500 Consumers Road
North York, Ontario M2J 1P8
PO Box 650
Scarborough ON M1K 5E3

Lorraine Chiasson
Regulatory Coordinator
Regulatory Affairs
phone: (416) 495-5499
fax: (416) 495-6072
Email: egdregulatoryproceedings@enbridge.com

October 29, 2013

VIA RESS, EMAIL and COURIER

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

Re: EB-2012-0459 - Enbridge Gas Distribution Inc. ("Enbridge")
2014 – 2018 Rate Application
Updated Evidence

Attached please find the following updated evidence:

Exhibit D1, Tab 2, Schedule 1, pages 1 and 11 to 20;
Exhibit D1, Tab 2, Schedule 2;
Exhibit D1, Tab 8, Schedule 1, pages 1 to 2 and 26 to 27;
Exhibit D3, Tab 3, Schedules 1 to 5.

The updated evidence is being filed through the Regulatory Electronic Submission System and will be available on Enbridge's website at www.enbridgegas.com/ratecase.

Please contact the undersigned if you have any questions.

Yours truly,

[original signed]

Lorraine Chiasson
Regulatory Coordinator

cc: Mr. F. Cass, Aird & Berlis
EB-2012-0459 Intervenors

2014 GAS COSTS, TRANSPORTATION, AND STORAGE

1. The purpose of this evidence is to provide an overview of the gas cost consequences of the gas supply activities, including storage and transportation of Enbridge Gas Distribution Inc. (the "Company" or "Enbridge Gas Distribution") during the 2014 Fiscal Year. The process for calculating budgeted gas costs is consistent with prior years. Using the forecasted volumetric demand requirements the Company develops a gas supply plan using a model known as "SENDOUT". This model determines the optimum monthly supply portfolio using existing contractual parameters, i.e., transportation contracts including storage deliverability and also provides the Company with a forecast of monthly storage targets. Once the monthly supply portfolio and storage targets have been established then gas costs can be calculated.

Gas Supply

2. Enbridge expects to acquire its system gas supply under the following types of contracts during the Fiscal Year:

- Western Canadian Supplies: These supplies source gas in the supply area of Western Canada and will be transported either via TransCanada PipeLines Limited ("TransCanada") or via Alliance Pipeline to the Company's franchise area.
- Ontario Production: The Ontario supply is *de minimus* in relative terms.
- Peaking contracts: These contracts source gas from other suppliers in the Eastern Zone during the winter season.

- Chicago Supply: These supplies are to be acquired in Chicago and transported to Dawn via the Company's contracted capacity on the Vector Pipeline.
- Delivered Supply: These supplies are forecasted to be acquired directly at the Dawn Hub.
- Niagara Supply: These supplies are forecasted to be acquired at the Niagara Import/Export point.

Enbridge Gas Distribution currently buys all of its gas on an indexed basis. It does not have any existing contracts that provide supply on a fixed price basis. The Company expects to continue this practice for its 2014 gas supply arrangements.

3. The following is Enbridge's forecast of gas supply acquisition during the 2014 Fiscal Year:

	Volume	
Contract Type	$10^6 m^3$	Bcf
Western Canadian Supply	4 833.0	170.6
Ontario Production	0.7	0.0
Peaking	36.1	1.3
Chicago Supply	1 847.1	65.2
Delivered Supply	932.8	32.9
Niagara Supply	0.0	0.0
	7649.7	270.0

Commodity Costs

4. The price assumptions reflect the market's assessment (as at the time of preparation of this evidence) of the different expected delivery points for the Company's forecast of gas supply.

5. The market's assessment is determined at any point in time by the use of the simple average of forward quoted prices as reported by various media and other services, over a period of 21 business days for a basket of pricing points, and pricing indices that reflect the Company's gas supply acquisition arrangements.

6. The Company prepared its gas supply forecast based upon a 21-day average of various indices from January 31, 2013 to February 28, 2013 for the 12 months commencing January 1, 2014 (Exhibit D3, Tab 3, Schedule 4) and applied these monthly prices to the 2014 budgeted annual volume of gas purchases.

7. In an effort to isolate the impact of commodity cost changes the Company removed the impact of the updated price forecast and the April 1, 2013 QRAM prices in a fashion similar to that used in the determination of the 2013 gas cost budget that was filed in EB-2011-0354.

8. Any variance between the actual commodity cost and the forecasted prices will be captured in the 2014 PGVA. Also, any variation in the forecasted transportation tolls and the actual tolls will be captured in the 2014 PGVA. While the Company has prepared the 2014 forecast assuming that it will be acquiring gas in 2014 via traditional transportation paths (ie TCPL, Alliance/Vector) the

possibility does exist in the future to acquire gas via alternative means (i.e., Shale Gas, Rockies, Renewable NG, etc).

Peak Day Coverage

9. In EB-2011-0354 Enbridge presented a new Design Criteria Study which all parties agreed to accept on a phased in approach. The Design Day Criteria is based upon a 1 in 5 recurrence interval. The new Design Criteria Study was filed in EB-2011-0354, at Exhibit D1, Tab 2, Schedule 3. The Company has prepared its 2014 Gas Cost budget assuming a peak day forecast based upon 41.4 degree days (Celsius) for the coldest peak. Based upon the information that was available at the time Enbridge is currently forecasting a design peak day level of 105 103 10^3m^3 (3.7 Bcf) during the winter season of the 2014 Fiscal Year.

10. The Company has chosen to maintain the same level of Peaking Services for 2014 as was forecast for 2013. Unlike 2013 however, when the Company chose to rely principally on TCPL STFT service, to meet the 2014 Peak Day Demand the Company has looked to other possible solutions. The driver for this decision is based upon recent events at the National Energy Board ("NEB"). On March 27, 2013 the NEB issued its decision in TransCanada PipeLines Limited ("TransCanada") Compliance Filing RH-003-2011. Subsequent to that decision TransCanada filed a Review and Variance Application for 2013 to 2017 with the NEB on May 1, 2013 in relation to RH-003-2011. On June 11, 2013 the NEB rendered its decision dismissing in its entirety TransCanada's Review and Variance Application. On June 12, 2013 TransCanada issued a news release stating their disappointment with the NEB decision and that they were considering all their options including the potential for an appeal. The June 11, 2013 NEB decision also stated that TransCanada must re-file its Tariff

Amendments by June 17, 2013 and that they will be considered as a separate application which will be heard as part of an oral hearing to commence September 3, 2013.

11. The expectation is that the Tariff Amendments that TransCanada proposed as a part of its Review and Variance Application will be the subject of the oral hearing mentioned above. The amended Tariff provisions are intended to provide TransCanada the flexibility required to capitalize on market opportunities for discretionary services as they arise. For example, the current Tariff provisions related to posting STFT availability stipulate that TransCanada post available STFT capacity for five banking days during January 1 to 15 for the Summer Period (April 1 to October 31) and for five banking days during July 1 to 15 for the Winter Period (November 1 to March 31). For the Summer Period, monthly blocks of STFT capacity are posted for five banking days during January 16 to 31 and for the Winter Period, monthly blocks of STFT capacity are posted for a five banking days during July 16-31. TransCanada is proposing to change the five banking day requirement to a period to be determined by TransCanada but no less than one day and could occur at any time.

12. Planning for STFT in such an environment would be difficult as the availability of this service might not be known until immediately prior to the period for which it is required. In addition, the minimum bid floor would most likely be set at a level higher than the FT toll during the periods that the Company would require STFT that is during the winter months when demand for this service is high. In order to ensure that it has the transportation assets in place to meet peak day demand in the EDA, the Company intends to contract for incremental long haul TCPL FT

capacity to the EDA as opposed to principally relying upon STFT in the winter of 2014.

13. As for the CDA, there are other options available to the Company to meet its peak day requirements. The Company has an agreement in principle with a third party to provide services to EGD in the CDA for the winter of 2014 which will supplement STFT service. The availability and cost of STFT in the CDA as well as concerns regarding TCPL Mainline capacity leads the Company to believe that it may need to rely more on long haul FT capacity in the CDA in the future. The Company intends to continue to monitor the availability of transport to the franchise and to look for alternatives that will provide value to the customers of EGD while still providing safe and reliable service. If alternatives are found then any differences from the cost of those services and those forecasted as part of the 2014 gas cost will be captured in the 2014 Purchased Gas Variance Account (PGVA). A breakdown of the peak day requirement and supply forecast is shown at Exhibit D3, Tab 3, Schedule 3.

14. Based upon the 2014 volumetric forecast and the level of transportation services to meet peak demand in 2014, the Company is forecasting $30.4 million in cost consequences associated with unutilized transportation capacity. This forecast is also based upon the TCPL tolls in place at the time of the derivation of the April 2013 QRAM. As a part of the Settlement Agreement in EB-2011-0354 parties also agreed to the establishment of the Design Day Criteria Transportation Deferral Account (DDCTDA) for 2013 and 2014. The Company's interpretation of the 2014 DDCTDA is that it should only capture the unutilized transportation costs in 2014 that are related to the increase in the Design Day Peak Demand in 2014 in comparison to 2013. Based upon its forecasted gas

costs (see Exhibit D3, Tab 3 Schedule 1, p. 2) the Company is forecasting to charge $17.2 million of unutilized transportation costs to gas cost in 2014 and $13.2 million to the 2014 DDCTDA.

15. As in prior decisions the Company is entitled to capture, as part of its gas cost forecast the cost consequences of any forecasted unutilized long haul TCPL transportation costs. For 2014 this amount translates to $17.2 million and these costs are included as part of the forecasted Storage and Transportation charges that can be found at Exhibit D3, Tab 3, Schedule 2, page 1, line Item # 6. Traditionally changes versus the forecast of these costs would not be eligible for capture and recovery within the current PGVA as previously defined. The Company is currently allowed, however, to include in the PGVA the impact of changes in TCPL tolls on any forecasted UDC (unutilized demand charge) amount.

16. In this application, the Company is proposing a change to the 2014 and subsequent years' PGVA methodology. Because of the uncertainty arising from the most recent TCPL decision and the impacts that it will have on the services the Company may or may not have at its disposal to meet its peak day requirements, the Company has chosen a conservative approach in preparing the 2014 gas costs, by the inclusion of incremental FT to the EDA. If, however, prior to the start of the fiscal year, the Company is able to enter into alternative arrangements that impact the amount of unutilized transportation capacity, the current PGVA methodology has no mechanism to capture those changes. The Company is proposing that if any alternative arrangements are subsequently entered into, then those arrangements would be included in the January 2014 QRAM Reference Price calculation and any variation between the forecasted

UDC costs included in gas costs and the actual amount should be captured in the PGVA. These amounts could also be included as part of the PGVA clearance mechanism in the January 2014 QRAM.

Transportation

17. Enbridge has a number of Firm Transportation ("FT") and other service entitlements in place for system gas sourced in Western Canada or in the United States (at the Chicago hub as well as U.S. supply area), or both, during the 2014 fiscal year. These include service entitlements with TransCanada (both long haul and short haul), Alliance Pipeline and Vector Pipeline. For purposes of this forecast, contracts were priced based upon current tolls and contracts if they had an expiry date during the Test Year and were deemed to be renewed with the following exception. As discussed earlier, the Company has included as part of its 2014 Gas Cost forecast an incremental level of FT service to the EDA. It is contemplated that the Company will acquire 175,000 GJ/day of TCPL FT-NR effective November 1, 2013 for two years expiring October 31, 2015. The inclusion of the incremental long haul capacity, while assisting with the ability to meet peak day, will also lower the overall Dawn discretionary requirement in the summer of 2014.

A copy of the Company's transportation contracts can be found at Exhibit D1, Tab 2, Schedule 2.

18. For the purposes of the 2014 Fiscal Year the Company has assumed the assignment of 42,500 Gj/day of TCPL short haul capacity to Direct Purchase

customers and will acquire 42,500 GJ/day of TCPL STFT from November to March.

