,979	0.4%
	2004*	1,673,665	2,715	1,676,380	1,672,586	3,794	0.2%
	2005	1,722,028	2,688	1,724,716	1,718,766	5,950	0.3%
CALENDAR YEAR	2006	1,780,308	2,505	1,782,813	1,792,615	(9,802)	-0.5%
	2007	1,822,768	2,021	1,824,789	1,823,258	1,531	0.1%
	2008	1,863,756	1,264	1,865,020	1,864,047	973	0.1%
	2009	1,886,949	656	1,887,605	1,906,437	(18,832)	-1.0%
	2010	1,925,735	559	1,926,294	1,931,528	(5,234)	-0.3%
	2011	1,959,912	466	1,960,378	1,965,538	(5,160)	-0.3%
	2012	1,994,474	429	1,994,903	1,984,734	10,169	0.5%
	2013	2,029,589	412	2,030,001	2,025,462	4,539	0.2%
	2014	2,063,443	394	2,063,837	2,059,619	4,218	0.2%

Witnesses: H. Sayyan
M. Suarez

BOMA INTERROGATORY #14

INTERROGATORY

Ref: Exhibit C2, Tab 1, Schedule 4, Page 1

How is underforecast or overforecast of customer additions adjusted for, if at all? What were 2014 Board approved customers additions (add column to the Table 1)? Are commercial customers broken down into components such as education, health, retail, office, etc.? If not, please explain why not. What are "traditional apartment buildings"? Do they include condominiums? Please explain.

RESPONSE

The test year forecast customer additions takes into consideration previous full year variations in customer additions versus forecast / Board Approved to the extent they are known at the time of the forecast.

2014 Board approved customer additions are provided in Col. 1 in table below.

Item No.	Sector	*Col 1* 2014 Budget Board Approved	*Col. 2* 2014 Actual	*Col. 3* 2015 Budget Board Approved	*Col 4* 2016 Forecast
	Residential[1]				
1.1	New Construction	26,967	23,595	24,678	24,346
1.2	Replacement[2]	7,221	8,451	7,428	8,435
1.0	Total Residential	34,188	32,046	32,106	32,781
	Commercial[3]				
2.1	New Construction	1,667	1,725	1,722	1,941
2.2	Replacement	788	730	703	864
2.0	Total Commercial	2,455	2,455	2,425	2,805
	Industrial				
3.1	New Construction	2	1	4	6
3.2	Replacement	2	2	1	0
3.0	Total Industrial	4	3	5	6
4.0	Total Gross Customer Additions	36,647	34,504	34,536	35,592

Any further breakdown of commercial customers forecast is unavailable. Although the Company works closely with all types of customers, the breakdown of customer additions forecast in components such as education, health, retail, and office is not essential to achieve the purpose for which this forecast is developed.

Traditional Apartment buildings are multi-residential buildings, which are served by a single bulk meter and may also include condominiums.

BOMA INTERROGATORY #15

INTERROGATORY

Ref: Exhibit C2, Tab 1, Schedule 4, Page 2

Please explain how the company will remove the impact of Community Expansion Program customer addition from the determination of final 2016 rates.

RESPONSE

The impact of 1,590 Community Expansion ("CE") program customer additions, included in the derivation of 2016 rates translated into an increase of 290 unlocks and 2 106m^3 volume. In determination of final 2016 rates, Enbridge will adjust its forecast of unlock customers and the associated volumes to remove the impact of CE program. Enbridge confirms that the costs associated with CE program were not included in its Custom Incentive Rate-setting ("Custom IR") application and as such are not included in Allowed Revenue for setting 2016 rates.

Witnesses: F. Ahmad
R. Small

FRPO INTERROGATORY #24

INTERROGATORY

REF: General

Please provide an update on New Community Expansion projects.

RESPONSE

Please refer to the Company's response to VECC Interrogatory #5 parts (a) and (b) found at Exhibit I.C1.EGDI.VECC.5.

Witnesses: F. Ahmad
S. McGill

VECC INTERROGATORY #5

INTERROGATORY

Reference: C2/T1/S4/pg.2

a) Please provide details as to the derivation of the 1,590 Community Expansion customers projected to take service in 2016.
b) Has EGD filed the referenced Leave to Construct Application? If not when is this application expected to be filed?

RESPONSE

a) The forecast of 1,590 community expansion customer additions was based on the assumption that the Company would be in a position to extend service to five communities in 2016: Fenelon Falls, Bobcaygeon, Kirkfield, Scugog Island, and Lanark & Balderson. Given the extended time it has taken to develop and compile the documentation necessary to complete the leave to construct applications required to gain the requisite Ontario Energy Board approvals for these projects, it will not be possible to provide service to all of these communities in 2016. It is now anticipated that the Company will be in a position to begin construction of facilities to serve Fenelon Falls late in 2016 with initial customer attachments beginning near the end of 2016 or early 2017. As such, the original forecast of 1,590 community expansion customers for 2016 is now estimated at 100.

b) As of yet the Company has not filed the required leave to construct applications for any of the communities noted in its response to part (a) above. The Company is currently preparing a leave to construct application to extend natural gas distribution services to the communities of Fenelon Falls and Bobcaygeon. It is expected that this application will be submitted to the Ontario Energy Board in February 2016.

Witness: F. Ahmad

BOMA INTERROGATORY #16

INTERROGATORY

Ref: Exhibit C3, Tab 2, Schedule 3, Page 3

Please explain Column 4, "Change in Use".

RESPONSE

The “Change in Use” at Column 4 is the volumetric variance between 2016 Forecast and 2015 Board Approved Budget after having excluded the volumetric impacts from weather and net customers.

As such, 37.5 10^6m^3 (as shown at col. 4, line 5) of the total volumetric increase of 279 10^6m^3 between 2016 Forecast and 2015 Board Approved Budget is due to the combined impacts of average use and DSM.

Witnesses: H. Sayyan
M. Suarez

BOARD STAFF INTERROGATORY #2

INTERROGATORY

Ref: D1/T1/S1/Table 1

Table 1 shows the total Cost of Service (excl. interest & return) for 2015 Board-approved, 2016 Placeholder, and 2016 Updated Forecast.

Please provide an explanation of the main drivers of the differences between the Board-approved 2015 and the 2016 Updated Forecast.

RESPONSE

Please refer to the response to Board Staff interrogatory #9, at Exhibit I.F1.EGDI.STAFF.9.

Witness: R. Small

BOARD STAFF INTERROGATORY #3

INTERROGATORY

Ref: D1/T2/S1/para 2

a/ Please explain whether or not the Gas Supply Plan has been developed assuming the GTA project is fully operational during 2016.

b/ If the GTA project is not fully operational, what is the expected in-service date of the GTA project and what is the cost impact of the delay on the Gas Supply plan? Please include a discussion of the impact on Peak Day supply contracting, and how the supply plan changes would be effected during the year, e.g. through the QRAM process.

RESPONSE

a) The 2016 Gas Supply Plan as filed contemplated the GTA project being in-service as of January 1, 2016.

b) The current anticipated timelines for the GTA project being in-service are December 2015 for Segment B and March 15, 2016 for Segment A.

The following demonstrates the impact that the GTA project, at a high level, will have on the 2016 gas costs versus 2015 gas costs. In order to illustrate this impact, a high level estimate of the reference price from the 2015 supply portfolio and relative pricing to the 2016 supply portfolio is required. The Company therefore recalculated the 2015 forecast gas costs as filed using January 2016 to December 2016 pricing data. Assuming a 21 day average of pricing for the October 1, 2015 to October 29, 2015 period to develop prices for the January 2016 to December 2016 period and then applying those monthly prices to the respective forecast 2015 and 2016 supply portfolios the recalculated reference prices would be $\$186.653/10^{3}\ m^{3}$ for the 2015 portfolio and $\$174.249/10^{3}\ m^{3}$ for the 2016 supply portfolio. The decrease of $\$12.404/10^{3}\ m^{3}$ which if applied to the 2016 volume forecast, equates to an impact or reduction to 2016 gas costs of $99.4 million. However as the attached table shows the forecast of Storage and Transportation costs increases by $12.2 million from 2015 to 2016 primarily due to the increase in contracted Union M12 transportation which taken together with the estimated supply cost reduction of $99.4 million results in a net reduction in gas costs of $87.2 million, assuming all other assumptions are constant.

Witness: D. Small

Since delays in major pipeline projects are a possibility, the Company made the decision to plan for a potential delay. A contingency plan was developed in which certain long haul capacity contracts with TCPL (approx. 200,000 GJ per day) will continue until the in-service date for Segment A of the GTA Project in order to provide a level of firm supply for peak day planning purposes. Included within the 2016 forecasted supply plan is approximately 450,000 GJ per day of discretionary supplies at Dawn. With the continuation of the long haul contracts on TCPL, the Company would utilize that capacity to buy Empress supply, thereby reducing the amount to be acquired at Dawn. All other elements of the Company's supply plan would remain the same i.e., end of month storage targets with the exception that the delay in the GTA Project will also require the need to contract for Peaking Service to the CDA for the 2016 winter.

If the Company were to recalculate the 2016 reference price using the same 21 day average described earlier but assume 200,000 GJ/day Empress supplies instead of Dawn supplies in the months of January and February of 2016 and to include the costs associated with Peaking Service then the recalculated 2016 reference price would be $\$176.290/10^3 m^3$ which would translate into a higher 2016 gas costs of approximately $16.4 million.

Recognizing that actual commodity pricing will be different from forecast pricing and that actual purchase volumes will vary from budget, the Company believes that changes in monthly purchase costs because of a delay in the GTA Project can be captured within in the PGVA and disposed of as part of the QRAM process.

	2015			2016			2016 GTA Delay		
	Col. 1 10^3m^3	Col. 2 $(000)	Col. 3 $\$/10^3m^3$ (Col.2 / Col.1)	Col. 1 10^3m^3	Col. 2 $(000)	Col. 3 $\$/10^3m^3$ (Col.2 / Col.1)	Col. 1 10^3m^3	Col. 2 $(000)	Col. 3 $\$/10^3m^3$ (Col.2 / Col.1)
Commodity Cost to Operations	7,445,672.6 (1)	1,389,753.5	186.653	8,017,136.0 (4)	1,396,974.5	174.249	8,017,136.0 (4)	1,413,340.4	176.290
Storage and Transportation Costs		105,009.1 (2)			117,214.7 (5)			117,214.7 (5)	
Gas Cost to Operations	7,445,672.6	1,494,762.5	200.756	8,017,136.0	1,514,189.2	188.869	8,017,136.0	1,530,555.1	190.910
T-Service Transportation Costs	1,033,375.6	76,758.1 (3)	74.279	1,018,737.4	75,670.8 (6)	74.279	1,018,737.4	75,670.8 (6)	74.279
Forecasted Gas Costs		1,571,520.6			1,589,860.0			1,606,225.9	

notes:
- (1) as per EB-2014-0276, Ex D1,T2,S4, page 2, Item # 13
- (2) as per EB-2014-0276, Ex D1,T2,S4, page 2, Item # 14
- (3) Forecasted 2015 Western T-Service volume updated with July 1, 2015 TCPL tolls
- (4) as per EB-2015-0114, Ex D1,T2,S4, page 2, Item # 13
- (5) as per EB-2015-0114, Ex D1,T2,S4, page 2, Item # 14
- (6) Forecasted 2016 Western T-Service volume updated with July 1, 2015 TCPL tolls

BOARD STAFF INTERROGATORY #4

INTERROGATORY

Ref: ExD1/T2/S1/para 3

In the discussion of the planned Chicago supply, Enbridge includes the following footnote.

> "Subsequent to the development of its gas supply plan the Company began exploring opportunities with suppliers for a portion of its requirements. One such supply opportunity was a means of base loading a portion of the Chicago requirement. The Company has entered into a tentative agreement with a counterparty for supply from western Canada to Chicago via an eleven month assignment of Alliance transportation capacity"

Please provide any updates to the proposal and a more detailed explanation of the Alliance assignment, including any cost consequences and how they will be treated in 2016.

RESPONSE

Enbridge historically had four different transportation contracts on Vector that provided a total of 275,000 Mmbtu's of capacity per day. Two of those contracts totaling 100,000 per day expired October 31, 2015. The other two contracts for 96,000 and 79,000 Mmbtu's per day respectively date back to the in-service date of the Vector Pipeline in December of 2000. The objective at the time the Vector contracts commenced was to diversify Enbridge's supply portfolio and to allow the Company to acquire gas in an alternative supply hub, in this case Chicago. However, instead of buying the entire Vector requirement at the Chicago hub, the decision was made to enter in a transportation agreement on the Alliance Pipeline which would allow the Company to purchase gas for some of that requirement in western Canada, move that gas on the Alliance Pipeline to Chicago and then along with purchases made in Chicago move gas on the Vector Pipeline to Dawn. In December 2010 the decision was made not to renew the Alliance Pipeline contract and allow it to expire November 30, 2015.

Coincident with the October 31, 2015 expiry of the two Vector contracts mentioned above and the expiry of the Alliance contract, the Company found itself in the position of acquiring $175,000 Mmbtu's (184,635 GJ's) per day in Chicago for the Vector contract term December 1, 2015 to October 31, 2016. The Company, as with any of its other long haul contracts, develops an acquisition plan as to how much of the capacity should be filled by acquiring commodity via either annual, seasonal, monthly or daily supply arrangements.

In the summer of 2015, a counterparty (Aux Sable) approached the Company about the possibility of selling gas to Enbridge at the Alliance Pipeline interconnect in western Canada and then take an assignment of their Alliance Pipeline capacity which would allow the Company to move the gas to Chicago and on to the Vector Pipeline for transportation to Dawn. The Company saw this as means to fulfill its daily supply requirements in Chicago and evaluated the economics of the alternative. The proposal which was based upon commodity prices at the time, including costs from the assignment of Alliance capacity, would provide the Company with gas landed in Chicago at $3.49/GJ compared to the projected Chicago prices at that time equal to $3.52/GJ. The Company decided to move forward with the deal for 26,376 GJ/day and based upon a $0.03 savings would provide a benefit to ratepayers of approximately $0.3 Million.

Another advantage to this transaction is that it creates supply diversity. This transaction represents around 14% of Enbridge's forecasted Chicago supply requirement. Enbridge reduces its Chicago requirement and in the event that Chicago prices increase relative to prices in Alberta, this provides additional benefit to customers.

Like any other gas supply acquisition should the actual market price deviate from the forecasted prices used in the derivation of the PGVA Reference Price then those differences will be captured in the PGVA account for future disposition.

BOARD STAFF INTERROGATORY #6

INTERROGATORY

Ref: D1/T2/S4/

Staff notes that the forecast transportation costs are showing an increase in 2016 compared to the approved 2015 forecast (EB-2014-0276 at D1/T2/S4). The 2016 transportation costs are showing $405.7 million as compared to 2015 at $375.8 million.

Please provide an explanation for the increased costs.

RESPONSE

The 2015 forecast of transportation costs was based upon TCPL tolls included in the October 2013 QRAM which were $1.566/GJ. TCPL tolls were updated as part of the January 2015 QRAM and again in the July 2015 QRAM to a toll of 1.998/GJ increasing the 2015 forecasted transportation Costs to $479.4 Million. The 2016 forecasted transportation costs of $405.7 Million assumes the same tolls as in place for the July 2015 QRAM and take into consideration the reduction in long haul contracted transportation capacity on TCPL to coincide with the forecast January 1, 2016 in-service date of the GTA project.

Witness: D. Small

BOARD STAFF INTERROGATORY #7

INTERROGATORY

Ref: D1/T2/S5/

The table shows the storage and transportation charges charged to gas cost to operations. The amount is $117.2 million.

Please provide the comparable 2015 amount and explain the main drivers of the differential.

RESPONSE

The forecasted 2015 Storage and Transportation charges were $105.0 Million (EB-2014-0276, Exhibit D1, Tab 2, Schedule 5). The primary driver for the increase in forecasted 2016 costs is the increase in contracted Union Transportation capacity (400,000 GJ/day) coincident with the GTA Project.

Witness: D. Small

BOARD STAFF INTERROGATORY #8

INTERROGATORY

Ref: D1/T2/S8/

The table shows the gas supply/demand balance for 2014, 2015 and 2016. Staff seeks to understand the trends in the gas supply portfolio mix over the past few years.

Please expand the table to include the supply mix from 2012 actual and 2013 actual.

RESPONSE

Please see expanded table below.

Gas Supply/Demand Balance

Item #		Col. 1 2016 Budget 10^3m^3	Col. 2 2015 Budget 10^3m^3	Col. 3 2014 Actual 10^3m^3	Col. 4 2013 Actual 10^3m^3	Col. 5 2012 Actual 10^3m^3
1.	Total Demand	11,672,327.1	11,275,584.4	12,943,320.4	12,177,237.6	11,042,801.7
	Deliveries					
2.1	Western Canadian Supplies	3,393,331.8	4,632,952.9	5,253,057.3	3,585,652.2	3,308,251.4
2.2	Peaking/Seasonal	2,154.4	7,750.7	60,725.2	10,611.7	5,547.8
2.3	Ontario Production	366.0	730.0	281.8	453.9	384.4
2.4	Chicago Supplies	1,793,050.4	1,843,671.0	1,550,160.6	1,784,446.2	1,833,315.2
2.5	Delivered Supplies	1,052,334.6	700,451.1	2,179,104.2	2,367,941.5	1,106,985.8
2.6	Niagara Supplies	1,942,159.7	323,693.3	-	-	-
2.7	Direct Purchase Delivery	3,631,350.4	3,823,270.8	4,584,781.7	4,530,226.3	4,763,462.4
2.8	Storage (Injection)/Withdrawal	(142,420.0)	(56,935.4)	(684,790.4)	(102,094.2)	24,854.7
2.	Total Delivery	11,672,327.2	11,275,584.4	12,943,320.4	12,177,237.6	11,042,801.7

Total Demand includes both System Sales and T-Service Consumption

Witness: D. Small

BOMA INTERROGATORY #17

INTERROGATORY

Ref: Exhibit D1, Tab 2, Page 2

Please explain the reference to "baseloading a portion of the Chicago requirement". Please provide a copy of the 2016 gas supply plan, and the "mitigation plan".

RESPONSE

Once the Company has determined the monthly amount of gas that is required to fulfill its Gas Supply, decisions will be made as to how those supplies will be acquired i.e., through an annual, seasonal or month RFP or through daily purchases. With respect to the forecasted Chicago purchase requirements, the Company decided to acquire a portion of the daily requirement via an annual arrangement. This approach is also referred to as "baseloading", because the same supply is procured for each day of the year.

The 2016 UDC Mitigation Plan is shown at Exhibit D1, Tab 2, Schedule 1, Appendix A

Witness: D. Small

BOMA INTERROGATORY #18

INTERROGATORY

Ref: Exhibit D1, Tab 2, Schedule 1, Appendix A

Please provide copies of the monthly UDC reports since January 2015.

RESPONSE

The January 2015 to October 2015 UDC reports, which have been distributed monthly to all interested parties, are attached.

Witness: D. Small

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January 30, 2015

VIA RESS and COURIER

Ms Kirsten Walli
Board Secretary
Ontario Energy Board
2300 Yonge Street, Suite 2700
Toronto, Ontario, M4P 1E4

Dear Ms Walli:

Re: Enbridge Gas Distribution Inc. 2014 to 2018 Rate Application
Ontario Energy Board File No. EB-2012-0459 / EB-2014-0276

As per the Settlement Agreement in EB-2012-0459 (Exhibit N1, Tab 2, Schedule 1, p. 6 of 19) the Company committed to provide a report to the parties of the Settlement Agreement to allow for the ongoing monitoring of UDC impacts in 2014. The Company as part of its 2015 Rate Application (EB-2014-0276, Exhibit D1, Tab 2, Schedule 1, page 6 of 11) committed to continue to provide monthly reporting in 2015. Please see the attached Report for January 2015.

Please do not hesitate to contact me with any questions.

