Enbridge Pipelines Inc.
(“Enbridge”)

COMPETITIVE TOLL SETTLEMENT
Dated July 1, 2011
(the “CTS”)

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PART I – INTRODUCTORY MATTERS

1. RECITALS

1.1 Enbridge is a body corporate continued under the laws of Canada, having its registered office in the City of Calgary, in the Province of Alberta. Enbridge owns and operates those assets set forth in Schedule "A" (the "**Canadian Mainline**"), a common carrier pipeline system regulated under the *National Energy Board Act*.

1.2 Enbridge Energy Limited Partnership owns and operates those assets set forth in Schedule "B" (the "**Lakehead System**"), a pipeline system regulated by the FERC.

1.3 Together the Canadian Mainline and the Lakehead System comprise the "**Enbridge Mainline**".

1.4 CAPP represents companies large and small, that explore for, develop, and produce natural gas and crude oil throughout Canada.

1.5 The CTS was negotiated by representatives from Enbridge, CAPP and from Shippers of Record that delivered the majority of the volumes of liquid hydrocarbons on the Enbridge Mainline in 2010 (the "**2011 Negotiating Team**") and where the context requires, reference to the "2011 Negotiating Team" includes Enbridge, CAPP and such Shippers of Record.

1.6 The CTS provides for an international joint toll for all hydrocarbons shipped from Western Canadian Receipt Points on the Canadian Mainline to delivery points on the Lakehead System and to delivery points on the Canadian Mainline located downstream of the Lakehead System during the Term. The CTS also establishes the local tolls for transportation services solely within Canada, from receipt points on the Canadian Mainline to delivery points on the Canadian Mainline through the Canadian Local Toll. Transportation and related services solely within the U.S., from receipt points on the Lakehead System to delivery points on the Lakehead System, will continue to be governed by the FERC Tariff Rates.

1.7 The Enbridge Board of Directors and the CAPP Board of Governors have approved the principles that comprise the CTS.

2. PRINCIPLES

2.1 No one element of the CTS is to be considered as acceptable to any party in isolation from all other aspects of this settlement. The parties intend that the CTS be viewed as a whole, reflecting the allocation of risks and rewards between Enbridge and its Shippers over the Term.

2.2 The 2011 Negotiating Team agrees that the CTS, including the rate principles set forth herein, are the result of good faith arm's length negotiations, which have resulted in an agreement that is believed to be fair and equitable to Enbridge and all Shippers. Accordingly, each member of the 2011 Negotiating Team has agreed not to, directly or indirectly, commence or support any application, motion or other proceeding before an applicable regulator for the purpose of asking such regulator to set rates for the Enbridge Mainline during the Term which are inconsistent with the rate design and rates contemplated by the CTS, unless otherwise provided hereunder. For clarity, neither the foregoing, nor anything else in this CTS, is intended to, and shall not, be construed as a waiver of any parties' right to complain, protest or otherwise dispute any agreement that may be reached between Enbridge and the Representative Shipper Group pursuant to any other matter as set out herein.

2.3 The rate design and rates contained in the CTS will be without prejudice to any positions that may be taken by any party in respect to matters governed by the CTS for periods following expiry or termination of the CTS. In particular, and without restricting the generality of the above, the 2011 Negotiating Team confirms that the selection of certain capital structures, interest rates, equity returns and operating costs, required for the purposes of implementing the backstopping principles set forth in Article 16 of the CTS, do not in any way form a precedent for the future, nor do these represent the position of either Enbridge or the Shippers as to the capital structure, interest expense, equity return and operating costs that would be appropriate absent this negotiated settlement.

2.4 The 2011 Negotiating Team intends that the principles set forth in the CTS will be applicable solely to the Enbridge Mainline during the Term and will not form a precedent.

2.5 There will be no priority access on the Enbridge Mainline during the Term.

2.6 Subject to Section 7.2, the existing U.S. Agreements in effect as of June 30, 2011 will not be impacted by the CTS during the Term. Moreover, the tolls and tariffs on file with FERC and in effect from time to time pursuant to such U.S. Agreements shall not apply to hydrocarbons transported on the Canadian Mainline or under the IJT unless otherwise agreed between Enbridge and the Representative Shipper Group.

2.7 For clarity, the CTS does not provide for an international joint tariff for hydrocarbons shipped from receipts points on the Lakehead System to delivery points on the Canadian Mainline. However, nothing in the CTS precludes Enbridge from offering additional joint tariffs.

PART II – INTERPRETATION

3. DEFINITIONS

3.1 The following terms found in the CTS have the meanings set out below:

(a) "**2010 Depreciation Technical Update Study**" means the depreciation study approved by the NEB on May 12, 2010 pursuant to file number E101-2010-04 01.

(b) "**2011 Interim ITS Tolls**" means those tolls in effect resulting from the 2011 ITS.

(c) "**2011 ITS**" means a negotiated toll settlement for the period from January 1, 2011, until December 31, 2011, approved by the NEB on March 31, 2011 pursuant to Order T0I-02-2011.

(d) "**2011 Negotiating Team**" has the meaning given to it in Section 1.5.

(e) "**2012 Edmonton Tanks**" means those four tanks described in Schedule "A".

(f) "**2021 Negotiating Team**" has the meaning set out in Section 25.1.

(g) "**Alberta Clipper Canada Settlement Agreement"** means the Alberta Clipper Canada Settlement dated June 28, 2007 as described in Schedule "H".

(h) "**Allowance Oil**" means the percentage of all hydrocarbons tendered to the Enbridge Mainline, which Enbridge is entitled to collect in kind as more fully described in Article 12.

(i) "**Backstopping Agreement**" means an agreement whereby a Shipper agrees to backstop Enbridge's revenue requirement for Shipper Supported Expansion Projects.

(j) "**Canadian Agreements**" means those agreements set forth in Schedule "H" which are in effect as of June 30, 2011.

(k) “**Canadian Mainline**” has the meaning given to it in Section 1.1.

(l) “**Canadian Sourced Hydrocarbons**” means volumes of liquid hydrocarbons produced in Canada and including the diluents required to facilitate transportation of such hydrocarbons in pipelines regardless of whether the diluents were produced in Canada or not.

(m) “**Capital Expenditures**” has the meaning given to it in Section 16.1.

(n) “**Capital Reporting Template**” means the template set forth in Schedule “M”.

(o) “**CAPP**” means Canadian Association of Petroleum Producers.

(p) “**CLT**” or “**Canadian Local Toll**” has the meaning given to it in Section 9.1.

(q) “**Contingent Toll Adjustment**” has the meaning given to it in Section 13.1.

(r) “**Currently Outstanding Adjustment Amounts**” has the meaning given to it in Section 11.3.

(s) “**Declining Bracket Mechanism**” means the methodology approved by the NEB on March 24, 2006 in order number A-TT-FT-ENB 09 (4200-E101-9).

(t) “**Dispute**” has the meaning given to it in Section 30.1.

(u) “**Dispute Notice**” has the meaning given to it in Section 30.2.

(v) “**Enbridge**” means Enbridge Pipelines Inc.

(w) “**Enbridge Service Levels**” means the service levels described within the Enbridge Service Levels Manual as modified from time to time, the current version of which is attached hereto as Schedule “N”.

(x) "**Enbridge Tariff**" means the tolls and tariffs, including the rules and regulations, for the Enbridge Canadian Mainline filed with the NEB.

(y) "**Enbridge Mainline**" has the meaning given to it in Section 1.3.

(z) "**Enbridge Mainline Receipt & Delivery Points**" has the meaning given to it in Section 14.2.

(aa) "**Enbridge Specific Regulatory Change**" means material change to an Existing Law or the coming into force of a New Law or regulatory action resulting in a Final Order that affects only the Enbridge Mainline, provided such action has not been initiated by Enbridge or Enbridge Energy Limited Partnership or is not the result of negligent or willful misconduct by Enbridge or Enbridge Energy Limited Partnership.

(bb) "**Existing Law**" means any law, regulation or order of a Canadian or U.S. governmental, tribunal or regulatory body enacted, promulgated, adopted or issued as of July 1, 2011, that has not been repealed, materially revised, rescinded or of spent force before July 1, 2011, even if the date of implementation or the date by which compliance is required occurs after July 1, 2011.

(cc) "**FERC**" means the Federal Energy Regulatory Commission.

(dd) "**FERC Tariff Rates**" or "**FTR**" means the existing tariff rates, including the rules and regulations, for the Lakehead System on file and in effect with the FERC, as amended and supplemented from time to time, including those tariff rates that FERC approves to go into effect pursuant to the U.S. Agreements.

(ee) "**Final Order**" means an order or directive, issued on or after the date the CTS is filed with the NEB, from a regulator having jurisdiction over Enbridge, including an order or directive to perform hydrostatic testing on the Enbridge Mainline, provided that such order or directive is not an interim order or a recommendation, Enbridge acts reasonably in mitigating the impact of any such order or directive, and Enbridge has given timely notice to the Representative Shipper Group of such order or directive.

(ff) "**Force Majeure**" means any act of God, war, acts of terrorism, civil disturbances, civil insurrection or disobedience, acts of public enemy, power disruptions or other disruptions of critical services, blockades, insurrections, riots, epidemics, landslides, lightning, earthquakes, explosions, fires or floods, or any other like event which is beyond the reasonable control of Enbridge and which Enbridge has been unable to prevent or provide against by the exercise of reasonable diligence at reasonable cost. For clarity, a pipeline leak, break, pressure restriction, repair, corrosion or other like event shall not on its own be considered a Force Majeure, unless such event is caused by one of the events set forth in the first sentence of this definition.

(gg) "**GDPP**" means the annual average Canada Gross Domestic Product at Market Prices Index, published by Statistics Canada on or about February 28th, (Catalogue No. 13-019-X "Implicit price indexes, gross domestic product") for the prior year.

(hh) "**GDPP Index**" in any given year is calculated as the ratio of the annual change in GDPP over the GDPP for the prior year and is expressed as a percentage. For clarity, the GDPP Index applicable for 2012 would be (GDPP for 2011- GDPP for 2010) / GDPP for 2010.

(ii) "**IJT**" or "**International Joint Tariff**" has the meaning given to it in Section 8.1.

(jj) "**Integrity Capital**" means Capital Expenditures incurred to repair, maintain or replace portions of the Enbridge Mainline in order to manage pipeline defects, which may occur as metal loss (eg. corrosion), cracks (eg. stress corrosion cracking), and mechanical damage (eg. dents).

(kk) "**Investment Grade**" has the meaning given to it in the Enbridge Tariff.

(ll) "**Lakehead System**" has the meaning given to it in Section 1.2.

(mm) "**Line 5 Claim**" means the claim by Enbridge referenced in Ontario Case Docket No. 07-CV-338616-PD3.

(nn) "**Line 9**" means those assets set forth in Schedule "C".

(oo) "**LMCI**" or "**Land Matters Consultation Initiative**" means the NEB Land Matters Consultation Initiative (RH-2-2008) and the decisions, directions and orders issued in that proceeding.

(pp) "**Major Enbridge Mainline Expansion Capital**" has the meaning given to it in Section 16.3.

(qq) "**Material Change in Business Circumstances**" has the meaning given to it in Section 20.1.

(rr) "**Minimum Threshold Volume**" has the meaning given to it in Section 19.1.

(ss) "**Monthly Moving Average Volume**" has the meaning given to it in Section 19.4.

(tt) "**NEB**" means National Energy Board.