19. The Company also has M12 service entitlements with Union Gas totaling 2,225,102 GJ/d (2,081 MMcf/d) for delivery of gas by Union at Dawn for storage injection or onward transportation, for gas withdrawn from storage at Tecumseh or Union, or both, and for gas sourced in Western Canada or the United States, or both, and delivered at Dawn for onward transportation. The Company also has M16 transportation capacity with Union to facilitate the Chatham "D" Storage pool. The gas cost forecast assumed January 1, 2013 Union tolls.

Storage

20. The Company has underground storage of its own at Tecumseh near Corunna in southwestern Ontario and at Crowland near Welland in the Niagara Region. Tecumseh is a large multiple-cycle facility, whereas Crowland is a small peak shaving facility.

21. Enbridge also held a storage entitlement with Union Gas Limited for 21,259,700 GJ broken down into three contracts with varied expiry dates. In its decision in the NGEIR proceeding dated November 7, 2006, the Board ruled that these contracts should be priced at cost of service rates and that a phased-in approach to market based storage was in the best interests of customers in Ontario. All three of these contracts have expired and effective April 1, 2010 all of the Company's contracted third party storage is at market based rates.

22. During 2013 the Company will be required to issue an RFP for a storage contract that will expire March 31, 2014. For purposes of the 2014 forecast, the cost

impacts of the current contract are assumed to be continued in the forecast for 2014 gas costs.

Energy Content

23. Enbridge has used a gross heating value of 37.69 MJ/m^3 to convert quantities (i.e., GJ, Dth) into volumes (i.e., 10^3m^3, MMcf). Quantities are the units specified in many of Enbridge's gas purchase and transportation service agreements, whereas Enbridge rates are volumetric.

UPDATED EVIDENCE

24. The Company has updated its Gas Cost forecast for 2014 to incorporate the October 2013 QRAM prices as filed in EB-2013-0295[1]. Please see the update to Exhibit D3, Tab 3, Schedule 1, pages 1 and 2 as well as Schedules 2, 3, 4 and 5.

25. In the original evidence filed at Exhibit D1, Tab 2, Schedule 1 in EB-2012-0459 the Company had expressed concerns regarding TransCanada PipeLine's ("TCPL") Review and Variance Application and the potential impact on tolls of any Tariff Amendments proposed by TCPL as a part of that Review and Variance Application. More specifically EGD was concerned with the availability and cost of STFT service which the Company had relied upon in recent years to assist it in meeting the peak day requirement of our customers.

26. Enbridge prepared its original 2014 supply portfolio based upon the assumption that it would acquire STFT at a cost equivalent to the TCPL FT toll as was the case in TCPL tolls previously. Included within the 2014 supply portfolio was a total of 257,500 GJ of STFT service (Empress to CDA) to assist in meeting the peak day requirement, as seen at Exhibit D1, Tab 2, Schedule 2, page 1. Part of that STFT service was intended to meet the increased demand resulting from the change in Peak Gas Day Design Criteria that was agreed in the 2013 rates proceeding (EB-2011-0354) to be phased in over two years (2013 and 2014).

27. Subsequent to the preparation of the 2014 gas supply portfolio, the NEB approved new tolls and provided TCPL with the opportunity to charge what it believed would be a market price for STFT. For example, TCPL is currently

[1] As adjusted to reflect the application of the FT unit price in TCPL's July toll against the STFT volumes in the 2013 Gas Supply Plan as indicated in the referenced Oct-2013 QRAM application EB-2013-0295.

Witnesses: J. Denomy
D. Small

asking for a minimum bid floor price for STFT equal to 260% of current FT toll price. That service would run from November 1st to March 31st (151 days).

28. In July 2013, Enbridge began to explore its requirement to contract for 2014 capacity to meet the system reliability agreement requirements pertaining to the replacement of the Dawn to CDA short haul capacity that is assigned to agents of mass market customers. The System Reliability Settlement Agreement (EB-2010-0231) provides for Enbridge to assign short haul firm transportation capacity to agents for mass market customers and to replace the assigned capacity with an equivalent volume of STFT capacity from Empress, Alberta. The System Reliability Settlement Agreement goes on to state that the cost consequences of this aspect of the Agreement will be recovered from sales and Western T-service customers allocated by volume, pursuant to the Board-approved cost allocation and rate design methodology. The volume of STFT service that Enbridge would have acquired effective November 1, 2013 pursuant to these provisions of the System Reliability Settlement Agreement is 38,000 GJ/day.

29. On July 12, 2013 Enbridge sent a letter to the Board and to interested parties informing them of Enbridge's intent to acquire FT transportation to meet the above requirement, instead of five months of STFT. Given the higher tolls for STFT service than for FT service, Enbridge would have had to pay more to acquire 38,000 GJ/day of STFT for five months than to acquire the same volume of FT for 12 months. The estimated annual savings were approximately $4.5 million. This projected savings was based upon the minimum floor bid price for winter STFT at that time which was posted as 290% of FT toll. Enbridge subsequently contracted for 38,000 GJ/day of FT capacity from November 1, 2013 to October 31, 2014.

Witnesses: J. Denomy
D. Small

30. Subsequent to the filing of that letter the Company continued to look for alternatives to meeting the outstanding peak day requirement. Enbridge was able to enter into an arrangement with a third party to provide 50,000 GJ/day of capacity to the CDA for the winter period at a price that is less than the updated STFT toll.

31. This left a remaining 170,000 GJ/day of STFT capacity, of the planned 257,500 GJs/day, still to be acquired by the Company to meet its peak day obligations.

32. EGD sent a second letter to the Board and interested parties dated August 30, 2013 identifying the various options available to Enbridge. The viable options were to contract for 5 months of STFT at a toll equivalent to 260% of the current FT toll or to contract for 1 year of FT long haul capacity.

33. Based upon the information available at the time the Company determined that the preferred option would be to acquire 170,000 GJ/day of FT capacity which would be at a lower overall annual cost than acquiring an equivalent amount of STFT capacity. However, as explained in the August 30th letter, there will be Unabsorbed Demand Costs ("UDC") associated with the unutilized capacity arising from this FT capacity.

34. A portion of the STFT capacity that Enbridge seeks to replace with FT capacity relates to increased capacity requirements to meet Enbridge's updated Peak Gas Day Design Criteria. The Board-approved Settlement Agreement in EB-2011-0354 (Enbridge 2013 Rates, Issue D.3) set out the agreement of parties that Enbridge would increase its Peak Gas Day Design Criteria to reflect a 1 in 5

recurrence interval and the peak day degree days associated with this recurrence interval. It was agreed that the resultant change to heating degree days would be increased equally over the 2013 and 2014 years. The EB-2011-0354 Settlement Agreement noted that, in order to meet the increased requirements, Enbridge would have to acquire increased transportation capacity. The EB-2011-0354 Settlement Agreement went on to set out the agreement of parties that the cost consequences of unutilized transportation capacity related to this incremental transportation capacity would be recorded in the 2013 and 2014 Design Day Criteria Transportation Deferral Account ("DDCTDA").

35. Enbridge requires an additional 85,000 GJ/day of winter capacity to accommodate the change in Peak Gas Day Design Criteria. Some of that capacity (approximately 10,500 GJ/day) is required for the EDA and was forecast to be filled through FT service. The balance of the capacity (approximately 74,500 GJ/per day) is required for the CDA, and had been forecast to be filled through STFT service. The acquisition of FT service, rather than STFT service, to meet the increased transportation requirements resulting from the change in Peak Gas Day Design Criteria means that, although transportation costs will be less, there will be unutilized transportation capacity not just over three months of STFT service as had previously forecast for the CDA, but over the one-year period of FT service commencing on November 1, 2013. Enbridge proposes that all UDC associated with the acquisition of FT service effective November 1, 2013 to meet requirements resulting from the change in Peak Gas Day Design Criteria be recorded in the 2014 DDCTDA.

36. Subject to the decision ultimately reached by the Board in this proceeding regarding the Company's gas volume forecast, the forecast UDC to be recorded in the 2014 DDCTDA is approximately $41.5 million. Details of that amount are

set out in the chart at the end of this updated evidence. Enbridge will use its best efforts to mitigate the UDC that would otherwise be recorded in the 2014 DDCTDA and the results of Enbridge's best efforts to mitigate such UDC will be reflected in the amounts recorded in the 2014 DDCTDA.

37. In addition to the UDC that will be recorded in the 2014 DDCTDA, there will be other UDC associated with the acquisition of FT service, effective November 1, 2013, instead of STFT service. The volume of FT capacity that will give rise to this UDC is approximately 133,000 GJ/day (which is equal to the total amount of STFT being replaced less the amount related to the change in Peak Gas Day Design Criteria). The amount of this UDC is currently forecast to be $62.8 million, subject to the decision ultimately reached by the Board in this proceeding regarding Enbridge's gas volume forecast. Details of that amount are set out in the chart at the end of this updated evidence.

38. Acquiring FT capacity to fill the remaining capacity of requirements to meet peak day demand is the preferred option due to the overall lower annual cost. However, under the current regulatory framework for Enbridge the Company is not able to recover unutilized transportation costs unless they are forecast and included within gas costs, or unless the costs can be included within the DDCTDA or another deferral account.

39. Enbridge does not propose to recover the $62.8 million of UDC (or such other revised amount as may result from the Board's decision regarding the gas volume forecast) in 2014 rates. Instead, Enbridge proposes to establish a new deferral account, called the 2014 Unabsorbed Demand Charges Deferral Account ("2014 UDCDA") to record this UDC that is in addition to the UDC to be

recorded in the 2014 DDCTDA. A description of the proposed UDCDA is filed in the updated evidence at Exhibit D1, Tab 8, Schedule 1.

40. The reason for this proposed approach is that Enbridge does not know what level of UDC will actually be incurred in 2014, because it is not yet known how much of the forecast unutilized capacity will actually be unused, nor whether some of the associated costs can be mitigated in other ways. During the winter or summer months if the Company requires this capacity for either satisfying customer demand and/or filling storage then this would also eliminate an associated level of unutilized transportation cost. The Company might also choose to use the FT service to displace discretionary gas purchases at Dawn. Another possibility of mitigating this cost may come during the summer of 2014. Unlike a Transactional Service exchange deal, whereby the Company purchases gas with the intent of injecting that gas into storage, this capacity is excess and the Company would not be buying gas to fill it. If the Company were to assign this capacity to a third party any monies received from that assignment will be used, in their entirety, to offset the unutilized transportation costs. The ability to assign capacity to a third party is a service attribute available to FT service and not to STFT service.

41. Given the uncertainty of the actual amount of unutilized transportation costs in 2014 the Company believes that the recovery of these costs should be deferred until such time that the actual costs are known. This would be accomplished through the proposed deferral account, along with the 2014 DDCTDA.

42. Enbridge will use its best efforts to mitigate the amount of UDC that would otherwise be recorded in the 2014 UDCDA and the 2014 DDCTDA and the results of Enbridge's best efforts to mitigate such UDC will be reflected in the

amounts recorded in the 2014 UDCDA and the 2014 DDCTDA. The amount recorded in the 2014 UDCDA will not be greater than the forecast amount of $62.8 million (or such other revised forecast amount as may result from the Board's decision regarding the gas volume forecast), but it may be less as a result of Enbridge's best efforts to mitigate UDC.

43. Additionally, the Company acknowledges that aspects of its 2014 gas supply plan are based on matters within its Customized IR application that are not yet approved (for example, 2014 heating degree days, average use, volumes and customer additions). The amount to be cleared from the 2014 UDCDA and the 2014 DDCTDA will recognize the implications of the Board approved volume forecast for 2014 that is established through this proceeding.

44. The Company proposes that as part of the QRAM process throughout 2014 it will provide an update as to the actual level of unutilized transportation costs and then either within the April 2015 QRAM application or at the time of the clearance of the 2014 ESM deferral account the Company would bring forward the actual 2014 unutilized transportation cost (as set out in the DDCTDA and the UDCDA) for disposition to customers either through a onetime charge or via a Rider mechanism to be collected over the subsequent 12 months.