Yours Truly,

(Original Signed)

Andrew Mandyam
Director, Regulatory Affairs and Financial Performance

Attach.

cc: EB-2014-0276 Interested Parties

January 2015 Report

	Estimate	Estimate	Budget	Budget	Budget	Budget	Budget	Budget	Budget	Budget	Budget	Budget	
Demand	January	February	March	April	May	June	July	August	September	October	November	December	
PJ's	83.9	65.9	53.8	33.3	20.9	14.7	13.4	13.3	15.0	27.3	41.7	60.6	443.8

Forecasted Monetary Impacts by Delivery Area													
$ millions													
	January	February	March	April	May	June	July	August	September	October	November	December	
UDCDA													
- CDA	-	-	5.5	8.3	6.7	6.7	6.7	6.7	7.9	7.9	4.8	4.8	65.7
- EDA	-	-	9.1	7.4	6.6	6.6	6.6	6.6	5.9	5.9	4.9	4.9	64.6
Revenue From Unutilized Capacity Released													
	-	-	-	-	-	-	-	-	-	-	-	-	-
Net Impact on Deferral Account													
	-	-	14.6	15.7	13.3	13.3	13.3	13.3	13.8	13.8	9.7	9.7	130.4

Forecasted Monthly Unutilized Capacity by Delivery Area													
PJ's -													
	January	February	March	April	May	June	July	August	September	October	November	December	
UDCDA													
- CDA	-	-	3.6	5.3	4.3	4.2	4.3	4.3	5.0	5.1	3.0	3.1	42.2
- EDA	-	-	5.7	4.5	4.2	4.1	4.2	4.2	3.6	3.7	3.0	3.1	40.3
Unutilized Capacity Released													
	-	-	-	-	-	-	-	-	-	-	-	-	-
Net Unutilized Capacity													
	-	-	9.3	9.8	8.5	8.3	8.5	8.5	8.6	8.8	6.0	6.2	82.5

Degree Days													
Central Region	780.7	636.5	562.8	389.9	222.8	54.6	5.1	-	31.0	147.1	307.1	492.9	3,630.5
Niagara Region	740.0	621.9	558.8	381.8	224.0	53.6	4.6	-	23.1	122.4	281.7	464.2	3,476.1
Eastern Region	946.9	759.6	670.0	454.8	255.8	75.5	16.1	3.0	66.0	186.1	363.0	579.4	4,376.2

Discretionary Requirement													
	January	February	March	April	May	June	July	August	September	October	November	December	
PJ's	13.5	14.8	-	0.0	0.0	3.0	3.1	3.1	3.0	3.1	-	3.1	46.7

Month end Storage Capacity Target												
% Fill	0.53	0.37	0.20	0.17	0.26	0.42	0.59	0.77	0.92	1.00	0.93	0.72
Bcf	60.56	42.57	22.64	19.08	29.56	47.69	68.06	88.50	106.01	113.00	106.21	82.42

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February 27, 2015

VIA RESS, EMAIL and COURIER

Ms Kirsten Walli
Board Secretary
Ontario Energy Board
2300 Yonge Street, Suite 2700
Toronto, Ontario, M4P 1E4

Dear Ms Walli:

Re: Enbridge Gas Distribution Inc. 2014 to 2018 Rate Application
Ontario Energy Board File No. EB-2012-0459 / EB-2014-0276

As per the Settlement Agreement in EB-2012-0459 (Exhibit N1, Tab 2, Schedule 1, page 6 of 19) the Company committed to provide a report to the parties of the Settlement Agreement to allow for the ongoing monitoring of UDC impacts in 2014. The Company as part of its 2015 Rate Application (EB-2014-0276, Exhibit D1, Tab 2, Schedule 1, page 6 of 11) committed to continue to provide monthly reporting in 2015. Please see the attached Report for February 2015.

Please do not hesitate to contact me with any questions.

Yours Truly,

(Original Signed)

Andrew Mandyam
Director, Regulatory Affairs and Financial Performance

Attach.

cc: EB-2014-0276 Interested Parties

Demand	Actual January	Estimate February	Estimate March	Budget April	Budget May	Budget June	Budget July	Budget August	Budget September	Budget October	Budget November	Budget December	
PJ's	83.4	84.7	58.8	33.3	20.9	14.7	13.4	13.3	15.0	27.3	41.7	60.6	467.1

Forecasted Monetary Impacts by Delivery Area
$ millions

	January	February	March	April	May	June	July	August	September	October	November	December	
UDCDA													
- CDA	-	-	-	10.6	8.5	8.5	8.5	8.5	10.0	10.0	6.1	6.1	76.9
- EDA	-	-	-	9.4	8.5	8.5	8.5	8.5	7.5	7.5	6.3	6.3	70.9
Revenue From Unutilized Capacity Released													
	-	-	-	-	-	-	-	-	-	-	-	-	-
Net Impact on Deferral Account													
	-	-	-	20.0	17.0	17.0	17.0	17.0	17.6	17.6	12.3	12.3	147.8

Forecasted Monthly Unutilized Capacity by Delivery Area
PJ's -

	January	February	March	April	May	June	July	August	September	October	November	December	
UDCDA													
- CDA	-	-	-	5.3	4.3	4.2	4.3	4.3	5.0	5.1	3.0	3.1	38.6
- EDA	-	-	-	4.5	4.2	4.1	4.2	4.2	3.6	3.7	3.0	3.1	34.5
Unutilized Capacity Released													
	-	-	-	-	-	-	-	-	-	-	-	-	-
Net Unutilized Capacity													
	-	-	-	9.8	8.5	8.3	8.5	8.5	8.6	8.8	6.0	6.2	73.2
Degree Days													
Central Region	782.4	850.1	545.5	306.0	133.0	27.0	-	5.0	59.0	238.0	392.0	592.0	3,930.0
Niagara Region	739.8	804.1	524.9	301.0	130.0	22.0	-	3.0	48.0	210.0	373.0	565.0	3,720.8
Eastern Region	955.0	947.3	627.4	339.0	152.0	38.0	8.0	21.0	110.0	285.0	467.0	720.0	4,669.7

Discretionary Requirement

	January	February	March	April	May	June	July	August	September	October	November	December	
PJ's	13.6	21.1	-	0.0	0.0	3.0	3.1	3.1	3.0	3.1	-	3.1	53.1
Month end Storage Capacity Target													
% Fill	0.53	0.37	0.20	0.17	0.26	0.42	0.59	0.77	0.92	1.00	0.93	0.72	
Bcf	60.56	42.57	22.64	19.08	29.56	47.69	68.06	88.50	106.01	113.00	106.21	82.42	

ENBRIDGE

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March 31, 2015

VIA RESS, EMAIL and COURIER

Ms Kirsten Walli
Board Secretary
Ontario Energy Board
2300 Yonge Street, Suite 2700
Toronto, Ontario, M4P 1E4

Dear Ms Walli:

Re: Enbridge Gas Distribution Inc. 2014 to 2018 Rate Application
Ontario Energy Board File No. EB-2012-0459 / EB-2014-0276

As per the Settlement Agreement in EB-2012-0459 (Exhibit N1, Tab 2, Schedule 1, page 6 of 19) the Company committed to provide a report to the parties of the Settlement Agreement to allow for the ongoing monitoring of UDC impacts in 2014. The Company as part of its 2015 Rate Application (EB-2014-0276, Exhibit D1, Tab 2, Schedule 1, page 6 of 11) committed to continue to provide monthly reporting in 2015. Please see the attached Report for March 2015.

Please do not hesitate to contact me with any questions.

Yours Truly,

(Original Signed)

Andrew Mandyam
Director, Regulatory Affairs and Financial Performance

Attach.

cc: EB-2014-0276 Interested Parties

March 2015 Report

	Actual	Actual	Estimate	Estimate	Budget	Budget	Budget	Budget	Budget	Budget	Budget	Budget	
Demand	January	February	March	April	May	June	July	August	September	October	November	December	
PJ's	83.4	84.3	64.4	37.1	20.9	14.7	13.4	13.3	15.0	27.3	41.7	60.6	476.1
Forecasted Monetary Impacts by Delivery Area													
$ millions													
	January	February	March	April	May	June	July	August	September	October	November	December	
UDCDA													
- CDA	-	-	-	4.5	4.0	4.0	4.0	4.0	5.5	5.5	6.1	6.1	43.4
- EDA	-	-	-	-	8.5	8.5	8.5	8.5	7.5	7.5	6.3	6.3	61.4
Revenue From Unutilized Capacity Released													
	-	-	-	(1.8)	(1.2)	(1.2)	(1.2)	(1.2)	(1.2)	(1.2)	-	-	(9.1)
Net Impact on Deferral Account													
	-	-	-	2.7	11.2	11.2	11.2	11.2	11.8	11.8	12.3	12.3	95.8
Forecasted Monthly Unutilized Capacity by Delivery Area													
PJ's -													
	January	February	March	April	May	June	July	August	September	October	November	December	
UDCDA													
- CDA	-	-	-	5.3	4.3	4.2	4.3	4.3	5.0	5.1	3.0	3.0	38.5
- EDA	-	-	-	-	4.2	4.1	4.2	4.2	3.6	3.7	3.0	3.0	29.9
Unutilized Capacity Released													
	-	-	-	(3.0)	(2.3)	(2.2)	(2.3)	(2.3)	(2.2)	(2.3)	-	-	(16.8)
Net Unutilized Capacity													
	-	-	-	2.2	6.2	6.0	6.2	6.2	6.3	6.5	6.0	6.0	51.6
Degree Days													
Central Region	782.4	846.8	595.9	306.0	133.0	27.0	-	5.0	59.0	238.0	392.0	592.0	3,977.1
Niagara Region	739.8	804.2	578.9	301.0	130.0	22.0	-	3.0	48.0	210.0	373.0	565.0	3,774.9
Eastern Region	955.0	944.2	683.2	339.0	152.0	38.0	8.0	21.0	110.0	285.0	467.0	720.0	4,722.4
Discretionary Requirement													
	January	February	March	April	May	June	July	August	September	October	November	December	
PJ's	13.6	22.2	6.8	0.0	0.0	3.0	3.1	3.1	3.0	3.1	-	3.1	61.1
Month end Storage Capacity Target													
% Fill	0.53	0.37	0.20	0.17	0.26	0.42	0.59	0.77	0.92	1.00	0.93	0.72	
Bcf	60.56	42.57	22.64	19.08	29.56	47.69	68.06	88.50	106.01	113.00	106.21	82.42	

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April 30, 2015

VIA RESS, EMAIL and COURIER

Ms Kirsten Walli
Board Secretary
Ontario Energy Board
2300 Yonge Street, Suite 2700
Toronto, Ontario, M4P 1E4

Dear Ms Walli:

Re: Enbridge Gas Distribution Inc. 2014 to 2018 Rate Application
Ontario Energy Board File No. EB-2012-0459 / EB-2014-0276

As per the Settlement Agreement in EB-2012-0459 (Exhibit N1, Tab 2, Schedule 1, page 6 of 19) the Company committed to provide a report to the parties of the Settlement Agreement to allow for the ongoing monitoring of UDC impacts in 2014.

The Company, as part of its 2015 Rate Application (EB-2014-0276, Exhibit D1, Tab 2, Schedule 1, page 6 of 11) committed to continue to provide monthly reporting in 2015. Also, the Company developed and filed a 2015 UDC Mitigation Strategy as part of the Supplemental Agreement in EB-2014-0276 and committed to file monthly updates to that mitigation strategy (Ex. N, Tab 1, Schedule 2, page 6, paragraph 4). Please see the attached Report for April 2015.

Please do not hesitate to contact me with any questions.

Yours Truly,

(Original Signed)

Andrew Mandyam
Director, Regulatory Affairs and Financial Performance

Attach.

cc: EB-2014-0276 Interested Parties

April 2015 Report

	Actual	Actual	Actual	Estimate	Estimate	Budget	Budget	Budget	Budget	Budget	Budget	Budget	
Demand	January	February	March	April	May	June	July	August	September	October	November	December	
PJ's	83.4	84.3	64.0	37.3	20.4	14.7	13.4	13.3	15.0	27.3	41.7	60.6	475.5

Forecasted Monetary Impacts
$ millions

	January	February	March	April	May	June	July	August	September	October	November	December	
UDCDA	-	-	-	6.2	9.1	10.6	10.6	10.6	11.2	11.2	12.2	12.2	94.0
Revenue From Unutilized Capacity Released													
- Seasonal	-	-	-	(1.2)	(1.6)	(1.6)	(1.6)	(1.6)	(1.6)	(1.6)	-	-	(10.9)
- Monthly				(0.6)	-	-	-	-	-	-	-	-	(0.6)
- Daily				-	-	-	-	-	-	-	-	-	-
Net Impact on Deferral Account	-	-	-	4.4	7.5	9.0	9.0	9.0	9.7	9.6	12.2	12.2	82.5

Forecasted Monthly Unutilized Capacity by Delivery Area
PJ's -

	January	February	March	April	May	June	July	August	September	October	November	December	
UDCDA	-	-	-	3.0	4.7	5.3	5.4	5.4	5.6	5.7	6.0	6.2	47.3
Unutilized Capacity Released													
- Seasonal	-	-	-	(2.2)	(3.1)	(3.0)	(3.1)	(3.1)	(3.0)	(3.1)	-	-	(20.9)
- Monthly	-	-	-	(0.8)	-	-	-	-	-	-	-	-	(0.8)
- Daily	-	-	-	-	-	-	-	-	-	-	-	-	-
Net Unutilized Capacity	-	-	-	-	1.5	2.2	2.3	2.3	2.5	2.6	6.0	6.2	25.6

Discretionary Requirement

	January	February	March	April	May	June	July	August	September	October	November	December	
PJ's	13.6	22.2	6.8	0.0	0.0	3.0	3.1	3.1	3.0	3.1	-	3.1	61.1
Month end Storage Capacity Target													
% Fill	0.53	0.37	0.20	0.17	0.26	0.42	0.59	0.77	0.92	1.00	0.93	0.72	
Bcf	60.56	42.57	22.64	19.08	29.56	47.69	68.06	88.50	106.01	113.00	106.21	82.42	
Month end Storage Capacity													
% Fill	0.52	0.34	0.17	0.15									
Bcf	59.91	38.85	19.02	17.52									

2015 Summer UDC Management Plan

Item #		Column 1	Column 2	Column 3	Column 4	Column 5	Column 6	Column 7	Column 8
	PJ's	April (estimate)	May (forecast)	June (forecast)	July (forecast)	August (forecast)	September (forecast)	October (forecast)	Total
	Days in the month	30	31	30	31	31	30	31	214
1.	Forecasted UDC To Be Mitigated	9.8	8.5	8.3	8.5	8.5	8.6	8.8	61.0
2.	Forecasted Dawn Discretionary Requirement Replaced with Utilization of Long Haul Capacity	0.0	0.0	3.0	3.1	3.1	3.0	3.1	15.3
3.	Potential UDC Shed	9.7	8.5	5.2	5.4	5.4	5.5	5.7	45.7
4.	Forecasted Added Utility Requirement	6.7	3.9	-	-	-	-	-	10.6
5.	Forecasted Summer Unutilized Capacity	3.0	4.6	5.2	5.4	5.4	5.5	5.7	35.1
6.	April to October Release	2.2	2.3	2.2	2.3	2.3	2.2	2.3	16.0
7.	April Capacity Released for the month	0.8							0.8
8.	May to October Release	-	0.8	0.8	0.8	0.8	0.8	0.8	4.9
9.	June to September Release (Target)	-	-	0.8	0.8	0.8	0.8	-	3.1
10.	July to September Release (Target)	-	-	-	0.8	0.8	0.8	-	2.3
11.	Remaining Daily/Monthly Release Capacity	(0.0)	1.5	1.5	0.7	0.7	1.0	2.6	8.0
12.	Total Targeted Daily Capactiy to be Released Daily/Monthly	-	48,713	48,713	23,713	23,713	33,713	83,713	

notes: - Item # 4 has been updated to reflect greater utilization of capacity for Utility purposes in the month of April due to higher than forecasted monthly demand

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May 29, 2015

VIA RESS, EMAIL and COURIER

Ms Kirsten Walli
Board Secretary
Ontario Energy Board
2300 Yonge Street, Suite 2700
Toronto, Ontario, M4P 1E4

Dear Ms Walli:

Re: Enbridge Gas Distribution Inc. 2014 to 2018 Rate Application
Ontario Energy Board File No. EB-2012-0459 / EB-2014-0276

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The Company, as part of its 2015 Rate Application (EB-2014-0276, Exhibit D1, Tab 2, Schedule 1, page 6 of 11) committed to continue to provide monthly reporting in 2015. Also, the Company developed and filed a 2015 UDC Mitigation Strategy as part of the Supplemental Agreement in EB-2014-0276 and committed to file monthly updates to that mitigation strategy (Ex. N, Tab 1, Schedule 2, page 6, paragraph 4). Please see the attached Report for May 2015.

Please do not hesitate to contact me with any questions.

Yours Truly,

(Original Signed)

Andrew Mandyam
Director, Regulatory Affairs and Financial Performance

Attach.

cc: EB-2014-0276 Interested Parties

May 2015 Report

	Actual	Actual	Actual	Estimate	Estimate	Budget	Budget	Budget	Budget	Budget	Budget	Budget	
Demand	January	February	March	April	May	June	July	August	September	October	November	December	
PJ's	83.4	84.3	64.0	37.1	18.3	14.7	13.4	13.3	15.0	27.3	41.7	60.6	473.2

Forecasted Monetary Impacts
$ millions

	January	February	March	April	May	June	July	August	September	October	November	December	
UDCDA	-	-	-	6.6	7.9	12.2	12.2	12.2	12.8	17.3	12.2	12.2	105.4
Revenue From Unutilized Capacity Released													
- Seasonal	-	-	-	(1.2)	(1.6)	(2.2)	(2.3)	(2.3)	(2.2)	(2.3)	-	-	(14.2)
- Monthly				(0.6)	-	-	-	-	-	-	-	-	(0.6)
- Daily				(0.1)	(0.4)	-	-	-	-	-	-	-	(0.5)
Net Impact on Deferral Account	-	-	-	4.7	5.8	9.9	9.9	9.9	10.5	15.0	12.2	12.2	90.2

Forecasted Monthly Unutilized Capacity by Delivery Area
PJ's -

	January	February	March	April	May	June	July	August	September	October	November	December	
UDCDA	-	-	-	3.3	3.9	6.0	6.2	6.2	6.3	8.8	6.0	6.2	53.0
Unutilized Capacity Released													
- Seasonal	-	-	-	(2.2)	(3.1)	(4.5)	(4.7)	(4.7)	(4.5)	(4.7)	-	-	(28.6)
- Monthly	-	-	-	(0.8)	-	-	-	-	-	-	-	-	(0.8)
- Daily	-	-	-	(0.3)	(0.8)	-	-	-	-	-	-	-	(1.1)
Net Unutilized Capacity	-	-	-	-	-	1.5	1.5	1.5	1.8	4.1	6.0	6.2	22.6

Discretionary Requirement

	January	February	March	April	May	June	July	August	September	October	November	December	
PJ's	13.6	22.2	6.8	0.0	0.0	0.0	-	-	0.0	-	-	3.1	45.8
Month end Storage Capacity Target													
% Fill	0.53	0.37	0.20	0.17	0.26	0.42	0.59	0.77	0.92	1.00	0.93	0.72	
Bcf	60.56	42.57	22.64	19.08	29.56	47.69	68.06	88.50	106.01	113.00	106.21	82.42	
Month end Storage Capacity													
% Fill	0.52	0.34	0.17	0.15									
Bcf	59.91	38.85	19.02	17.52									

2015 Summer UDC Management Plan

Item #		Column 1	Column 2	Column 3	Column 4	Column 5	Column 6	Column 7	Column 8
	PJ's	April (estimate)	May (forecast)	June (forecast)	July (forecast)	August (forecast)	September (forecast)	October (forecast)	Total
	Days in the month	30	31	30	31	31	30	31	214
1.	Forecasted UDC To Be Mitigated	9.8	8.5	8.3	8.5	8.5	8.6	8.8	61.0
2.	Forecasted Dawn Discretionary Requirement Replaced with Utilization of Long Haul Capacity	0.0	0.0	-	-	-	-	-	0.0
3.	Potential UDC Shed	9.7	8.5	8.3	8.5	8.5	8.6	8.8	61.0
4.	Forecasted Added Utility Requirement	6.4	4.6	2.3	2.3	2.3	2.3	-	20.2
5.	Forecasted Summer Unutilized Capacity	3.3	3.9	6.0	6.2	6.2	6.3	8.8	40.8
6.	April to October Release	2.2	2.3	2.2	2.3	2.3	2.2	2.3	16.0
7.	April Capacity Released for the month	0.8							0.8
8.	April Capacity Released on the day	0.3							
9.	May to October Release	-	0.8	0.8	0.8	0.8	0.8	0.8	4.9
10.	May Capacity Released on the day	-	0.8						
11.	June to October Release	-	-	1.5	1.6	1.6	1.5	1.6	7.7
12.	July to September Release (Target)	-	-	-	0.8	0.8	0.8	-	2.3
13.	Remaining Daily/Monthly Release Capacity	(0.0)	(0.0)	1.5	0.7	0.7	1.0	4.1	9.2
14.	Total Targeted Daily Capactiy to be Released Daily/Monthly	-	(0)	48,560	23,560	23,560	33,560	133,560	

notes: - Item # 11 - The UDC Mitigation Strategy assumed a June to September release of approximately 25,000 GJ's per day. Based upon a review of its summer injection schedule the Company determined that it could release 50,000 GJ's per day for the June to October period

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June 30, 2015

VIA RESS, EMAIL and COURIER

Ms Kirsten Walli
Board Secretary
Ontario Energy Board
2300 Yonge Street, Suite 2700
Toronto, Ontario, M4P 1E4

Dear Ms Walli:

Re: Enbridge Gas Distribution Inc. 2014 to 2018 Rate Application
Ontario Energy Board File No. EB-2012-0459 / EB-2014-0276

As per the Settlement Agreement in EB-2012-0459 (Exhibit N1, Tab 2, Schedule 1, page 6 of 19) the Company committed to provide a report to the parties of the Settlement Agreement to allow for the ongoing monitoring of UDC impacts in 2014.

The Company, as part of its 2015 Rate Application (EB-2014-0276, Exhibit D1, Tab 2, Schedule 1, page 6 of 11) committed to continue to provide monthly reporting in 2015. Also, the Company developed and filed a 2015 UDC Mitigation Strategy as part of the Supplemental Agreement in EB-2014-0276 and committed to file monthly updates to that mitigation strategy (Ex. N, Tab 1, Schedule 2, page 6, paragraph 4). Please see the attached Report for June 2015.