(uu) "**New Law"** means any law, regulation, order or directive of a Canadian or U.S, governmental, tribunal or regulatory body enacted, promulgated, issued or adopted after July 1, 2011 and includes any material change to or amendment of Existing Law or any final and binding decision of any relevant judicial or regulatory authority interpreting

Existing Law in a manner that is materially different than how such Existing Law was interpreted or applied as of July 1, 2011.

(vv) “**NGL**” means natural gas liquids.

(ww) “**Nine Month Moving Average**” has the meaning given to it in Section 19.3.

(xx) “**Non Enbridge Mainline Receipt & Delivery Points**” has the meaning given to it in Section 14.3.

(yy) “**Northern PADD II or Sarnia**” means the following delivery points included in the Enbridge Mainline Delivery Points: Clearbrook, Minnesota; Superior, Wisconsin; Lockport & Mokena, Illinois; Flanagan, Illinois; Griffith, Indiana; Stockbridge, Michigan; Marysville, Michigan; Rapid River, Michigan; West Seneca, New York; Sarnia, Ontario; and Nanticoke, Ontario.

(zz) “**Oil Pipeline Uniform Accounting Regulations**” means the Oil Pipeline Uniform Accounting Regulations as issued by the NEB in Canada and 18 C.F.R. Part 352 in the United States.

(aaa) “**Outstanding Amount Surcharge**” has the meaning given to it in Section 11.1.

(bbb) “**Over/Short Position**” has the meaning given to it in Enbridge’s Practice Applicable to Automatic Balancing**.**

(ccc) “**Regulatory Change(s)**” means the coming into force of a New Law broadly applicable to the Enbridge Mainline and all similar liquids pipelines, excluding changes to Existing Laws with respect to (i) the FERC Index Rate and, (ii) tax rates, but including, changes to Existing Laws or a New Law that establishes a new type of tax or taxation, such as the implementation of a new carbon tax on the transportation of hydrocarbons.

(ddd) “**Renegotiation Notice**” means a written notice to renegotiate the CTS given under Article 21;

(eee) “**Renegotiating Team**” has the meaning given to it in Section 21.4.

(fff) “**Representative Shipper Group**” has the meaning given to it in Section 22.2.

(ggg) “**Shipper**” means a shipper of hydrocarbons on the Enbridge Mainline.

(hhh) “**Shipper of Record**” means the Shipper invoiced for provision of services on the Enbridge Mainline.

(iii) “**Shipper Supported Expansion Project**” has the meaning given to it in Section 16.4.

(jjj) “**Shippers Line 5 Portion**” has the meaning given to it in Section 17.1.

(kkk) **“Supporting Shipper”** means a Shipper who supports a Shipper Supported Expansion Project by executing a Backstopping Agreement pursuant to Article 16.

(lll) “**Term**” has the meaning given to it in Section 5.1.

(mmm) “**U.S.**” means United States of America.

(nnn) “**U.S. Agreements**” means all existing and future agreements and/or settlements for the transportation of hydrocarbons on the Lakehead System, including but not limited to, those settlements set forth in Schedule ”I”.

(ooo) “**Western Canadian Producers**” means producers of hydrocarbons originating in the Northwest Territories, British Columbia, Alberta, Saskatchewan and Manitoba.

(ppp) “**Western Canadian Receipt Points**” means receipt points on the Canadian Mainline in Alberta, Saskatchewan and Manitoba.

4. INTERPRETATION

4.1 In the CTS, unless the context otherwise requires:

(a) the singular includes the plural and vice versa;

(b) a grammatical variation of a defined term has a corresponding meaning;

(c) subject to the definitions of Existing Law and New Law, reference to any law means such law as amended, modified, codified, replaced or re-enacted, in whole or in part, and in effect from time to time, including rules and regulations promulgated thereunder and reference to any section or other provision of any laws means that provision of such law from time to time in effect and constituting the substantive amendment, modification, codification, replacement or re-enactment of such section or other provision;

(d) references to an Article, Section, Subsection, Paragraph or Schedule by number or letter or both refer to the CTS;

(e) "CTS", "the CTS", "herein", "hereby", "hereunder", "hereof", "hereto" and words of similar import are references to the whole of the CTS in which it is used and not, unless a particular Section or other part thereof is referred to, to any particular Section or other part;

(f) "including" means including without limiting the generality of any description preceding or succeeding such term and for purposes hereof the rule of *ejusdem generis* shall not be applicable to limit a general statement, followed by or referable to an enumeration of specific matters, to matters similar to those specifically mentioned;

(g) Schedules attached to the CTS, form part of the CTS. Where there is a conflict between the body of the CTS and any Schedule other than Schedules "J", "K", "L", "M" and "O", the language of such Schedule will prevail. Schedules "J", "K", "L", "M" and "O" are included for illustrative purposes only, and where there is a conflict between the body of the CTS and a Schedule, the body of the CTS will prevail for only those Schedules;

(h) the phrases “the aggregate of”, “the total of”, “the sum of”, or a similar phrase means “the aggregate (or total or sum), without duplication, of”;

(i) all references to currency are to the lawful money of Canada, unless otherwise indicated;

(j) references to time of day or date means the local time or date in Calgary, Alberta;

(k) if any word, phrase or expression is not defined in the CTS, such word, phrase or expression will, unless the context otherwise requires, have the meaning attributed to it in the usage or custom of the hydrocarbon pipeline transportation business in North America;

(l) where any payment or calculation is to be made, or any other action is to be taken, on or as of a day that is not a business day, that payment or calculation is to be made, or that other action is to be taken, as applicable, on or as of the next following business day; and

(m) the division of the CTS and the recitals, table of contents and headings are for convenience of reference only and shall not affect the construction or interpretation hereof.

PART III – TERM AND APPLICABILITY

5. TERM OF SETTLEMENT

5.1 The term of the CTS will commence July 1, 2011 and terminate on June 30, 2021 (the "**Term**"), unless terminated earlier hereunder or extended pursuant to Section 5.2. The CTS will replace the 2011 ITS, effective as of the start of the Term.

5.2 The Term may be extended by mutual agreement of Enbridge and the 2021 Negotiating Team, provided that such extension shall be for a period of no less than 1 year.

6. APPLICABILITY OF CTS vs. CANADIAN AGREEMENTS

6.1 During the Term, the CTS will supersede the Canadian Agreements, provided however that any calculations that would otherwise have been made pursuant to the Canadian Agreements will be deemed to have been made during the Term.

6.2 Upon the termination or expiry of the CTS, any of the Canadian Agreements that have not expired or terminated will come back into effect as of the date of termination or expiry of the CTS. Any toll and other adjustments that are permitted in the Canadian Agreements shall continue thereafter for their respective then remaining terms. For clarity, the terms under any of the Canadian Agreements shall be deemed to have been applicable during the Term and shall continue to apply thereafter. The assets under the Canadian Agreements will be included in the Canadian Mainline at their remaining undepreciated costs. An illustrative example is set forth in Schedule "J".

6.3 Notwithstanding this Article 6, CAPP preserves the audit rights pursuant to the terms of the Alberta Clipper Canada Settlement agreement.

7. APPLICABILITY OF CTS vs. U.S. AGREEMENTS

7.1 Subject to Section 7.2, the U.S. Agreements will remain in place, and the tariff rates on file with FERC and in effect from time to time pursuant to such U.S. Agreements shall continue to be utilized in calculating the FTR during the Term but neither such tariff rate nor the FTR will apply to hydrocarbons transported under the IJT during the term of the CTS unless otherwise agreed between Enbridge and the Representative Shipper Group pursuant to Section 13.1.

7.2 Where any of the U.S. Agreements expires or terminates during the Term and is replaced by a future agreement and/or settlement for the transportation of hydrocarbons on the Lakehead System, such future agreements and/or settlements will apply in accordance with their respective terms; provided, however, that any tariff rates on file with FERC and in effect from time to time pursuant to such future agreements and/or settlements will not apply to hydrocarbons transported under the IJT unless otherwise agreed between Enbridge and the Representative Shipper Group pursuant to Section 13.1 Any toll and other adjustments that are permitted pursuant to a U.S. Agreement shall continue to be utilized in calculating the FTR during the Term.

PART IV – TOLLS AND RELATED FINANCIAL MATTERS

8. INTERNATIONAL JOINT TOLLS

8.1 Subject to applicable law, effective as of July 1, 2011, tolls for transportation, inclusive of receipt and delivery terminalling services, of hydrocarbons from Western Canada Receipt Points on the Enbridge Mainline to delivery points (i) on the Lakehead System, and (ii) on the Canadian Mainline that are downstream of the Lakehead System are the amounts set forth in Schedule "D" as adjusted pursuant to Section 10.1 (the "**International Joint Tariff**" or "**IJT**"). All IJT tolls are calculated on a distance adjusted basis for transmission and for commodity types, based on and with reference to an initial IJT toll of U.S. $3.85 per barrel for movement of heavy crude oil from Hardisty, Alberta to any of the delivery points in the Chicago, Illinois area (Mokena, Griffith, Lockport). In addition, the applicable Outstanding Amount Surcharge as provided in Section 11 will also be collected.

9. CANADIAN LOCAL TOLLS

9.1 Subject to applicable law, and approval by the NEB, effective as of July 1, 2011, tolls, inclusive of receipt and delivery terminalling services, for transportation of hydrocarbons solely on the Canadian Mainline are the amounts set forth in Schedule "E" (the "**Canadian Local Toll**", or "**CLT**"). The CLTs are calculated using the 2011 Interim ITS Tolls as a starting point, adjusted for the Currently Outstanding Adjustment Amounts outlined in Section 11.3 which will be collected through the Outstanding Amount Surcharge. The CLT is intended to replace the 2011 Interim ITS Tolls as of July 1, 2011. After July 1, 2011 there will be no further true-up for prior Canadian Mainline tolls.

10. ANNUAL TOLL ADJUSTMENT

10.1 Commencing effective July 1, 2012, the IJT tolls and the CLT shall be adjusted annually, up or down, at a rate equal to 75% of the GDPP Index.

10.2 The tankage revenue requirement used to determine receipt and delivery tankage fees in Canada in effect on July 1, 2011 will be adjusted annually, up or down, by 75% of the GDPP Index beginning July 1, 2012. An annual volume forecast will then be used to determine the average tankage fees in effect on July 1 each year and establish the actual receipt and delivery tankage fees in accordance with the Declining Bracket Mechanism. If the actual revenues collected for receipt and delivery tankage fees are greater than, or less than, what the tankage revenue requirement was for the applicable calendar year, (including differences due to the Declining Bracket Mechanism), then such difference will be used to subtract from or add to, as applicable, the next year's tankage revenue requirement. Shippers will be required to pay the applicable receipt and delivery tankage fees for volumes transported under the IJT or the CLT. Notwithstanding the preceding, Enbridge may seek future NEB approval for a different toll design and regulatory treatment for tankage fees with the endorsement of the Representative Shipper Group.

10.3 The CLT from receipt points in Canada to the International Boundary, near Gretna, Manitoba, from the International Boundary, near Sarnia, Ontario to delivery points in Canada and from receipt points in Ontario to the International Boundary, near Chippawa, Ontario will be further adjusted in the event that the sum of the CLT and FTR is not greater than or equal to the IJT tolls in effect in any given year. Enbridge will file with the NEB an application to adjust only the CLT from receipt points in Canada to the International Boundary near Gretna, Manitoba; from the International Boundary, near Sarnia, Ontario to delivery points in Canada; and from receipt points in Ontario to the International Boundary, near Chippawa, Ontario to ensure that the IJT is maintained in accordance with regulatory requirements.