45. Enbridge held a Consultation Meeting on October 2, 2013 to explain and discuss its updated gas supply contracting plans. All parties to this proceeding were invited to participate. In advance of the Consultation Meeting, Enbridge provided stakeholders with explanatory materials, setting out details about Enbridge's proposed updated 2014 gas supply plan, including the savings to ratepayers as compared to the as-filed gas supply plan and the increased forecast UDC resulting from an increased amount of FT capacity.

Witnesses: J. Denomy
D. Small

46. Following the Consultation Meeting, Enbridge prepared and provided a draft version of this updated evidence setting out and explaining the updated 2014 gas supply plan, and the proposal for the 2014 UDCDA.

47. During the Information Session in this proceeding held on October 11, 2013 pursuant to Procedural Order No. 2, Enbridge and parties discussed the draft version of updated evidence regarding the 2014 gas supply plan, the proposal for establishment of the 2014 UDCDA, and the proposal for use of the updated 2014 gas supply plan in QRAM applications. Enbridge's discussions with intervenors continued after the Information Session and the additional items discussed are addressed within this updated evidence.

48. One of the items that arose from the additional discussions was a request for Enbridge to provide further detailed information about the forecast UDC impacts of the acquisition of the STFT service instead of FT service, and about the forecast UDC impacts of the changes in Peak Gas Day Design Criteria. Set out at the end of this updated evidence is a chart containing the requested information. Also provided, as requested, is Enbridge's forecast of heating degree days for each month in 2014 (for the EDA, CDA), as well as Enbridge's forecast of the discretionary supplies that will be purchased at Dawn during the summer of 2014.

49. Another requested item relates to the impact of warmer than forecast weather on the forecast level of Dawn Discretionary supply that would be required. Enbridge has done some estimation calculations that can be used for sensitivity analysis purposes. These estimates are based upon volumetric forecasts as filed, meaning that any changes to the demand forecast (including the degree day

forecast and other assumptions underpinning the demand forecast) could impact the supply plan and the sensitivity calculations.

50. Currently, there is approximately 18 Bcf of Dawn Discretionary supply forecast within the 2014 gas supply plan. Assuming that the 2014 winter weather is exactly as forecast, then that volume would be available to mitigate the forecast level of UDC, in the event that Enbridge decided to refrain from buying Dawn discretionary supply and instead acquired the same volume at Empress and transported it to Dawn using surplus TCPL FT capacity. However, if winter weather is warmer than normal, then the required amount of Dawn Discretionary supply will be reduced. Enbridge estimates that if the level of Heating Degree Days (HDD) in the winter of 2014 (January to March) is 5% lower than forecast, then winter demand would decline by approximately 6.8 Bcf. Consequently the level of required Dawn Discretionary supply will be reduced to approximately 11 Bcf, as compared to the current forecast of approximately 18 Bcf. On an approximate basis, for each 1% reduction in the level of HDD, the level of forecast Dawn Discretionary supply will be reduced by around 1.4 Bcf.

Forecasted Monetary Impacts by Delivery Area													
$ millions													
UDCDA													
- CDA	44.0												
- EDA	18.8												
	62.8												
DDCTDA													
- CDA	36.2												
- EDA	5.3												
	41.5												
Forecasted Monthly Unutilized Capacity by Delivery Area													
PJs (millions of GJs)													
	January	February	March	April	May	June	July	August	September	October	November	December	
UDCDA													
- CDA	4.250	3.740	4.590	1.950	2.015	1.950	2.015	2.015	1.950	2.015	1.603	-	28.093
- EDA	2.125	1.870	4.077	0.450	0.465	0.450	0.465	0.465	0.450	0.465	0.330	-	11.612
	6.375	5.610	8.667	2.400	2.480	2.400	2.480	2.480	2.400	2.480	1.933	-	39.705
DDCTDA													
- CDA	1.863	1.639	2.012	2.235	2.310	2.235	2.310	2.310	2.235	2.310	1.639	-	23.095
- EDA	0.263	0.231	0.284	0.315	0.326	0.315	0.326	0.326	0.315	0.326	0.231	-	3.255
	2.125	1.870	2.295	2.550	2.635	2.550	2.635	2.635	2.550	2.635	1.870	-	26.350
Total													
- CDA	6.113	5.379	6.602	4.185	4.325	4.185	4.325	4.325	4.185	4.325	3.242	-	51.188
- EDA	2.388	2.101	4.361	0.765	0.791	0.765	0.791	0.791	0.765	0.791	0.561	-	14.867
	8.500	7.480	10.962	4.950	5.115	4.950	5.115	5.115	4.950	5.115	3.803	-	66.055
Forecasted Degree Days													
Central Region	682	591	504	302	130	29	0	5	56	240	391	587	3517
Niagara Region	659	592	490	305	**137**	23	0	3	43	215	365	554	3386
Eastern Region	821	701	592	338	152	38	7	21	109	285	463	716	4243
Forecasted Summer Discretionary Requirement													
PJs	18.301												

Witnesses: J. Denomy
D. Small

STATUS OF TRANSPORTATION CONTRACTS
2014 FISCAL YEAR

Item #	Transportation	Route	Total Contracted Daily Volume		Fuel Rate	Estimated Monthly Demand Charge		Estimated Commodity Charge		Effective Date	Expiry Date
	Current Contracts expected to be continued in 2014										
1	TCPL FT - CDA	Empress to CDA	63,468	GJ	varies	47.628036	$/GJ	-	$/GJ		31-Oct-13
2	TCPL FT - EDA	Empress to EDA	197,421	GJ	varies	49.135970	$/GJ	-	$/GJ		31-Oct-13
3	TCPL FT Dawn to CDA		149,818	GJ	varies	7.164530	$/GJ	-	$/GJ		31-Oct-13
4	TCPL FT Dawn to CDA	Assignment to Direct Purchase	(38,000)	GJ	varies	7.164530	$/GJ	-	$/GJ		31-Oct-13
5	TCPL FT Dawn to EDA		114,000	GJ	varies	13.284330	$/GJ	-	$/GJ		31-Oct-13
6	TCPL FT Dawn to Iroquois		40,000	GJ	varies	12.769190	$/GJ	-	$/GJ		31-Mar-14
7	TCPL FT Parkway to CDA		572	GJ	varies	3.786090	$/GJ	-	$/GJ		31-Oct-13
8	TCPL FT-SN Parkway to CDA		85,000	GJ	varies	3.948780	$/GJ	-	$/GJ		1-Jan-18
9	TCPL STS Parkway to CDA		283,892	GJ	varies	3.786090	$/GJ	-	$/GJ		31-Oct-13
10	TCPL STS Parkway/Kirkwall to EDA		70,895	GJ	varies	9.755480	$/GJ	-	$/GJ		31-Oct-13
11	TCPL STS Parkway to EDA		9,716	GJ	varies	9.755480	$/GJ	-	$/GJ		31-Oct-13
12	Nova Transmission	AECO to Empress	764.0	10^3m^3	N/A	221.240300	$\$/10^3m^3$	-	$\$/10^3m^3$		31-Oct-14
13	Nova Transmission	AECO to Empress	213.2	10^3m3	N/A	221.240300	$\$/10^3m^3$	-	$\$/10^3m^3$		31-Oct-14
14	Alliance Pipeline	Alberta to US border	2,124.6	10^3m^3	varies	981.160000	$\$/10^3m^3$	-	$\$/10^3m^3$		31-Oct-15
15		US border to Chicago	75.0	mmcf	varies	16.500000	$US/dth	-	$US/dth		31-Oct-15
16	Vector Pipeline -	Chicago to Cdn border	96,000	dth	varies	7.014000	$US/dth	-	$US/dth		31-Oct-15
17		Cdn border to Dawn	101,285	GJ	varies	0.570500	$/GJ	-	$/GJ		31-Oct-15
18	Vector Pipeline	Chicago to Cdn border	79,000	dth	varies	7.014000	$US/dth	-	$US/dth		31-Oct-15
19		Cdn border to Dawn	83,349	GJ	varies	0.570500	$/GJ	-	$/GJ		31-Oct-15
20	Vector Pipeline -	Chicago to Cdn border	50,000	dth	varies			Negotiated Toll			31-Oct-15
21		Cdn border to Dawn	52,753	GJ	varies			Negotiated Toll			31-Oct-15
22	Vector Pipeline -	Chicago to Cdn border	50,000	dth	varies			Negotiated Toll			31-Oct-15
23		Cdn border to Dawn	52,753	GJ	varies			Negotiated Toll			31-Oct-15
24	Union Gas Dawn to Parkway		1,764,678	GJ	varies	2.382000	$/GJ	-	$/GJ		31-Mar-14
25	Union Gas Dawn to Parkway		106,000	GJ	varies	2.382000	$/GJ	-	$/GJ		31-Oct-18
26	Union Gas Dawn to Parkway		57,100	GJ	varies	2.382000	$/GJ	-	$/GJ		31-Oct-19
27	Union Gas Dawn to Parkway		18,703	GJ	varies	2.382000	$/GJ	-	$/GJ		31-Oct-14
28	Union Gas Dawn to Parkway		200,000	GJ	varies	2.961000	$/GJ	-	$/GJ		31-Oct-22
29	Union Gas Dawn to Lisgar		10,692	GJ	varies	2.382000	$/GJ	-	$/GJ		31-Oct-14
30	Union Gas Dawn to Kirkwall		35,806	GJ	varies	2.011000	$/GJ	-	$/GJ		31-Oct-14
31	Union Gas Dawn to Kirkwall		32,123	GJ	varies	2.011000	$/GJ	-	$/GJ		31-Mar-14
32	Union Gas Parkway to Dawn		236,586	GJ	varies	0.579000	$/GJ	-	$/GJ		31-Mar-14
	Additional Contracts to meet Peak Day in 2013										
33	Peaking Service - CDA		105,505			varies		varies		1-Dec-12	31-Mar-13
34	Peaking Service - EDA		52,753			varies		varies		1-Dec-12	31-Mar-13
			158,258								
35	TCPL STFT - CDA	Empress to CDA	42,500	GJ	varies	n/a	$/GJ	-	$/GJ	1-Nov-12	31-Mar-13
36	TCPL STFT - CDA	Empress to CDA	195,000	GJ	varies	n/a	$/GJ	-	$/GJ	1-Dec-12	28-Feb-13
37	TCPL STFT - CDA	Empress to CDA	65,000	GJ	varies	n/a	$/GJ	-	$/GJ	1-Jan-13	31-Mar-13
38	TCPL STFT - EDA	Empress to EDA	60,000	GJ	varies	n/a	$/GJ	-	$/GJ	1-Dec-12	28-Feb-13
38	TCPL STFT - EDA	Empress to EDA	30,000	GJ	varies	n/a	$/GJ	-	$/GJ	1-Jan-13	31-Mar-13
			392,500								
	Contracts to meet Peak Day in 2014										
39	Peaking Service - CDA	- pending	105,505			varies		varies		1-Dec-13	31-Mar-14
40	Peaking Service - EDA	- pending	52,753			varies		varies		1-Dec-13	31-Mar-14
			158,258								
41	TCPL FT - CDA	Empress to CDA	38,000	GJ	varies	47.62804	$/GJ	-	$/GJ	1-Nov-13	31-Oct-14
42	TCPL FT - CDA	Empress to CDA	50,000	GJ	varies	47.62804	$/GJ	-	$/GJ	10-Sep-13	31-Oct-14
43	TCPL FT - CDA	Empress to CDA - pending	120,000	GJ	varies	47.62804	$/GJ	-	$/GJ	1-Nov-13	31-Oct-14
44	Niagara to CDA		50,000			Negotiated				1-Nov-13	31-Mar-14
45	Niagara to CDA		25,000			Negotiated				1-Nov-13	31-Mar-15
46	Dawn to CDA		50,000			Negotiated				1-Nov-13	31-Mar-14
47	Dawn to CDA		25,000			Negotiated				1-Nov-13	31-Mar-15
48	TCPL FT - EDA	Empress to EDA	50,000	GJ	varies	49.13597	$/GJ	-	$/GJ	1-Nov-13	31-Mar-15
49	TCPL FT - EDA	Empress to EDA	96,250	GJ	varies	49.13597	$/GJ	-	$/GJ	1-Nov-13	31-Oct-15
50	TCPL FT - EDA	Empress to Iroquois - pending	26,956	GJ	varies	49.45575	$/GJ	-	$/GJ	1-Nov-13	31-Oct-16
			531,206								