Please do not hesitate to contact me with any questions.

Yours Truly,

(Original Signed)

Andrew Mandyam
Director, Regulatory Affairs and Financial Performance

Attach.

cc: EB-2014-0276 Interested Parties

June 2015 Report

	Actual	Actual	Actual	Actual	Estimate	Estimate	Budget	Budget	Budget	Budget	Budget	Budget	
Demand	January	February	March	April	May	June	July	August	September	October	November	December	
PJ's	85.1	86.2	64.7	37.6	18.2	15.4	13.4	13.3	15.0	27.3	41.7	60.6	478.7

Forecasted Monetary Impacts
$ millions

	January	February	March	April	May	June	July	August	September	October	November	December	
UDCDA	-	-	-	6.6	7.9	12.0	13.7	13.7	12.8	17.3	12.2	12.2	108.2
Revenue From Unutilized Capacity Released													
- Seasonal	-	-	-	(1.2)	(1.6)	(2.2)	(2.7)	(2.7)	(2.6)	(2.7)	-	-	(15.6)
- Monthly				(0.6)	-	-	-	-	-	-	-	-	(0.6)
- Daily				(0.1)	(0.4)	(0.6)	-	-	-	-	-	-	(1.1)
Net Impact on Deferral Account	-	-	-	4.7	5.8	9.2	11.0	11.0	10.2	14.7	12.2	12.2	91.0

Forecasted Monthly Unutilized Capacity by Delivery Area
PJ's -

	January	February	March	April	May	June	July	August	September	October	November	December	
UDCDA	-	-	-	3.3	3.9	6.0	7.0	7.0	6.3	8.8	6.0	6.2	54.5
Unutilized Capacity Released													
- Seasonal	-	-	-	(2.2)	(3.1)	(4.5)	(5.5)	(5.5)	(5.3)	(5.5)	-	-	(31.6)
- Monthly	-	-	-	(0.8)	-	-	-	-	-	-	-	-	(0.8)
- Daily	-	-	-	(0.3)	(0.8)	(1.5)	-	-	-	-	-	-	(2.5)
Net Unutilized Capacity	-	-	-	-	-	-	1.5	1.5	1.0	3.4	6.0	6.2	19.6

Discretionary Requirement

	January	February	March	April	May	June	July	August	September	October	November	December	
PJ's	13.6	22.2	6.8	-	0.0	0.0	-	-	0.0	-	-	3.1	45.8

Month end Storage Capacity Target												
% Fill	0.53	0.37	0.20	0.17	0.26	0.42	0.59	0.77	0.92	1.00	0.93	0.72
Bcf	60.56	42.57	22.64	19.08	29.56	47.69	68.06	88.50	106.01	113.00	106.21	82.42

Month end Storage Capacity					
% Fill	0.52	0.34	0.17	0.16	0.32
Bcf	59.91	38.85	19.07	18.22	36.43

2015 Summer UDC Management Plan

Item #		Column 1	Column 2	Column 3	Column 4	Column 5	Column 6	Column 7	Column 8
	PJ's	April (actual)	May (estimate)	June (estimate)	July (forecast)	August (forecast)	September (forecast)	October (forecast)	Total
	Days in the month	30	31	30	31	31	30	31	214
1.	Forecasted UDC To Be Mitigated	9.8	8.5	8.3	8.5	8.5	8.6	8.8	61.0
2.	Forecasted Dawn Discretionary Requirement Replaced with Utilization of Long Haul Capacity	0.0	0.0	-	-	-	-	-	0.0
3.	Potential UDC Shed	9.7	8.5	8.3	8.5	8.5	8.6	8.8	61.0
4.	Forecasted Added Utility Requirement	6.4	4.6	2.3	1.6	1.6	2.3	-	18.6
5.	Forecasted Summer Unutilized Capacity	3.3	3.9	6.0	7.0	7.0	6.3	8.8	42.3
6.	April to October Release	2.2	2.3	2.2	2.3	2.3	2.2	2.3	16.0
7.	April Capacity Released for the month	0.8							0.8
8.	April Capacity Released on the day	0.3							0.3
9.	May to October Release	-	0.8	0.8	0.8	0.8	0.8	0.8	4.9
10.	May Capacity Released on the day	-	0.8						0.8
11.	June to October Release	-	-	1.5	1.6	1.6	1.5	1.6	7.7
12.	June Capacity Released on the day			1.5					1.5
13.	July to October Release	-	-	-	0.8	0.8	0.8	0.8	3.1
14.	Remaining Daily/Monthly Release Capacity	(0.0)	(0.0)	-	1.5	1.5	1.0	3.4	7.4
15.	Total Targeted Daily Capactiy to be Released Daily/Monthly	-	(0)	-	48,560	48,560	33,560	108,560	

notes: -

Item # 11 - The UDC Mitigation Strategy assumed a June to September release of approximately 25,000 GJ's per day. Based upon a review of its summer injection schedule the Company determined that it could release 50,000 GJ's per day for the June to October period

Item # 13 - The UDC Mitigation Strategy assumed a July to September release of approximately 25,000 GJ's per day. Based upon a review of its summer injection schedule the Company determined that it could release this amount for the July to October period

ENBRIDGE

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July 31, 2015

VIA RESS, EMAIL and COURIER

Ms Kirsten Walli
Board Secretary
Ontario Energy Board
2300 Yonge Street, Suite 2700
Toronto, Ontario, M4P 1E4

Dear Ms Walli:

Re: Enbridge Gas Distribution Inc. 2014 to 2018 Rate Application
Ontario Energy Board File No. EB-2012-0459 / EB-2014-0276

As per the Settlement Agreement in EB-2012-0459 (Exhibit N1, Tab 2, Schedule 1, page 6 of 19) the Company committed to provide a report to the parties of the Settlement Agreement to allow for the ongoing monitoring of UDC impacts in 2014.

The Company, as part of its 2015 Rate Application (EB-2014-0276, Exhibit D1, Tab 2, Schedule 1, page 6 of 11) committed to continue to provide monthly reporting in 2015. Also, the Company developed and filed a 2015 UDC Mitigation Strategy as part of the Supplemental Agreement in EB-2014-0276 and committed to file monthly updates to that mitigation strategy (Ex. N, Tab 1, Schedule 2, page 6, paragraph 4). Please see the attached Report for July 2015.

Please do not hesitate to contact me with any questions.

Yours Truly,

(Original Signed)

Andrew Mandyam
Director, Regulatory Affairs and Financial Performance

Attach.

cc: EB-2014-0276 Interested Parties

July 2015 Report

	Actual	Actual	Actual	Actual	Actual	Estimate	Estimate	Estimate	Budget	Budget	Budget	Budget	
Demand	January	February	March	April	May	June	July	August	September	October	November	December	
PJ's	85.1	86.2	64.7	37.6	18.5	15.3	14.4	13.4	15.0	27.3	41.7	60.6	479.9
Forecasted Monetary Impacts													
$ millions													
	January	February	March	April	May	June	July	August	September	October	November	December	
UDCDA	-	-	-	6.6	7.9	12.0	13.9	13.7	12.8	17.3	12.2	12.2	108.5
Revenue From Unutilized Capacity Released													
- Seasonal	-	-	-	(1.2)	(1.6)	(2.2)	(2.7)	(2.7)	(2.6)	(2.7)	-	-	(15.6)
- Monthly				(0.6)	-	-	-	-	-	-	-	-	(0.6)
- Daily				(0.1)	(0.4)	(0.6)	(0.7)	(0.6)	-	-	-	-	(2.4)
Net Impact on Deferral Account	-	-	-	4.7	5.8	9.2	10.6	10.4	10.2	14.7	12.2	12.2	90.0
Forecasted Monthly Unutilized Capacity by Delivery Area													
PJ's -	January	February	March	April	May	June	July	August	September	October	November	December	
UDCDA	-	-	-	3.3	3.9	6.0	7.1	7.0	6.3	8.8	6.0	6.2	54.7
Unutilized Capacity Released													
- Seasonal	-	-	-	(2.2)	(3.1)	(4.5)	(5.5)	(5.5)	(5.3)	(5.5)	-	-	(31.6)
- Monthly	-	-	-	(0.8)	-	-	-	-	-	-	-	-	(0.8)
- Daily	-	-	-	(0.3)	(0.8)	(1.5)	(1.7)	(1.5)	-	-	-	-	(5.7)
Net Unutilized Capacity	-	-	-	-	-	-	-	-	1.0	3.4	6.0	6.2	16.6
Discretionary Requirement	January	February	March	April	May	June	July	August	September	October	November	December	
PJ's	13.6	22.2	6.8	-	0.0	0.0	-	-	0.0	-	-	3.1	45.8
Month end Storage Capacity Target													
% Fill	0.53	0.37	0.20	0.17	0.26	0.42	0.59	0.77	0.92	1.00	0.93	0.72	
Bcf	60.56	42.57	22.64	19.08	29.56	47.69	68.06	88.50	106.01	113.00	106.21	82.42	
Month end Storage Capacity													
% Fill	0.52	0.34	0.17	0.16	0.32	0.48							
Bcf	59.91	38.85	19.07	18.22	36.43	54.81							

2015 Summer UDC Management Plan

Item #		Column 1	Column 2	Column 3	Column 4	Column 5	Column 6	Column 7	Column 8
	PJ's	April (actual)	May (actual)	June (estimate)	July (estimate)	August (forecast)	September (forecast)	October (forecast)	Total
	Days in the month	30	31	30	31	31	30	31	214
1.	Forecasted UDC To Be Mitigated	9.8	8.5	8.3	8.5	8.5	8.6	8.8	61.0
2.	Forecasted Dawn Discretionary Requirement Replaced with Utilization of Long Haul Capacity	0.0	0.0	-	-	-	-	-	0.0
3.	Potential UDC Shed	9.7	8.5	8.3	8.5	8.5	8.6	8.8	61.0
4.	Forecasted Added Utility Requirement	6.4	4.6	2.3	1.4	1.6	2.3	-	18.5
5.	Forecasted Summer Unutilized Capacity	3.3	3.9	6.0	7.1	7.0	6.3	8.8	42.5
6.	April to October Release	2.2	2.3	2.2	2.3	2.3	2.2	2.3	16.0
7.	April Capacity Released for the month	0.8							0.8
8.	April Capacity Released on the day	0.3							0.3
9.	May to October Release	-	0.8	0.8	0.8	0.8	0.8	0.8	4.9
10.	May Capacity Released on the day	-	0.8						0.8
11.	June to October Release	-	-	1.5	1.6	1.6	1.5	1.6	7.7
12.	June Capacity Released on the day			1.5					1.5
13.	July to October Release	-	-	-	0.8	0.8	0.8	0.8	3.1
14.	July Capacity Released on the day				1.7				
15.	August Capacity Released on the day - est					1.5			
16.	Remaining Daily/Monthly Release Capacity	(0.0)	(0.0)	-	-	-	1.0	3.4	7.5
15.	Total Targeted Daily Capactiy to be Released Daily/Monthly	-	(0)	-	-	-	33,560	108,560	

notes: -

Item # 11 - The UDC Mitigation Strategy assumed a June to September release of approximately 25,000 GJ's per day. Based upon a review of its summer injection schedule the Company determined that it could release 50,000 GJ's per day for the June to October period

Item # 13 - The UDC Mitigation Strategy assumed a July to September release of approximately 25,000 GJ's per day. Based upon a review of its summer injection schedule the Company determined that it could release this amount for the July to October period

Item # 15 - Estimate includes anticipated daily releases throughout the month of August

ENBRIDGE

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Director, Regulatory Affairs
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Enbridge Gas Distribution
500 Consumers Road
North York, Ontario M2J 1P8
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August 31, 2015

VIA RESS, EMAIL and COURIER

Ms Kirsten Walli
Board Secretary
Ontario Energy Board
2300 Yonge Street, Suite 2700
Toronto, Ontario, M4P 1E4

Dear Ms Walli:

Re: Enbridge Gas Distribution Inc. 2014 to 2018 Rate Application
Ontario Energy Board File No. EB-2012-0459 / EB-2014-0276

As per the Settlement Agreement in EB-2012-0459 (Exhibit N1, Tab 2, Schedule 1, page 6 of 19) the Company committed to provide a report to the parties of the Settlement Agreement to allow for the ongoing monitoring of UDC impacts in 2014.

The Company, as part of its 2015 Rate Application (EB-2014-0276, Exhibit D1, Tab 2, Schedule 1, page 6 of 11) committed to continue to provide monthly reporting in 2015. Also, the Company developed and filed a 2015 UDC Mitigation Strategy as part of the Supplemental Agreement in EB-2014-0276 and committed to file monthly updates to that mitigation strategy (Ex. N, Tab 1, Schedule 2, page 6, paragraph 4). Please see the attached Report for August 2015.

Please do not hesitate to contact me with any questions.

Yours Truly,

[original signed]

Andrew Mandyam
Director, Regulatory Affairs and Financial Performance

Attach.

cc: EB-2014-0276 Interested Parties

August 2015 Report

	Actual	Actual	Actual	Actual	Actual	Actual	Estimate	Estimate	Budget	Budget	Budget	Budget	
Demand	January	February	March	April	May	June	July	August	September	October	November	December	
PJ's	85.1	86.2	64.7	37.6	18.5	15.7	14.4	13.4	15.0	27.3	41.7	60.6	480.3

Forecasted Monetary Impacts
$ millions

	January	February	March	April	May	June	July	August	September	October	November	December	
UDCDA	-	-	-	6.6	7.9	12.0	14.0	11.9	14.3	17.3	12.2	12.2	108.3
Revenue From Unutilized Capacity Released													
- Seasonal	-	-	-	(1.2)	(1.6)	(2.2)	(2.7)	(2.7)	(2.6)	(2.7)	-	-	(15.6)
- Monthly				(0.6)	-	-	-	-	(0.2)	-	-	-	(0.8)
- Daily				(0.1)	(0.4)	(0.6)	(0.7)	(0.2)	(0.6)	-	-	-	(2.6)
Net Impact on Deferral Account	-	-	-	4.7	5.8	9.2	10.7	9.0	11.0	14.7	12.2	12.2	89.5

Forecasted Monthly Unutilized Capacity by Delivery Area
PJ's -

	January	February	March	April	May	June	July	August	September	October	November	December	
UDCDA	-	-	-	3.3	3.9	6.0	7.1	6.0	7.1	8.8	6.0	6.2	54.5
Unutilized Capacity Released													
- Seasonal	-	-	-	(2.2)	(3.1)	(4.5)	(5.5)	(5.5)	(5.3)	(5.5)	-	-	(31.6)
- Monthly	-	-	-	(0.8)	-	-	-	-	(0.3)	-	-	-	(1.1)
- Daily	-	-	-	(0.3)	(0.8)	(1.5)	(1.7)	(0.6)	(1.4)	-	-	-	(6.2)
Net Unutilized Capacity	-	-	-	-	-	-	-	-	-	3.4	6.0	6.2	15.6

Discretionary Requirement

	January	February	March	April	May	June	July	August	September	October	November	December	
PJ's	13.6	22.2	6.8	-	0.0	0.0	-	-	0.0	-	-	3.1	45.8

Month end Storage Capacity Target												
% Fill	0.53	0.37	0.20	0.17	0.26	0.42	0.59	0.77	0.92	1.00	0.93	0.72
Bcf	60.56	42.57	22.64	19.08	29.56	47.69	68.06	88.50	106.01	113.00	106.21	82.42
Month end Storage Capacity												
% Fill	0.52	0.34	0.17	0.16	0.32	0.48	0.62					
Bcf	59.91	38.85	19.07	18.22	36.43	54.81	71.18					

2015 Summer UDC Management Plan

Item #		Column 1	Column 2	Column 3	Column 4	Column 5	Column 6	Column 7	Column 8
	PJ's	April (actual)	May (actual)	June (actual)	July (estimate)	August (estimate)	September (forecast)	October (forecast)	Total
	Days in the month	30	31	30	31	31	30	31	214
1.	Forecasted UDC To Be Mitigated	9.8	8.5	8.3	8.5	8.5	8.6	8.8	61.0
2.	Forecasted Dawn Discretionary Requirement Replaced with Utilization of Long Haul Capacity	0.0	0.0	-	-	-	-	-	0.0
3.	Potential UDC Shed	9.7	8.5	8.3	8.5	8.5	8.6	8.8	61.0
4.	Forecasted Added Utility Requirement	6.4	4.6	2.3	1.4	2.5	1.5	-	18.7
5.	Forecasted Summer Unutilized Capacity	3.3	3.9	6.0	7.1	6.0	7.1	8.8	42.3
6.	April to October Release	2.2	2.3	2.2	2.3	2.3	2.2	2.3	16.0
7.	April Capacity Released for the month	0.8							0.8
8.	April Capacity Released on the day	0.3							0.3
9.	May to October Release	-	0.8	0.8	0.8	0.8	0.8	0.8	4.9
10.	May Capacity Released on the day	-	0.8						0.8
11.	June to October Release	-	-	1.5	1.6	1.6	1.5	1.6	7.7
12.	June Capacity Released on the day			1.5					1.5
13.	July to October Release	-	-	-	0.8	0.8	0.8	0.8	3.1
14.	July Capacity Released on the day				1.7				
15.	August Capacity Released on the day - est					0.6			
16.	September Capacity Released for the month					-	0.3		
17.	Remaining Daily/Monthly Release Capacity	(0.0)	(0.0)	-	-	-	1.4	3.4	7.3
18.	Total Targeted Daily Capactiy to be Released Daily/Monthly (GJ's)	-	(0)	-	-	-	48,009	108,560	

notes: - Item # 11 - The UDC Mitigation Strategy assumed a June to September release of approximately 25,000 GJ's per day. Based upon a review of its summer injection schedule the Company determined that it could release 50,000 GJ's per day for the June to October period

Item # 13 - The UDC Mitigation Strategy assumed a July to September release of approximately 25,000 GJ's per day. Based upon a review of its summer injection schedule the Company determined that it could release this amount for the July to October period

Item # 15 - Estimate includes anticipated daily releases throughout the month of August

Andrew Mandyam
Director, Regulatory Affairs
and Financial Performance

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September 30, 2015

VIA RESS, EMAIL and COURIER

Ms Kirsten Walli
Board Secretary
Ontario Energy Board
2300 Yonge Street, Suite 2700
Toronto, Ontario, M4P 1E4

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Ontario Energy Board File No. EB-2012-0459 / EB-2014-0276

As per the Settlement Agreement in EB-2012-0459 (Exhibit N1, Tab 2, Schedule 1, page 6 of 19) the Company committed to provide a report to the parties of the Settlement Agreement to allow for the ongoing monitoring of UDC impacts in 2014.

The Company, as part of its 2015 Rate Application (EB-2014-0276, Exhibit D1, Tab 2, Schedule 1, page 6 of 11) committed to continue to provide monthly reporting in 2015. Also, the Company developed and filed a 2015 UDC Mitigation Strategy as part of the Supplemental Agreement in EB-2014-0276 and committed to file monthly updates to that mitigation strategy (Ex. N, Tab 1, Schedule 2, page 6, paragraph 4). Please see the attached Report for September 2015.

Please do not hesitate to contact me with any questions.