11. OUTSTANDING AMOUNT SURCHARGE

11.1 A per barrel toll surcharge in the amount set forth in Schedule "F" (the "**Outstanding Amount Surcharge**") will be added to the IJT tolls and the CLT for the 24 month period from July 1, 2011 to June 30, 2013 in order to permit Enbridge to collect Currently Outstanding Adjustment Amounts. The Outstanding Amount Surcharge is $0.067 per barrel for movements of heavy crude oil from Hardisty, Alberta to the U.S. border near Gretna, Manitoba and is adjusted for distance and by commodity-type for all barrels transported in Canada.

11.2 Any of the Currently Outstanding Adjustment Amounts that remain uncollected by Enbridge as of June 30, 2013 shall be immediately due to Enbridge. Likewise, an over collection of the Currently Outstanding Adjustment Amounts collected through the Outstanding Amount Surcharge as of June 30, 2013 will be immediately due to the Shippers. For clarity, any under or over collection of the Currently Outstanding Adjustment Amounts as of June 30, 2013 will be recovered or paid by increasing or decreasing, as applicable, the 2014 IJT and CLT tolls effective July 1, 2014 through a one-time surcharge, which adjustment will be on a per barrel basis. The Outstanding Amount Surcharge will be based on a forecast of total sum shipment volume for the IJT and CLT for the calendar year beginning July 1, 2014, which surcharge will be adjusted for distance and by commodity-type for all barrels transported in Canada. Any under or over collection remaining as of July 1, 2015 will not be collected or refunded. For clarity, the Currently Outstanding Adjustment Amounts are amounts due to Enbridge as a result of the interim tolls from January 1, 2010 to June 30, 2011. Any variance relative to the period from April 1, 2011 to June 30, 2011 shall be for Enbridge's sole account.

11.3 The **"Currently Outstanding Adjustment Amounts"** total $69.7 million and is comprised of the following:

(i) a total of $130.0 million as of December 31, 2010 to recover the remaining 2010 ITS revenue shortfall;

(ii) a total of $72.7 million as of March 31, 2011 to credit all applicable net tax loss carry forwards calculated using the applicable 2011 tax rates; and

(iii) a total of $12.4 million to recover amounts due to Enbridge under the 2011 ITS for the toll variance from January 1, 2011 until March 31, 2011.

12. ALLOWANCE OIL

12.1 For transportation under the IJT, Enbridge shall collect in kind a percentage of all hydrocarbons delivered off the Enbridge Mainline in the amount of 1/10th of 1 percent of the volume of hydrocarbons physically delivered under the IJT. The IJT Allowance Oil will be collected and divided between the Canadian Mainline and the Lakehead System as 1/20th of 1 percent to each carrier.

12.2 For transportation under the CLT, Enbridge shall collect in kind or deduct as Allowance Oil a percentage of all hydrocarbons delivered off the Enbridge Mainline, in the amount of 1/20th of 1 percent of the volume of hydrocarbons physically delivered under the CLT.

12.3 Enbridge shall be permitted, at its discretion, to resell to Shippers the Allowance Oil hydrocarbons collected for transportation under the IJT or CLT at a price determined in accordance with the method described in the following Sections.

12.4 Each month, each Shipper who either: (i) has crude or NGL delivered off the Enbridge Mainline in such month; or (ii) holds an Over/Short Position on the Enbridge Mainline at the end of such month, shall furnish to Enbridge a unit price for each crude and NGL stream delivered or held, as applicable. For each refined product stream Enbridge will utilize the prices it receives from refined product Shippers for the purpose of balancing delivery of product batches. Except as provided below, the prices for crude, NGL, and refined product streams so furnished shall be the prices at which Shippers' Allowance Oil for each hydrocarbon stream tendered to Enbridge by each Shipper shall be resold to each Shipper by Enbridge.

12.5 In the event a Shipper does not provide a price for any crude or NGL stream, the Allowance Oil value for that Shipper will be deemed to be the simple average of the prices for that crude or NGL stream received by Enbridge from all other Shippers of that crude or NGL stream for the month that the Allowance Oil volume is being collected whose transaction prices have been accepted by Enbridge as reasonable pursuant to Section 12.6.

12.6 Notwithstanding the provisions of Section 12.4, if the price furnished to Enbridge by any Shipper for any crude or NGL stream is unreasonable, in the sole opinion of Enbridge, acting reasonably, the Allowance Oil resale value for that Shipper for the crude or NGL stream in question shall be the simple average of the prices for that crude or NGL stream received by all other Shippers of that crude or NGL stream for the month whose transaction prices have been accepted by Enbridge as reasonable. Alternatively, Enbridge may choose to use the average of the monthly prices posted for light sweet crude at Edmonton by Imperial Oil Limited, Shell Canada Ltd., Flint Hills Resources and Suncor Energy Inc., or their respective successors, adjusted for quality, pursuant to industry information determined by Enbridge. The average of the monthly prices posted for light sweet crude at Edmonton must be based on all posted prices if all are posted, but if not all are posted, based on no less than three posted prices. In the event that the posted prices cannot be determined in accordance with the above, Enbridge will meet with impacted Shippers to negotiate an appropriate price.

13. CONTINGENT TOLL ADJUSTMENTS

13.1 In addition to those other adjustments described in this Part IV, the IJT and the CLT will be adjusted for the following, subject to NEB approval (each, a "**Contingent Toll Adjustment**"):

(a) any changes in toll methodology that may be agreed to by Enbridge and the Representative Shipper Group;

(b) any incremental tolls resulting from an NEB order in relation to the Land Matters Consultation Initiative;

(c) any Major Enbridge Mainline Expansion Capital as described in Article 16;

(d) any Material Change in Business Circumstances as described in Article 20; and

(e) any other changes that are mutually agreed to by Enbridge and the Representative Shipper Group.

13.2 For clarity, if Enbridge and the Representative Shipper Group are unable to reach agreement on the amount of any Contingent Toll Adjustment identified under Section 13.1 (c) or (d), then Enbridge or the Representative Shipper Group may refer the issue of the amount of the Contingent Toll Adjustment to dispute resolution under Article 30.

13.3 If the NEB does not approve any Contingent Toll Adjustment identified under Section 13.1 that has been agreed to by Enbridge and the Representative Shipper Group, then a NEB hearing to determine the amount of such Contingent Toll Adjustment may be requested.

14. TOLL INCENTIVES

14.1 Enbridge may offer toll incentives onto the Enbridge Mainline, provided such toll incentives on the Enbridge Mainline are offered equally to all Shippers to all Enbridge Mainline Receipt & Delivery Points, as adjusted for distance and commodity types.

14.2 "**Enbridge Mainline Receipt & Delivery Points**" means those receipt and delivery points as set forth in Schedule "A" and Schedule "B" as may be adjusted with the agreement of Enbridge and the Representative Shipper Group. For greater certainty, the IJT tolls applicable to delivery points on the Enbridge Mainline shall be the same, irrespective of the specific facilities or path used to effect such deliveries.

14.3 "**Non Enbridge Mainline Receipt & Delivery Points**" means any receipt or delivery points that are not Enbridge Mainline Receipt & Delivery Points.

14.4 A toll incentive may also be offered for delivery of hydrocarbons to Non Enbridge Mainline Receipt & Delivery Points subject to Section 14.5.

14.5 As required by regulations, tolls to Non Enbridge Mainline Receipt & Delivery Points must be greater than the toll to the nearest upstream Enbridge Mainline Receipt & Delivery Point and must be offered equally to all similarly situated Shippers, as adjusted for distance and commodity types.

15. LAND MATTERS CONSULTATION INITIATIVE

15.1 All Canadian pipeline assets owned by Enbridge that are regulated by the NEB, including the Canadian Mainline, are being addressed in the LMCI. The LMCI will determine the methodology by which costs for abandonment should be collected by a pipeline. Enbridge will file all required information under LMCI as per the NEB schedules for the Canadian Mainline.

15.2 The CTS is unrelated to the ultimate decision regarding the responsibility for abandonment costs for the Canadian Mainline. The CTS is agreed to on a "without prejudice" basis with respect to pipeline abandonment costs for the Canadian Mainline and does not in any way limit either Enbridge or any Shipper's right to make submissions and fully participate in the LMCI or any other proceeding related to abandonment of a pipeline.

16. CAPITAL EXPENDITURES

16.1 "**Capital Expenditures**" means expenditures on the Enbridge Mainline made by Enbridge which, under Oil Pipeline Uniform Accounting Regulations, require capitalization as fixed assets and which would be capitalized on, or after, July 1, 2011. Capital Expenditures must be prudent, reasonable and to the benefit of the Enbridge Mainline and include, but are not limited to, maintenance, integrity, equipment additions, improvements and new facilities. Capital Expenditures would include expansion of the Enbridge Mainline such as expanded pipeline capacity, increased storage capacity, or the creation of new or expansion of existing Enbridge Mainline Receipt & Delivery Points.

16.2 Enbridge is responsible for all Capital Expenditures during the Term, meaning the IJT tolls and CLT will not be adjusted for Capital Expenditures unless otherwise agreed to by Enbridge and the Representative Shipper Group. The 2012 Edmonton Tanks are deemed to be included in the Canadian Mainline as at June 30, 2011, and are therefore included in the IJT tolls and the CLT.

16.3 Enbridge will negotiate with the Representative Shipper Group prior to undertaking any single project on the Enbridge Mainline with expected Capital Expenditures greater than $250 million that expands pipeline capacity, increases storage capacity, or creates or expands Enbridge Mainline Receipt & Delivery Points ("**Major Enbridge Mainline Expansion Capital**"). With the agreement of Enbridge and the Representative Shipper Group, the IJT tolls and respective CLT may be adjusted to allow Enbridge to recover Major Enbridge Mainline Expansion Capital as allowed for under Section 13.1(c). An illustrative example of Major Enbridge Mainline Expansion Capital is set forth as Example #1 in Schedule "K".

16.4 Projects on the Enbridge Mainline which require Capital Expenditures and which are not supported by Enbridge because the incremental revenues associated with such project would not cover the incremental costs, may proceed if there is sufficient financial support from Supporting Shipper(s) pursuant to this Article 16 (a "**Shipper Supported Expansion Project**"). An illustrative example of a Shipper Supported Expansion Project is set forth as Example #2 in Schedule "K".

16.5 By execution of a Backstopping Agreement and confirmation that the proposed project creates no adverse operational issues for Enbridge, as determined by Enbridge acting reasonably, Enbridge will agree to undertake such Shipper Supported Expansion Projects in accordance with the terms of such Backstopping Agreement. In the event that Enbridge is unable to secure NEB approval for construction of the Shipper Supported Expansion Project, the Supporting Shipper(s) will be required to reimburse Enbridge for all of such Shipper Supported Expansion Project's reasonable and prudent development costs as defined in the applicable Backstopping Agreement.

16.6 Subject to Section 16.10, additional revenues derived from tolls, including receipt and delivery terminalling and transmission, collected on the incremental volumes transported on the Enbridge Mainline related to such Shipper Supported Expansion Project, net of any direct incremental costs ("**Net Incremental Revenue**") will be credited to the Backstopping Agreement's revenue requirement.