STATUS OF TRANSPORTATION CONTRACTS
2015 FORECAST YEAR

Item #	Transportation	Route	Total Contracted Daily Volume		Fuel Rate	EstimatedM onthly Demand Charge		Estimated Commodity Charge		Expiry Date
	Current Contracts expected to be continued in 2015									
1	TCPL FT - CDA	Empress to CDA	63,468	GJ	varies	63.84842	$/GJ	0.14377	$/GJ	31-Oct-13
2	TCPL FT - EDA	Empress to EDA	197,421	GJ	varies	63.84842	$/GJ	0.14377	$/GJ	31-Oct-13
3	TCPL FT Dawn to CDA		149,818	GJ	varies	7.49321	$/GJ	0.01360	$/GJ	31-Oct-13
4	TCPL FT Dawn to CDA	Assignment to Direct Purchase	(42,500)	GJ	varies	7.49321	$/GJ	0.01360	$/GJ	31-Oct-13
5	TCPL FT Dawn to EDA		114,000	GJ	varies	15.52514	$/GJ	0.03229	$/GJ	31-Oct-13
6	TCPL FT Dawn to Iroquois		40,000	GJ	varies	14.71519	$/GJ	0.03038	$/GJ	31-Mar-14
7	TCPL FT Parkway to CDA		572	GJ	varies	3.14523	$/GJ	0.00350	$/GJ	31-Oct-13
8	TCPL FT-SN Parkway to CDA		85,000	GJ	varies	3.17490	$/GJ	0.00326	$/GJ	1-Jan-18
9	TCPL STS Parkway to CDA		283,892	GJ	varies	1.69730	$/GJ	0.00024	$/GJ	31-Oct-13
10	TCPL STS Parkway/Kirkwall to EDA		70,895	GJ	varies	4.84530	$/GJ	0.00757	$/GJ	31-Oct-13
11	TCPL STS Parkway to EDA		9,716	GJ	varies	4.84530	$/GJ	0.00757	$/GJ	31-Oct-13
12	Niagara to CDA		200,000	GJ	N/A					
13	TCPL Bram West		800,000	GJ	N/A					
14	Nova Transmission	AECO to Empress	764.0	10^3m^3	N/A	221.2403	$\$/10^3m^3$	-	$\$/10^3m^3$	31-Oct-14
15	Nova Transmission	AECO to Empress	213.2	10^3m3	N/A	221.2403	$\$/10^3m^3$	-	$\$/10^3m^3$	31-Oct-14
16	Alliance Pipeline	Alberta to US border	2,124.6	10^3m^3	varies	981.1600	$\$/10^3m^3$	-	$\$/10^3m^3$	31-Oct-15 [1]
17		US border to Chicago	75.0	mmcf	varies	16.5000	$US/dth	-	$US/dth	31-Oct-15
18	Vector Pipeline -	Chicago to Cdn border	96,000	dth	varies	7.0140	$US/dth	-	$US/dth	31-Oct-15
19		Cdn border to Dawn	101,285	GJ	varies	0.5705	$/GJ	-	$/GJ	31-Oct-15
20	Vector Pipeline	Chicago to Cdn border	79,000	dth	varies	7.0140	$US/dth	-	$US/dth	31-Oct-15
21		Cdn border to Dawn	83,349	GJ	varies	0.5705	$/GJ	-	$/GJ	31-Oct-15
22	Vector Pipeline -	Chicago to Cdn border	50,000	dth	varies		Negotiated Toll			31-Oct-13 [2]
23		Cdn border to Dawn	52,753	GJ	varies		Negotiated Toll			31-Oct-13 [2]
24	Vector Pipeline -	Chicago to Cdn border	50,000	dth	varies		Negotiated Toll			31-Oct-15 [2]
25		Cdn border to Dawn	52,753	GJ	varies		Negotiated Toll			31-Oct-15 [2]
26	Union Gas Dawn to Parkway		1,764,678	GJ	varies	2.3820	$/GJ	-	$/GJ	31-Mar-14 [3]
27	Union Gas Dawn to Parkway		106,000	GJ	varies	2.3820	$/GJ	-	$/GJ	31-Oct-18
28	Union Gas Dawn to Parkway		57,100	GJ	varies	2.3820	$/GJ	-	$/GJ	31-Oct-19
29	Union Gas Dawn to Parkway		18,703	GJ	varies	2.3820	$/GJ	-	$/GJ	31-Oct-14
30	Union Gas Dawn to Parkway		200,000	GJ	varies	2.9610	$/GJ	-	$/GJ	31-Oct-22
31	Union Gas Dawn to Lisgar		10,692	GJ	varies	2.3820	$/GJ	-	$/GJ	31-Oct-14
32	Union Gas Dawn to Kirkwall		35,806	GJ	varies	2.0110	$/GJ	-	$/GJ	31-Oct-14
33	Union Gas Dawn to Kirkwall		32,123	GJ	varies	2.0110	$/GJ	-	$/GJ	31-Mar-14
34	Union Gas Parkway to Dawn		236,586	GJ	varies	0.5790	$/GJ	-	$/GJ	31-Mar-14

notes:
(1) the Alliance contract will not be renewed beyond the October 31, 2015 expiry date
(2) these Vector contracts will not be renewed beyond the October 31, 2015 expiry date
(3) the Company is planning to contract for an incremental 400,000 Gj/day of M12 capacity effective November 1, 2015

Item #	Transportation	Route	Volume		Fuel Rate	Demand Charge		Commodity Charge		Effective Date	Expiry Date
	Pending Contracts to meet Peak Day in 2015										
35	Peaking Service - CDA		105,505	GJ		varies		varies		1-Dec-14	31-Mar-15
36	Peaking Service - EDA		52,753	GJ		varies		varies		1-Dec-14	31-Mar-15
			158,258								
37	TCPL STFT - CDA	Empress to CDA	42,500	GJ	varies	63.84842	$/GJ	0.14377	$/GJ	1-Nov-14	31-Mar-15
38	TCPL STFT - CDA	Empress to CDA	100,000	GJ	varies	63.84842	$/GJ	0.14377	$/GJ	1-Dec-14	27-Feb-15
39	TCPL STFT - CDA	Empress to CDA	140,000	GJ	varies	63.84842	$/GJ	0.14377	$/GJ	1-Jan-15	28-Feb-15
40	TCPL STFT - CDA	Empress to CDA	100,000	GJ	varies	63.84842	$/GJ	0.14377	$/GJ	1-Jan-15	31-Mar-15
41	TCPL FT - EDA	Empress to EDA	175,000	GJ	varies	63.84842	$/GJ	0.14377	$/GJ	1-Nov-13	31-Oct-15
			557,500								

STATUS OF TRANSPORTATION CONTRACTS
2016 FORECAST YEAR

Item #	Transportation	Route	Total Contracted Daily Volume		Fuel Rate	EstimatedM onthly Demand Charge		Estimated Commodity Charge		Expiry Date	
	Current Contracts expected to be continued in 2016										
1	TCPL FT - CDA	Empress to CDA	63,468	GJ	varies	63.84842	$/GJ	0.14377	$/GJ	31-Oct-13	
2	TCPL FT - EDA	Empress to EDA	197,421	GJ	varies	63.84842	$/GJ	0.14377	$/GJ	31-Oct-13	
3	TCPL FT Dawn to CDA		149,818	GJ	varies	7.49321	$/GJ	0.01360	$/GJ	31-Oct-13	
4	TCPL FT Dawn to CDA	Assignment to Direct Purchase	0	GJ	varies	7.49321	$/GJ	0.01360	$/GJ	31-Oct-13	
5	TCPL FT Dawn to EDA		114,000	GJ	varies	15.52514	$/GJ	0.03229	$/GJ	31-Oct-13	
6	TCPL FT Dawn to Iroquois		40,000	GJ	varies	14.71519	$/GJ	0.03038	$/GJ	31-Mar-14	
7	TCPL FT Parkway to CDA		572	GJ	varies	3.14523	$/GJ	0.00350	$/GJ	31-Oct-13	
8	TCPL FT-SN Parkway to CDA		85,000	GJ	varies	3.17490	$/GJ	0.00326	$/GJ	1-Jan-18	
9	TCPL STS Parkway to CDA		283,892	GJ	varies	1.69730	$/GJ	0.00024	$/GJ	31-Oct-13	
10	TCPL STS Parkway/Kirkwall to EDA		70,895	GJ	varies	4.84530	$/GJ	0.00757	$/GJ	31-Oct-13	
11	TCPL STS Parkway to EDA		9,716	GJ	varies	4.84530	$/GJ	0.00757	$/GJ	31-Oct-13	
12	Niagara to CDA		200,000	GJ	N/A						
13	TCPL Bram West		800,000	GJ	N/A						
14	Nova Transmission	AECO to Empress	764.0	10^3m^3	N/A	221.2403	$\$/10^3m^3$	-	$\$/10^3m^3$	31-Oct-14	
15	Nova Transmission	AECO to Empress	213.2	10^3m3	N/A	221.2403	$\$/10^3m^3$	-	$\$/10^3m^3$	31-Oct-14	
16	Vector Pipeline -	Chicago to Cdn border	96,000	dth	varies	7.0140	$US/dth	-	$US/dth	31-Oct-15	
17		Cdn border to Dawn	101,285	GJ	varies	0.5705	$/GJ	-	$/GJ	31-Oct-15	
18	Vector Pipeline	Chicago to Cdn border	79,000	dth	varies	7.0140	$US/dth	-	$US/dth	31-Oct-15	
19		Cdn border to Dawn	83,349	GJ	varies	0.5705	$/GJ	-	$/GJ	31-Oct-15	
20	Union Gas Dawn to Parkway		1,764,678	GJ	varies	2.3820	$/GJ	-	$/GJ	31-Mar-14	
21	Union Gas Dawn to Parkway		400,000		varies	2.3820	$/GJ	-	$/GJ		(1)
22	Union Gas Dawn to Parkway		106,000	GJ	varies	2.3820	$/GJ	-	$/GJ	31-Oct-18	
23	Union Gas Dawn to Parkway		57,100	GJ	varies	2.3820	$/GJ	-	$/GJ	31-Oct-19	
24	Union Gas Dawn to Parkway		18,703	GJ	varies	2.3820	$/GJ	-	$/GJ	1-Nov-19	
25	Union Gas Dawn to Parkway		200,000	GJ	varies	2.9610	$/GJ	-	$/GJ	2-Nov-19	
26	Union Gas Dawn to Lisgar		10,692	GJ	varies	2.3820	$/GJ	-	$/GJ	1-Nov-19	
27	Union Gas Dawn to Kirkwall		35,806	GJ	varies	2.0110	$/GJ	-	$/GJ	31-Oct-14	
28	Union Gas Dawn to Kirkwall		32,123	GJ	varies	2.0110	$/GJ	-	$/GJ	31-Mar-14	
29	Union Gas Parkway to Dawn		236,586	GJ	varies	0.5790	$/GJ	-	$/GJ	31-Mar-14	

notes:
(1) the Company is planning to contract for an incremental 400,000 Gj/day of M12 capacity effective November 1, 2015

	Pending Contracts to meet Peak Day in 2015										
										Effective Date	Expiry Date
30	Peaking Service - CDA		0	GJ		varies		varies		1-Dec-15	31-Mar-16
31	Peaking Service - EDA		52,753	GJ		varies		varies		1-Dec-15	31-Mar-16
			52,753								
32	TCPL STFT - CDA	Empress to CDA	100,000	GJ	varies	63.84842 $/GJ		0.14377	$/GJ	1-Jan-16	31-Mar-16
33	TCPL FT - EDA	Empress to EDA	150,000	GJ	varies	63.84842 $/GJ		0.14377	$/GJ	1-Nov-15	n/a
			250,000								

DEFERRAL AND VARIANCE ACCOUNTS

2013 Test Year Approved Deferral and Variance Accounts

1. The following is EGD's list of 2013 Board Approved deferral and variance accounts ("DA" and "VA"). For the 2013 deferral and variance accounts approved and listed below, EGD will file a separate application requesting a process for the review and proposed clearance of the accounts as soon as feasibly possible following the public release of its fiscal 2013 year-end financial results (in March or April 2014).