Yours Truly,

[original signed by]

Andrew Mandyam
Director, Regulatory Affairs and Financial Performance

Attach.

cc: EB-2014-0276 Interested Parties

September 2015 Report

	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Estimate	Estimate	Budget	Budget	Budget	
Demand	January	February	March	April	May	June	July	August	September	October	November	December	
PJ's	85.1	86.2	64.7	37.6	18.5	15.7	15.4	15.1	14.2	27.3	41.7	60.6	482.1

Forecasted Monetary Impacts
$ millions

	January	February	March	April	May	June	July	August	September	October	November	December	
UDCDA	-	-	-	6.6	7.9	12.0	14.0	11.9	14.1	13.5	12.0	12.0	104.0
Revenue From Unutilized Capacity Released													
- Seasonal	-	-	-	(1.2)	(1.6)	(2.2)	(2.7)	(2.7)	(2.6)	(2.7)	-	-	(15.6)
- Monthly				(0.6)	-	-	-	-	-	-	-	-	(0.6)
- Daily				(0.1)	(0.4)	(0.6)	(0.7)	(0.3)	(1.0)	-	-	-	(3.0)
Net Impact on Deferral Account	-	-	-	4.7	5.8	9.2	10.7	9.0	10.5	10.8	12.0	12.0	84.8

Forecasted Monthly Unutilized Capacity by Delivery Area
PJ's -

	January	February	March	April	May	June	July	August	September	October	November	December	
UDCDA	-	-	-	3.3	3.9	6.0	7.1	6.0	6.8	7.0	6.0	6.2	52.4
Unutilized Capacity Released													
- Seasonal	-	-	-	(2.2)	(3.1)	(4.5)	(5.5)	(5.5)	(5.3)	(5.5)	-	-	(31.6)
- Monthly	-	-	-	(0.8)	-	-	-	-	-	-	-	-	(0.8)
- Daily	-	-	-	(0.3)	(0.8)	(1.5)	(1.7)	(0.6)	(1.5)	-	-	-	(6.3)
Net Unutilized Capacity	-	-	-	-	-	-	-	-	-	1.5	6.0	6.2	13.7

Discretionary Requirement

	January	February	March	April	May	June	July	August	September	October	November	December	
PJ's	13.6	22.2	6.8	-	0.0	0.0	-	-	0.0	-	-	3.1	45.8
Month end Storage Capacity Target													
% Fill	0.53	0.37	0.20	0.17	0.26	0.42	0.59	0.77	0.92	1.00	0.93	0.72	
Bcf	60.56	42.57	22.64	19.08	29.56	47.69	68.06	88.50	106.01	113.00	106.21	82.42	
Month end Storage Capacity													
% Fill	0.52	0.34	0.17	0.16	0.32	0.48	0.62	0.76					
Bcf	59.91	38.85	19.07	18.22	36.43	54.81	71.18	86.86					

2015 Summer UDC Management Plan

Item #		Column 1	Column 2	Column 3	Column 4	Column 5	Column 6	Column 7	Column 8
	PJ's	April (actual)	May (actual)	June (actual)	July (actual)	August (estimate)	September (estimate)	October (forecast)	Total
	Days in the month	30	31	30	31	31	30	31	214
1.	Forecasted UDC To Be Mitigated	9.8	8.5	8.3	8.5	8.5	8.6	8.8	61.0
2.	Forecasted Dawn Discretionary Requirement Replaced with Utilization of Long Haul Capacity	0.0	0.0	-	-	-	-	-	0.0
3.	Potential UDC Shed	9.7	8.5	8.3	8.5	8.5	8.6	8.8	61.0
4.	Forecasted Added Utility Requirement	6.4	4.6	2.3	1.4	2.5	1.7	1.9	20.8
5.	Forecasted Summer Unutilized Capacity	3.3	3.9	6.0	7.1	6.0	6.8	7.0	40.2
6.	April to October Release	2.2	2.3	2.2	2.3	2.3	2.2	2.3	16.0
7.	April Capacity Released for the month	0.8							0.8
8.	April Capacity Released on the day	0.3							0.3
9.	May to October Release	-	0.8	0.8	0.8	0.8	0.8	0.8	4.9
10.	May Capacity Released on the day	-	0.8						0.8
11.	June to October Release	-	-	1.5	1.6	1.6	1.5	1.6	7.7
12.	June Capacity Released on the day			1.5					1.5
13.	July to October Release	-	-	-	0.8	0.8	0.8	0.8	3.1
14.	July Capacity Released on the day				1.7				1.7
15.	August Capacity Released on the day					0.6			0.6
16.	September Capacity Released on the day -est					-	1.5		1.5
17.	Remaining Daily/Monthly Release Capacity	(0.0)	(0.0)	-	-	-	-	1.5	1.5
18.	Total Targeted Daily Capactiy to be Released Daily/Monthly (GJ's)	-	(0)	-	-	-	-	48,560	

notes: -

Item # 11 - The UDC Mitigation Strategy assumed a June to September release of approximately 25,000 GJ's per day. Based upon a review of its summer injection schedule the Company determined that it could release 50,000 GJ's per day for the June to October period

Item # 13 - The UDC Mitigation Strategy assumed a July to September release of approximately 25,000 GJ's per day. Based upon a review of its summer injection schedule the Company determined that it could release this amount for the July to October period

Item # 16 - Estimate includes anticipated daily releases throughout the month of September

ENBRIDGE

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Director, Regulatory Affairs
and Financial Performance

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Enbridge Gas Distribution
500 Consumers Road
North York, Ontario M2J 1P8
Canada

October 30, 2015

VIA RESS, EMAIL and COURIER

Ms Kirsten Walli
Board Secretary
Ontario Energy Board
2300 Yonge Street, Suite 2700
Toronto, Ontario, M4P 1E4

Dear Ms Walli:

Re: Enbridge Gas Distribution Inc. 2014 to 2018 Rate Application
Ontario Energy Board File No. EB-2012-0459 / EB-2014-0276

As per the Settlement Agreement in EB-2012-0459 (Exhibit N1, Tab 2, Schedule 1, page 6 of 19) the Company committed to provide a report to the parties of the Settlement Agreement to allow for the ongoing monitoring of UDC impacts in 2014.

The Company, as part of its 2015 Rate Application (EB-2014-0276, Exhibit D1, Tab 2, Schedule 1, page 6 of 11) committed to continue to provide monthly reporting in 2015. Also, the Company developed and filed a 2015 UDC Mitigation Strategy as part of the Supplemental Agreement in EB-2014-0276 and committed to file monthly updates to that mitigation strategy (Exhibit N, Tab 1, Schedule 2, page 6, paragraph 4). Please see the attached Report for October 2015.

Please do not hesitate to contact me with any questions.

Yours Truly,

[original signed]

Andrew Mandyam
Director, Regulatory Affairs and Financial Performance

Attach.

cc: EB-2014-0276 Interested Parties

October 2015 Report

Demand	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Estimate September	Estimate October	Estimate November	Budget December	
PJ's	85.1	86.2	64.7	37.6	18.5	15.7	15.4	15.1	15.2	28.2	42.4	60.6	484.8

Forecasted Monetary Impacts
$ millions

	January	February	March	April	May	June	July	August	September	October	November	December	
UDCDA	-	-	-	6.6	7.9	12.0	14.0	11.9	13.4	14.7	-	12.0	92.5
Revenue From Unutilized Capacity Released													
- Seasonal	-	-	-	(1.2)	(1.6)	(2.2)	(2.7)	(2.7)	(2.6)	(2.7)	-	-	(15.6)
- Monthly				(0.6)	-	-	-	-	-	-	-	-	(0.6)
- Daily				(0.1)	(0.4)	(0.6)	(0.7)	(0.3)	(1.0)	(0.7)	-	-	(3.7)
Net Impact on Deferral Account	-	-	-	4.7	5.8	9.2	10.7	9.0	9.9	11.3	-	12.0	72.6

Forecasted Monthly Unutilized Capacity by Delivery Area
PJ's -

	January	February	March	April	May	June	July	August	September	October	November	December	
UDCDA	-	-	-	3.3	3.9	6.0	7.1	6.0	6.8	7.4	-	6.2	46.9
Unutilized Capacity Released													
- Seasonal	-	-	-	(2.2)	(3.1)	(4.5)	(5.5)	(5.5)	(5.3)	(5.5)	-	-	(31.6)
- Monthly	-	-	-	(0.8)	-	-	-	-	-	-	-	-	(0.8)
- Daily	-	-	-	(0.3)	(0.8)	(1.5)	(1.7)	(0.6)	(1.5)	(2.0)	-	-	(8.2)
Net Unutilized Capacity	-	-	-	-	-	-	-	-	-	-	-	6.2	6.2

Discretionary Requirement

	January	February	March	April	May	June	July	August	September	October	November	December	
PJ's	13.6	22.2	6.8	-	0.0	0.0	-	-	0.0	-	-	3.1	45.8

Month end Storage Capacity Target

% Fill	0.53	0.37	0.20	0.17	0.26	0.42	0.59	0.77	0.92	1.00	0.93	0.72
Bcf	60.56	42.57	22.64	19.08	29.56	47.69	68.06	88.50	106.01	113.00	106.21	82.42

Month end Storage Capacity

% Fill	0.52	0.34	0.17	0.16	0.32	0.48	0.62	0.76	0.92
Bcf	59.91	38.85	19.07	18.22	36.43	54.81	71.18	86.86	105.29

2015 Summer UDC Management Plan

Item #	PJ's	Column 1 April (actual)	Column 2 May (actual)	Column 3 June (actual)	Column 4 July (actual)	Column 5 August (actual)	Column 6 September (estimate)	Column 7 October (estimate)	Column 8 Total
	Days in the month	30	31	30	31	31	30	31	214
1.	Forecasted UDC To Be Mitigated	9.8	8.5	8.3	8.5	8.5	8.6	8.8	61.0
2.	Forecasted Dawn Discretionary Requirement Replaced with Utilization of Long Haul Capacity	0.0	0.0	-	-	-	-	-	0.0
3.	Potential UDC Shed	9.7	8.5	8.3	8.5	8.5	8.6	8.8	61.0
4.	Forecasted Added Utility Requirement	6.4	4.6	2.3	1.4	2.5	1.7	1.3	20.2
5.	Forecasted Summer Unutilized Capacity	3.3	3.9	6.0	7.1	6.0	6.8	7.5	40.7
6.	April to October Release	2.2	2.3	2.2	2.3	2.3	2.2	2.3	16.0
7.	April Capacity Released for the month	0.8							0.8
8.	April Capacity Released on the day	0.3							0.3
9.	May to October Release	-	0.8	0.8	0.8	0.8	0.8	0.8	4.9
10.	May Capacity Released on the day	-	0.8						0.8
11.	June to October Release	-	-	1.5	1.6	1.6	1.5	1.6	7.7
12.	June Capacity Released on the day			1.5					1.5
13.	July to October Release	-	-	-	0.8	0.8	0.8	0.8	3.1
14.	July Capacity Released on the day				1.7				1.7
15.	August Capacity Released on the day					0.6			0.6
16.	September Capacity Released on the day -est					-	1.5	2.0	3.5
17.	Remaining Daily/Monthly Release Capacity	(0.0)	(0.0)	-	-	-	-	0.0	0.0
18.	Total Targeted Daily Capactiy to be Released Daily/Monthly (GJ's)	-	(0)	-	-	-	-	-	

notes: -

Item # 11 - The UDC Mitigation Strategy assumed a June to September release of approximately 25,000 GJ's per day. Based upon a review of its summer injection schedule the Company determined that it could release 50,000 GJ's per day for the June to October period

Item # 13 - The UDC Mitigation Strategy assumed a July to September release of approximately 25,000 GJ's per day. Based upon a review of its summer injection schedule the Company determined that it could release this amount for the July to October period

Item # 16 - Estimate includes anticipated daily releases throughout the month of September

BOMA INTERROGATORY #19

INTERROGATORY

Ref: Exhibit D1, Tab 2, Schedule 3

Please provide the UUF forecast using both the new method and the method used to determine 2015 rates. Show what the actual results in the last five years would have been using the proposed method.

RESPONSE

Table 1 below shows the 2016 UAF forecast using both the proposed model (Model B) and the model used to determine 2015 rates (Model A).

Table 1

UAF Forecast (10^3m^3)		
Col. 1	*Col. 2*	*Col. 3*
Calendar Year	**Model A (from 2015)**	**Model B (Proposed)**
2016F	84,766	92,515

The resulting UUF using Model A with the addition of the unbilled forecast is 101,641.7 10^3m^3.

Table 2 below shows what the UAF forecast would have been in the last five years using the proposed model (Model B).

Table 2

UAF Forecast (10^3m^3)	
Col. 1	*Col. 2*
Calendar Year	**Model B**
2010	48,919
2011	55,972
2012	66,131
2013	118,333
2014	124,213

Witnesses: H. Sayyan
M. Suarez

BOMA INTERROGATORY #20

INTERROGATORY

Ref: Exhibit D1, Tab 2, Schedule 3

Please provide the most recent actuals for UUF for 2015.

RESPONSE

The methodology for forecasting volumes and all inputs to the volumetric determination utilizes the last full year of actual data at the time that forecasts are developed for the rate application. This approach has been applied consistently for ratemaking purposes.
For the 2016 forecast, actual data up to and including 2014 were utilized. From that standpoint, it is the Company's position that partial year information is not indicative of full year results, and is therefore not appropriately used to inform test year expectations.

Witnesses: H. Sayyan
M. Suarez

BOMA INTERROGATORY #21

INTERROGATORY

Ref: Exhibit D1, Tab 2, Schedule 3

Please explain the rationale for changing methods of forecasting UUF at this time, within the IRM period.

RESPONSE

Please see response to VECC Interrogatory # 6 found at Exhibit I.D1.EGDI.VECC.6.

Witnesses: H. Sayyan
M. Suarez

BOMA INTERROGATORY #22

INTERROGATORY

Ref: Exhibit D1, Tab 2, Schedule 4, Page 2

Please provide a detailed explanation for lines 12, 14 and 16.

RESPONSE

For the purpose of forecasting the volumes to be purchased in 2016 (Line Item #11) the Company must take into consideration the forecasted demand and storage requirements in the 1st quarter of 2017. This will assist the Company in forecasting its December 31 storage targets. Line Item # 12 represents the net volumetric injection/withdrawal forecasted to occur during 2016 which when added to the forecast of purchases (Item # 11) will equal the forecasted Sales Sendout for the year (Line Item #13) inclusive of Company Use, UUF and LUF.

Line Item #14 represents the forecasted Storage and Transmission costs to be charged to Gas Costs in 2016 and are broken down in detail in Exhibit D1, Tab 2, Schedule 5.

Line Item # 16 represents the forecasted TCPL transportation costs to move Western T-Service volumes from Empress to the CDA / EDA that are charged to Gas Costs.

Witness: D. Small

BOMA INTERROGATORY #23

INTERROGATORY

Ref: Exhibit D1, Tab 2, Schedule 4, Page 5

Please explain the Total Transportation items, line 2 of $79,412.90. How does this differ from the Transportation Costs at line 8 of Schedule 4?

RESPONSE

The amount of $79.4 million shown on Exhibit D1, Tab 2, Schedule 5, represents the amount the Company is forecasting to recover as a part of its 2016 Gas Cost forecast for costs payable to Union Gas for transmission services from Dawn to Parkway / Lisgar / Kirkwall. The transportation costs shown on line 8 of Exhibit D1, Tab 2, Schedule 4, page 1 represent the costs payable to TCPL and to Vector.

Witness: D. Small

BOMA INTERROGATORY #24

INTERROGATORY

Ref: Exhibit D1, Tab 2, Schedule 4, Page 5

Please explain line 1.4 Market Based Storage $15,185.30 in Exhibit D1, Tab 2, Schedule 5. Is this a payment made by the utility to the unregulated storage company or entity? How was market price determined? Please explain fully.

RESPONSE

The $15.2 million shown at Exhibit D1, Tab 2, Schedule 5 represents the forecasted amount payable to third party storage providers to be recovered as part of the 2016 Gas Cost forecast. None of this amount is for services provided by the Unregulated Storage business of the Utility. The amounts payable to the third parties are the result of an RFP process held annually by the Company for contracted capacity that will be expiring. A listing of those contracts can be found at Exhibit D1, Tab 2, Schedule 2, page 2 of 2.

Witness: D. Small

BOMA INTERROGATORY #25

INTERROGATORY

Ref: Exhibit D1, Tab 2, Schedule 6, Page 1

BOMA would like to better understand how the various transportation contracts underpin the 2016 Budget Peak Day Demand. Could EGD provide for each of lines 4 through 11, inclusive, for 2016, separately for CDA and EDA, which transportation contracts underpin the volumes provided to meet peak day demand? Could you cross-reference the list to the list of Transportation Contracts provided at D1, T2 Schedule 2, Page 1 to ensure all contracts are accounted for, other than ones that expire before the test year begins? Please provide the expiry date for each of the contracts.

RESPONSE

The attached table provides the corresponding contract references for Item #'s 4, 6, 7 and 9. Item #5 refers to STFT which the Company is forecasting zero in the CDA and the EDA. Item #8 represents the forecasted daily deliveries into the CDA and the EDA from Ontario T-Service customers. The delivery into the CDA of 231,114 GJ's includes a volume of 122,978 GJ's forecasted to be delivered at Dawn and transported to the CDA via short haul TCPL transportation that the Company has assigned to customers as a part of Phase 1 of the Dawn Access Consultative. Item #10 is made up of two components; an arrangement with a third party for delivery to the CDA and withdrawals from the Crowland Storage facility which is a Company owned storage facility located in the Niagara Region of the Company's distribution system. Item #11 is the forecasted amount of Peaking Service required in the EDA which, at the time the evidence was prepared, had not been contracted for.

The following Items have not been included in the attached spreadsheet:

Item #'s 15 and 33 are contracts that come into effect November 1, 2016 and are therefore not available for meeting 2016 Peak Day.

Item # 17 is for transportation capacity to move NIT supplies to Empress which then would be transported on one of the long haul TCPL contracts i.e., TCPL FT – CDA.

Item # 18 is transportation capacity on Alliance to move gas from CREC to Chicago which then would be transported on Vector to Dawn.

Witness: D. Small

Item #'s 19 – 22 are transportation capacity on the Vector Pipeline to move gas from Chicago to Dawn. For Peak Day purposes these volumes are transported to the franchise area either on Union Gas Dawn to Parkway capacity or TCPL FT Dawn to CDA/EDA capacity.

Item #31 is intended to move gas westerly on the Union system from Parkway to Dawn and is not used on Peak Day.

Item # 32 is contracted capacity from Union Dawn to Parkway but does not come into effect until November 1, 2017.

Witness: D. Small

2016 Budget Peak Day Demand

Item #	GJ's	Column 4 CDA	Ex D1, T2, S2, page 1 Reference - Item #'s	Column 5 EDA	Ex D1, T2, S2, page 1 Reference - Item #'s	Column 6 Total
1.	Demand	3,321,901		686,930		4,008,832
2.	Less Curtailment	(87,208)		(36,056)		(123,263)
3.	Net Peak Day Demand	3,234,694		650,875		3,885,568
4.	TCPL FT Capacity	138,468	1 + 2	390,377	3 + 4 + 5	528,845
5.	TCPL STFT	-		-		-
6.	TCPL Short Haul	226,840	6 + 7 + 16	154,000	8 + 9	380,841
7.	TCPL STS	369,465	10 + 11+ 12	80,611	13 + 14	450,076
8.	Ontario T-Service	231,114		5,417		236,531
9.	Union Deliveries	2,175,027	23 to 30 + 32 Less Item # 7	-		2,175,027
10.	Delivered Service	132,738		-		132,738
11.	Peaking Service	-		20,469		20,469
12.	Total Supply	3,273,653		650,875		3,924,527
13.	Sufficency/(Deficiency)	38,959		-		38,959

ENERGY PROBE INTERROGATORY #4

INTERROGATORY

Ref: Exhibit D1, Tab 1, Schedule 2

Please break down the $134.8 million increase in gas costs into the amounts associated with the updated 2016 volume forecast, the gas supply plan and the July 1, 2015 QRAM prices.

RESPONSE

As the attached table illustrates there are three primary reasons for the difference in the gas cost forecast between the 2016 Utility Placeholder and the 2016 Updated Forecast.

First, the 2016 Placeholder was based upon the April 2013 QRAM Reference Price in place at that time while the 2016 Updated Forecast is based upon the July 15 QRAM Reference Price.

Second, while the TCPL tolls in place at the time of the development of the 2016 Updated Forecast are lower than when the 2016 Placeholder was prepared there has been an increase in the forecasted Western T- Service volumes.

And third, the forecast of Storage and Transportation Charges has increased as a result of increases in the contracted Union M12 capacity.

Witnesses: D. Small
R. Small

Item #		Adjusted April 13 QRAM 2016 Placeholder			Adjusted July 15 QRAM 2016 Updated Forecast			Difference
		10*3 m*3	$/10*3 m*3	$ million's	10*3 m*3	$/10*3 m*3	$ million's	$ million's
1.	Sendout Volume	7,973,311.2	183.599	1,463.9	8,017,136.0	196.253	1,573.4	109.5
2.	Western T-Service	745,954.9	84.535	63.1	1,018,737.4	75.303	76.7	13.7
3.	- excludes Ontario T-Service volumes	8,719,266.1		1,527.0	9,035,873.4		1,650.1	123.1
4.	Storage And Transportation Charges			105.6			117.2	11.7
5.	- as Ex D1, T1, Sch. 2, page 1 of 2 - Line # 1			1,632.5			1,767.3	134.8

ENERGY PROBE INTERROGATORY #5

INTERROGATORY

Ref: Exhibit D1, Tab 2, Schedule 3

a) Please provide the forecast of 2016 UUF using Model A. Please provide the calculation in the same level of detail as shown on page 7.

b) How is the variance between the actual and forecasted UUF treated? Please explain fully.

RESPONSE

a) 2016 UUF (2016 Model A)*
= (Forecast of UAF Gas) + (Change in Unbilled Gas)
= (Forecast of UAF Gas) + (Dec2016 Unbilled - Dec2015 Unbilled Forecast)
= 72,419 103m3 + (736,570.1 103m3– 719,794.4 103m3)
= 72,419 103m3 + 16,775.7 103m3
= 89,194.7 103m3

**Relies on unlocks as explanatory variable and dummy variable for high UAF values.*

b) The variance between the actual and forecasted UUF is trued-up through the UAF Variance Account ("UAFVA").

As described in the Accounting Treatment for the UAFVA, the purpose of the UAFVA is to record the cost of gas that is associated with volumetric variances between the actual volume of Unaccounted For Gas ("UAF") and the Board approved UAF volumetric forecast.

The UAF annual variance will be allocated on a monthly basis in proportion to actual sales and costed at the monthly PGVA reference price. Where there are recoveries of gas loss amounts invoiced as part of third party damages, the gas loss amounts will be removed from the UAFVA balance. Carrying costs for the UAFVA will be calculated using the Board Approved EB-2006-0117 interest rate methodology. The balance of the UAFVA, together with the carrying charges, will be disposed of in a manner designated by the Board in a future rate hearing.