16.7 The Backstopping Agreement will ensure that the annual revenue requirement associated with the incremental project capital is met either through Net Incremental Revenue from associated incremental throughput or with annual or lump sum payments from the Supporting Shipper(s). The form and terms of a Backstopping Agreement will be developed on a project by project basis but will utilize the following parameters: a) the term will be no less than 5 years and no more than 10 years and can extend past the end of the Term; b) threshold return on equity of between 11 to 15 percent after tax; and c) capital structure of 45 percent equity. The return on equity will be negotiated between Enbridge and the Supporting Shipper(s), and the parties acting reasonably will consider such risks as volume, capital, cost, credit, financial or other relevant risks. An 11 percent return would be appropriate in a circumstance when Enbridge accepted no volume risk, did not share in any operating or capital cost risk, and credit risk was secured by either a letter of credit or a shipper with an Investment Grade credit rating. A 15 percent return would be appropriate in a circumstance when Enbridge accepts substantially more risk with respect to volumes, capital, cost, credit or financial elements of the project. Similar Shipper Supported Expansion Projects will be evaluated on a similar basis and using similar principles.

16.8 At the end of the Term, there will be no net rate base impact to the Enbridge Mainline as a result of Shipper Supported Expansion Projects.

16.9 For example, for a Shipper Supported Expansion Project to construct new tanks, the Backstopping Agreement will require the recovery of the capital cost of the tank through accelerated depreciation. To the extent that such accelerated depreciation exceeds Enbridge's normal depreciation rates, the excess will be credited against rate base and future depreciation expense will be reduced accordingly.

16.10 Enbridge will consider the Net Incremental Revenue from incremental volumes associated with the Shipper Supported Expansion Projects compared to the incremental capital cost to determine the amount and type of Backstopping Arrangement it will require. To establish incremental volumes from existing movements, Enbridge will use an appropriate time frame, typically the 12 month period immediately preceding the month in which Enbridge anticipates the in-service date for the new facilities.

16.11 The Backstopping Agreement will incorporate any terms that would allow the Supporting Shipper(s)'s commitment to be reduced by Net Incremental Revenue or capital contribution provided by one or more other Shipper(s).

16.12 Backstopping Agreements are to allow the provision of services, but nothing in this Section 16 is intended to provide any priority service to Supporting Shipper(s).

17. LINE 5 CLAIM

17.1 Following final resolution of the Line 5 Claim, the Canadian Mainline portion of any amounts (net of reasonable litigation costs incurred after June 30, 2011) actually paid to Enbridge, recovered for that period of the Line 5 Claim from January 1, 1995 to March 31, 2011, including any accrued interest, shall be determined, and such portion shall be shared between Enbridge and the Shippers, with Enbridge to receive 50% and the Shippers to receive 50% (the "**Shippers Line 5 Portion**"). Enbridge shall credit the Shippers Line 5 Portion against the next applicable toll filing for both the IJT and the CLT. The Shippers Line 5 Portion will be calculated on the basis of the required sharing under the various incentive tolling settlements that cover the period from January 1, 1995 to March 31, 2011 where the associated costs were shared between Enbridge and the Shippers.

18. COMMODITY SURCHARGE

18.1 Any changes in the commodity surcharge in effect on April 1, 2011, must be mutually agreed to by both Enbridge and the Representative Shipper Group. The intent of any adjustment to the commodity surcharge methodology considered during the Term is to be revenue neutral.

PART V - RENEGOTIATION AND/OR TERMINATION OF THE CTS

19. MIMIMUM THRESHOLD VOLUMES

19.1 "**Minimum Threshold Volume**" means a throughput of:

(a) 1,250,000 barrels per day to December 31, 2014, then

(b) 1,350,000 barrels per day during the remainder of the Term

of Canadian Sourced Hydrocarbons on the Enbridge Mainline ex-Gretna, Manitoba, as may be adjusted pursuant to Section 19.2 and 19.5.

19.2 The Minimum Threshold Volume will be reduced by the amount that the Bakken/Three Forks U.S. production receipts exceed 305,000 barrels per day into the Enbridge Mainline, less those volumes in excess of 305,000 barrels per day that are transported to delivery points other than the Enbridge Mainline Delivery Points into Northern PADD II or Sarnia (for example, incremental transportation of Bakken/Three Forks U.S. production on Mustang/Spearhead or other Non Enbridge Mainline Delivery Points).

19.3 "**Nine Month Moving Average**" means the sum of the Monthly Moving Average Volumes for the 9 months preceding the date of calculation, divided by 9.

19.4 "**Monthly Moving Average Volume**" means the volume of Canadian Sourced Hydrocarbons transported on the Enbridge Mainline ex-Gretna, Manitoba in a calendar month, divided by the number of days in such month.

19.5 In the event that Nine Month Moving Average falls below the Minimum Threshold Volume, Enbridge and the Representative Shipper Group will determine if the cause of the shortfall was due to capacity loss on the Enbridge Mainline. If it is determined that the shortfall was due to capacity loss on the Enbridge Mainline for reasons other than Force Majeure, the Minimum

Threshold Volume will be reduced by the corresponding shortfall amount. For purposes of determining the applicable capacity loss, Enbridge will use the historical Nine Month Moving Average of volumes from Canadian receipt points through Gretna as well as deliveries ex-Superior. Schedule "G" sets forth upstream and downstream capacity amounts as at December 31, 2010 as reference points for ex-Gretna capacity.

19.6 Illustrative examples of the calculation of Minimum Threshold Volume are set forth in Schedule "L".

20. MATERIAL CHANGE IN BUSINESS CIRCUMSTANCES

20.1 "**Material Change in Business Circumstances**" means:

(i) Regulatory Change(s) or Enbridge Specific Regulatory Change(s) which results in cumulative expenditures in a calendar year for operating costs on the Enbridge Mainline, calculated to include an amount for depreciation expense (not including depreciation expense resulting from Integrity Capital) and subtract applicable capital cost allowance, increasing by more than $10,000,000 over what such annual operating costs would have been (based on Enbridge's applicable operating standards immediately prior to the Regulatory Change(s) or Enbridge Specific Regulatory Change(s)) absent the Regulatory Change(s) or Enbridge Specific Regulatory Change(s); or

(ii) Regulatory Change(s) which results in cumulative expenditures (commencing on the date of the first such Regulatory Change) for Integrity Capital on the Enbridge Mainline increasing by more than $100,000,000 over what such costs would have been absent the Regulatory Changes, provided however that such Regulatory Changes(s) are broadly applicable to the Enbridge Mainline and all similar liquids pipelines.

20.2 The IJT and CLT include (and therefore Enbridge is responsible for) the first $10,000,000 in operating expenses in each calendar year on the Enbridge Mainline associated with any Regulatory Changes or Enbridge Specific Regulatory Changes, as applicable, and the first $100,000,000 of Integrity Capital during the Term on the Enbridge Mainline associated with any Regulatory Changes. In calculating that amounts attributable to such operating expenses or Integrity Capital, Enbridge shall deduct from such calculation any amount that Enbridge would have otherwise spent absent such Regulatory Change or Enbridge Specific Regulatory Change, as applicable.

21. EVENTS TRIGGERING A RENEGOTIATION PERIOD

21.1 If the Keystone XL pipeline project does not receive the required U.S. presidential permit by January 1, 2013, then the Representative Shipper Group may, on or before February 1, 2013, provide to Enbridge a Renegotiation Notice.

21.2 If the Material Change in Business Circumstances referred to in Section 20.1(ii) occurs, Enbridge will, as soon as reasonably practicable following such occurrence, provide notice to the Representative Shipper Group. Following receipt of such notice, the Representative Shipper Group and Enbridge shall meet to determine whether they can agree to a Contingent Toll Adjustment under Article 13. In the event a Contingent Toll Adjustment is not agreed to within 90 days, then the Representative Shipper Group may provide to Enbridge a Renegotiation Notice.

21.3 If the Nine-Month Moving Average is less than the Minimum Threshold Volume, then Enbridge may, as soon as is reasonably practicable following the occurrence of such event, provide to the Representative Shipper Group a Renegotiation Notice.

21.4 Upon receipt by either Enbridge or the Representative Shipper Group of a Renegotiation Notice, Enbridge and the Representative Shipper Group (the "**Renegotiating Team**") shall meet and use reasonable efforts to agree on how the CTS can be amended to accommodate the events referred to in Section 21.1, 21.2, or 21.3 above.

21.5 If, within 90 days following receipt of the Renegotiation Notice, the Renegotiating Team is unable to agree on how the CTS can be amended, then the Renegotiating Team may agree to extend the renegotiation period. If the Renegotiating Team does not agree to extend the renegotiation period, then the CTS terminates and Enbridge will file a new toll application for the Canadian Mainline.

21.6 The IJT and the CLT will apply during the renegotiation period and will become the interim toll after the renegotiation period until a new toll filing is approved by the NEB.

PART VI – OTHER CTS MATTERS

22. REPRESENTATIVE SHIPPER GROUP

22.1 Enbridge will work with its Shippers, CAPP and Western Canadian Producers to develop, by July 3, 2012, and thereafter file with the NEB, a transparent process, in compliance with current regulatory requirements, to review and administer issues related to the CTS and the formation of the Representative Shipper Group. This process is intended to be used toward reaching agreement on the resolution of issues related to the CTS during the Term and to provide a counter-party to negotiate any required changes to the CTS resulting from unanticipated events relating to the CTS, with a view to reducing adversarial aspects of NEB and FERC hearings, as well as reducing hearing time and associated costs.

22.2 The Representative Shipper Group will have representation from CAPP, CAPP members and other Shippers or interested parties as applicable (the "**Representative Shipper Group**").

23. SERVICE LEVELS

23.1 The Enbridge Service Levels, as adjusted from time to time, will continue to apply.

24. GENERAL TANKAGE PRINCIPLES

24.1 During the Term, Enbridge will provide sufficient receipt and breakout tankage to manage the receipt and transportation of crude petroleum in accordance with the Enbridge Service Levels under normal operating conditions.

24.2 Any incremental delivery tankage requirements requested by a Shipper are the responsibility of that Shipper.

25. END OF TERM ISSUES

25.1 Enbridge and the Representative Shipper Group will, no later than July 1, 2019, establish a group for the purposes of negotiating a new settlement following expiry of the CTS (the "**2021 Negotiating Team**"). The 2021 Negotiation Team will begin to negotiate a new settlement that is applicable after the expiry of the CTS. The 2021 Negotiating Team will also review and endorse discretionary capital projects proposed by Enbridge under the CTS in the last two years of the CTS, prior to Enbridge undertaking any such discretionary capital projects. Discretionary capital projects will include any projects less than $250 million excluding maintenance capital and Integrity Capital projects. If negotiations for a new settlement fail, the CTS will terminate on June 30, 2021 and Enbridge will, exercising reasonable diligence, file a new application for tolls with the NEB for the Canadian Mainline. The IJT and CLT tolls will become the interim tolls until the new toll application is approved by the NEB.

25.2 At the end of the Term, Enbridge will not carry forward amounts based on toll or volume variances in a new settlement agreement or extended CTS unless otherwise agreed to by Enbridge and the 2021 Negotiation Team.

25.3 Unless otherwise mutually agreed to by Enbridge and the 2021 Negotiating Team, the cumulative amount spent by Enbridge on maintenance and integrity in the last two years of the CTS must be equal to or greater than an amount equal to the average annual amount spent by Enbridge on maintenance and integrity, excluding any amounts spent as a result of Regulatory Changes or Enbridge Specific Regulatory Changes, in the first eight years of the CTS multiplied by 2.

25.4 The 2010 Depreciation Technical Update Study incorporates a truncation date of 2039 which was approved by the NEB on May 8, 2010. At the end of the Term, the depreciation rates to be applied to rates subject to the NEB's jurisdiction, exclusive of the rates covered by Section 25.5

below, will be based on the depreciation truncation date implicit in the 2010 Depreciation Technical Update Study subject to Section 25.5.

25.5 Applicable depreciation rates for the assets comprising the Enbridge Mainline are set forth in Schedules “H” and “I”.