2013 Purchased Gas Variance Account ("PGVA"),
2013 Design Day Criteria Transportation Deferral Account ("DDCTDA"),
2013 Transactional Services Deferral Account ("TSDA"),
2013 Unaccounted for Gas Variance Account ("UAFVA"),
2013 Storage and Transportation Deferral Account ("S&TDA")
2013 Deferred Rebate Account ("DRA"),
2013 Customer Care CIS Rate Smoothing Deferral Account ("CCCISRSDA"),
2013 Average Use True Up Variance Account ("AUTUVA"),
2013 Carbon Dioxide Offset Credits Deferral Account ("CDOCDA"),
2013 Manufactured Gas Plant Deferral Account ("MGPDA"),
2013 Gas Distribution Access Rule Costs Deferral Account ("GDARCDA"),
2013 Ontario Hearing Costs Variance Account ("OHCVA"),
2013 Electric Program Earnings Sharing Deferral Account ("EPESDA"),
2013 Open Bill Revenue Variance Account ("OBRVA"),
2013 Ex-Franchise Third Party Billing Services Deferral Account ("EFTPBSDA"),
2013 Post-Retirement True-Up Variance Account (PTUVA"),
2013 Transition Impact of Accounting Changes Deferral Account ("TIACDA"),
2013 Demand-Side Management Variance Account ("DSMVA"),

2013 Lost Revenue Adjustment Mechanism Variance Account ("LRAM"),
2013 Demand Side Management Incentive Deferral Account ("DSMIDA")

2014, 2015, & 2016 Fiscal Year Proposed Deferral and Variance Accounts

2. The Company has reviewed the existing required and potential requirement for deferral and variance accounts during the 2014-2016 rate making period and proposes the following accounts be established for use during the period. Within the list of accounts, the following are newly proposed accounts, CCSPDA, GGEIDA, CDNSADA, UDCDA and GTAPVA with separate written evidence provided within /u the D1 series of exhibits. The remainder of the accounts have been previously /u approved, though there are proposed revisions to the ongoing scope of several of these accounts: GDARIDA, OBRVA, TIACDA, TSDA and DSMVA.

2014-2018 Purchased Gas Variance Account ("PGVA"),
2014 Unabsorbed Demand Cost Deferral Account ("UDCDA") /u
2014 Design Day Criteria Transportation Deferral Account ("DDCTDA"),
2014-2018 Transactional Services Deferral Account ("TSDA"),
2014-2018 Unaccounted for Gas Variance Account ("UAFVA"),
2014-2018 Storage and Transportation Deferral Account ("S&TDA")
2014-2018 Deferred Rebate Account ("DRA"),
2014-2018 Customer Care Services Procurement Deferral Account ("CCSPDA"),
2014-2018 Customer Care CIS Rate Smoothing Deferral Account ("CCCISRSDA"),
2014-2018 Average Use True Up Variance Account ("AUTUVA"),
2014-2018 Greenhouse Gas Emissions Impact Deferral Account ("GGEIDA"),
2014-2018 Earnings Sharing Mechanism Deferral Account ("ESMDA")
2014-2018 Manufactured Gas Plant Deferral Account ("MGPDA"),
2014-2018 Gas Distribution Access Rule Impact Deferral Account ("GDARIDA"),
2014-2018 Ontario Hearing Costs Variance Account ("OHCVA"),

Witnesses: K. Culbert
D. Small

2014-2018 Electric Program Earnings Sharing Deferral Account ("EPESDA"),
2014-2018 Open Bill Revenue Variance Account ("OBRVA"),
2014-2018 Ex-Franchise Third Party Billing Services Deferral Account ("EFTPBSDA"),
2014-2018 Post-Retirement True-Up Variance Account ("PTUVA"),
2014-2018 Constant Dollar Net Salvage Adjustment Deferral Account ("CDNSADA"),
2014-2018 Transition Impact of Accounting Changes Deferral Account ("TIACDA"),
2014-2018 Demand-Side Management Variance Account ("DSMVA"),
2014-2018 Lost Revenue Adjustment Mechanism Variance Account ("LRAM"),
2014-2018 Demand Side Management Incentive Deferral Account ("DSMIDA"),
2014-2018 Greater Toronto Area Project Variance Account ("GTAPVA").

Following the end of each year (2014 to 2018), EGD will file a separate application requesting a process for the review and proposed clearance of these deferral and variance accounts as soon as feasibly possible following the public release of its fiscal year-end financial results for that year (in March or April of the following fiscal year).

Descriptions of Accounts

Purchased Gas Variance Account ("2014 to 2018 PGVA")

3. The purpose of the PGVA is to record the effect of price variances between actual gas purchase prices and forecast prices which underpin the revenue rates to be charged in each fiscal year. Without this variance account, the ratepayers and the Company are exposed to the risk of purchased gas price variances, which could unduly penalize or benefit one party at the benefit or expense of the other. Lower

than forecast gas purchase prices would result in an over recovery from the customers and higher prices would result in an under recovery to the Company. This variance account ensures that such effects are eliminated.

4. The Company has outlined the following methodology and scope to be in effect for the determination of amounts to be captured and cleared with respect to the 2014 PGVA. At this time, the basic premise and methodology to be used in determining what is to be included within the 2015 through 2018 PGVA accounts will not likely be materially different than that currently approved. However, the Company is not able to fully define what scope changes will potentially be required as a result of the planned GTA project and its gas supply plan implications. The Company proposes that it will bring forward a methodology scope for each of the 2015 through 2018 PGVAs within the rate adjustment applications for each of 2015 through 2018 (as outlined in evidence at Exhibit A3, Tab 3, Schedule 1).

<u>2014 PGVA Methodology</u>

5. The actual unit cost is determined by dividing the total commodity and transportation costs (less the demand charges related to unutilized TransCanada PipeLine Limited ("TCPL") firm service transportation capacity, if any) plus any other costs associated with emerging gas pricing mechanisms incurred in the month by the actual volumes purchased in the month. The rate differential between the PGVA reference price and the actual unit cost of the purchases, multiplied by the actual volumes purchased, is recorded monthly in the PGVA.

6. The fixed cost component of the TCPL firm service transportation costs (i.e., Transportation Demand Charge) is included in the determination of the reference price. However, any demand charges relating to unutilized long haul

TCPL ("FT") transportation capacity, either forecast or actual, are excluded. This treatment of forecast and actual long haul TCPL Transportation Demand Charges for unutilized transportation capacity is consistent with the Board's concerns that these amounts be excluded from the PGVA. However, due to the uncertainty arising from the most recent TCPL decision, the Company is proposing a change for 2014. If the Company enters into alternative arrangements that allow it to satisfy its Peak Day Design Criteria Demand prior to the start of the fiscal year then the Company would propose that if these alternative arrangements impact the amount of forecasted UDC then the Company will amend its forecast and bring forward any changes as part of the January 2014 QRAM.

7. Since all transportation costs on volumes purchased by the Company related to forecast utilized capacity are included in the determination of the PGVA reference price, any changes in the TCPL tolls will be recorded in the PGVA. Any toll changes related to the cost of forecast unutilized long haul TCPL transportation capacity will also be recorded in the PGVA. The inclusion of changes in TCPL tolls in the PGVA is consistent with past practice.

8. Since the transportation tolls for the Alliance and Vector pipelines that were used in the determination of the PGVA reference price were based on an estimate, any variation between the actual transportation costs (including associated fuel costs) and the estimated transportation costs will be recorded in the PGVA.

9. Since transportation costs related to the transport of Western Canada Bundled T-service volumes are not included in the derivation of the PGVA reference price, changes in TCPL tolls will be recorded in the PGVA as a separate adjustment.

10. For the period January 1 to December 31, 2014, expenditures related to TCPL's Storage Transportation Services, including balancing fees related to TCPL's Limited Balancing Agreement, will be recorded in the 2014 PGVA. The PGVA will also record amounts related to a Limited Balancing Agreement with Union Gas.

11. The PGVA will record adjustments related to Transactional Services activities which are designed to record the impact of direct and avoided costs between the PGVA and the TSDA. These adjustments are required to ensure appropriate allocation of costs and benefits to the underlying transactions and appropriate recording of amounts in the 2014 PGVA and 2014 TSDA for purposes of deferral account dispositions.

12. In addition, the 2014 PGVA will record the amounts related to unforecast penalty revenues received from interruptible customers who do not comply with the Company's curtailment requirements, unauthorized overrun gas revenues, the use of electronic bulletin boards, and the unforecast Unabsorbed Demand Charge ("UDC") that arises as a consequence of the Company voluntarily leaving transportation capacity unutilized in order to gain a net benefit for the customer by purchasing lower priced unforecast discretionary delivered supplies.

13. The 2014 PGVA will also record an inventory valuation adjustment every time a recalculated “Utility Price” or PGVA Reference Price comes into effect at the beginning of a quarter within the fiscal year. The adjustment consists of the storage inventory valuation adjustment necessary to price actual opening inventory volumes at a rate equal to the Board approved quarterly PGVA reference price.

14. The 2014 PGVA will also record any refund/collection associated with Board approved Gas Cost Adjustment Riders.

15. The Company will record, at the time a Banked Gas Account Balance is purchased from a customer, the difference in the amount payable to the customer and the amount included in the PGVA (Transportation Service Rider A). This amount would be credited to a sub-account of the PGVA. 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.

16. The commodity sale price on the disposition of Banked Gas Account Balances, the incentive sale price, is set at 120% of an average Empress price over the 12 months of the contractual year. Any amount in excess of 100% of the gas supply charge stated in the applicable rate schedule, net of the commodity related bad debt, will be included in the PGVA for each fiscal year.

17. Simple interest is to be calculated on the opening monthly balance of the 2014 PGVA at the approved short-term debt interest rate.

<u>2014 Design Day Criteria Transportation Deferral Account ("2014 DDCTDA")</u>

18. The Company has prepared its 2014 Gas Cost budget inclusive of the impact of the increased requirements resulting from the update of the Peak Gas Design Day Criteria approved by the Board in EB-2011-0354, to be phased in equally over the 2013 and 2014 fiscal years. Consequently, the DDCTDA is not required for fiscal years beyond 2014.

19. The purpose of the proposed 2014 DDCTDA is to record the actual cost consequences of unutilized transportation capacity contracted by the Company to meet increased requirements resulting from the Approved changes in the Peak Gas Design Day Criteria.

20. Simple interest is to be calculated on the opening monthly balance of the 2014 DDCTDA using the Board Approved EB-2006-0117 interest rate methodology. The balance of this account, together with carrying charges, will be disposed of in a manner designated by the Board in a future rate hearing.

<u>2014-2018 Transactional Services Deferral Account ("2014-2018 TSDA")</u>

21. The proposal for the 2014-2018 TSDA is to record the incremental ratepayer share of net revenue from transportation and storage related Transactional Services, to be shared 90/10 between EGD's ratepayers and shareholders.