Witnesses: H. Sayyan
M. Suarez

FRPO INTERROGATORY #3

INTERROGATORY

REF: Exhibit D, Tab 2, Schedule 1, Page 2

Preamble: *"Subsequent to the development of its gas supply plan the Company began exploring opportunities with suppliers for a portion of its requirements. One such supply opportunity was a means of base loading a portion of the Chicago requirement. The Company has entered into a tentative agreement with a counterparty for supply from western Canada to Chicago via an eleven month assignment of Alliance transportation capacity".*

In addition to the update request by Board staff in their interrogatories submitted 20151023:

Please provide a comparison of alternatives considered including some form of landed gas cost analysis and dates any Vector capacity could be turned back.

RESPONSE

Please see response to Board Staff Interrogatory #4 at Exhibit I.D1.EGDI.STAFF.4.
As set out in response to Board Staff Interrogatory #4, the deal in question would result in approximately $0.3 million in savings assuming the prices at the time the analysis was prepared.

The Vector transportation contracts currently expire November 30, 2018 and require 3 years notice for renewal of an additional year.

Witness: D. Small

FRPO INTERROGATORY #4

INTERROGATORY

REF: Exhibit D, Tab 2, Schedule 1, Page 2

Preamble: *"Subsequent to the development of its gas supply plan the Company began exploring opportunities with suppliers for a portion of its requirements. One such supply opportunity was a means of base loading a portion of the Chicago requirement. The Company has entered into a tentative agreement with a counterparty for supply from western Canada to Chicago via an eleven month assignment of Alliance transportation capacity".*

In addition to the update request by Board staff in their interrogatories submitted 20151023:

Please confirm that the counter-party was not Tidal Energy Marketing or other Enbridge affiliated company.

RESPONSE

The arrangement is with an Enbridge affiliate – Aux Sable.

Witness: D. Small

FRPO INTERROGATORY #5

INTERROGATORY

REF: Exhibit D, Tab 2, Schedule 1, Page 3

Preamble: "*In an effort to isolate the impact of commodity costs changes the Company removed the impact of the updated price forecast and the July 1, 2015 QRAM prices in a fashion similar to that used in the determination of the 2015 gas cost budget that was filed in EB-2014-0276.*"

We would like to understand this approach better as the descriptive paragraph does not reference any depiction of this work.

Please explain the need to isolate the impact of commodity cost changes by removing the updated price forecast.

a) Please show the effect of this removal (i.e., before and after)
b) Please show the effect of using the values from the most recent QRAM (EB-2015-0242)

RESPONSE

a) Within the Board's EB-2005-0494 initiative, the Minimum Filing Requirement for Natural Gas Distribution Cost of Service Applications determined that Utilities should provide any Test Year revenue sufficiency or deficiency calculations net of gas commodity price changes captured in a QRAM. It was also required that within any annual rate application filing, the commodity cost used would be that available from the most recent approved QRAM at the time of the filing.

   Enbridge's current budget process, as described below, ensures that the impact of commodity price changes does not influence the revenue sufficiency/deficiency calculations for an upcoming Test Year.

   To calculate the July 2015 QRAM, the Company takes the same 21 day average of forward monthly pricing that underpins its most recent QRAM and applies those monthly averages to the updated supply portfolio. For example, the July 2015 QRAM was based upon a 21 day average of prices for the July 2015 to June 2016 period calculated from May 1, 2015 to May 29, 2015, with these prices applied to the applicable monthly volumes within the 2015 Board approved supply plan. The starting point in the costing of the 2016 supply portfolio is to use the same 21 day period that underpins the July 2015 QRAM but calculate monthly averages of pricing for the January 2016 to December 2016 period and apply these forecast of prices to the applicable monthly volumes within the 2016 supply portfolio. However, in doing so this will create a commodity price change or variance when the corresponding gas costs are compared to 2016 forecasted revenues which are calculated using the revenue rates from the July 2015 QRAM. Therefore, by using the average annual rates from the July 2015 QRAM and applying them to the annual 2016 supply portfolio then commodity differences are eliminated. However, because the mix of supplies for the 2016 Test Year is different from the 2015 Test Year, a slightly different PGVA Reference price will be calculated which will be captured in the determination of the sufficiency/deficiency, i.e the impact of a supply change with no impact due to price changes.

The gas exhibits as shown at Exhibit D1, Tab 2, Schedule 4 are developed using the forecast of 2016 forward prices applied to the 2016 supply portfolio but then increased by $86.1 million as a forecast PGVA adjustment to bring the overall purchase cost to the Adjusted PGVA Reference price described above in order to eliminate the impact of commodity price changes in the derivation of the 2016 sufficiency/deficiency calculations.

b) There is no need to update the gas commodity reference price used within the forecast of revenues, gas costs, and gas in storage in 2016 as commodity price changes are handled within the approved QRAM process. This has been the consistent approach since the Board approved the current QRAM process.

Witness: D. Small

FRPO INTERROGATORY #6

INTERROGATORY

REF: Exhibit D, Tab 2, Schedule 1, Page 5

Preamble: "*The Company has another short haul contract with TCPL for capacity from Dawn to Iroquois. In previous years, the Company assumed utilization of this capacity for purposes of meeting its peak day requirements in the Enbridge CDA . With incremental transport on Union Gas available in 2016, the Company intends to use this capacity for purposes of meeting peak day demand in the Enbridge EDA for 2016. With incremental transport on Union Gas available in 2016, the Company intends to use this capacity for purposes of meeting peak day demand in the Enbridge EDA for 2016.*"

We would like to understand these arrangements better.

For the previous years, why was an Iroquois delivery point used for a CDA peaking need?

RESPONSE

It was under the terms of TCPL's service, a diversion on TCPL from Iroquois to CDA would be considered an upstream diversion and not subject to a possible interruption, therefore it is appropriate for meeting peaking needs in the CDA.

Witness: D. Small

FRPO INTERROGATORY #7

INTERROGATORY

REF: Exhibit D, Tab 2, Schedule 1, Page 5

Preamble: "*The Company has another short haul contract with TCPL for capacity from Dawn to Iroquois. In previous years, the Company assumed utilization of this capacity for purposes of meeting its peak day requirements in the Enbridge CDA . With incremental transport on Union Gas available in 2016, the Company intends to use this capacity for purposes of meeting peak day demand in the Enbridge EDA for 2016. With incremental transport on Union Gas available in 2016, the Company intends to use this capacity for purposes of meeting peak day demand in the Enbridge EDA for 2016.*"

We would like to understand these arrangements better.

What evidence does Enbridge have of the incremental transport on Union Gas being available in 2015?

a) How does EGD intend to contract for that transport to ensure firm deliveries on a peak day?

RESPONSE

Enbridge has a contract with Union Gas for an incremental 400,000 GJ/day of capacity from Union Dawn to Parkway. Please see Exhibit D1, Tab 2, Schedule 2, page 1, Item #32.

Witness: D. Small

FRPO INTERROGATORY #8

INTERROGATORY

REF: Exhibit D, Tab 2, Schedule 1, Page 5

Preamble: "*The Company has another short haul contract with TCPL for capacity from Dawn to Iroquois. In previous years, the Company assumed utilization of this capacity for purposes of meeting its peak day requirements in the Enbridge CDA . With incremental transport on Union Gas available in 2016, the Company intends to use this capacity for purposes of meeting peak day demand in the Enbridge EDA for 2016. With incremental transport on Union Gas available in 2016, the Company intends to use this capacity for purposes of meeting peak day demand in the Enbridge EDA for 2016.*"

We would like to understand these arrangements better.

When does EGD intend to initiate Phase 2 of the Dawn Access Consultative?

RESPONSE

The Company intends to initiate Phase 2 of the Dawn Access Settlement on November 1, 2017. In accordance with section 2.2.7 of the Dawn Access Settlement, elections made by eligible customers for the Dawn Transportation Service are expected to come into effect on the later of November 1, 2017 and their current pool renewal date.

Witness: D. Small

FRPO INTERROGATORY #9

INTERROGATORY

REF: Exhibit D, Tab 2, Schedule 1, Page 6

Preamble: "*The Company is forecasting storage targets such that maximum deliverability from storage can be maintained until the end of February and that deliverability from storage is sufficient to meet March peak day demand as late as March 31.*

While we respect that Enbridge has made some changes to storage planning that, in our view, are improvements, we would like to understand this shift better.

How is a March peak day, as referenced above, different from a winter peak day?

a) Please quantify the difference and the data used to set the March day.
b) How much additional gas must EGD keep in storage using this approach than quantifying a March 31st peak day determined by using a "one in ten" highest HDD for the March 15-31st period.

RESPONSE

In order to provide an accurate record for this proceeding, the Company notes that the preamble reference is located on Page 9, and not Page 6 of Exhibit D, Tab 2, Schedule 1.

a) For the 2015 gas supply plan, the level of demand for the winter peak day is 4.0 PJ and for the March peak day is 2.7 PJ. The data used to establish the level of demand is predicated on the gas volume budget identified in Exhibit C1, Tab 2, Schedule 1, the budget degree days identified in Exhibit C2, Tab 1, Schedule 2, and customer additions identified in Exhibit C2, Tab 1, Schedule 4. This information is used in conjunction with the design criteria that have been approved by the Board in EB-2011-0354 which includes heating degree days used for the 18 multi-peaks based on a 1 in 5 recurrence interval as filed in EB-2011-0354, at Exhibit D2, Tab 4, Schedule 2.

b) The Company is not seeking to change the design criteria approved by the Board in EB-2011-0354 which assumed a 1 in 5 recurrence interval. The Company has not evaluated the implications of incorporating alternative design criteria such as a "one in ten" recurrence interval. The Company declines to provide the requested information as it is beyond the scope of this proceeding and would require significant work to complete.

Witness: D. Small

FRPO INTERROGATORY #10

INTERROGATORY

REF: Exhibit D, Tab 2, Schedule 1, Page 10

Preamble: "*Enbridge has used a gross heating value of 37.69 MJ/m3 to convert quantities (i.e., GJ, Dth) into volumes (i.e., 103m3, MMcf). Quantities are the units specified in many of Enbridge's gas purchase and transportation service agreements, whereas Enbridge rates are volumetric*"

How does Enbridge account for the variability in heating value as it pertains to:
a) Unbilled and unaccounted for gas?
b) Consumption conversions for direct purchase customers?

RESPONSE

a) The monthly unbilled volumetric information is determined by the Unbilled Regression Model and the input data to the model is based upon customer billed consumption information which is recorded in cubic metres (m*3) and therefore variations in actual heat value will be captured over time.

   Monthly purchases of gas from suppliers and delivery of that gas by shippers to Enbridge is billed in GJ. To convert the monthly purchases from GJ to 10*3 m*3 the Company uses a weighted average heat value for that month. It is this weighted average heat value that is used to determine the 10*3 m*3 equivalent for the Company's "Sendout" for the month which when compared to customer consumption is the basis for Unaccounted For.

b) For purposes of establishing a Direct Purchase customer's daily GJ delivery, the estimated annual consumption, in m*3, is converted assuming 37.69MJ/m*3. Estimated monthly deliveries, in GJ, are converted to m*3 using the same 37.69 MJ/m*3 conversion. Ultimately, differences between actual and estimated consumption for Direct Purchase customers are captured and charged / credited through the Banked Gas Account. Therefore, no variability in heat value exists.

Witness: D. Small

FRPO INTERROGATORY #11

INTERROGATORY

REF: Exhibit D, Tab 2, Schedule 1, Page 10

Preamble: "*Enbridge has used a gross heating value of 37.69 MJ/m3 to convert quantities (i.e., GJ, Dth) into volumes (i.e., 103m3, MMcf). Quantities are the units specified in many of Enbridge's gas purchase and transportation service agreements, whereas Enbridge rates are volumetric"*

Please provide the average heating value for each of the last twelve months of available data for deliveries into EGD franchise .

a) Using the average heating value for the last 12 months:
   i) What impact would using that value instead of 37.69 MJ/m3 have on rates? To be clear, we are not asking for a specific rates but any % adjustment

RESPONSE

The table on the following pages provides the average monthly heat value for the period October 14 to September 15.

Witness: D. Small

	CDA	Parkway	EDA
		Average MJ/m*3	
Oct-14	37.063	38.042	37.809
Nov-14	37.941	38.702	38.117
Dec-14	38.684	38.839	38.431
Jan-15	38.416	38.599	38.383
Feb-15	38.598	38.650	38.588
Mar-15	38.610	38.829	38.505
Apr-15	38.271	38.501	38.268
May-15	37.806	38.052	38.050
Jun-15	37.839	38.064	38.032
Jul-15	37.935	38.073	38.045
Aug-15	37.903	37.951	37.946
Sep-15	38.650	38.787	38.650
	38.143	38.424	38.235

As shown in the table above, on average the actual monthly heating values in the last 12 months were slightly higher than the heating value assumption of 37.69 MJ/m3 used by the Company.

For purposes of establishing the volumetric forecast, the Company uses actual billed information and normalizes for both degree days and heat content to determine a use per degree day assuming 37.69 MJ/m*3. Should the heating value of gas delivered into the Company's franchise area remain consistently higher than is currently used in the forecasting process, then using a higher heat value in the forecasting process would translate (everything else being equal) into a lower volumetric consumption at the burner tip (i.e. a higher heating value of gas means that less volumetric units are required at the burner tip to achieve the same energy / heat output of a burner tip).

A lower forecasted consumption at the burner tip would put an upward pressure on the Company's delivery rates as the distribution revenue requirement / allowed revenues would be divided over a smaller denominator in the rate design process.

Therefore, the result of using a higher heat value in the forecasting process would be an increase in the Company's delivery rates.

Witness: D. Small

With respect to gas costs, the actual Purchase Gas variance Account (“PGVA”) reference price in a month reflects the actual gas costs divided by the actual volumes purchased for a month which do reflect the average heat content for that month. Actual purchase costs that are higher / lower than the forecast and/or actual volumes that are higher / lower than the forecast will be reflected in the derivation of the actual PGVA reference price.

The difference between the forecast PGVA and the actual PGVA reference price is recorded in the PGVA. This PGVA account ensures that the customers and the utility are kept whole with respect to gas costs.

FRPO INTERROGATORY #12

INTERROGATORY

REF: Exhibit D, Tab 2, Schedule 2, Page 1 and EB-2014-0276, Ex. D, Tab 2, Sch. 2, Pg. 1 and EB-2012-0459/2014-0276 EDGI_MONTHLY_UDC_GAS REPORT 20150930

We would like to understand the transition of long-haul (LH) and short-haul (SH) contracts and the impact on storage fill.

Comparing the two referenced tables, it appears that the TCPL FT-CDA contracts in lines 2-4 of last year's status summary scheduled for expiry in Oct. 15 have been converted into one smaller contract in line 2 of this year's report extended to Oct. 18.

a) Please confirm our reading or explain if different.
b) Please discuss what drove the change to extend some of the capacity as opposed to terminating all of the capacity.
c) Please describe how the decision to contract for the 25,000 mcf in line 18 of this year's summary fit into the conversion plan

RESPONSE

a) The three contracts identified on Line Items 2 to 4 of the Status of Transportation Contracts schedule filed in EB-2014-0276 (Exhibit D1, Tab 2, Schedule 2) have not been converted into one smaller contract. The 201,070 GJ's of capacity identified as Item # 2 was scheduled to expire October 31, 2015, but was renewed until either October 31, 2016 or the in-service date of the GTA Project whichever came first. Items # 3 and 4 for 9,000 GJ's and 56,000 GJs respectively were non-renewable contracts and expired October 31, 2015 and December 31, 2015. Item # 43 of the same exhibit identified a pending contract for 75,000 GJ's per day. This is the contract that is identified as Item # 2 on the 2016 schedule. Also, Item 1 identifies 63,468 GJ's per day of Long Haul capacity which will be converted to Short Haul effective November 1, 2017.

b) See response to a)

c) As described in Note 1 on page 2 of the pre-filed evidence (Exhibit D1, Tab 2, Schedule 1), the Company was looking to acquire a portion of the forecasted Chicago supply via an annual arrangement. A potential supplier submitted a proposal whereby the Company would acquire Alberta supply and take an assignment of Alliance capacity to move the gas to Chicago. The Company would then use its contracted Vector capacity to move the gas to Dawn. Line 18 represents the assignment of Alliance capacity. This arrangement is further described in response to Board Staff Interrogatory #4 at Exhibit I.DI.EGDI.STAFF.4

FRPO INTERROGATORY #13

INTERROGATORY

REF: Exhibit D, Tab 2, Schedule 2, Page 1 and EB-2014-0276, Ex. D, Tab 2, Sch. 2, Pg. 1 and EB-2012-0459/2014-0276 EDGI_MONTHLY_UDC_GAS REPORT 20150930

We would like to understand the transition of long-haul (LH) and short-haul (SH) contracts and the impact on storage fill.

With TCPL'S Kings North incomplete as of Nov. 1, 2015, will EGD be indeed flowing gas as January 1, 2016 as described in this year's summary status:

a) Please summarize the amount flowing on each path on January1, 2016 with an expected summer 2016 in-service date for Kings North.
b) How is the transitional service being tolled?
c) Please summarize arrangements made for transition to the new paths upon in-service completion.
d) Does EGD intend to operate transitional long-haul contracts differently during the non-peak winter season?

RESPONSE

As indicated in the response to CCC Interrogatory #4 found at I.D2.EGDI.CCC.4, the expected in-service date for TransCanada's King's North Connection Pipeline Project is November 1, 2016 and not November 1, 2015. The transportation contracts identified in Exhibit D1, Tab 2, Schedule 2, page 1 of 2 are not dependent on TransCanada's King's North Connection Pipeline Project and as a result the Company anticipates that the transportation contracts will be available on January 1, 2016. For discussion of the impacts of the updated in-service dates for the GTA project Segment A, please see the response to Board Staff Interrogatory #3 found at Exhibit I.D1.EGDI.STAFF.3

a) Please see the main response to this interrogatory.

b) It is unclear what specific transitional service is being referred to in this interrogatory. If the reference to transitional service corresponds to a contingency transportation service for January 1, 2016 in the event of in-service delays for the King's North Connection Pipeline Project, the Company has not contracted for any such service for reasons indicated in the main response to this interrogatory.

Witnesses: A. Kacicnik
D. Small

c) Please see the response to part b) of this interrogatory.

d) Please see the response to part b) of this interrogatory.

Witnesses: A. Kacicnik
D. Small

FRPO INTERROGATORY #14

INTERROGATORY

REF: Exhibit D, Tab 2, Schedule 2, Page 1 and EB-2014-0276, Ex. D, Tab 2, Sch. 2, Pg. 1 and EB-2012-0459/2014-0276 EDGI_MONTHLY_UDC_GAS REPORT 20150930

We would like to understand the transition of long-haul (LH) and short-haul (SH) contracts and the impact on storage fill.

Referring to the September 2015 UDC Report:

a) Please explain the need to shed 6 plus PJ in November and December.
b) Does EGD have any delivered service or Dawn discretionary purchases scheduled for these months?
c) What is the UDC impact of the additional negotiated Alliance contract for December UDC?

RESPONSE

a) The Company has attached a copy of the October 2015 UDC Report as a reference. The October 2015 Report has been updated to reflect that the Company is now forecasting zero UDC in the month of November 2015. While the forecast for December 2015 still shows the need to shed 6.2 PJ of UDC in that month, the original forecast also indicated a discretionary requirement of 3.1 PJ. The expectation at this time is the Company will require that supply and rather than acquiring this supply at Dawn, the Company will use unutilized transport first before acquiring Dawn discretionary supply.

b) See response to part a).

c) There is no UDC impact because of the assignment of Alliance capacity. The decision to take on the assignment was intended to provide diversity within the 2016 supply portfolio and to act as an alternative to buying gas in Chicago which will be moved on the Vector contracted capacity.

Witness: D. Small

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Director, Regulatory Affairs
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Enbridge Gas Distribution
500 Consumers Road
North York, Ontario M2J 1P8
Canada

October 30, 2015

VIA RESS, EMAIL and COURIER

Ms Kirsten Walli
Board Secretary
Ontario Energy Board
2300 Yonge Street, Suite 2700
Toronto, Ontario, M4P 1E4

Dear Ms Walli:

Re: Enbridge Gas Distribution Inc. 2014 to 2018 Rate Application
Ontario Energy Board File No. EB-2012-0459 / EB-2014-0276

As per the Settlement Agreement in EB-2012-0459 (Exhibit N1, Tab 2, Schedule 1, page 6 of 19) the Company committed to provide a report to the parties of the Settlement Agreement to allow for the ongoing monitoring of UDC impacts in 2014.

The Company, as part of its 2015 Rate Application (EB-2014-0276, Exhibit D1, Tab 2, Schedule 1, page 6 of 11) committed to continue to provide monthly reporting in 2015. Also, the Company developed and filed a 2015 UDC Mitigation Strategy as part of the Supplemental Agreement in EB-2014-0276 and committed to file monthly updates to that mitigation strategy (Exhibit N, Tab 1, Schedule 2, page 6, paragraph 4). Please see the attached Report for October 2015.

Please do not hesitate to contact me with any questions.