PART VII – GENERAL PROVISIONS

26. REPORTING AND FILING REQUIREMENTS

26.1 Each February during the Term, Enbridge will provide the Representative Shipper Group with a summary of capital additions for the prior year and forecast capital additions for the current year to the Enbridge Mainline rate base in total and will detail individual items that exceed $50 million, and the aggregate amount of capital under Shipper Supported Expansion Project(s) in accordance with the Capital Reporting Template. Enbridge will continue to meet with Shippers to annually review the Enbridge Mainline integrity plan, metrics and overall operating plan.

26.2 In addition, each February of 2019, 2020 and 2021, Enbridge will provide a summary of the forecast capital additions to the Enbridge Mainline rate base for all pending projects or future projects anticipated to be initiated before the end of the Term that exceed $50 million that could result in an addition to the Enbridge Mainline rate base either before or after the end of the Term.

26.3 Enbridge shall file with the applicable regulator and make available to interested parties copies of the CTS tolls and tariffs for each year.

26.4 Subject to NEB approval, the intention of the CTS is that Enbridge will be exempt from the requirement for Enbridge to file financial forecasts and Financial Surveillance Reports, consistent with the relief granted pursuant to Board Order TO-3-2000, as amended.

27. AUDIT

27.1 Enbridge shall file an external auditors’ report for the Enbridge consolidated financial statements with the NEB annually for each fiscal year ending December 31 by March 31 of the following year. The same such auditor’s report will be provided to all other interested parties on request.

27.2 The Enbridge consolidated financial statements for each fiscal year ending December 31st will be audited by an independent auditor and reported in a manner consistent with Canadian Auditing

Standards. The purpose of this audit is to confirm that the financial results as reflected on are in accordance with the provisions of the CTS, including the completeness and accuracy of the annual tolls and any relevant surcharges.

27.3 Upon 60 days notice to Enbridge by the Representative Shipper Group, and subject to Enbridge's confidentiality obligations to third parties, the Representative Shipper Group shall be able to, on two occasions, elect to engage an independent accountant or other auditor to conduct its own audit of the Enbridge financial results and of all data and information related to and necessary to establish compliance with the CTS, provided that no such audit shall occur any later than 24 months from the end of the Term. The independent accountant or other auditor will enter into a confidentiality agreement with Enbridge to ensure non-disclosure of confidential or commercial information. Enbridge agrees to undertake all reasonable commercial efforts to assist in the completion of the audit on a timely basis, during normal business hours. Shippers shall bear all third party costs associated with such audits.

28. ACCOUNTING

28.1 Enbridge will continue to use flow through tax accounting as directed by the NEB under order Order TO-1-92.

29. AFFILIATES

29.1 Enbridge agrees to abide by the Enbridge Canadian Affiliate Relationship Code which was developed in collaboration with CAPP, as may be amended from time to time, the current version of which is posted on Enbridge's website at:

http://www.enbridge.com/InvestorRelations/CorporateGovernance/~/media/Site%20Documents/Investor%20Relations/Corporate%20Governance/Key%20Documents/carc-epi-2010.ashx .

30. DISPUTE RESOLUTION

30.1 To facilitate the resolution of any disputes regarding the CTS in an efficient and expedited manner, disputes arising under this CTS ("**Dispute**") shall be resolved in accordance with the dispute resolution mechanism set forth in this Article 30. For clarity, this Article 30 is not intended to permit a party to renegotiate terms that have been agreed to in the CTS or to resolve deadlocks between the parties over an action where the approval of any parties is required under this CTS to such action.

30.2 In the event of a Dispute, either of Enbridge or a Shipper(s) (the Shipper or group of Shippers initiating the Dispute the "**Disputing Shipper Group**") that wishes to initiate dispute resolution shall give written notice (the "**Dispute Notice**") to any party of a Dispute and outline in reasonable detail the relevant information concerning the Dispute. The Disputing Shipper Group may self-form and is not dependent on formation pursuant to Section 22.1. Within fourteen (14) days following receipt of the Dispute Notice, Enbridge and the Disputing Shipper Group will each appoint representatives to meet to discuss and attempt to resolve the Dispute. Such representatives shall be individuals that are technically qualified to appreciate and assess the Dispute and have authority to negotiate the Dispute. If the Dispute is not settled within ninety (90) days of receipt of the Dispute Notice, the negotiation will be deemed to have failed.

30.3 If the Dispute is not resolved pursuant to the process above, the Dispute may be referred to the NEB or other applicable regulator by either Enbridge or the Disputing Shipper Group, to be resolved on an expedited basis.

30.4 Notwithstanding the above, any parties retain all rights for dispute resolution with the applicable regulator.

PART VIII – LINE 9 MATTERS

31. LINE 9

31.1 Enbridge owns and operates Line 9, a common carrier pipeline system regulated under the NEB Act. The assets included in Line 9 are outlined in Schedule "C".

31.2 Line 9 tolls are currently set on a standalone basis and will continue to be set on a standalone basis under the CTS regardless of whether Line 9 is used for East to West or West to East service or is used for partial East to West and partial West to East service. Standalone tolling under the CTS continues to treat Line 9 assets as separate and distinct assets from the Enbridge Mainline assets. Standalone tolling under the CTS continues to base Line 9 tolls on the separate and distinct Line 9 rate base.

31.3 Line 9 tolls are currently published under an NEB approved Line 9 Tariff. Subject to applicable law and approval by the NEB, tolls for transportation of hydrocarbons on Line 9 will continue to be published under a separate Line 9 tariff. In the event that Enbridge applies to reverse service on Line 9 and such reversal is approved by the NEB, such that Line 9 or a portion of Line 9 is operated in a fashion that allows volumes to flow from the Canadian Mainline into Line 9 and supports flow of hydrocarbons from West to East in Line 9, Enbridge may file, at its discretion, a negotiated International Joint Tariff for delivery on Line 9 at that time.

31.4 In the event that Enbridge files an application to reverse service on Line 9 or a portion of Line 9 and such reversal is approved by the NEB, the stand alone toll for the transportation of hydrocarbons on Line 9 in a West to East service ("**Line 9 Local Tolls"**) shall be adjusted annually, up or down, at a rate of 75% of the GDPP Index.

31.5 The CTS is unrelated to any decision regarding the possible reversal of Line 9. The CTS does not limit in any way a party's rights to make submissions and fully participate in any Line 9 reversal facilities application and is entirely without prejudice to the position of any party in such an application.

31.6 Subject to applicable law, tolls under a negotiated international joint tariff for the transportation of hydrocarbons from the Canadian Mainline to delivery points on Line 9 will be published when available.

31.7 Enbridge may offer incentives in order to attract incremental volumes onto Line 9, provided such toll incentives on Line 9 are offered equally to all shippers on Line 9, as adjusted for distance and commodity types.

31.8 The CTS is unrelated to any decision regarding the responsibility for the costs of abandoning Line 9. The CTS is entirely without prejudice to the position of any party on the question of responsibility for the cost of abandonment of Line 9.

31.9 All Canadian pipeline assets owned by Enbridge that are regulated by the NEB, including Line 9, are being addressed in the LMCI process. The LMCI process will determine the methodology by which costs for abandonment should be collected by a pipeline. Enbridge will file all required information under LMCI as per the NEB schedules for Line 9. Through the LMCI process, whatever abandonment costs the NEB approves for pre-collection from shippers on Line 9 will form part of the standalone costs of Line 9. Enbridge will not apply for abandonment of Line 9 during the Term unless ordered to do so by the NEB.

31.10 For greater certainty, all parties may fully participate in the LMCI process or any other proceeding related to abandonment and the CTS does not limit in any way a party's right to make submissions regarding Line 9 abandonment or abandonment costs. The CTS is unrelated to the ultimate decision regarding the responsibility for abandonment costs for Line 9.

31.11 "**Line 9 Capital Expenditures**" means expenditures on the Line 9 made by Enbridge which, under Oil Pipeline Uniform Accounting Regulations, require capitalization as fixed assets. Line 9 Capital Expenditures must be prudent, reasonable and to the benefit of Line 9 and include, but are not limited to, maintenance, integrity, equipment additions, improvements and new facilities. Line 9 Capital Expenditures would include expansion of Line 9 such as expanded pipeline capacity, increased storage capacity, or the creation or expansion of new Line 9 receipt and delivery points.

31.12 Enbridge is responsible for all Line 9 Capital Expenditures on Line 9 during the Term.

31.13 Enbridge will negotiate with shippers on Line 9 prior to any single project on Line 9 with expected Line 9 Capital Expenditures greater than $25 million that expands pipeline capacity, increases storage capacity, or creates or expands new Line 9 receipt and delivery points.

31.14 Projects on Line 9 which require Line 9 Capital Expenditures and which are not supported by Enbridge because the incremental revenues associated with such project would not cover the incremental costs, may proceed if there is sufficient financial support from a shipper(s) on Line 9 (a "**Line 9 Shipper Supported Expansion Project**").

31.15 By execution of an agreement whereby a shipper on Line 9 agrees to backstop Enbridge's revenue requirement for Line 9 Shipper Supported Expansion Projects (a "**Line 9 Backstopping Agreement**") and confirmation that the proposed project creates no adverse operational issues for Enbridge, as determined by Enbridge acting reasonably, Enbridge will agree to undertake such Line 9 Shipper Supported Expansion Projects in accordance with the terms of such Line 9 Backstopping Agreement. In the event that Enbridge is unable to secure NEB approval for construction of the project, the shipper on Line 9 who supports a Line 9 Shipper Supported Expansion Project by executing a Line 9 Backstopping Agreement (the "**Line 9 Supporting**

Shipper(s)") will be required to reimburse Enbridge for all of the project's reasonable and prudent development costs as defined in the applicable Line 9 Backstopping Agreement.

31.16 Subject to Section 31.20, additional revenues derived from tolls, including receipt and delivery terminalling and transmission, collected on the incremental volumes transported on the Enbridge Mainline and Line 9 related to such Line 9 Shipper Supported Expansion Project, net of any direct incremental costs ("**Net Line 9 Incremental Revenue**") will be credited to the Line 9 Backstopping Agreement's revenue requirement.

31.17 The Line 9 Backstopping Agreement will ensure that the annual revenue requirement associated with the incremental project capital is met either through Net Line 9 Incremental Revenue from associated incremental throughput or lump sum payments from the Line 9 Supporting Shipper(s). The form and terms of a Line 9 Backstopping Agreement will be developed on a project by project basis but will utilize the following parameters: a) the term will be no less than 5 years and no more than 10 years and can extend past the end of the Term; b) threshold return on equity of between 11 to 15 percent after tax; and c) capital structure of 45 percent equity. The return on equity will be negotiated between, Enbridge and the Line 9 Supporting Shipper(S), and the parties acting reasonably, will consider such risks as volume, capital, cost, credit, financial or other relevant risks. An 11 percent return would be appropriate in a circumstance when Enbridge accepted no volume risk, did not share in any operating or capital cost risk, and credit risk was secured by either a letter of credit or a shipper with an Investment Grade credit rating. A 15 percent return would be appropriate in a circumstance when Enbridge accepts substantially more risk with respect to volumes, capital, cost, credit or financial elements of the project. Similar Line 9 Shipper Supported Expansion Projects will be evaluated on a similar basis and using similar principles.

31.18 At the end of the Term, there will be no net rate base impact to Line 9 as a result of Line 9 Shipper Supported Expansion Projects.

31.19 For example, for a Line 9 Shipper Supported Expansion Project to construct new tanks, the Line 9 Backstopping Agreement will require the recovery of the capital cost of the tank through accelerated depreciation. To the extent that such accelerated depreciation exceeds Enbridge's normal depreciation rates for Line 9, the excess will be credited against the Line 9 rate base and future depreciation expense will be reduced accordingly.