22. While the Company plans to continue to include a forecast of $12.0 million in Transactional Services revenue as an offset to rates, the Company is proposing a change to the derivation of amounts in the TSDA. Given the recent NEB changes within TCPL tolls and unknowns within the future prices and potential related impacts, EGD is proposing an updat to the TSDA methodology and scope. In the event that the ratepayer share of 2014-2018 TS net revenue exceeds $12.0 million, then such amounts over $12.0 million will be credited to the TSDA. In the event that the ratepayer share of 2014 TS net revenue is less than $12.0 million, then EGD will be credited with the difference between the actual ratepayer share of 2014-2018 TS net revenue and $12.0 million. This is a change from the 2013 TSDA. Currently the

maximum credit to Enbridge is $ 4.0 million. The Company is proposing that there be no cap on the amount being credited to Enbridge should the ratepayer share of TS net revenue be less than $12.0 million.

23. Simple interest is to be calculated on the opening monthly balance of the 2014-2018 TSDA using the Board Approved EB-2006-0117 interest rate methodology. The balance of this account, together with carrying charges, will be disposed of in a manner designated by the Board in a future rate hearing.

<u>2014-2018 Unaccounted for Gas Variance Account ("2014-2018 UAFVA")</u>

24. The purpose of the 2014-2018 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 Company proposes that for each of these fiscal years, the UAF volume variance calculation will measure each fiscal year's actual UAF against the UAF volume forecast.

25. The gas costs associated with the UAF variance will be calculated at the end of each calendar based on the estimated volumetric variance between the Board approved level of UAF for the subject year and the then-current estimate of the UAF for that year. This amount will be included within the UAF for the subject year. An adjustment will be made to the UAFVA in the subsequent year to record any differences between the estimated UAF used within the prior year's UAFVA and actual UAF experienced for that year.

26. The UAF annual variance would then be allocated on a monthly basis in proportion to actual sales and the related cost would be calculated using the monthly PGVA reference price.

27. 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.

<u>2014-2018 Storage and Transportation Deferral Account ("2014-2018 S&TDA")</u>

28. The purpose of each of the 2014-2018 S&TDA is to record the difference between the forecast of Storage and Transportation rates (both cost of service and market based pricing) included in the Company's approved rates and the final Storage and Transportation rates (both cost of service and market based pricing) incurred by the company. It will also be used to record variances between the forecast Storage and Transportation rebate programs and the final rebates received by the Company.

29. The S&TDA for each fiscal year will also record the variance between the forecast Storage and Transportation demand levels and the actual Storage and Transportation demand levels. In addition, this account will be used to record amounts related to deferral account dispositions received or invoiced from Storage and Transportation suppliers.

30. The S&TDA for each fiscal year will also record the variance between the forecasted commodity cost for fuel and the updated QRAM Reference Price.

31. Simple interest is to be calculated on the opening monthly balance of each of the 2014-2018 S&TDA using the Board Approved EB-2006-0117 interest rate methodology. The balance of this account, together with carrying charges, will be disposed of in a manner designated by the Board in a future rate hearing.

2014-2018 Deferred Rebate Account ("2014-2018 DRA")

32. The Company proposes to establish a DRA for each of 2014-2018, to record any amounts payable to, or receivable from, customers of the Company as a result of the clearing of deferral accounts authorized by the Board which remain outstanding due to the Company's inability to locate such customers. The account will also include amounts arising from differences between actual and forecast volumes used for the purpose of clearing deferral account balances.

33. Simple interest is to be calculated on the opening monthly balance of this account using the Board approved EB-2006-0117 interest rate methodology The balance of this account, together with carrying charges, will be disposed of in a manner designated by the Board in a future rate hearing.

2014-2018 Customer Care Services Procurement Deferral Account ("2014-2018 CCSPDA")

34. The costs approved for recovery in rates by the EB-2011-0226 Decision included Enbridge's major customer care outsourcing and internal O&M costs in addition to the remaining capital and related costs associated with the Enbridge Customer Information System ("CIS")that was implemented in September 2009.

35. The two major outsourced customer care agreements addressed in the EB-2011-0226 proceeding will reach their normal expiry dates as on

December 31, 2017 subject to extension rights available to the Company. The Company is planning on conducting benchmarking and tendering processes with respect to the services conveyed via these agreements beginning in 2014. As such, the Company requests that a new deferral account be established, the Customer Care Services Procurement Deferral Account ("CCPDA"), to be in effect for 2014, 2015 and 2016 to capture the costs associated with the benchmarking, tendering and potential transition of customer care services to new service provider(s). The Company would then bring the costs recorded in this account for recovery in rates in 2017. Further details are provided in the Customer Care Services Procurement Deferral Account evidence at Exhibit D1, Tab 8, Schedule 4.

36. Simple interest is to be calculated on the opening monthly balance of this account using the Board approved EB-2006-0117 interest rate methodology. The balance of this account, together with carrying charges, will be disposed of in a manner designated by the Board in a future rate hearing.

<u>2014-2018 Customer Care / CIS Rate Smoothing Deferral Account ("2014-2018 CCCISRSDA")</u>

37. The CCCISRSDA is required for each of these years to capture the difference between the forecast customer care and CIS costs versus the amount to be collected in revenues. This approach was approved by the Board in the EB-2011-0226 CIS Customer Care Settlement Agreement and proceeding. The amount to be debited or credited to the deferral account for 2014 and for each subsequent year through 2018, will be calculated by multiplying the difference in cost per customer and smoothed costs per customer, times the updated customer forecast for the year. The balances in the account will not be cleared during the 2014 through 2018 period. The balance will build up during the years 2013 to 2015

when the cost per customer exceeds the smoothed cost per customer being collected in rates, and then the balance will be drawn down during the years 2016 to 2018 when the cost per customer is lower than the smoothed cost per customer being collected in rates. After 2018, any remaining balance in the account it is to be cleared along with the clearance of other 2018 deferral and variance accounts.

38. As determined in the EB-2011-0226 Settlement Agreement, interest is to be calculated on the balance of this account at a fixed annual rate of 1.47%, and will not change during the period the deferral account is allowed to continue through 2018. The interest carrying charges will be disposed of annually at the same time of clearance of all other deferral and variance accounts.

<u>2014-2018 Average Use True Up Variance Account (“2014-2018 AUTUVA”)</u>

39. The purpose of the AUTUVA for each of these fiscal years is to record (“true-up”) the revenue impact, exclusive of gas costs, of the difference between the forecast of average use per customer, for general service rate classes (Rate 1 and Rate 6), embedded in the volume forecast that underpins Rates 1 and 6 and the actual weather normalized average use experienced during the year. The calculation of the volume variance between forecast average use and actual normalized average use will exclude the volumetric impact of Demand Side Management programs in that year. The revenue impact will be calculated using a unit rate determined in the same manner as for the derivation of the Lost Revenue Adjustment Mechanism (“LRAM”), extended by the average use volume variance per customer and the number of customers.

40. Simple interest is to be calculated on the opening monthly balance of this account using the Board approved EB-2006-0117 interest rate methodology. The balance of

this account, together with carrying charges, will be disposed of in a manner designated by the Board in a future rate hearing.

2014-2018 Greenhouse Gas Emissions Impact Deferral Account ("2014-2018 GGEIDA")

41. The purpose of the GGEIDA for each of these years is to record amounts associated with any and all impacts of potential Provincial and or Federal regulations in relation to Greenhouse Gas Emission requirements effected onto EGD during these fiscal years along with the impacts resulting from the sale of or other dealings in earned carbon dioxide offset credits. EGD has provided the context for the potential regulation changes in relation to greenhouse gas emissions in Exhibit D1, Tab 8, Schedule 5.

42. EGD is proposing that this new account will take the place of the account which was formerly intended to deal with the potential impacts of any dealings in earned carbon dioxide offset credits which was called the Carbon Dioxide Offset Credits Deferral Account ("CDOCDA"). The CDOCDA was originally approved by the Board in its Natural Gas Generic DSM proceeding, EB-2006-0021.

43. Simple interest is to be calculated on the opening monthly balance of this account using the Board approved EB-2006-0117 interest rate methodology. The balance of this account, together with carrying charges, will be disposed of in a manner designated by the Board in a future rate hearing.

2014-2018 Earnings Sharing Mechanism Deferral Account ("ESMDA")

44. The purpose of the ESMDA is to record the ratepayer share of utility earnings that result from the application of the earnings sharing mechanism. If the actual utility

return on equity, calculated on a weather normalized basis, is more than 100 basis points over the level of ROE determined by the application of the Board's ROE Formula, the resultant earnings amount above 100 basis points will be shared equally (i.e., 50/50) between the Company's ratepayers and shareholders. The calculation of a utility return for earnings sharing determination purposes, will include all revenues that would otherwise be included in earnings and only those expenses (whether operating or capital) that would otherwise be allowable deductions from earnings as within a cost of service application. In addition, the following shareholder incentives and other amounts are outside of the ambit of the earnings sharing mechanism: amounts related to the Shared Savings Mechanism ("SSM") and Lost Revenue Adjustment Mechanism ("LRAM"), amounts related to Transactional Services incentives, amounts related to Open Bill program incentives, and amounts related to Electric Program Earnings Sharing incentives. The ESM is non-symmetrical, such that ratepayers will not be responsible for sharing any level of under-earnings.

45. Simple interest is to be calculated on the opening monthly balance of this account using the Board approved EB-2006-0117 interest rate methodology. The balance of this account, together with carrying charges, will be disposed of in a manner designated by the Board in a future rate hearing.

<u>2014-2018 Manufactured Gas Plant Deferral Account ("2014-2018 MGPDA")</u>

46. The Company is proposing to establish a MGPDA for each fiscal year of the IR term in order to capture all costs incurred in managing and resolving issues related to the Company's Manufactured Gas Plant ("MGP") legacy operations. Amounts recorded in the 2013 MGPDA will be transferred to the 2014 MGPDA. Costs charged to the

account could include, but are not limited to:

- Responding to all enquiries, demands and court actions relating to former MGP sites;
- All oral and written communications with existing and former third party liability and property insurers of the Company;
- Conducting all necessary historical research and reviews to facilitate the Company's responses to all enquiries, demands, court actions and communications with claimants, third parties and insurers;
- Engaging appropriate experts (for example, environmental, insurance archivists, engineers, etc.) for the purposes of evaluating any alleged contamination that may have resulted from former MGP operations and providing advice regarding the appropriate steps to remediate/contain/monitor such contamination, if any;
- Engaging legal counsel to respond to all demands and court actions by claimants, and to take appropriate steps in relation to the Company's existing and former third party liability and property insurers; and
- Undertaking appropriate research into the regulatory treatment of costs resulting from former MGP operations in the United States.

47. The MGPDA would also be used to record any amounts which are payable to any claimant following settlement or trial, including any damages, interest, costs and disbursements and any recoveries from insurers or third parties.

48. Simple interest is to be calculated on the opening monthly balance of the MGPDA in each fiscal year using the Board approved EB-2006-0117 interest rate methodology. The balance of this account together with carrying charges will be disposed of in a manner designated by the Board in a future rate hearing.

<u>2014-2018 Gas Distribution Access Rule Impact Deferral Account ("GDARIDA")</u>

49. The purpose of the GDARIDA is to record all incremental unbudgeted capital and operating impacts associated with the development, implementation, and operation of the Gas Distribution Access Rule and any ongoing amendments to the rule. Such impacts would include, but not be limited to, market restructuring oriented customer education and communication programs, legal or expert advice required, operating costs or revenue changes in relation to the establishment of contractual agreements and developing revised business processes and related computer hardware and software required to meet the requirements of the GDAR.