Yours Truly,

[original signed]

Andrew Mandyam
Director, Regulatory Affairs and Financial Performance

Attach.

cc: EB-2014-0276 Interested Parties

October 2015 Report

	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Estimate	Estimate	Estimate	Budget	
Demand	January	February	March	April	May	June	July	August	September	October	November	December	
PJ's	85.1	86.2	64.7	37.6	18.5	15.7	15.4	15.1	15.2	28.2	42.4	60.6	484.8

Forecasted Monetary Impacts
$ millions

	January	February	March	April	May	June	July	August	September	October	November	December	
UDCDA	-	-	-	6.6	7.9	12.0	14.0	11.9	13.4	14.7	-	12.0	92.5
Revenue From Unutilized Capacity Released													
- Seasonal	-	-	-	(1.2)	(1.6)	(2.2)	(2.7)	(2.7)	(2.6)	(2.7)	-	-	(15.6)
- Monthly				(0.6)	-	-	-	-	-	-	-	-	(0.6)
- Daily				(0.1)	(0.4)	(0.6)	(0.7)	(0.3)	(1.0)	(0.7)	-	-	(3.7)
Net Impact on Deferral Account													
	-	-	-	4.7	5.8	9.2	10.7	9.0	9.9	11.3	-	12.0	72.6

Forecasted Monthly Unutilized Capacity by Delivery Area
PJ's -

	January	February	March	April	May	June	July	August	September	October	November	December	
UDCDA	-	-	-	3.3	3.9	6.0	7.1	6.0	6.8	7.4	-	6.2	46.9
Unutilized Capacity Released													
- Seasonal	-	-	-	(2.2)	(3.1)	(4.5)	(5.5)	(5.5)	(5.3)	(5.5)	-	-	(31.6)
- Monthly	-	-	-	(0.8)	-	-	-	-	-	-	-	-	(0.8)
- Daily	-	-	-	(0.3)	(0.8)	(1.5)	(1.7)	(0.6)	(1.5)	(2.0)	-	-	(8.2)
Net Unutilized Capacity													
	-	-	-	-	-	-	-	-	-	-	-	6.2	6.2

Discretionary Requirement

	January	February	March	April	May	June	July	August	September	October	November	December	
PJ's	13.6	22.2	6.8	-	0.0	0.0	-	-	0.0	-	-	3.1	45.8
Month end Storage Capacity Target													
% Fill	0.53	0.37	0.20	0.17	0.26	0.42	0.59	0.77	0.92	1.00	0.93	0.72	
Bcf	60.56	42.57	22.64	19.08	29.56	47.69	68.06	88.50	106.01	113.00	106.21	82.42	
Month end Storage Capacity													
% Fill	0.52	0.34	0.17	0.16	0.32	0.48	0.62	0.76	0.92				
Bcf	59.91	38.85	19.07	18.22	36.43	54.81	71.18	86.86	105.29				

2015 Summer UDC Management Plan

Item #	PJ's	Column 1 April (actual)	Column 2 May (actual)	Column 3 June (actual)	Column 4 July (actual)	Column 5 August (actual)	Column 6 September (estimate)	Column 7 October (estimate)	Column 8 Total
	Days in the month	30	31	30	31	31	30	31	214
1.	Forecasted UDC To Be Mitigated	9.8	8.5	8.3	8.5	8.5	8.6	8.8	61.0
2.	Forecasted Dawn Discretionary Requirement Replaced with Utilization of Long Haul Capacity	0.0	0.0	-	-	-	-	-	0.0
3.	Potential UDC Shed	9.7	8.5	8.3	8.5	8.5	8.6	8.8	61.0
4.	Forecasted Added Utility Requirement	6.4	4.6	2.3	1.4	2.5	1.7	1.3	20.2
5.	Forecasted Summer Unutilized Capacity	3.3	3.9	6.0	7.1	6.0	6.8	7.5	40.7
6.	April to October Release	2.2	2.3	2.2	2.3	2.3	2.2	2.3	16.0
7.	April Capacity Released for the month	0.8							0.8
8.	April Capacity Released on the day	0.3							0.3
9.	May to October Release	-	0.8	0.8	0.8	0.8	0.8	0.8	4.9
10.	May Capacity Released on the day	-	0.8						0.8
11.	June to October Release	-	-	1.5	1.6	1.6	1.5	1.6	7.7
12.	June Capacity Released on the day			1.5					1.5
13.	July to October Release	-	-	-	0.8	0.8	0.8	0.8	3.1
14.	July Capacity Released on the day				1.7				1.7
15.	August Capacity Released on the day					0.6			0.6
16.	September Capacity Released on the day -est					-	1.5	2.0	3.5
17.	Remaining Daily/Monthly Release Capacity	(0.0)	(0.0)	-	-	-	-	0.0	0.0
18.	Total Targeted Daily Capactiy to be Released Daily/Monthly (GJ's)	-	(0)	-	-	-	-	-	

notes: - Item # 11 - The UDC Mitigation Strategy assumed a June to September release of approximately 25,000 GJ's per day. Based upon a review of its summer injection schedule the Company determined that it could release 50,000 GJ's per day for the June to October period

Item # 13 - The UDC Mitigation Strategy assumed a July to September release of approximately 25,000 GJ's per day. Based upon a review of its summer injection schedule the Company determined that it could release this amount for the July to October period

Item # 16 - Estimate includes anticipated daily releases throughout the month of September

FRPO INTERROGATORY #15

INTERROGATORY

REF: Exhibit D, Tab 2, Schedule 2, Page 2

Please provide the total storage capacity available to EGD each of the last three winters.

RESPONSE

The total available capacity the last three winters is as follows:

PJ	
2013	120.2
2014	120.5
2015	121.5

The marginal year over year increase has occurred due to the replacement of expiring contracts with offers from counter parties from the RFP process.

Every year the Company goes through a RFP process to replace a portion of its third party storage arrangements that will be expiring. RFP's received provide a variety of storage offerings not only with respect to the amount of storage capacity being offered but the various terms around that capacity including injection and withdrawal capabilities and daily flexibility.

This can mean that in exchange for lower cost or other attributes offered the amount of storage can vary somewhat. When evaluating responses from counterparties for storage service a number of factors must be considered such as firm injections late season and deliverability from storage throughout the winter. What also must be considered is the type of service available as a part of the non-expiring contracts in order to ensure that collectively the services from all storage contracts meet the needs of the Company.

As a consequence the replacement of expiring storage is not necessarily always on a one for one basis in terms of storage capacity.

Witness: D. Small

FRPO INTERROGATORY #16

INTERROGATORY

REF: Exhibit D, Tab 2, Schedule 2, Page 2

In previous proceedings, EGD indicated its intent to purchase more storage after some analysis.
a) Please file the analysis that supports the current approach
b) Please provide any analysis that supports plans to evolve the storage capacity figure.

RESPONSE

a) The Company has not applied to change the total storage capacity in this application from what was approved in the previous year's rate application (EB-2014-0276). The Company chose to maintain the current level of total storage capacity in anticipation of the storage analysis that is discussed in part b) of this response.

b) The Company has conducted a preliminary analysis of incremental storage capacity and a summary is provided in the table below. The summary was included in the Company's presentation at the 2014 Natural Gas Market Review (EB-2014-0289) and in the 2014 Earning Sharing Mechanism proceeding (EB-2015-0122, Exhibit D, Tab 3, Schedule 1, page 109) as part of the 2015 Customer IR Stakeholder Day presentation.

Incremental Storage Requirements*: Various Design Criteria (Normal Distribution)

Design Criteria Recurrence Interval	Associated Probability of Being ≥	Central Weather Zone Winter HDD	Incremental Storage Requirement (Bcf)
Current 1 in 2	50%	2,945	-
1 in 5	20%	3,207	9
1 in 10	10%	3,303	14
1 in 15	≈6%	3,364	16
Peak Day Equivalent	5.7%	3,369	16
1 in 20	5%	3,384	21
* Analysis based on 2015 budget			

Witness: D. Small

The Company does not have a complete and detailed analysis at this point in time. The Company intends to perform a detailed review of the need for incremental storage and will update the Board and interested parties when the analysis has been completed.

FRPO INTERROGATORY #17

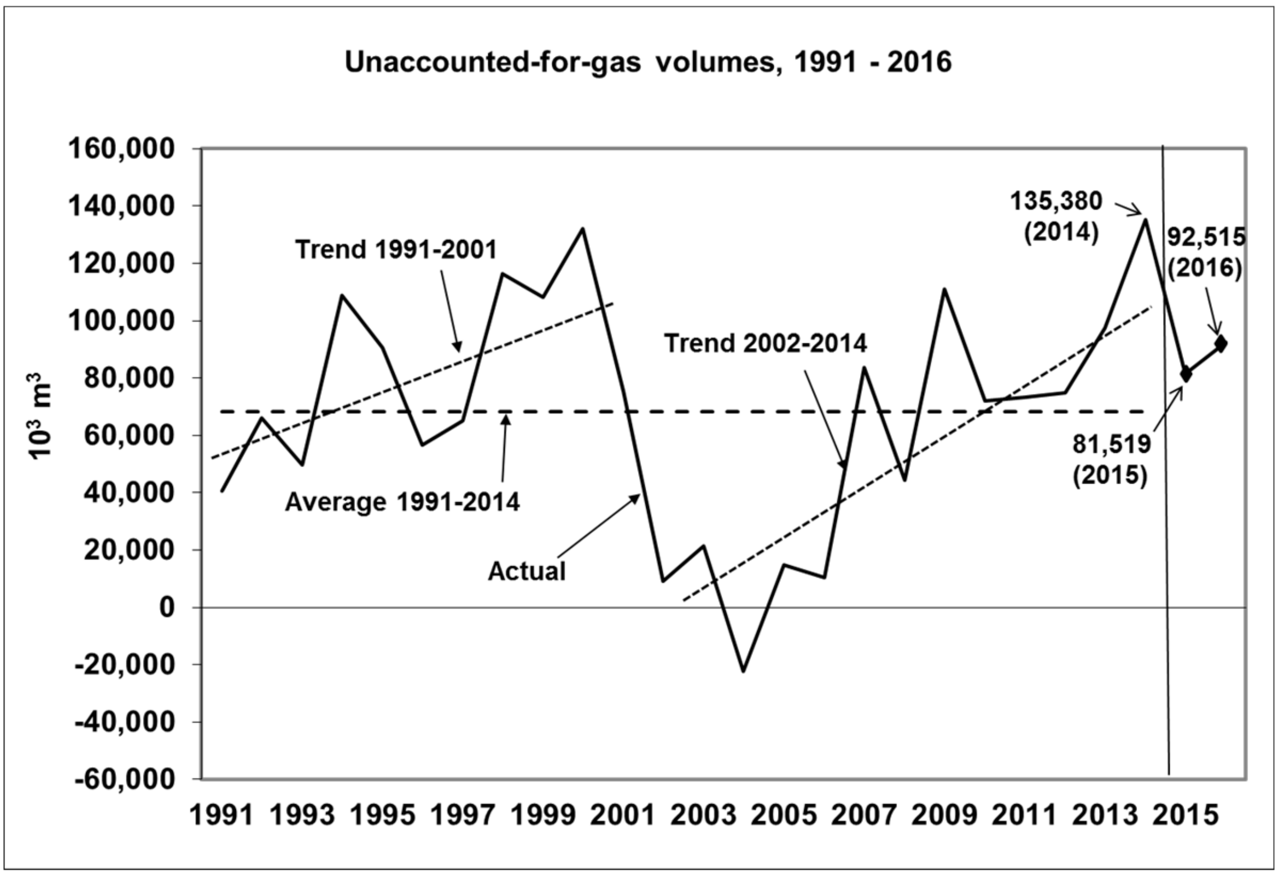
INTERROGATORY

REF: Exhibit D1, Tab 2, Schedule 3, Page 3

Please describe the 2002 structural change and the company's resulting choice to segregate the periods for the purposes of trending UAF.

RESPONSE

Figure 3 from Exhibit D1, Tab 2, Schedule 3, page 6 is reproduced below to provide a visual aid to the explanation.



Witnesses: H. Sayyan
M. Suarez

Prior to 2002, UAF values generally tended to be higher than the UAF values over the same period following 2002. This could be related to a number of steps taken by the Company to curb UAF that could arise from factors including measurement error, differences in line leakage, unmetered use and third party damage. For example, measurement error was reduced by the application of pressure factors to meters that did not adjust for atmospheric pressure beginning in 2001. Line leakages were addressed by the iron main replacement program. Third party damages have also been addressed via the implementation of the One Call program which aims to increase locate requests and thereby reduce accidental damage.

The trend of UAF prior to 2002 was found to be steeper than the trend of UAF after 2002 and it is believed that this was at least partially the result of the Company's initiatives as outlined above. A dummy variable was included in the model to account for the structural change in 2002 and it has achieved the desired intent to improve the model specification of the model and the accuracy of the forecast.

Witnesses: H. Sayyan
M. Suarez

FRPO INTERROGATORY #18

INTERROGATORY

REF: Exhibit D1, Tab 2, Schedule 3, Page 6, Figure 3

We assume the trend line shown is Model B.

a) If so, please replicate the figure and include the trend line for Model A.
b) What would what be the forecasted UAF using Model A.

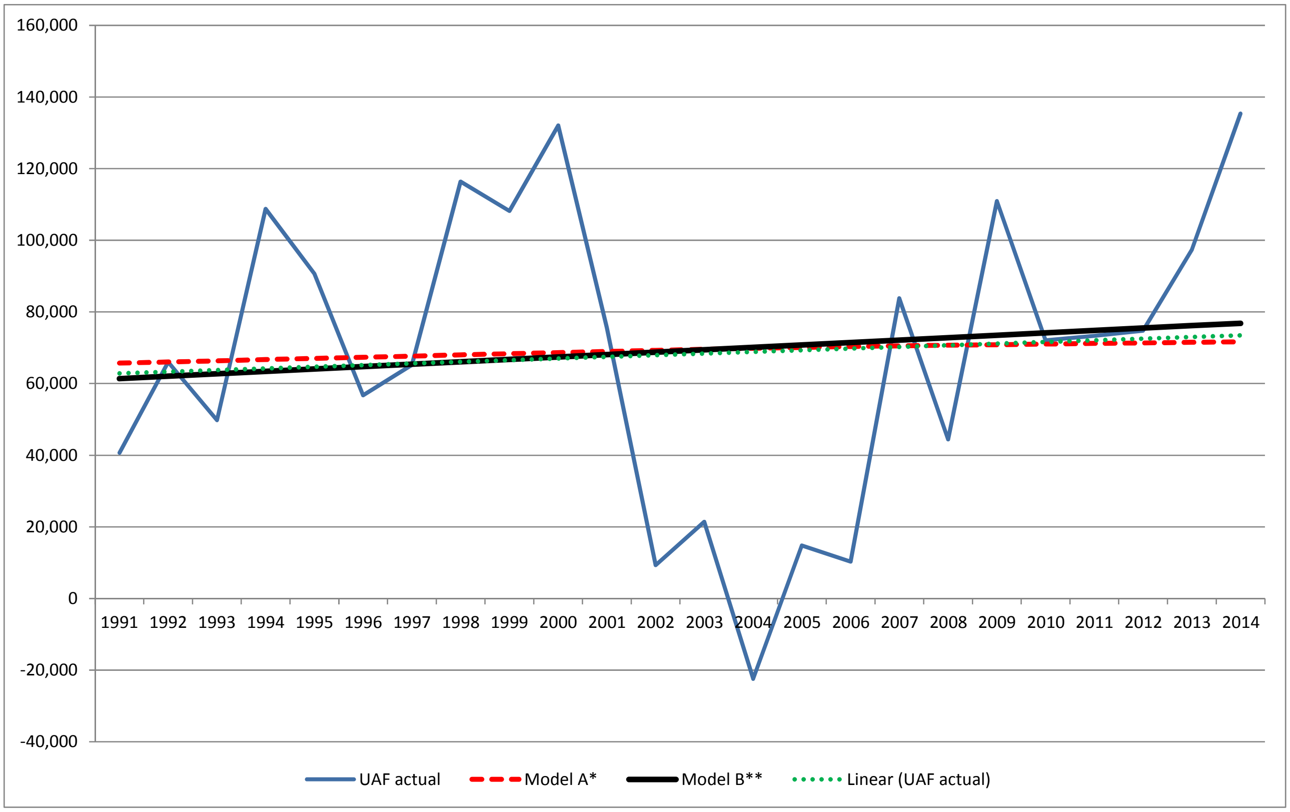
RESPONSE

a) The trend lines in the referenced Figure 3 are not related to any of the forecast models. They are provided in the figure to highlight a significant shift in the pattern of the historical data, or what the Company has referred to as a “structural change”. Prior to 2002, UAF values generally tended to be higher than the UAF values since 2002. Please see the response to FRPO Interrogatory #17 at Exhibit I.D1.EGDI.FRPO.17 for more information.

   For the purpose of providing representative trend lines for Model A and Model B, the reproduced figure on the next page depicts the estimated fitted values (without the dummy variables) for each model alongside the actual UAF trend line to allow for comparison of the estimated relationships.

   It is evident that the results are very close, and that Model B, which relies on the trend, reflects the higher UAF values in the most recent years.

Witnesses: H. Sayyan
M. Suarez



*without dummies (only uaf and unlocks)
**without dummies (only uaf and time trend)

b) There forecasted UAF using Model A as described in evidence for 2016 is 72,419 10^3m^3.

Witnesses: H. Sayyan
M. Suarez

FRPO INTERROGATORY #19

INTERROGATORY

REF: Exhibit D1, Tab 2, Schedule 4

Please explain how and why EGD predicts a reversal in PGVA adjustment line from 2015 to 2016.

RESPONSE

The forecasted dollar amounts shown as an adjustment to the PGVA in the 2015 and 2016 applications are a function of the required regulatory process within the OEB's filing requirements for annual rate applications to determine the prices underpinning the respective gas cost calculations. Please see the response to FRPO Interrogatory #5 found at Exhibit I.D1.EGDI.FRPO.5.

Witness: D. Small

FRPO INTERROGATORY #20

INTERROGATORY

REF: Exhibit D1, Tab 2, Schedule 6

With a surplus of almost 40,000GJ, could the company not reduce its delivered service to closer to 100,000 GJ to reduce the surplus? If not, why not?

a) If the plan would be implemented as presented, the 40,000GJ would be surplus, all the time, including a peak day, assuming these deliveries are firm. What is the expected value of transportation if EGD were to sell 40,000 GJ/day of Empress to CDA transport for the entire winter.

RESPONSE

When the Company began developing how it intended to satisfy peak day demand in the CDA for 2016 it did so assuming that the entire 149,818 GJ's per day of TCPL short haul capacity from Dawn to the CDA would be assigned to those Direct Purchase customers electing to deliver their gas to Dawn as a result of the Dawn Access Consultative. However, upon completing the election process with Direct Shippers the total volume that would be delivered to Dawn effective November 1, 2015 was less than anticipated.

The 2016 supply plan forecasts 100 % utilization of the contracted long haul capacity during January 2016 to March 2016. If the Company were to release this capacity to a third party then in order to maintain the forecasted storage targets the Company would have to substitute Empress supplies with Dawn supplies. Currently Dawn pricing for this winter is trading above CDA which provides value if the Company were to release some long haul capacity.

However, given the delay in the in-service date of the GTA Project until March 15, 2016, the Company intends to use this surplus capacity as part of its contingency plan to meet peak day.

Therefore, there is no longer any surplus for the upcoming winter season. See response to Board Staff Interrogatory #3 found at Exhibit I.D1.EGDI.STAFF.3 for further discussion of plans to adjust the supply plan to meet customer needs given the delay in the GTA Project.

As discussed in response to Board Staff Interrogatory # 3, certain long haul capacity contracts with TCPL (approx., 200,000 GJ per day) will continue until the in-service date of

Witness: D. Small

Segment A of the GTA Project. However, while the Company will have an additional 400,000 GJ of capacity available from Union for service from Dawn to Parkway, the delay in the GTA Project precludes the ability to move additional supply from Parkway to the CDA creating a shortfall on peak day. This will result in the need for the Company to acquire Peaking Service in the CDA. The previously forecasted surplus on peak day will now be useful and will lessen the amount of peaking service required.

Witness: D. Small

FRPO INTERROGATORY #25

INTERROGATORY

REF: General

Please describe the company's intent relative to moving to a Dawn reference price for gas commodity.

RESPONSE

Please see the Company's submission on this topic, dated January 16, 2015, which was made as part of the Natural Gas Market Review (Ontario Energy Board File: EB-2014-0289).

For ease of reference the relevant pages (pages 13 to 16) are attached to this interrogatory response.

Witness: A. Kacicnik

continuation of the NGMR process and does not oppose the NGMR being conducted on a more frequent basis if it will assist the Board in the assessment of future natural gas applications. Enbridge notes that (along with Union) it has also committed to providing stakeholders with an annual review of its gas supply plan – this was one of the commitments made by Enbridge in its application for approval of the 2014-2018 Incentive Regulation Plan. Discussions during these annual reviews are another avenue through which the Board can keep up to date on relevant developments.

3) What is the appropriate role of the Board in relation to the efficient operation of the natural gas market in the public interest, for example, regarding the sufficiency of Ontario access to northeastern U.S. gas supplies?

39. Enbridge notes that the natural gas market has undergone, and will continue to undergo, significant and rapid change. Enbridge submits that the Board's role in such an environment should evolve to allow timely responses to changes in the natural gas market.

4) In what ways, if any, do the Board's public interest mandate and/or views in relation to the overarching outcome(s) for Ontario's natural gas market require clarification?

40. Enbridge does not believe that any clarification of the Board's public interest mandate and/or views on Ontario's natural gas market is required.

5) What are the merits and disadvantages of replacing the Empress (AECO-C) price with the Dawn Hub price as the reference price for the commodity used for regulatory purposes?