31.20 Enbridge will consider the Net Line 9 Incremental Revenue from incremental volumes associated with Line 9 Shipper Supported Expansion Projects compared to the incremental capital cost to determine the amount and type of Line 9 Backstopping Arrangement it will require. To establish incremental volumes from existing movements, Enbridge will use an appropriate time frame, typically the 12 month period immediately preceding the month in which Enbridge anticipates the in-service date for the new facilities.

31.21 The Line 9 Backstopping Agreement will incorporate any terms that would allow the Line 9 Supporting Shipper's commitment to be reduced by Net Line 9 Incremental Revenue or capital contribution provided by one or more other shipper(s) on Line 9.

31.22 Line 9 Backstopping Agreements are to allow the provision of services, but nothing in this Article 31 is intended to provide any priority service to Line 9 Supporting Shippers.

31.23 Each February during the Term, Enbridge will provide shippers on Line 9 with a summary of capital additions for the prior year and forecast capital additions for the current year to the Line 9 rate base in total and will detail individual items that exceed $5 million, and the aggregate amount of capital under a Shipper Supported Expansion Project in accordance with the Line 9 Capital Reporting Template included in Schedule "O". Enbridge will continue to meet with shippers on Line 9 to annually review the Line 9 integrity plan, metrics and overall operating plan.

31.24 In addition, each February of 2019, 2020 and 2021, Enbridge will provide a summary of the forecast capital additions to the Line 9 rate base for all pending projects or future projects anticipated to be initiated before the end of the Term that exceed $5 million that could result in an addition to the Line 9 rate base before the end of the Term.

31.25 Enbridge shall file with the NEB and make available to interested parties copies of the Line 9 tolls and tariffs for each year.

SCHEDULE “A” - CANADIAN MAINLINE

PIPELINES & FACILITIES
Line 1
Line 2
Line 3
Line 4
Line 5
Line 6B
Line 7
Line 10
Line 11
Line 65
Line 67
All related facilities associated with the above noted pipelines

RECEIPT POINTS	DELIVERY POINTS
Edmonton, Alberta	Edmonton, Alberta
Hardisty, Alberta	Hardisty, Alberta
Kerrobert, Saskatchewan	Kerrobert, Saskatchewan
Regina, Saskatchewan	Stony Beach, Saskatchewan
Cromer, Manitoba	Regina, Saskatchewan
Sarnia, Ontario	Milden, Saskatchewan
Westover, Ontario	Gretna, Manitoba
	Sarnia, Ontario
	Nanticoke, Ontario

<u>2012 Edmonton Tanks</u>

(a) Tank #36, shell capacity of 260,000 barrels per day in service on or about September 1, 2012;

(b) Tank #38, shell capacity of 186,000 barrels per day in service, on or about September 1, 2012;

(c) Tank # 33 and Tank # 37 each with shell capacity of 372,000 barrels expected to be in service on, or about, December 1, 2012; and

(d) the demolition of Tank #13 and Tank #17.

SCHEDULE “B” - LAKEHEAD SYSTEM

PIPELINES & FACILITIES
Line 1
Line 2
Line 3
Line 4
Line 5
Line 6A
Line 6B
Line 10
Line 14/64
Line 61
Line 62
Line 65
Line 67
All related facilities associated with the above noted pipelines

RECEIPT POINTS	DELIVERY POINTS
Clearbrook, Minnesota	Clearbrook, Minnesota
Mokena, Illinois	Superior, Wisconsin
Griffith, Indiana	Lockport & Mokena, Illinois
Stockbridge, Michigan	Flanagan, Illinois
Lewiston, Michigan	Griffith, Indiana
	Stockbridge, Michigan
	Marysville, Michigan
	Rapid River, Michigan
	West Seneca, New York

SCHEDULE "C" - LINE 9 FACILITIES EAST BOUND SERVICE

PIPELINES & FACILITIES
Line 9
All related facilities associated with the above noted pipeline

RECEIPT POINTS	**DELIVERY POINTS**
Sarnia, Ontario	North Westover, Ontario
	Montreal, Quebec

SCHEDULE "D" - TABLE OF IJT TOLLS

These tolls will escalate each July 1 by 75% of GDPP Index beginning July 1, 2012.

<u>Schedule "D" (Part 1) - IJT Tolls in U.S. Dollars per Cubic Meter</u>

IJT - JOINT TRANSPORTATION RATES ($USD PER CUBIC METER)						
FROM	TO	RATE				
		NGL	CND	LIGHT	MEDIUM	HEAVY
Edmonton Terminal, Alberta	Clearbrook, Minnesota	-	12.5702	13.3780	14.3201	15.9705
	Superior, Wisconsin	14.3227	15.0655	15.8733	17.0053	18.9850
	Lockport, Illinois	-	20.7469	21.5547	23.1509	25.9473
	Mokena, Illinois	-	20.7469	21.5547	23.1509	25.9473
	Flanagan, Illinois	-	20.7469	21.5547	23.1509	25.9473
	Griffith, Indiana	-	20.7469	21.5547	23.1509	25.9473
	Stockbridge, Michigan	-	22.8831	23.6909	25.4579	28.5542
	Rapid River, Michigan	17.1569	-	-	-	-
	Marysville, Michigan	21.4046	22.8831	23.6909	25.4579	28.5542
	Corunna or Sarnia Terminal, Ontario	21.7335	23.2139	24.0295	25.8058	28.9124
	Nanticoke, Ontario	-	25.2211	26.2112	28.1620	31.5741
	West Seneca, New York	-	25.5215	26.5317	28.5270	32.0181
Hardisty Terminal, Alberta	Clearbrook, Minnesota	-	-	11.9587	12.7872	14.2390
	Superior, Wisconsin	-	-	14.4540	15.4724	17.2535
	Lockport, Illinois	-	-	20.1354	21.6180	24.2158
	Mokena, Illinois	-	-	20.1354	21.6180	24.2158
	Flanagan, Illinois	-	-	20.1354	21.6180	24.2158
	Griffith, Indiana	-	-	20.1354	21.6180	24.2158
	Stockbridge, Michigan	-	-	22.2716	23.9250	26.8227
	Rapid River, Michigan	-	-	-	-	-
	Marysville, Michigan	-	-	22.2716	23.9250	26.8227
	Corunna or Sarnia Terminal, Ontario	-	-	22.6102	24.2729	27.1809
	Nanticoke, Ontario	-	-	24.7919	26.6291	29.8425
	West Seneca, New York	-	-	25.1124	26.9941	30.2865

Schedule "D" (Part 1) - IJT Tolls in U.S. Dollars per Cubic Meter - continued

IJT - JOINT TRANSPORTATION RATES ($USD PER CUBIC METER)						
FROM	TO	RATE				
		NGL	CND	LIGHT	MEDIUM	HEAVY
Kerrobert Station, Saskatchewan	Clearbrook, Minnesota	-	-	10.5313	-	12.4975
	Superior, Wisconsin	11.7606	-	13.0266	-	15.5120
	Lockport, Illinois	-	-	18.7080	-	22.4743
	Mokena, Illinois	-	-	18.7080	-	22.4743
	Flanagan, Illinois	-	-	18.7080	-	22.4743
	Griffith, Indiana	-	-	18.7080	-	22.4743
	Stockbridge, Michigan	-	-	20.8442	-	25.0812
	Rapid River, Michigan	14.5948	-	-	-	-
	Marysville, Michigan	18.8425	-	20.8442	-	25.0812
	Corunna or Sarnia Terminal, Ontario	19.1715	-	21.1828	-	25.4394
	Nanticoke, Ontario	-	-	23.3645	-	28.1011
	West Seneca, New York	-	-	23.6850	-	28.5450
Regina Terminal, Saskatchewan	Clearbrook, Minnesota	-	-	7.6683	-	9.0047
	Superior, Wisconsin	-	-	10.1636	-	12.0192
	Lockport, Illinois	-	-	15.8450	-	18.9815
	Mokena, Illinois	-	-	15.8450	-	18.9815
	Flanagan, Illinois	-	-	15.8450	-	18.9815
	Griffith, Indiana	-	-	15.8450	-	18.9815
	Stockbridge, Michigan	-	-	17.9812	-	21.5884
	Rapid River, Michigan	-	-	-	-	-
	Marysville, Michigan	-	-	17.9812	-	21.5884
	Corunna or Sarnia Terminal, Ontario	-	-	18.3198	-	21.9466
	Nanticoke, Ontario	-	-	20.5015	-	24.6083
	West Seneca, New York	-	-	20.8221	-	25.0522
Cromer Terminal, Manitoba	Clearbrook, Minnesota	-	-	5.6002	5.9201	6.4816
	Superior, Wisconsin	7.3226	-	8.0955	8.6053	9.4961
	Lockport, Illinois	-	-	13.7769	14.7509	16.4584
	Mokena, Illinois	-	-	13.7769	14.7509	16.4584
	Flanagan, Illinois	-	-	13.7769	14.7509	16.4584
	Griffith, Indiana	-	-	13.7769	14.7509	16.4584
	Stockbridge, Michigan	-	-	15.9131	17.0579	19.0653
	Rapid River, Michigan	10.1568	-	-	-	-
	Marysville, Michigan	14.4045	-	15.9131	17.0579	19.0653
	Corunna or Sarnia Terminal, Ontario	14.7335	-	16.2517	17.4057	19.4235
	Nanticoke, Ontario	-	-	18.4334	19.7620	22.0852
	West Seneca, New York	-	-	18.7539	20.1269	22.5291

Schedule "D" (Part 2) - IJT Tolls in U.S. Dollars per Barrel

IJT - JOINT TRANSPORTATION RATES ($USD PER BARREL)						
FROM	TO	RATE				
		NGL	CND	LIGHT	MEDIUM	HEAVY
Edmonton Terminal, Alberta	Clearbrook, Minnesota	-	1.9985	2.1269	2.2767	2.5391
	Superior, Wisconsin	2.2771	2.3952	2.5237	2.7036	3.0184
	Lockport, Illinois	-	3.2985	3.4269	3.6807	4.1253
	Mokena, Illinois	-	3.2985	3.4269	3.6807	4.1253
	Flanagan, Illinois	-	3.2985	3.4269	3.6807	4.1253
	Griffith, Indiana	-	3.2985	3.4269	3.6807	4.1253
	Stockbridge, Michigan	-	3.6381	3.7666	4.0475	4.5398
	Rapid River, Michigan	2.7277	-	-	-	-
	Marysville, Michigan	3.4031	3.6381	3.7666	4.0475	4.5398
	Corunna or Sarnia Terminal, Ontario	3.4554	3.6907	3.8204	4.1028	4.5967
	Nanticoke, Ontario	-	4.0098	4.1672	4.4774	5.0199
	West Seneca, New York	-	4.0576	4.2182	4.5354	5.0905
Hardisty Terminal, Alberta	Clearbrook, Minnesota	-	-	1.9013	2.0330	2.2638
	Superior, Wisconsin	-	-	2.2980	2.4599	2.7431
	Lockport, Illinois	-	-	3.2013	3.4370	3.8500
	Mokena, Illinois	-	-	3.2013	3.4370	3.8500
	Flanagan, Illinois	-	-	3.2013	3.4370	3.8500
	Griffith, Indiana	-	-	3.2013	3.4370	3.8500
	Stockbridge, Michigan	-	-	3.5409	3.8038	4.2645
	Rapid River, Michigan	-	-	-	-	-
	Marysville, Michigan	-	-	3.5409	3.8038	4.2645
	Corunna or Sarnia Terminal, Ontario	-	-	3.5947	3.8591	4.3214
	Nanticoke, Ontario	-	-	3.9416	4.2337	4.7446
	West Seneca, New York	-	-	3.9926	4.2917	4.8152