50. The GDARIDA was formerly approved as and known as the Gas Distribution Access Rule Cost Deferral Account, ("GDARCDA"). The Company is proposing a slight alteration of the scope of the account, which is to include all impacts which could arise as a result of ongoing changes in GDAR. As an example, in 2011, the Board approved an amendment to GDAR which prospectively required a change in the manner in which late payment penalties ("LPP") and related revenue was applied (exempting the application of LPPs in certain situations where they had previously applied). This amendment meant that the manner and level of which LPP revenue was embedded as an offset to EGD's rates at the outset of its first Generation IR term was too high relative to the level of LPP revenue which would be recovered in 2012 from late paying customers. To address such situations in future years, without knowing what further amendments to GDAR might come about between 2014 and 2018, EGD is proposing that the account is more properly scoped to include all impacts of any amendments to GDAR as opposed to simply including cost related impacts.

51. Simple interest is to be calculated on the opening monthly balance of this account using the Board approved EB-2006-0117 interest rate methodology. The balance of the account along with interest charges will be disposed of after review and as designated by the Board.

<u>2014-2018 Ontario Hearing Costs Variance Account ("2014-2018 OHCVA")</u>

52. The purpose of the OHCVA for each of these years is to record the variance between actual rate proceeding and other proceedings, activities and related expenses and the budgeted level of $8 million for 2014, $6 million for 2015, and $6 million for 2016 contained within this 2014-2018 rate application.

53. Simple interest will be calculated on the opening monthly balance of the account using the Board approved EB-2006-0117 interest rate methodology. The balance of the account along with interest charges will be disposed of after review and as designated by the Board.

<u>2014-2018 Electric Program Earnings Sharing Deferral Account ("2014-2018 EPESDA")</u>

54. The Company will continue the EPESDA for 2014 to 2018 under the same parameters as established and approved within the 2013 EB-2011-0354 proceeding. The account will be used to track and account for the ratepayer's 50% share of net revenue generated by DSM services provided under contract to the OPA and electric LDCs. Net revenue is determined, using fully allocated costs, as was determined is the DSM guidelines proceeding EB-2008-0346.

55. Simple interest will be calculated on the opening monthly balance of the account using the Board approved EB-2006-0117 interest rate methodology. The balance of the account along with interest charges will be disposed of after review and as designated by the Board.

2014-2018 Open Bill Revenue Variance Account ("2014-2018 OBRVA")

56. The purpose of the OBRVA is to track and record the ratepayer share of net revenue for Open Bill Services. The account as currently approved for 2013, allows for net annual revenue amounts in excess of $5.389 million to be shared 50/50 with ratepayers, and allows for a credit to Enbridge in the event that net annual revenues are less than $4.889 million, equal to the shortfall between actual net revenues and $4.889 million. Within the Open Bill Access Services EB-2013-0099 application and proceeding EGD is proposing to update the terms of the OBRVA. The proposed updated terms are that in the event that net revenues fall below $4.889 million in any one Enbridge fiscal year, then in the remaining fiscal years up to and including the final year of Enbridge's 2nd Generation IR term (2014-2018), Enbridge will be entitled to a credit equal to the total shortfall between actual net revenues and $5.389 million. The net revenue amounts will be determined in accordance with the EB-2009-0043 Board Approved Open Bill Access Settlement Proposal dated October 15, 2009, with updated Fees and Costs as determined in the EB-2013-0099 proceeding.

57. Simple interest is to be calculated on the opening monthly balance of this account using the Board approved EB-2006-0117 interest rate methodology. The balance of this account, together with carrying charges, will be disposed of in a manner designated by the Board in a future rate hearing.

<u>2014-2018 Ex-Franchise Third Party Billing Services DA ("2014-2018 EFTPBSDA")</u>

58. The purpose of the EFTPBSDA is to record and track the ratepayer share of revenues generated from third party billing services provided to ex-franchise parties net of incremental costs associated with the services. The net revenue is to be shared on a 50/50 basis with ratepayers. The net revenue amounts will be determined in accordance with the EB-2009-0043 Board Approved Open Bill Access Settlement Proposal dated October 15, 2009, with updated Fees and Costs as determined in the EB-2013-0099 proceeding.

59. Simple interest is to be calculated on the opening monthly balance of this account using the Board approved EB-2006-0117 interest rate methodology. The balance of this account, together with carrying charges, will be disposed of in a manner designated by the Board in a future rate hearing.

<u>2014-2018 Constant Dollar Net Salvage Adjustment Deferral Account ("2014-2018 CDNSADA")</u>

60. The CDNSADA is being proposed by the Company in conjunction with the Depreciation Study review and proposal being made in this case. The depreciation study filed at Exhibit D2, Tab 1, Schedule 1 proposes implementing the constant Dollar Net Salvage method to calculate site restoration cost requirements. As explained at Exhibit D1, Tab 5, Schedule1 this results in a reduction to the net salvage value or depreciation reserve liability recorded on EGD's books of $259.8 million.

61. EGD is proposing this deferral account as the means of recording and clearing annual credit amounts to ratepayers over each of fiscal years 2014 through 2018. The proposal is to clear the following annual amounts, 2014 - $68.1 million, 2015 -

$63.1 million, 2016 - $58.1 million, 2017 - $53.1 million and 2018 - $17.4 million. This proposed pattern of clearance was determined in conjunction with the Company's expert, Gannett Fleming. In addition, EGD also considered the impact of the revenue requirements, coming out of the five year 2014-2018 period, and determined that a greater portion of the balance being cleared in that time frame could help mitigate the bill impacts, to a degree, arising from capital requirements of EGD during the period.

62. Additionally, for each year, EGD will determine the annual amount actually cleared to ratepayers versus the amount the Company proposed were to be cleared. The difference between those amounts will be included within a future year CDNSADA as a debit or credit. The result will be that the projected remaining un-cleared amount would be adjusted annually to ensure that the total amount cleared through the use of this account, upon true up post 2018, would equal the proposed clearance of $259.8 million.

63. The $259.8 million is currently recorded in a liability account which for utility rate base determination purposes is accounted for as an offset against property, plant and equipment. EGD proposes to transfer the total amount to this deferral account and clear amounts on a monthly basis beginning in January of 2014 through December of 2018, through a rate rider as shown and explained in evidence at Exhibit H1, Tab 1, Schedule . EGD proposes and has calculated rate base for the 2014 through 2016, in a manner which debits the deferral account each and every month by the amount to be cleared out of the $259.8 million which results in a required and equal monthly value increase to rate base during these years. This treatment will continue for rate base determinations in 2017 and 2018.

64. Due to the nature of the proposed treatment of this deferral account, which is that the balance in the account will serve as an offset to rate base while it is being cleared through the proposed rate rider to be in effect for 2014 through 2018, EGD proposes that no interest is required to be calculated for this account.

2014-2018 Transition Impact of Accounting Changes DA ("2014-2018 TIACDA")

65. The TIACDA is required to track and record the remaining un-cleared balances associated with Other Post Employment Benefit "("OPEB") amounts in respect of which the Board approved recovery within the EB-2011-0354 proceeding. In that proceeding, the Board approved recovery of an original estimated amount of $90 million evenly at an amount of $4.5 million over 20 years commencing in 2013. The final estimate which EGD recorded in the TIACDA at the end of 2012 was $88.7 million, which EGD will clear evenly over 20 years commencing in 2013. EGD is requesting clearance of $4.4 million in 2013 within its ESM and deferral and variance account review proceeding EB-2013-0046. The same amount will be cleared in subsequent years, including 2014 to 2018.

66. Interest is not applicable to the balance of this account.

2014-2018 Post-Retirement True-Up VA ("2014-2018 PTUVA")

67. The purpose of the PTUVA is be to record the differences between the forecast pension and other post-employment benefit expenses ("OPEBs") of $37.3 million for 2014, $33.8 million for 2015, and $30.9 million for 2016 included within each of those year's forecast Allowed Revenue amount. The annual estimate details and support are found in evidence in Mercer reports filed as Appendices to Exhibit D1, Tab 16, Schedule 1.

68. EGD proposes that, as part of the annual rate adjustment proceedings for 2015 and 2016, it will provide updated forecasts of pension and OPEBs costs for the subject year, which forecast will replace the original forecast within the Allowed Revenue amount for the subject year. The Company believes that this should mitigate the amount of any annual variances.

69. EGD proposes that the 2014 to 2018 PTUVA will operate in a manner that is similar to the manner in which the 2013 PTUVA operates. That is, any variances between forecast and actual expenses will be recorded and cleared from the 2014-2018 PTUVA subject to the condition that any amount in excess of $5 million (credit or debit) will be transferred into a next year's account, so that large variances can be cleared over time. Under this approach, the maximum amount that will be cleared from each annual PTUVA would be $5 million and any remaining amount from each year's PTUVAs would be transferred to a next year PTUVA for future clearance.

70. Simple interest is to be calculated on the opening monthly balance of this account using the Board approved EB-2006-0117 interest rate methodology. The balance of this account, together with carrying charges, will be disposed of in a manner designated by the Board in a future rate hearing.

<u>DSM Related Variance Accounts (3)</u>
2014-2018 Demand Side Management Variance Account ("2014-2018 DSMVA"),
2014-2018 Lost Revenue Adjustment Mechanism Variance Account ("2014-2018 LRAM"),
2014-2018 Demand Side Management Incentive Deferral Account ("2014-2018 DSMIDA")

71. The Company currently has three DSM related deferral and variance accounts for 2014 as approved by the Board in EGD's 2013, EB-2011-0354 rate proceeding and as described and scoped within the Demand Side Management Guidelines for Natural Gas Utilities EB-2008-0346, EB-2011-0295 and EB-2012-0394 DSM related proceedings. The Company proposes to establish that same group of DSM related deferral and variance accounts for 2015 through 2018 but has not yet received direction from the Board in that regard. Additionally, EGD is proposing that any further variances in DSM spending and results, beyond those included within the 2014-2018 forecasts, which occur as a result of Board decisions in any other proceeding or docket be included within each of the 2014-2018 DSM variance accounts. EGD has included the approved or projected level of DSM spending in each of its 2014-2018 forecasts of costs.

72. Simple interest is to be calculated on the opening monthly balance of these accounts using the Board Approved EB-2006-0117 interest rate methodology. The balances in these accounts, together with carrying charges, will be disposed of in a manner designated by the Board in a future rate hearing.

2015-2018 Greater Toronto Area Project Variance Account ("2015-2018 GTAPVA")

73. The purpose of this variance account is to track and record the variance which may occur annually between the forecast GTA related Allowed Revenue embedded within EGD's overall Allowed Revenue amounts in this rate application and the eventual actual GTA related Allowed Revenue amounts which occur in each of 2015 through 2018, once the actual impacts of the project are known. Details of the planned GTA project and the proposed variance account are found in evidence at Exhibit D1, Tab 8, Schedule 2.

74. Simple interest is to be calculated on the opening monthly balance of these accounts using the Board Approved EB-2006-0117 interest rate methodology. The balances in these accounts, together with carrying charges, will be disposed of in a manner designated by the Board in a future rate hearing.

Criteria for Establishment of Deferral and Variance Accounts

75. The criteria adopted by the Company in determining when to come forward for a rate order or an accounting order request for a deferral or variance account includes the following considerations:
    - the materiality of the amount at risk (revenue or expense);
    - protection of the ratepayer or the shareholder from benefitting at the expense of the other party related to a variance in the forecast amount;
    - the level of uncertainty associated with a forecast of the amount at risk; and
    - the aspect of control - are the underlying circumstances beyond the Company's ability to control.

UPDATED DEFERRAL ACCOUNT EVIDENCE

Unabsorbed Demand Costs Deferral Account (UDCDA) and DDCTDA

76. As described in its updated gas cost evidence at Exhibit D1, Tab 2, Schedule 1, the Company intends to contract for incremental one year long haul FT capacity on TCPL to meet its Peak Day requirements in 2014. A consequence of contracting for incremental long haul capacity is the possibility of Unabsorbed Demand Charges ("UDC").