41. In Enbridge's view, if the Board is going to consider changing the commodity reference price, it should convene a consultative process to address the implications of doing so. There are numerous considerations that must be taken into account before a shift to a new reference price can be made, including but not limited to, compatibility with current services and changes to business processes and systems. Many of these implications are elaborated upon in the discussion that follows.

Empress Price Index as a Reference Price (Current State)

42. Enbridge develops its gas supply plan by forecasting the gas supply needs specific to its system gas and direct purchase customers. Gas supply costs are based on a forecast of price indices at the various supply basins/market hubs from which Enbridge procures natural gas, plus the associated transportation cost to deliver that gas to the franchise area. The Purchased Gas Variance Account ("PGVA") reference price captures the forecast upstream acquisition costs, including commodity, transportation and delivered supply costs. This approach provides Enbridge with the means to adjust its forecast gas supply plan costs and its rates on a quarterly basis using the Board-approved QRAM methodology. Board-approved cost allocation and rate design principles are used to allocate the costs among different types of services and customer classes, through the establishment of gas supply, transportation and load balancing charges.

43. Enbridge estimates that approximately 62% of the total supply of gas required by the 2015 gas supply plan will be sourced from Western Canada, with the rest of the supplies being sourced from the Chicago hub (approximately 25%) and from within Ontario (approximately 13% sourced from the Dawn hub, from Niagara, or delivered directly into Enbridge's franchise areas). Enbridge sources gas from a number of market hubs, and it contracts for transportation on a number of different paths, in order to achieve diversity, reliability, flexibility and lower landed costs for its gas supply plan.

44. The rate currently charged to customers by Enbridge for gas supply service (*i.e.*, the gas supply charge) is underpinned by and based on a 21-day forecast of market commodity prices at Empress for the nest 12-month period and is adjusted each quarter through the QRAM. The Empress price index is readily available through various sources, it is an appropriate reference point for the costing of gas supplies from Western Canada because of close proximity to the supply basin, and it reflects one of the most geographically distant procurement points used by Enbridge.

45. Proximity to a large producing basin means that the price of gas at Empress represents the price of the commodity itself, while the price of gas at hubs such as Chicago or Dawn will reflect not only the cost of the commodity itself but also the cost of transporting gas to the particular hub. In other words, the price differential, also known as the basis, between Chicago or Dawn as compared to Empress notionally reflects the cost of getting the gas to Chicago or Dawn.

46. Bearing in mind that more than 60% of total supply is sourced from Western Canada, the Empress price is appropriate as a commodity reference price in the context of Enbridge's current gas supply plan and current service offerings.

Dawn Hub Price Index as a Reference Price

47. It is unclear whether the issue, as it is set out in the Proposed Issues List, refers to a "Dawn hub price index" or an "Ontario landed price". As noted above, Enbridge sources and transports gas supply from a number of producing basins and market hubs. While the proportion of gas supplies sourced at these various points will change over time as compared to the current gas supply plan, Enbridge will continue to ensure diversity in its supply portfolio. If the Dawn hub price refers to the Dawn price index, the resulting gas supply charge would not reflect the actual cost of landing gas supplies for Enbridge's system gas customers in Ontario.

Ontario Landed Price as a Reference Price

48. An Ontario landed price that is based on Enbridge's supply plan and that reflects diversity of purchases among the various market hubs and associated transportation paths would provide an appropriate reference price. To the extent that Enbridge's gas supply plan evolves towards the procurement of more gas supply from Dawn, then it becomes more reasonable to consider adoption of an Ontario landed reference price.

49. However, the structure of Western T-service is not compatible with an Ontario landed reference price. Should an Ontario landed price be adopted as a reference price for the gas supply charge, Western T-service might need to be discontinued.

50. Also, to facilitate a shift to an Ontario landed reference price, Enbridge would need to change a number of its business processes and systems and it would need to communicate the changes to its customers. Accordingly, stakeholder support for the change and for recovery of the associated costs of implementation would be essential to support a shift to an Ontario landed reference price.

51. While there may be additional factors to be considered, Enbridge has compiled the following lists to summarize some of the merits and disadvantages of an Empress reference price compared to an Ontario landed reference price.

Empress Price as Reference Price

Merits
- Appropriate for the current gas supply plan, given that more than 60% of total supply is sourced from the WCSB.
- Reflects cost causality/cost incurrence; no cross-subsidy between different service types or between system gas and direct purchase options.
- The concept of the gas supply charge and transportation charge resonates well with customers; customers picture gas supply basins as remote to Ontario and understand the need (and associated cost) to transport gas supplies from western Canada and the U.S. to Enbridge in Ontario.

Disadvantages
- The Empress price would become less relevant as a reference price for the gas supply charge should the majority of gas supply be sourced in Ontario.

Ontario Landed Price as a Reference Price

Merits
- Appropriate for a future gas supply plan in circumstances where Enbridge sources a majority of the gas supply for its system gas customers in Ontario.
- Would reflect cost causality/cost incurrence; no cross-subsidy between different service types or between system gas and direct purchase options.

Disadvantages
- The structure of Western T-service is not compatible with a gas supply charge that reflects the landed cost of gas in Ontario; Western T-service may need to be discontinued (but note that most market participants have indicated a preference to move their direct purchase arrangements to Dawn, so discontinuance of Western T-service may not be a significant disadvantage).
- Implementation would necessitate changes to Enbridge's business processes and systems.

SEC INTERROGATORY #3

INTERROGATORY

Ref: [D1/1/2, p.2 and D1/6/2]

Please confirm that the following statements are correct:

a. O&M Costs have been increased in this Application by $3.7 million from the EB-2012-0459 placeholder amount to reflect the increase in Pension and OPEB costs, calculated on an accrual basis, from $30.9 million to $34.6 million, as set out in the Mercer report dated July 9, 2015.
b. Cash Pension and OPEB costs to Enbridge have decreased by $28.6 million, from the $35.7 million included in the EB-2012-0459 tax calculation, to $7.1 million as set out in the Mercer report dated July 9, 2015.
c. The effect of the decrease in the cash costs is to increase income tax expense by $7.6 million for 2016, and to increase grossed-up income tax expense included in rates by $10.3 million.
d. Enbridge thus proposes to increase its rates by $14.0 million as a result of Pension and OPEB changes, at the same time as it is reducing its net cash outlay for those costs by $28.6 million.

RESPONSE

a) Confirmed. The updated forecast of accrual-based Pension and OPEB costs, as calculated by Mercer, included within O&M in this application, have increased by $3.7 million in comparison to the forecast amounts included within the EB-2012-0459 2016 placeholder accrual.

b) Confirmed. The updated forecast of cash-based Pension and OPEB costs, as calculated by Mercer, included within the tax calculation in this application, have decreased by $28.6 million in comparison to the forecast amounts included within the EB-2012-0459 2016 placeholder tax calculation.

c) When comparing the 2016 updated forecast of allowed revenues included within this application, to the EB-2012-0459 2016 placeholder allowed revenues, the $28.6 million decrease in the forecast of cash-based Pension and OPEB costs which are included as a tax deduction, does result in an increase to income taxes of

$7.6 million, and is required to be grossed-up to $10.3 million within the allowed revenue calculation.

d) When comparing the 2016 updated forecast of allowed revenues included within this application, to the EB-2012-0459 2016 placeholder allowed revenues, the combined impact of a non-tax deductible $3.7 million O&M increase, due to an updated forecast of accrual-based Pension and OPEB costs, and a $28.6 million decrease to an allowable tax deduction, due to an updated forecast of cash-based Pension and OPEB costs, is an increase to allowed revenues, to be recovered in rates, of $15.3 million.

This approach is consistent with the way that Enbridge's Pension and OPEB costs have been treated since the settlement in Enbridge's 2013 rate case (EB-2011-0354).

Witnesses: J. Barradas
R. Small

VECC INTERROGATORY #6

INTERROGATORY

Reference: D1/T2/S3

a) EGS is proposing to change the UAF model for 2016. Please reference the section of the Board Decision/Settlement which contemplates changes to forecasting methodologies.
b) Please provide a table, similar to Table 3, which shows for 2010 through 2016, the UAF actuals, Board Approved (and Model A forecast if different from Board approved) and the UAF forecast if based on the proposed revised Model B (trend) methodology. For this table please use 2015 actual UAF to-date.

RESPONSE

a) UAF is volatile, and because it cannot be measured directly, it presents unique challenges for forecasting. The Company has, over the years, expressed its commitment to minimize forecast errors of UAF at every opportunity. For each forecast year, it uses the previous model as a starting point and re-runs the model with the additional year of actual data. Results are then compared against a variety of models to determine the model that provides the best results.

   The annual volumetric update within the IRM period is the annual opportunity at which to include new information (latest actuals). During the 2014 ESM proceeding concern was expressed about the variance between forecast and actual UAF volumes. The Company took this as a signal that it is appropriate to take steps to limit such variances in future years. This is being addressed through efforts to better forecast UAF and through efforts to try to reduce actual UAF volumes.

   With the inclusion of the 2014 actuals, the results suggested an alternative model which would potentially minimize forecast error. That is the model proposed by the Company to forecast 2016 UAF.

b) Please see the table below which provides actuals to 2014 in Column 2, Board Approved UAF using Model A in column 3, Model A results using the specification in the 2016 application in column 4, and Model B results in column 5. 2015 actual UAF is not available as this is only calculated at year-end.

Witnesses: H. Sayyan
M. Suarez

During the course of completing this response, an error was discovered in the calculation of the average forecast errors. The discrepancy is minor and does not change the conclusions derived, nor the recommendations put forth.

UAF Forecast (10^3m^3)				
Col. 1	*Col. 2*	*Col. 3*	*Col. 4*	*Col. 5*
Calendar Year	**Actual**	**Board Approved**	**Model A**	**Model B**
2010	72,104	37,795	41,294	48,919
2011	73,355	64,211	45,906	55,972
2012	74,762	68,925	53,472	66,131
2013	97,361	73,092	105,359	118,333
2014	135,380	77,660	109,306	124,213
2015	-	81,519	70,216	87,361
2016	-		72,419	92,515

Witnesses: H. Sayyan
M. Suarez

VECC INTERROGATORY #7

INTERROGATORY

Reference: D1/T1/S1/pg.12

a) Given EGD does not anticipate any further activity for the CCSPDA is the Company seeking continuation in 2016 for this account. If yes please explain why.

RESPONSE

As indicated on page 12 of Exhibit D2, Tab 1, Schedule 1, as a result of exercising the option to extend its main customer care service agreement with Accenture through 2018 and 2019, the Company does not anticipate recording any costs in the CCSPDA during 2016. The Company has, however, maintained the CCSPDA in its list of approved and proposed 2016 deferral and variance accounts, because as part of the EB-2012-0459 Decision, the Board approved the establishment of the account for 2014 through 2016.

Witness: R. Small

CCC INTERROGATORY #3

INTERROGATORY

Reference: Ex.D2/T1/S1/p. 15

Please explain what type of costs Enbridge will record in the 2016 Greenhouse Gas Emissions Impact Deferral Account. Please give examples of costs that Enbridge believes should qualify for recovery through this account. Has Enbridge incurred any costs to date that it intends to record in this account?

RESPONSE

As a result of the Ontario Government's plan to implement a carbon Cap and Trade system, Enbridge believes the revenue requirement associated with incremental costs incurred to assess (impacts to customers and the Company), implement, and ensure compliance with carbon Cap and Trade legislation, should be recoverable through the Greenhouse Gas Emissions Impact Deferral Account ("GGEIDA"). Given that the Cap and Trade legislation has not been finalized at this time, nor has the appropriate regulatory treatment, the Company is unable to provide a definitive list of costs to be recorded within the GGEIDA. Examples of potential costs could include:

- Consulting costs required to understand the implications and necessary changes that may be required as a result of Cap and Trade legislation on the Company and customers,
- Billing system changes,
- Measurement, verification, and reporting compliance requirement costs,
- Customer communication/education costs (ie. website changes, bill inserts),
- OEB consultation costs.

To date, Enbridge has incurred consultant costs in relation to gaining an understanding of the impacts of Cap and Trade legislation on the Company and its customers.

Witness: R. Small

CCC INTERROGATORY #4

INTERROGATORY

Reference: Ex.D2/T1/S1/p. 23

What is the current expected in-service date for TransCanda's King's north Project?

RESPONSE

The most recent formal communication from TransCanada on the King's North Connection Project, a letter and fact sheet issued to stakeholders on October 2, 2015, indicates an expected in-service date of Q4 2016, subject to land rights and permitting, and dependent on seasonal and environmental conditions.

Witnesses: D. Small
R. Small

CCC INTERROGATORY #5

INTERROGATORY

Reference: Ex.D2/T1/S3/p. 1

Please explain what incentives are in place for Enbridge to mitigate UDC in 2016.

RESPONSE

There are no incentives that accrue to Enbridge to mitigate UDC in 2016. Enbridge is committed to mitigating UDC to the extent possible through all opportunities in 2016, just as it agreed to and has done in previous years.

Witness: D. Small

FRPO INTERROGATORY #21

INTERROGATORY

REF: Exhibit D2, Tab 1, Schedule 1, page 7-8

Preamble: "*In the event the Company incurs unforecast UDC costs as a result of having to purchase Banked Gas Account Balances then the amount in such sub-account will be used to offset corresponding UDC costs. All amounts remaining in this sub-account, after offsetting these UDC costs, will be rolled up into the PGVA*."

Is this policy to reduced UDC costs new? If not, please provide its introduction for approval.

a) Is the gas commodity put into the system gas pool at the commodity reference price and any discount used to reduce load balancing costs as opposed to commodity costs? If not, why not?

RESPONSE

This is not a new policy. Direct Purchase customers are given the opportunity to load balance the difference between their delivery volume and their consumption volume which is captured in their Bank Gas Account ("BGA"). In the circumstances where a Direct Purchase customer delivers more than they consume then they have load balancing alternatives such as Title Transfers with another Direct Purchase customer or they can request to suspend their deliveries for a period of time. If they fail to load balance on their own, the Company will purchase the excess delivery volume from them at 80% of the Empress price. Any variance between this cost and the PGVA Reference price will accrue back to customers through the PGVA account.

The issue of UDC arises when the Company has made its own supply arrangements in anticipation of Direct Purchase customers properly managing their BGA balances through load balancing and then they do not and the Company is required to purchase their BGA balance leaving the Company with excess supply.

Witnesses: D. Small
R. Small

FRPO INTERROGATORY #22

INTERROGATORY

REF: Exhibit D2, Tab 1, Schedule 1, page 7 and EB-2014-0276 Exhibit N1, Tab 1, Schedule 2, Appendix B, Page 1 Filed April 9, 2015

Preamble: "*In accordance with the EB-2014-0276 Settlement Agreement, where the Company committed to providing draft UDC mitigation plans as part of future gas supply plans, a draft UDC mitigation plan for 2016 (similar to the one agreed to in 2015) is shown at Appendix A of Exhibit D1, Tab 2, Schedule 1.*"

Please update the Potential Shed Analysis based on actual results.
a) Please comment on the approach and ideas to improve for 2016.

RESPONSE

As stated at Exhibit D1, Tab 2, Schedule 1, page 6, "Similar to 2015, the Company intends to continue to provide monthly reporting of the on-going amounts in the 2016 UDCDA as well as an update to the UDC mitigation plan with the March 2016 report."

The March 2016 update will set out any planned changes to the UDC mitigation plan based upon actual information to date at that time.

Witnesses: D. Small
R. Small

ENERGY PROBE INTERROGATORY #6

INTERROGATORY

Ref: Exhibit E1, Tab 2, Schedule 1

Please update the cost of capital, deficiency calculations and rate impacts to reflect the Board ROE of 9.19% as set out in its letter of October 15, 2015.

RESPONSE

Please refer to the response to VECC Interrogatory #8, Exhibit I.E1.EGDI.VECC.8, which provides updated cost of capital, allowed revenue, and deficiency calculations incorporating an ROE of 9.19% (as compared to the forecast of 9.13% included within the pre-filed evidence), as determined in the Ontario Energy Board's *Cost of Capital Parameter Updates for 2016 Applications* published October 15, 2015. For rate impacts which reflect an updated ROE of 9.19%, please refer to the response to Energy Probe Interrogatory #8 (a) found at Exhibit I.H1.EGDI.EP.8.

Witnesses: A. Kacicnik
R. Small

ENERGY PROBE INTERROGATORY #7

INTERROGATORY

Ref: Exhibit E1, Tab 3, Schedule 1

a) Please explain, and show any calculations used, how the short term debt rate of 1.52% and the preferred shares rate of 2.16% shown in Table 1 have been calculated.

b) What is the date of the information used in Tables 1 and 2?

c) If more recent information is now available, please update Tables 1 and 2 to reflect the most recent information available.

RESPONSE

a) The short-term debt rate of 1.52% is the weighted average forecast for commercial paper factoring in outstanding short term hedges combined with the fixed 1.85% interest rate applicable to the $300 million three-year note issued in April 2014 which is to be treated as short term debt as per the EB-2014-0276 Settlement Agreement.

The preferred share rate of 2.16% is calculated as 80% of the forecast Canadian Prime Rate of 2.70%.

b) The information used to prepare Tables 1 and 2 was based on a survey of financial institutions dated July 17, 2015.

c) An updated survey of financial institutions was conducted on September 23, 2015 as a result of which the following changes were noted:

- No change to the Canadian Prime Rate
- CDOR decreased by 10 bps
- Government of Canada 10 year bond yield decreased by 20 bps

The following changes in corporate spreads were also noted:

- Commercial paper spread increased by 10 bps
- Corporate 10 year spread increased by 40 bps

Witnesses: R. Craddock
R. Small

Tables 1 and 2 from Exhibit E1, Tab 3, Schedule 1 have been updated to reflect the noted changes and are presented below.

The updated tables also reflect the impacts of updating for actual 2015 term debt issuances. Within the pre-filed evidence, the Company forecast the issuance of $300 million of ten-year notes and $300 million of thirty-year notes, split evenly between September and November 2015. On September 11, 2015, the Company issued $400 million of ten-year notes and $170 million of thirty-year notes (re-opening of the August 2014 issuance) for gross proceeds of $570 million. There are no further term debt issuances planned for 2015.

Tables 1 and 2 also reflect an increase in planned 2016 issuances as a result of lower than anticipated 2015 issuances combined with increases to capital expenditures. The Company now anticipates issuing $250 million of ten-year notes in March 2016, as compared to the original forecast of $200 million in October 2016. In addition, a $150 million Floating Rate Note ("FRN") with a term of three-years is expected to be issued in March 2016 at a floating rate of 1.9%. The FRN has been included in the updated weighted average short-term debt rate consistent with the treatment of the three-year MTN currently outstanding.

TABLE 1
COST OF DEBT SUMMARY

Line		2016 Updated Forecast (excluding CIS)				
No.		Principal	Component	Cost Rate	Return	Return
		($Millions)	%	%	%	($Millions)
1.	Long-term debt	3,546.1	61.35%	4.96%	3.043%	175.9
2.	Short-term debt	53.0	0.92%	1.57%	0.014%	0.8
3.	Preferred shares	100.0	1.73%	2.16%	0.037%	2.2
4.	Total	3,699.1	64.00%		3.094%	178.9

TABLE 2

Item No.	Amount ($MM)	Issue Date	Term (Yrs)	Canada Yield	Corporate Spread	Coupon	Amortized Issue Costs	Effective Cost
1	250	16-Mar	10	2.62%	1.80%	4.42%	0.05%	4.47%

Witnesses: R. Craddock
R. Small

VECC INTERROGATORY #8

INTERROGATORY

Reference: E1/T1/S1

a) Please update Table 3 for the OEB cost of capital values issued on October 15, 2015.
b) Please update all associated tables and provide the revised requested revenue requirement (e.g. E2/T1/S1/pg.1).

RESPONSE

a) Attachment 1 to this interrogatory provides an updated version of Table 3, from Exhibit E1, Tab 1, Schedule 1, which incorporates an ROE of 9.19% (as compared to the forecast of 9.13% included within the pre-filed evidence) as determined in the Ontario Energy Board's *Cost of Capital Parameter Updates for 2016 Applications* published October 15, 2015.

b) Attachments 2 and 3 to this interrogatory provide updated Cost of Capital and Allowed Revenue and Deficiency calculations, Exhibit E2, Tab 1, Schedule 1, and Exhibit F1, Tab 2, Schedule 1, incorporate an ROE of 9.19%.