Schedule "D" (Part 2) - IJT Tolls in U.S. Dollars per Barrel - continued

IJT - JOINT TRANSPORTATION RATES ($USD PER BARREL)						
FROM	TO	RATE				
		NGL	CND	LIGHT	MEDIUM	HEAVY
Kerrobert Station, Saskatchewan	Clearbrook, Minnesota	-	-	1.6743	-	1.9869
	Superior, Wisconsin	1.8698	-	2.0711	-	2.4662
	Lockport, Illinois	-	-	2.9743	-	3.5731
	Mokena, Illinois	-	-	2.9743	-	3.5731
	Flanagan, Illinois	-	-	2.9743	-	3.5731
	Griffith, Indiana	-	-	2.9743	-	3.5731
	Stockbridge, Michigan	-	-	3.3140	-	3.9876
	Rapid River, Michigan	2.3204	-	-	-	-
	Marysville, Michigan	2.9957	-	3.3140	-	3.9876
	Corunna or Sarnia Terminal, Ontario	3.0480	-	3.3678	-	4.0445
	Nanticoke, Ontario	-	-	3.7147	-	4.4677
	West Seneca, New York	-	-	3.7656	-	4.5383
Regina Terminal, Saskatchewan	Clearbrook, Minnesota	-	-	1.2192	-	1.4316
	Superior, Wisconsin	-	-	1.6159	-	1.9109
	Lockport, Illinois	-	-	2.5192	-	3.0178
	Mokena, Illinois	-	-	2.5192	-	3.0178
	Flanagan, Illinois	-	-	2.5192	-	3.0178
	Griffith, Indiana	-	-	2.5192	-	3.0178
	Stockbridge, Michigan	-	-	2.8588	-	3.4323
	Rapid River, Michigan	-	-	-	-	-
	Marysville, Michigan	-	-	2.8588	-	3.4323
	Corunna or Sarnia Terminal, Ontario	-	-	2.9126	-	3.4892
	Nanticoke, Ontario	-	-	3.2595	-	3.9124
	West Seneca, New York	-	-	3.3104	-	3.9830
Cromer Terminal, Manitoba	Clearbrook, Minnesota	-	-	0.8904	0.9412	1.0305
	Superior, Wisconsin	1.1642	-	1.2871	1.3681	1.5098
	Lockport, Illinois	-	-	2.1904	2.3452	2.6167
	Mokena, Illinois	-	-	2.1904	2.3452	2.6167
	Flanagan, Illinois	-	-	2.1904	2.3452	2.6167
	Griffith, Indiana	-	-	2.1904	2.3452	2.6167
	Stockbridge, Michigan	-	-	2.5300	2.7120	3.0311
	Rapid River, Michigan	1.6148	-	-	-	-
	Marysville, Michigan	2.2901	-	2.5300	2.7120	3.0311
	Corunna or Sarnia Terminal, Ontario	2.3424	-	2.5838	2.7673	3.0881
	Nanticoke, Ontario	-	-	2.9307	3.1419	3.5113
	West Seneca, New York	-	-	2.9816	3.1999	3.5818

SCHEDULE "E" - TABLE OF CLT TOLLS

These tolls will escalate each July 1 by 75% of GDPP Index beginning July 1, 2012.

Schedule "E" (Part 1) - CLT Tolls in Canadian Dollars per Cubic Meter

CLT - LIGHT CRUDE TRANSMISSION AND TERMINALLING TOLLS
($CDN PER CUBIC METRE)

To (Delivery Points) ↓	← ← From (Receipt Points) → →							
	Edmonton Terminal, AB	Hardisty Terminal, AlB	Kerrobert Station, SK	Regina Terminal, SK	Cromer Terminal, MB	International Boundary near Sarnia, ON	Sarnia Terminal, ON	Westover, ON
Edmonton Terminal, AB	1.484	-	-	-	-	-	-	-
Hardisty Terminal, AB	2.947	-	-	-	-	-	-	-
Kerrobert Station, SK	4.418	2.955	-	-	-	-	-	-
Milden, SK	5.370	3.908	-	-	-	-	-	-
Stony Beach Take-off, SK	7.368	5.905	4.434	-	-	-	-	-
Regina Terminal, SK	7.368	5.905	4.434	1.484	-	-	-	-
Gretna Station, MB	11.865	-	-	5.981	-	-	-	-
International Boundary near Gretna, MB	11.404	9.941	8.470	5.519	3.388	-	-	-
Corunna or Sarnia Terminal, ON	11.990	10.528	9.056	6.106	3.975	0.586	1.484	-
Nanticoke, ON	14.239	12.776	11.305	8.354	6.223	2.835	3.732	1.121
International Boundary near Chippawa, ON	14.012	12.549	11.078	8.127	5.996	2.608	3.505	0.886

CLT - MEDIUM CRUDE TRANSMISSION AND TERMINALLING TOLLS
($CDN PER CUBIC METRE)

To (Delivery Points) ↓	← ← From (Receipt Points) → →				
	Edmonton Terminal, AB	Hardisty Terminal, AlB	Cromer Terminal, MB	International Boundary near Sarnia, ON	Westover, ON
Edmonton Terminal, AB	1.484	-	-	-	-
Hardisty Terminal, AB	3.064	1.484	-	-	-
Kerrobert Station, SK	-	3.073	-	-	-
Stony Beach Take-off, SK	7.839	6.259	-	-	-
Regina Terminal, SK	7.839	6.259	-	-	-
International Boundary near Gretna, MB	12.236	10.657	3.579	-	-
Corunna or Sarnia Terminal, ON	12.831	11.251	4.174	0.594	-
Nanticoke, ON	15.259	13.679	6.602	3.023	1.172
International Boundary near Chippawa, ON	15.053	13.473	6.396	2.816	0.957

Schedule "E" (Part 1) - CLT Tolls in Canadian Dollars per Cubic Meter - continued

CLT - HEAVY CRUDE TRANSMISSION AND TERMINALLING TOLLS
($CDN PER CUBIC METRE)

To (Delivery Points) ↓	←← From (Receipt Points) →→					
	Edmonton Terminal, AB	Hardisty Terminal, AlB	Kerrobert Station, SK	Regina Terminal, SK	Cromer Terminal, MB	International Boundary near Sarnia, ON
Edmonton Terminal, AB	1.484	-	-	-	-	-
Hardisty Terminal, AB	3.268	1.484	-	-	-	-
Kerrobert Station, SK	5.063	3.279	-	-	-	-
Stony Beach Take-off, SK	8.663	6.878	5.083	-	-	-
Regina Terminal, SK	8.663	6.878	5.083	1.484	-	-
International Boundary near Gretna, MB	13.693	11.909	10.114	6.514	3.914	-
Corunna or Sarnia Terminal, ON	14.302	12.517	10.722	7.123	4.523	0.609
Nanticoke, ON	17.045	15.260	13.465	9.866	7.266	3.352
International Boundary near Chippawa, ON	16.875	15.090	13.295	9.696	7.096	3.182

CLT - GASOLINE AND CONDENSATE TRANSMISSION AND TERMINALLING TOLLS
($CDN PER CUBIC METRE)

To (Delivery Points) ↓	←← From (Receipt Points) →→				
	Edmonton Terminal, AB	Hardisty Terminal, AlB	Regina Terminal, SK	International Boundary near Sarnia, ON	Sarnia Terminal, ON
Edmonton Terminal, AB	1.484	-	-	-	-
Hardisty Terminal, AB	2.829	-	-	-	-
Kerrobert Station, SK	4.183	2.837	-	-	-
Milden, SK	5.060	-	-	-	-
Stony Beach Take-off, SK	6.897	-	-	-	-
Regina Terminal, SK	6.897	-	1.484	-	-
Gretna Station, MB	11.034	-	5.621	-	-
International Boundary near Gretna, MB	10.571	-	-	-	-
Corunna or Sarnia Terminal, ON	11.150	-	-	0.578	1.484
Nanticoke, ON	13.218	-	-	2.647	3.552
International Boundary near Chippawa, ON	12.970	-	-	2.399	3.305

Schedule "E" (Part 1) - CLT Tolls in Canadian Dollars per Cubic Meter - continued

CLT - NATURAL GAS LIQUIDS TRANSMISSION AND TERMINALLING TOLLS
($CDN PER CUBIC METRE)

To (Delivery Points) ↓	← From (Receipt Points) →		
	Edmonton Terminal, AB	Kerrobert Station, SK	Cromer Terminal, MB
International Boundary near Gretna, MB	10.363	7.723	3.149
Corunna or Sarnia Terminal, ON	10.940	8.299	3.726

Schedule “E” (Part 2) - CLT Tolls in Canadian Dollars per Barrel

CLT - LIGHT CRUDE TRANSMISSION AND TERMINALLING TOLLS
($CDN PER BARREL)

To (Delivery Points) ↓	←← From (Receipt Points) →→							
	Edmonton Terminal, AB	Hardisty Terminal, AIB	Kerrobert Station, SK	Regina Terminal, SK	Cromer Terminal, MB	International Boundary near Sarnia, O	Sarnia Terminal, ON	Westover, ON
Edmonton Terminal, AB	0.236	-	-	-	-	-	-	-
Hardisty Terminal, AB	0.468	-	-	-	-	-	-	-
Kerrobert Station, SK	0.702	0.470	-	-	-	-	-	-
Milden, SK	0.854	0.621	-	-	-	-	-	-
Stony Beach Take-off, SK	1.171	0.939	0.705	-	-	-	-	-
Regina Terminal, SK	1.171	0.939	0.705	0.236	-	-	-	-
Gretna Station, MB	1.886	-	-	0.951	-	-	-	-
International Boundary near Gretna, MB	1.813	1.580	1.347	0.878	0.539	-	-	-
Corunna or Sarnia Terminal, ON	1.906	1.674	1.440	0.971	0.632	0.093	0.236	-
Nanticoke, ON	2.264	2.031	1.797	1.328	0.989	0.451	0.593	0.178
International Boundary near Chippawa, ON	2.228	1.995	1.761	1.292	0.953	0.415	0.557	0.141

CLT - MEDIUM TRANSMISSION AND TERMINALLING TOLLS
($CDN PER BARREL)

To (Delivery Points) ↓	←← From (Receipt Points) →→				
	Edmonton Terminal, AIB	Hardisty Terminal, AB	Cromer Terminal, MB	International Boundary near Sarnia, ON	Westover, ON
Edmonton Terminal, AB	0.236	-	-	-	-
Hardisty Terminal, AB	0.487	0.236	-	-	-
Kerrobert Station, SK	-	0.488	-	-	-
Stony Beach Take-off, SK	1.246	0.995	-	-	-
Regina Terminal, SK	1.246	0.995	-	-	-
International Boundary near Gretna, MB	1.945	1.694	0.569	-	-
Corunna or Sarnia Terminal, ON	2.040	1.789	0.664	0.095	-
Nanticoke, ON	2.426	2.175	1.050	0.481	0.186
International Boundary near Chippawa, ON	2.393	2.142	1.017	0.448	0.152

Schedule "E" (Part 2) - CLT Tolls in Canadian Dollars per Barrel - continued

CLT - HEAVY CRUDE TRANSMISSION AND TERMINALLING TOLLS
($CDN PER BARREL)