77. To the extent that the Company is unable to utilize 100% of its contracted long haul TCPL FT capacity to meet customer demand and/or fill storage then the associated UDC costs will be debited in the UDCDA deferral account (excluding the amounts that will be captured in the DDCTDA – please refer to the Updated Exhibit D1, Tab 2, Schedule 1). Enbridge's forecast of UDC costs for 2014, excluding amounts that may be recorded within the 2014 DDCTDA, is $62.8 million. That is the maximum amount that may be recorded within the 2014 UDCDA.

78. Enbridge will use its best efforts to mitigate the UDC that would otherwise be recorded in the 2014 DDCTDA and the 2014 UDCDA. For example, Enbridge will use transportation capacity to fill storage (by displacing discretionary purchases of gas at Dawn) where that is reasonably possible, to reduce the total amount of unutilized capacity. Where there is unutilized capacity, Enbridge will make best efforts to assign that capacity to third parties, to mitigate the UDC costs. The outcome of Enbridge's best efforts to mitigate UDC will be reflected in the amounts recorded in the 2014 DDCTDA and the 2014 UDCDA.

79. Simple interest is to be calculated on the opening balance of this account at the approved short-term debt interest rate.

Witnesses: K. Culbert
D. Small

80. In order to keep the Board and interested parties informed as to the total unutilized transportation costs the Company intends to provide the actual balance in the UDCDA and DDCTDA and the applicable interest through the QRAM process.

81. The Company proposes that as part of the April 2015 QRAM (or subsequent QRAM depending upon the clearance of the 2014 ESM) to clear the 2014 balance in the UDCDA and DDCTDA either through a onetime charge or over the subsequent 12 months which is consistent with the clearance of PGVA balances.

Witnesses: K. Culbert
D. Small

SUMMARY OF GAS COST TO OPERATIONS
YEAR ENDED DECEMBER 31, 2014

Item #		Col. 1 10^3m^3	Col. 2 $(000)	Col. 3 $/$10^3m^3$ (Col.2 / Col.1)	Col. 4 $/GJ (Col.3 / 37.69)
	Western Canadian Supplies				
1.1	Alberta Production	0.0	0.0	0.000	0.000
1.2	Western - @ Empress - TCPL	2,932,223.6	364,714.7	124.382	3.300
1.3	Western - @ Nova - TCPL	938,105.2	117,147.7	124.877	3.313
1.4	Western Buy/Sell - with Fuel	1,326.7	168.6	127.094	3.372
1.5	Western - @ Alliance	962,756.8	125,441.6	130.294	3.457
1.6	Less TCPL Fuel Requirement	(72,504.3)	0.0		
1.	Total Western Canadian Supplies	4,761,908.0	607,472.6	127.569	3.385
2.	Peaking Supplies	36,068.0	8,637.9	239.488	6.354
3.	Ontario Production	730.0	130.6	178.843	4.745
4.	Chicago Supplies	1,847,142.8	271,897.1	147.199	3.906
5.	Delivered Supplies	924,668.5	150,356.2	162.606	4.314
6.	Total Supply Costs	7,570,517.3	1,038,494.3	137.176	3.640
	Transportation Costs				
7.1	TCPL - FT - Demand		229,942.4		
7.2	- FT - Commodity	3,799,151.2	0.0	-	-
7.3	- Parkway to CDA		3,410.5		
7.4	- STS - CDA		12,924.1		
7.5	- STS - EDA		9,436.8		
7.6	- Dawn to CDA		9,226.6		
7.7	- Dawn to EDA		18,173.0		
7.8	- Dawn to Iroquois		6,129.2		
7.9	Other Charges		0.0		
7.10	Nova Transmission		7,039.6		
7.11	Alliance Pipeline		43,550.1		
7.12	Vector Pipeline		25,929.2		
7.	Total Transportation Costs		365,761.4		
8.	Total Before PGVA Adjustment	7,570,517.3	1,404,255.7	185.490	4.921
9.	PGVA Adjustment		(88,369.7)		
10.	Total Purchases & Receipt	7,570,517.3	1,315,886.0	173.817	4.612

SUMMARY OF GAS COST TO OPERATIONS
YEAR ENDED DECEMBER 31, 2014

Item #		Col. 1 10^3m^3	Col. 2 $(000)	Col. 3 $\$/10^3m^3$ (Col.2 / Col.1)	Col. 4 $/GJ (Col.3 / 37.69)
10.	Total Purchases & Receipt	7,570,517.3	1,315,886.0	173.817	4.612
11.	Storage Fluctuation	(86,272.7)	(14,995.7)		
12.	Commodity Cost to Operations	7,484,244.5	1,300,890.3	173.817	
13.	Storage and Transportation Costs		105,281.1		
14.	Gas Cost to Operations	7,484,244.5	1,406,171.5	187.884	4.985
15.	Western T-Service		49,681.4		
16.	Forecasted Gas Costs	7,484,244.5	1,455,852.8	194.522	5.161

Reconciliation Of Natural Gas Sendout Volumes
To Sales Volumes
Year ended December 31, 2014

Item #		
1.	Sendout To Operations	7,484,244.5
2.	T-Service Volumes	3,747,940.5
3.	Total Sendout	11,232,185.0
4.1	Residential Sales	4,131,122.5
4.2	Commercial Sales	2,645,971.2
4.3	Industrial Sales	450,613.0
4.4	T-Service	3,733,346.0
4.5	Rate 200 T-Service (Gazifere)	41,475.4
4.6	Rate 200 Sales (Gazifere)	123,411.8
4.7	Company Use	4,197.7
4.8	Unaccounted For (UAF)	77,660.0
4.9	Unbilled Forecast - Sales	27,504.9
4.10	Unbilled Forecast - T-Service	(26,880.9)
4.11	Lost and Unaccounted For (LUF)	23,763.6
4.	Total System Requirements	11,232,185.0

SUMMARY OF STORAGE & TRANSPORTATION COST
FISCAL 2014

Item #	Units - $(000)	Col. 1 Storage & Transportation Charges Incurred in Fiscal 2014	Col. 2 Fiscal 2014 Storage Charges Recovered in Fiscal 2014	Col. 3 Fiscal 2013 Storage Charges Recovered in Fiscal 2014	Col. 4 Total Storage & Transportation Charges Recovered in Fiscal 2013
	Storage				
1.1	Chatham D	132.3	75.0	57.8	132.8
1.2	Injection	90.5	27.1	84.5	111.7
1.3	Withdrawal	69.5	69.5	0.0	69.5
1.4	Market Based Storage	17,412.0	9,576.1	7,493.4	17,069.5
1.5	Unutilized Transportation Costs	0.0	0.0	0.0	0.0
1.6	Other	1,279.0	1,279.0	1,396.8	2,675.8
1.	Total Storage	18,983.4	11,026.8	9,032.4	20,059.2
2.	Total Transportation	66,402.7	36,530.0	29,710.7	66,240.7
	Dehydration				
3.1	Demand	1,012.6	557.0	453.7	1,010.8
3.2	Commodity	207.2	207.2	0.0	207.2
3.	Total Dehydration	1,219.8	764.3	453.7	1,218.0
4.	Total Storage & Other Costs	86,605.8	48,321.1	39,196.8	87,517.9
	Fuel Costs				
5.1	Tecumseh	3,002.8	1,975.8	1,176.2	3,152.0
5.2	Union Storage	671.6	417.2	378.3	795.5
5.3	Union Transportation	13,649.2	13,509.3	306.3	13,815.6
5.	Total Fuel Costs	17,323.6	15,902.3	1,860.7	17,763.1
6.	Unutilized Transportation Costs	0.0	0.0	0.0	0.0
7	Total Storage & Transportation	103,929.4	64,223.4	41,057.6	105,281.0
8.	Storage and Transportation Costs Charged to Gas Cost to Operations				105,281.0

	2013 Budget Peak Day Demand	Column 1	Column 2	Column 3	2014 Budget Peak Day Demand	Column 4	Column 5	Column 6
Item #	GJ's	CDA	EDA	Total	GJ's	CDA	EDA	Total
1.	Demand	3,229,260	592,864	3,822,124	Demand	3,288,088	673,262	3,961,350
2.	Less Curtailment	(129,737)	(31,788)	(161,524)	Less Curtailment	(133,995)	(28,705)	(162,700)
3.		3,099,523	561,076	3,660,600		3,154,093	644,557	3,798,650
4.	TCPL FT Capacity	63,468	197,421	260,889	TCPL FT Capacity	271,468	370,627	642,095
5.	TCPL STFT	302,500	90,000	392,500	TCPL STFT	-	-	-
6.	TCPL Short Haul	147,318	114,000	261,318	TCPL Short Haul	151,818	114,000	265,818
7.	TCPL STS	369,464	80,611	450,076	TCPL STS	369,464	80,611	450,075
8.	Ontario T-Service	308,176	28,137	336,313	Ontario T-Service	300,354	26,576	326,930
9.	Union Deliveries	1,775,027	-	1,775,027	Union Deliveries	1,775,027	-	1,775,027
10.	Delivered Service	32,753	-	32,753	Delivered Service	182,738	-	182,738
11.	Peaking Service	105,505	52,753	158,258	Peaking Service	105,505	52,753	158,258
12.	Total Supply	3,104,212	562,922	3,667,134	Total Supply	3,156,374	644,567	3,800,941
13.	Sufficency/(Deficiency)	4,688	1,846	6,535	Sufficency/(Deficiency)	2,281	10	2,291

MONTHLY PRICING INFORMATION

	Col. 1 21 Day Average Empress CGPR	Col. 2 21 Day Average NYMEX	Col. 3 21 Day Average Chicago	Col. 4 21 Day Average US Exchange	Col. 5 $CAD/10^{3}m^3 Equivalent (Note 1)
	$CAD/GJ	$US/MMBtu	$US/MMBtu	$CAD/$US	
Jan-14	3.2267	3.8242	3.9370	1.0451	
Feb-14	3.2260	3.8259	3.9337	1.0459	
Mar-14	3.1920	3.7927	3.8905	1.0466	
Apr-14	3.1686	3.7358	3.7301	1.0474	
May-14	3.1813	3.7572	3.7512	1.0481	
Jun-14	3.1876	3.7883	3.7825	1.0489	
Jul-14	3.2109	3.8211	3.8111	1.0497	
Aug-14	3.2216	3.8378	3.8238	1.0505	
Sep-14	3.2373	3.8382	3.8236	1.0513	
Oct-14	3.3159	3.8592	3.8525	1.0521	
Nov-14	3.5150	3.9403	3.9634	1.0529	
Dec-14	3.6284	4.1052	4.1310	1.0537	
	3.2759	3.8438	3.8692	1.0494	123.4698
TCPL Fuel Ratio		1.91%			125.8270

(Note 1) $CAD/10^{3}m^3 = $CAD/GJ * 37.69 Mj/m3

21 Day Period 2-Aug-13 to 30-Aug-13

Natural Gas Conversions

mcf times 0.028328 = 10^{3}m^3

1 Dth = 1 mcf

MMBtu times 1.055056 = GJ's

$/mcf divided by .028328 = $/10^{3}m^3

$/MMBtu divided by 1.055056 = $/GJ

$/GJ times MJ/m^3 = $/10^{3}m^3

Enbridge Gas Distribution Inc. assumes a heat content of 37.69 Mj/m^3

Gas Supply/Demand Balance

Item #		Col. 1 2014 Budget 10^3m^3	Col. 2 2013 Budget 10^3m^3
1.	Total Demand	11,232,185.0	11,576,371.2
	Deliveries		
2.1	Western Canadian Supplies	4,761,908.0	3,886,090.9
2.2	Peaking/Seasonal	36,068.0	37,998.7
2.3	Ontario Production	730.0	730.0
2.4	Chicago Supplies	1,847,142.8	1,832,109.7
2.5	Delivered Supplies	924,668.5	1,553,462.5
2.6	Direct Purchase Delivery	3,742,271.6	4,383,689.4
2.7	Storage (Injection)/Withdrawal	(80,603.8)	(117,710.0)
2.	Total Delivery	11,232,185.0	11,576,371.2

Total Demand includes both System Sales and T-Service Consumption