Witnesses: R. Craddock
R. Small

COST OF CAPITAL SUMMARY

Line No.		2016 Updated Forecast (excluding CIS) Principal	Component	Cost Rate	Return	Return
		($Millions)	%	%	%	($Millions)
1.	Long-term debt	3,445.7	59.62%	5.04%	3.005%	173.7
2.	Short-term debt	153.4	2.65%	1.52%	0.040%	2.3
3.	Preferred shares	100.0	1.73%	2.16%	0.037%	2.2
4.	Common Equity	2,080.8	36.00%	9.19%	3.308%	191.2
5.	Total	5,779.9	100.00%		6.390%	369.3

COST OF CAPITAL
2016 UPDATED FORECAST

Line No.		Col. 1 Principal Excl. CC/CIS	Col. 2 Component	Col. 3 Cost Rate	Col. 4 Return Component
		($Millions)	%	%	%
1.	Long and Medium-Term Debt	3,445.7	59.62	5.04	3.005
2.	Short-Term Debt	153.4	2.65	1.52	0.040
3.		3,599.1	62.27		3.045
4.	Preference Shares	100.0	1.73	2.16	0.037
5.	Common Equity	2,080.8	36.00	9.19	3.308
6.		5,779.9	100.00		6.390
7.	Rate Base	($Millions)			5,779.9
8.	Utility Income	($Millions)			291.9
9.	Indicated Rate of Return				5.050
10.	Deficiency in Rate of Return				(1.340)
11.	Net Deficiency	($Millions)			(77.5)
12.	Gross Deficiency	($Millions)	(other than CC - CIS)		(105.4)
13.	Customer Care/CIS Deficiency	($Millions)	($122.4 vs $118.1)		(4.3)
14.	Total Gross Revenue Deficiency	($Millions)			(109.7)
15.	Revenue at Existing Rates	($Millions)			2,811.1
16.	Allowed Revenue	($Millions)			2,920.8
17.	Gross Revenue Deficiency	($Millions)			(109.7)
	Common Equity				
18.	Allowed Rate of Return				9.190
19.	Earnings on Common Equity				5.467
20.	Deficiency in Common Equity Return				(3.723)

ALLOWED REVENUE AND SUFFICIENCY/(DEFICIENCY)
2016 UPDATED FORECAST

Line No.		Col. 1 EB-2012-0459 Excl. CIS 2016 Allowed Revenue Placeholder ($Millions)	Col. 2 EB-2012-0459 CIS 2016 Allowed Revenue Placeholder ($Millions)	Col. 3 EB-2012-0459 2016 Total Allowed Revenue Placeholder ($Millions)	Col. 4 2016 CIR Updates Excl. CIS ($Millions)	Col. 5 2016 CIR Updates for CIS ($Millions)	Col. 6 2016 Updated Forecast Allowed Revenue Excl. CIS ($Millions)	Col. 7 2016 Approved CIS Allowed Revenue ($Millions)	Col. 8 2016 Total Updated Forecast Allowed Revenue ($Millions)
	Cost of capital								
1.	Rate base	5,663.6	32.4	5,696.0	116.3	-	5,779.9	32.4	5,812.3
2.	Required rate of return	7.00	6.44	7.00	(0.61)	-	6.39	6.44	6.39
3.		396.5	2.1	398.6	(27.2)	-	369.3	2.1	371.4
	Cost of service								
4.	Gas costs	1,632.5	-	1,632.5	134.8	-	1,767.3	-	1,767.3
5.	Operation and maintenance	330.7	100.4	431.1	33.7	(1.1)	364.4	99.3	463.7
6.	Depreciation and amortization	276.2	12.7	288.9	-	-	276.2	12.7	288.9
7.	Fixed financing costs	1.9	-	1.9	-	-	1.9	-	1.9
8.	Municipal and other taxes	45.5	-	45.5	-	-	45.5	-	45.5
9.		2,286.8	113.1	2,399.9	168.5	(1.1)	2,455.3	112.0	2,567.3
	Miscellaneous operating and non-operating revenue								
10.	Other operating revenue	(42.7)	-	(42.7)	-	-	(42.7)	-	(42.7)
11.	Interest and property rental	-	-	-	-	-	-	-	-
12.	Other income	(0.1)	-	(0.1)	-	-	(0.1)	-	(0.1)
13.		(42.8)	-	(42.8)	-	-	(42.8)	-	(42.8)
	Income taxes on earnings								
14.	Excluding tax shield	39.2	7.9	47.1	(3.9)	-	35.3	7.9	43.2
15.	Tax shield provided by interest expense	(49.2)	(0.4)	(49.6)	2.6	-	(46.6)	(0.4)	(47.0)
16.		(10.0)	7.5	(2.5)	(1.3)	-	(11.3)	7.5	(3.8)
	Taxes on sufficiency / (deficiency)								
17.	Gross sufficiency / (deficiency)	(77.9)	-	(77.9)	(27.5)	-	(105.4)	-	(105.4)
18.	Net sufficiency / (deficiency)	(57.3)	-	(57.3)	(20.2)	-	(77.5)	-	(77.5)
19.		20.6	-	20.6	7.3	-	27.9	-	27.9
20.	**Sub-total revenue requirement**	2,651.1	122.7	2,773.8	147.3	(1.1)	2,798.4	121.6	2,920.0
21.	Customer Care Rate Smoothing V/A Adjustment	-	0.8	0.8	-	-	-	0.8	0.8
22.	**Allowed revenue**	2,651.1	123.5	2,774.6	147.3	(1.1)	2,798.4	122.4	2,920.8
	Revenue at existing Rates								
23.	Gas sales	2,372.7	91.8	2,464.5	73.8	11.7	2,446.5	103.5	2,550.0
24.	Transportation service	198.7	18.4	217.1	46.0	(3.8)	244.7	14.6	259.3
25.	Transmission, compression and storage	1.8	-	1.8	0.1	-	1.9	-	1.9
26.	Rounding adjustment	-	-	-	(0.1)	-	(0.1)	-	(0.1)
27.	Revenue at existing rates	2,573.2	110.2	2,683.4	119.8	7.9	2,693.0	118.1	2,811.1
28.	**Gross revenue sufficiency / (deficiency)**	(77.9)	(13.3)	(91.2)	(27.5)	9.0	(105.4)	(4.3)	(109.7)

VECC INTERROGATORY #9

INTERROGATORY

Reference: E1/T3/S1

a) Please provide the source and date of the 2.84% Canada yield. Please update this variable for the most current based on the same source.
b) Please explain the derivation of the corporate spread of 1.40%.

RESPONSE

a) The 2.84% Canada yield is a weighted average of hedged and unhedged amounts. The hedged amount is comprised of a $162 million pre-issuance hedge with a fixed rate of 3.01%. The unhedged amount is based on the forecast 10 year Government of Canada bond yield of 2.1% derived from a survey of financial institutions dated July 17, 2015. An updated forecast was completed on September 23, 2015 which resulted in a forecast 10 year Government of Canada bond yield of 1.9%.

b) The corporate spread of 1.40% was based on indicative spreads received from financial institutions. Indicative corporate spreads from Enbridge have since increased and the forecast corporate spread has increased to 1.80%, consistent with the corporate spread realized on the September 2015 debt issuance.

Witnesses: R. Craddock
R. Small

BOARD STAFF INTERROGATORY #9

INTERROGATORY

Ref: F1/T1/S1/table 1

Table 1 shows the Utility Revenue deficiency / sufficiency for 2015 Board-approved, 2016 Placeholder, and 2016 Updated Forecast.

Please provide an explanation of the main drivers of the differences between Board-approved 2015 and 2016 Updated Forecast.

RESPONSE

Attachment #1 to this response provides a comparison between each of the components of 2016 Updated Forecast allowed revenues, revenues at existing rates, and resultant deficiency, relative to the 2015 Approved values, and identifies the main drivers for the variances.

Witness: R. Small

2016 UPDATD FORECAST VERSUS 2015 APPROVED VARIANCE EXPLANATIONS

Note: Explanation

a) Rate Base

As seen below, the increase in 2016 updated forecast ratebase is primarily due to the increase in forecast net property plant and equipment that was reviewed and approved within Enbridge's CIR proceeding EB-2012-0459, reflecting an additional year of core capital spending and the full year impact of the GTA project. The property, plant, and equipment increase was paritally offset by reductions in gas in storage and working cash allowance which were updated in accordance with CIR plan parameters, and reflect an updated volume forecast, gas supply plan, PGVA reference price, and O&M inputs.

	2016 Forecast	2015 Approved	Variance	
Net property, plant and equip.	5,448.8	4,573.8	875.0	Reviewed and approved in EB-2012-0459
A/R rebillable projects	1.4	1.3	0.1	Reviewed and approved in EB-2012-0459
Materials and supplies	34.6	33.7	0.9	Reviewed and approved in EB-2012-0459
Mortages receivable	-	0.1	(0.1)	Reviewed and approved in EB-2012-0459
Customer security deposits	(64.6)	(65.1)	0.5	Reviewed and approved in EB-2012-0459
Prepaid expenses	1.0	0.9	0.1	Reviewed and approved in EB-2012-0459
Gas in storage	391.1	403.6	(12.5)	Updated per CIR plan parameters
Working cash allowance	-	8.2	(8.2)	Updated per CIR plan parameters
Total working capital	363.5	382.7	(19.2)	
Total rate base	5,812.3	4,956.5	855.8	

b) Required rate of return

The reduction in the 2016 updated forecast required rate of return reflects the impact of a reduction in the forecast ROE, 9.13% in 2016 versus 9.30% in 2015 Approved, and a reduction in the forecast weighted average cost of debt rate, which reflects updated forecast debt issuances and cost rates. ROE and cost of debt forecast updates are performed in accordance with CIR plan parameters.

c) Cost of capital

The increase in the 2016 updated forecast cost of capital results from financing a higher rate base (discussed in a) above), partially offset by a lower required rate of return (discussed in b) above).

d) Gas costs

The increase in 2016 updated forecast gas costs is primarily due to an increase in forecast volumes, partially offset by a lower PGVA reference. The updated forecast 2016 gas costs reflect an adjusted July 2015 PGVA reference price of $196.253, while 2015 approved gas costs reflect an adjusted October 2014 PGVA reference price of $204.293. Gas costs have also increased due to higher storage and transportation costs, and higher T-Service transportation costs resulting from higher TCPL tolls. Gas costs were updated in accordance with CIR plan parameters. Corresponding updates for price and volumetric impacts are also reflected in updated forecast revenue at existing rates.

2016 UPDATD FORECAST VERSUS 2015 APPROVED VARIANCE EXPLANATIONS

Note: Explanation

e) Operation and maintenance

The increase in 2016 updated forecast O&M is detailed below, but is primarily driven by a higher forecast DSM budget, which has been updated in accordance with CIR plan parameters and reflects the proposed budget included within Enbridge's DSM Multi-Year Plan proceeding EB-2015-0049. Customer Care and CIS costs have been updated in accordance with CIR plan parameters to reflect the EB-2011-0226 settlement agreement, which requires annual updates for the forecast number of customers and the current year's approved cost per customer. Pension and OPEB costs have been updated to reflect current forecast costs provided by Mercer, as per CIR plan parameters.

	2016 Forecast	2015 Approved	Variance	
Customer Care / CIS	99.3	95.9	3.4	Updated per CIR plan parameters
DSM	63.5	35.0	28.5	Updated per CIR plan parameters
Pension and OPEB	34.6	37.3	(2.7)	Updated per CIR plan parameters
RCAM	33.8	34.0	(0.2)	Reviewed and approved in EB-2012-0459
Other O&M	232.6	230.3	2.3	Reviewed and approved in EB-2012-0459
Total O&M	463.7	432.4	31.3	

f) Depreciation and amortization

The increase in 2016 updated forecast depreciation and amortization was reviewed and approved within Enbridge's CIR proceeding EB-2012-0459, and reflects the impact of growth in forecast gross property, plant, and equipment.

g) Municipal and other taxes

The increase in 2016 updated forecast municipal and other taxes was reviewed and approved within Enbridge's CIR proceeding EB-2012-0459, and reflects the impact of forecast capital growth and inflation.

h) Income taxes on earnings and deficiency

The increase in 2016 updated forecast income taxes is primarily attributable to a higher rate base (discussed in a) above) and the associated higher income taxes on the equity return component.

i) Customer Care Rate Smoothing V/A Adjustment

The Customer Care Rate Smoothing V/A Adjustment has been updated, similar to Customer Care & CIS O&M costs, to reflect the impact of the EB-2011-0226 settlement agreement which requires annual updates for the forecast number of customers, as well as the current year's approved cost per customer and normalized cost per customer.

j) Revenue at existing rates

The increase in 2016 updated forecast revenue at existing rates is due primarily to the updated 2016 volumetric forecast, partially offset by a lower gas commodity (PGVA) reference price embedded within rates (discussed in d) above). The 2016 updated forecast revenue at existing rates also do not include any Rate 332 revenues which are not forecast to be available in 2016. Rate 332 revenues were forecast and included within 2015 transmission, compression and storage revenues, but were not realized.

BOARD STAFF INTERROGATORY #10

INTERROGATORY

Ref: H1/T1/S1/para 8

Enbridge explains the following with respect to the Rate 332 impacts.

> "The proposed 2016 rate impacts are higher than the estimated 2016 impacts due to a higher (by approximately $30.0M) than estimated 2016 Demand Side Management (DSM) budget and an expectation that Rate 332: Parkway to Albion Transportation Service will not be available during 2016 (which means approximately $13M of the revenue requirement that would be recovered from Rate 332 customers will be recovered from the Company's bundled customers in 2016). Absent these two increases in the 2016 revenue requirement, the 2016 rate impacts would have been lower than the preliminary 2016 rate impacts."

a/ Please explain the rationale for the request that $13 million in revenue requirement should be recovered from bundled customers.

b/ If the transportation service on Segment A is being delayed in its implementation, why would the $13 million exist at all, given that it relates to an asset not yet in service and hence not closed to rate base?

c/ If the $13 million needs to be recovered (for example because the Custom IR allowed for a Segment A revenue recovery), then why would it not be placed in the new Rate 332 deferral account?

RESPONSE

a) As per the Board's decision in EB-2012-0451(GTA LTC Project), 60% of the annual revenue requirement for Segment A of the GTA project will be recovered from shippers through Rate 332 Contract Demand charges. These parameters for Rate 332 were confirmed and approved by the Board in the Custom IR Decision with Reasons (EB-2012-0459, at page 77). The 2016 Revenue requirement associated with the 60% shippers portion of Segment A is approximately $17.9 million as discussed at Exhibit H1, Tab 1, Schedule1, page 10.

   Also in the EB-2012-0451 Decision, the Board determined that should there be no Rate 332 Shippers, the annual revenue requirement impact of $55 million (representing the cost difference between the NPS 36 and the NPS 42 pipelines) would be recorded in a deferral account for eventual recovery from Rate 332 customers. The Board approved the creation of the GTA Incremental Transmission Capital Revenue Requirement Deferral Account ("GTAITCRRDA").

As explained at EB-2015-0114 at Exhibit H1, Tab 1, Schedule 1, page 8, paragraph 19, there is uncertainty as to whether the Company will be able to provide Rate 332 service in 2016 due to the uncertainty of the completion of the King's North pipeline project from TransCanada Pipeline (TCPL"). The total 2016 revenue requirement associated with the $55 million of incremental Segment A pipeline capacity cost is approximately $4.9 million. The Company proposes to record the $4.9 million in the 2016 GTAITCRRDA to be recovered in the future from Rate 332 customers through the clearing of the deferral account.

In order to recover the remaining $13.0 million which together with the $4.9 million represents the 60% share of the 2016 Segment A revenue requirement of $17.9 million, the Company proposes to recover this amount from bundled customers in 2016. In the GTA Leave to Construct Decision (EB-2012-0451), the Board endorsed the approach that Enbridge is now proposing. In that Decision (at pages 50-51) the Board specifically addressed the scenario where Segment A of the GTA Project is in rate base prior to the time when transportation customers are taking service under Rate 332. The Board recognized this could occur where the Union and TransCanada facilities needed to facilitate Rate 332 service were not yet complete. The Board stated that Enbridge's shareholder should not be at risk for 60% of the revenue requirement for Segment A because the project is a combined distribution and transportation project.

Due to the uncertainty of providing Rate 332 service in 2016, the Company is proposing the establishment of the 2016 Rate 332 Deferral Account ("R332DA"). In the event that the Company will be able to provide Rate 332 service in 2016, the R332DA will record the revenue generated from Rate 332 customers. The amount to be recorded in the R332DA and refunded to bundled customers will be, revenue generated through Rate 332 from the time Rate 332 is offered, net of the amount that was forecast to be recovered through the GTAITCRRDA for that same time period.

b) The Board's Decision in the Custom IR case set 2016 rate base and revenue requirement based on the GTA project being in service for all of 2016. Enbridge requested a variance account to address, among other things, timing differences for the GTA project. The Board declined to approve the account. Therefore, the approved ratemaking approach is to assume the full GTA project at the forecast cost is in service for all of 2016.

Witnesses: J. Collier
A. Kacicnik
R. Small

c) In part (a) above, Enbridge has explained why the $13 million is appropriately recoverable from bundled customers.

While it would be possible to re-define the Rate 332DA in a manner to facilitate a clearance of the $13.0 million through this deferral account, the current parameters of the account would not accommodate this. If this amount is to be recorded in the Rate 332DA, then the account will have to be updated to allow for clearance to bundled customers, as well as to transportation customers. It should be highlighted that the deferral account clearance of approximately $13.0 million could result in considerable billing adjustments to bundled customers in the subsequent year.

Witnesses: J. Collier
A. Kacicnik
R. Small

ENERGY PROBE INTERROGATORY #8

INTERROGATORY

Ref: Exhibit H1, Tab 1, Schedule 1

a) Please provide a version of Table 1 that reflects the updated return on equity as issued by the Board on October 15, 2015.

b) Please provide a version of Table 1 requested in part (a) above, that shows the rate increases in the absence of the $30 million increase associated with DSM.

c) Please provide a version of Table 1 requested in part (a) above, that shows the rate increases if the $13 million was recovered from Rate 332 customers rather than from bundled customers.

RESPONSE

a) As indicated in VECC interrogatory #8, found at I.E1.EGDI.VECC.8, the impact on the proposed 2016 revenue deficiency resulting from the updated return on equity from 9.13% to 9.19% is an increase of approximately $1.0 million. The version of Table 1 below provides the approximate average T-service rate impacts inclusive of the additional $1.0 million deficiency. As can be seen, there are no discernible rate impacts from this $1Million change. This scenario forms the base case for responses to parts b) and c) below.

Witnesses: J. Collier
A. Kacicnik
R. Small

Table 1: 2016 Average Rate Impacts

Rate Class	Approximate T-Service Rate Impacts
1	5.8%
6	5.7%
9	3.2%
100	2.0%
110	2.5%
115	1.7%
135	2.8%
145	2.5%
170	1.7%
200	3.3%
	Delivery Rate Impact
125	9.9%
300	3.0%

b) The version of Table 1 below provides the approximate average T-service rate impacts assuming the 2016 proposed DSM budget is reduced by approximately $30 million.

Table 1: 2016 Average Rate Impacts

Rate Class	Approximate T-Service Rate Impacts
1	4.3%
6	4.1%
9	3.1%
100	2.0%
110	2.4%
115	1.6%
135	2.8%
145	2.4%
170	1.6%
200	3.3%
	Delivery Rate Impact
125	9.9%
300	3.0%

Witnesses: J. Collier
A. Kacicnik
R. Small

c) The version of Table 1 below provides the approximate average T-service rate impacts assuming the $13 million in revenue requirement associated with Segment A was recovered from Rate 332 customers in 2016.

Table 1: 2016 Average Rate Impacts

Rate Class	Approximate T-Service Rate Impacts
1	5.3%
6	5.0%
9	3.2%
100	1.9%
110	2.3%
115	1.6%
135	2.8%
145	1.8%
170	1.3%
200	2.2%
	Delivery Rate Impact
125	9.9%
300	3.0%

Witnesses: J. Collier
A. Kacicnik
R. Small

ENERGY PROBE INTERROGATORY #9

INTERROGATORY

Ref: Exhibit H1, Tab 1, Schedule 1 &
Exhibit G1, Tab 1, Schedule 1

a) Please explain the relationship between the $13 million of the revenue requirement that should be recovered from Rate 332 customers that will be recovered from the company's bundled customers in 2016 (Exhibit H1, Tab 1, Schedule 1, pages 2-3) and the $4.9 being recorded in the GTAUTCRRDA as noted on page 4 of Exhibit G1, Tab 1, Schedule 1.

b) Please explain paragraph 10 in Exhibit H1, Tab 1, Schedule 1. In particular, why do bundled customers pay $13 million, which is the difference between the amount recovered from Rate 332 customers if it was available throughout 2016, and the $4.9 million to be placed in the account and recovered from Rate 332 customers in the future?

c) Please confirm that the reference to "annual revenue requirement of $55 million" in paragraph 9 of Exhibit G1, Tab 1, Schedule 1 is actually the annual revenue requirement of $55 million in incremental Segment A pipeline capacity, as referenced in paragraph 10. If this cannot be confirmed, please explain fully.

RESPONSE

a) Please see response to Board Staff interrogatory #10, found at I.H1.EGDI.STAFF.10.

b) Please see response to Board Staff interrogatory #10, found at I.H1.EGDI.STAFF.10.

c) Yes, confirmed.

Witnesses: J. Collier
A. Kacicnik
R Small

FRPO INTERROGATORY #23

INTERROGATORY

REF: Exhibit H1, Tab 1, Schedule 1, page 5-6

Preamble: "*Storage and unaccounted for gas (i.e., distribution commodity) costs are recovered through the Company's delivery rates. The distribution costs are recovered in the Company's rates primarily from the delivery rates, however, some distribution related costs are recovered from the commodity and load balancing rates.*"

Does this statement mean that storage costs do not get recovered through load balancing?

a) Please explain.

RESPONSE

a) Correct, at Enbridge the storage and unaccounted costs for gas are recovered through the Company's delivery rates.

Witnesses: A. Kacicnik
J. Collier
R. Small