To (Delivery Points) ↓	← ← From (Receipt Points) → →					
	Edmonton Terminal, AlB	Hardisty Terminal, AlB	Kerrobert Station, SK	Regina Terminal, SK	Cromer Terminal, MB	International Boundary near Sarnia, ON
Edmonton Terminal, AB	0.236	-	-	-	-	-
Hardisty Terminal, AB	0.520	0.236	-	-	-	-
Kerrobert Station, SK	0.805	0.521	-	-	-	-
Stony Beach Take-off, SK	1.377	1.094	0.808	-	-	-
Regina Terminal, SK	1.377	1.094	0.808	0.236	-	-
International Boundary near Gretna, MB	2.177	1.893	1.608	1.036	0.622	-
Corunna or Sarnia Terminal, ON	2.274	1.990	1.705	1.132	0.719	0.097
Nanticoke, ON	2.710	2.426	2.141	1.569	1.155	0.533
International Boundary near Chippawa, ON	2.683	2.399	2.114	1.542	1.128	0.506

CLT - GASOLINE AND CONDENSATE TRANSMISSION AND TERMINALLING TOLLS
($CDN PER BARREL)

To (Delivery Points) ↓	← ← From (Receipt Points) → →				
	Edmonton Terminal, AB	Hardisty Terminal, AB	Regina Terminal, SK	International Boundary near Sarnia, ON	Sarnia Terminal, ON
Edmonton Terminal, AB	0.236	-	-	-	-
Hardisty Terminal, AB	0.450	-	-	-	-
Kerrobert Station, SK	0.665	0.451	-	-	-
Milden, SK	0.804	-	-	-	-
Stony Beach Take-off, SK	1.097	-	-	-	-
Regina Terminal, SK	1.097	-	0.236	-	-
Gretna Station, MB	1.754	-	0.894	-	-
International Boundary near Gretna, MB	1.681	-	-	-	-
Corunna or Sarnia Terminal, ON	1.773	-	-	0.092	0.236
Nanticoke, ON	2.102	-	-	0.421	0.565
International Boundary near Chippawa, ON	2.062	-	-	0.381	0.525

Schedule “E” (Part 2) - CLT Tolls in Canadian Dollars per Barrel - continued

CLT - NATURAL GAS LIQUIDS TRANSMISSION AND TERMINALLING TOLLS
($CDN PER BARREL)

To (Delivery Points) ↓	← From (Receipt Points) →		
	Edmonton Terminal, AB	Kerrobert Station, SK	Cromer Terminal, MB
International Boundary near Gretna, MB	1.648	1.228	0.501
Corunna or Sarnia Terminal, ON	1.739	1.319	0.592

SCHEDULE “F” - TABLE OF OUTSTANDING AMOUNT SURCHARGE

The Outstanding Amount Surcharge does not escalate.

Schedule “F” (Part 1) - IJT Surcharges in U.S. Dollars per Cubic Meters

IJT - SURCHARGES
($USD PER CUBIC METER)

FROM	TO	RATE				
		NGL	CND	LIGHT	MEDIUM	HEAVY
Edmonton Terminal, Alberta	Clearbrook, Minnesota	-	0.3703	0.4025	0.4347	0.4911
	Superior, Wisconsin	0.3623	0.3703	0.4025	0.4347	0.4911
	Lockport, Illinois	-	0.3703	0.4025	0.4347	0.4911
	Mokena, Illinois	-	0.3703	0.4025	0.4347	0.4911
	Flanagan, Illinois	-	0.3703	0.4025	0.4347	0.4911
	Griffith, Indiana	-	0.3703	0.4025	0.4347	0.4911
	Stockbridge, Michigan	-	0.3703	0.4025	0.4347	0.4911
	Rapid River, Michigan	0.3623	-	-	-	-
	Marysville, Michigan	0.3623	0.3703	0.4025	0.4347	0.4911
	Corunna or Sarnia Terminal, Ontario	0.3658	0.3739	0.4064	0.4389	0.4958
	Nanticoke, Ontario	-	0.4539	0.4934	0.5328	0.6019
	West Seneca, New York	-	0.4631	0.5034	0.5437	0.6141
Hardisty Terminal, Alberta	Clearbrook, Minnesota	-	-	0.3459	0.3736	0.4220
	Superior, Wisconsin	-	-	0.3459	0.3736	0.4220
	Lockport, Illinois	-	-	0.3459	0.3736	0.4220
	Mokena, Illinois	-	-	0.3459	0.3736	0.4220
	Flanagan, Illinois	-	-	0.3459	0.3736	0.4220
	Griffith, Indiana	-	-	0.3459	0.3736	0.4220
	Stockbridge, Michigan	-	-	0.3459	0.3736	0.4220
	Rapid River, Michigan	-	-	-	-	-
	Marysville, Michigan	-	-	0.3459	0.3736	0.4220
	Corunna or Sarnia Terminal, Ontario	-	-	0.3498	0.3778	0.4268
	Nanticoke, Ontario	-	-	0.4368	0.4717	0.5329
	West Seneca, New York	-	-	0.4468	0.4826	0.5451

Schedule “F” (Part 1) - IJT Surcharges in U.S. Dollars per Cubic Meters - continued

IJT - SURCHARGES
($USD PER CUBIC METER)

FROM	TO	RATE				
		NGL	CND	LIGHT	MEDIUM	HEAVY
Kerrobert Station, Saskatchewan	Clearbrook, Minnesota	-	-	0.2890	-	0.3526
	Superior, Wisconsin	0.2601	-	0.2890	-	0.3526
	Lockport, Illinois	-	-	0.2890	-	0.3526
	Mokena, Illinois	-	-	0.2890	-	0.3526
	Flanagan, Illinois	-	-	0.2890	-	0.3526
	Griffith, Indiana	-	-	0.2890	-	0.3526
	Stockbridge, Michigan	-	-	0.2890	-	0.3526
	Rapid River, Michigan	0.2601	-	-	-	-
	Marysville, Michigan	0.2601	-	0.2890	-	0.3526
	Corunna or Sarnia Terminal, Ontario	0.2636	-	0.2929	-	0.3574
	Nanticoke, Ontario	-	-	0.3799	-	0.4635
	West Seneca, New York	-	-	0.3899	-	0.4757
Regina Terminal, Saskatchewan	Clearbrook, Minnesota	-	-	0.1749	-	0.2134
	Superior, Wisconsin	-	-	0.1749	-	0.2134
	Lockport, Illinois	-	-	0.1749	-	0.2134
	Mokena, Illinois	-	-	0.1749	-	0.2134
	Flanagan, Illinois	-	-	0.1749	-	0.2134
	Griffith, Indiana	-	-	0.1749	-	0.2134
	Stockbridge, Michigan	-	-	0.1749	-	0.2134
	Rapid River, Michigan	-	-	-	-	-
	Marysville, Michigan	-	-	0.1749	-	0.2134
	Corunna or Sarnia Terminal, Ontario	-	-	0.1788	-	0.2181
	Nanticoke, Ontario	-	-	0.2658	-	0.3242
	West Seneca, New York	-	-	0.2758	-	0.3365

Schedule "F" (Part 1) - IJT Surcharges in U.S. Dollars per Cubic Meters - continued

IJT - SURCHARGES
($USD PER CUBIC METER)

FROM	TO	RATE				
		NGL	CND	LIGHT	MEDIUM	HEAVY
Cromer Terminal, Manitoba	Clearbrook, Minnesota	-	-	0.0925	0.0999	0.1128
	Superior, Wisconsin	0.0832	-	0.0925	0.0999	0.1128
	Lockport, Illinois	-	-	0.0925	0.0999	0.1128
	Mokena, Illinois	-	-	0.0925	0.0999	0.1128
	Flanagan, Illinois	-	-	0.0925	0.0999	0.1128
	Griffith, Indiana	-	-	0.0925	0.0999	0.1128
	Stockbridge, Michigan	-	-	0.0925	0.0999	0.1128
	Rapid River, Michigan	0.0832	-	-	-	-
	Marysville, Michigan	0.0832	-	0.0925	0.0999	0.1128
	Corunna or Sarnia Terminal, Ontario	0.0867	-	0.0963	0.1041	0.1175
	Nanticoke, Ontario	-	-	0.1833	0.1980	0.2236
	West Seneca, New York	-	-	0.1933	0.2088	0.2359

Schedule “F” (Part 2) - IJT Surcharges in U.S. Dollars per Barrel

IJT - SURCHARGES
($USD PER BARREL)

FROM	TO	RATE				
		NGL	CND	LIGHT	MEDIUM	HEAVY
Edmonton Terminal, Alberta	Clearbrook, Minnesota	-	0.0589	0.0640	0.0691	0.0781
	Superior, Wisconsin	0.0576	0.0589	0.0640	0.0691	0.0781
	Lockport, Illinois	-	0.0589	0.0640	0.0691	0.0781
	Mokena, Illinois	-	0.0589	0.0640	0.0691	0.0781
	Flanagan, Illinois	-	0.0589	0.0640	0.0691	0.0781
	Griffith, Indiana	-	0.0589	0.0640	0.0691	0.0781
	Stockbridge, Michigan	-	0.0589	0.0640	0.0691	0.0781
	Rapid River, Michigan	0.0576	-	-	-	-
	Marysville, Michigan	0.0576	0.0589	0.0640	0.0691	0.0781
	Corunna or Sarnia Terminal, Ontario	0.0582	0.0594	0.0646	0.0698	0.0788
	Nanticoke, Ontario	-	0.0722	0.0784	0.0847	0.0957
	West Seneca, New York	-	0.0736	0.0800	0.0864	0.0976
Hardisty Terminal, Alberta	Clearbrook, Minnesota	-	-	0.0550	0.0594	0.0671
	Superior, Wisconsin	-	-	0.0550	0.0594	0.0671
	Lockport, Illinois	-	-	0.0550	0.0594	0.0671
	Mokena, Illinois	-	-	0.0550	0.0594	0.0671
	Flanagan, Illinois	-	-	0.0550	0.0594	0.0671
	Griffith, Indiana	-	-	0.0550	0.0594	0.0671
	Stockbridge, Michigan	-	-	0.0550	0.0594	0.0671
	Rapid River, Michigan	-	-	-	-	-
	Marysville, Michigan	-	-	0.0550	0.0594	0.0671
	Corunna or Sarnia Terminal, Ontario	-	-	0.0556	0.0601	0.0679
	Nanticoke, Ontario	-	-	0.0694	0.0750	0.0847
	West Seneca, New York	-	-	0.0710	0.0767	0.0867

Schedule “F” (Part 2) - IJT Surcharges in U.S. Dollars per Barrel - continued

IJT - SURCHARGES
($USD PER BARREL)

FROM	TO	RATE				
		NGL	CND	LIGHT	MEDIUM	HEAVY
Kerrobert Station, Saskatchewan	Clearbrook, Minnesota	-	-	0.0460	-	0.0561
	Superior, Wisconsin	0.0414	-	0.0460	-	0.0561
	Lockport, Illinois	-	-	0.0460	-	0.0561
	Mokena, Illinois	-	-	0.0460	-	0.0561
	Flanagan, Illinois	-	-	0.0460	-	0.0561
	Griffith, Indiana	-	-	0.0460	-	0.0561
	Stockbridge, Michigan	-	-	0.0460	-	0.0561
	Rapid River, Michigan	0.0414	-	-	-	-
	Marysville, Michigan	0.0414	-	0.0460	-	0.0561
	Corunna or Sarnia Terminal, Ontario	0.0419	-	0.0466	-	0.0568
	Nanticoke, Ontario	-	-	0.0604	-	0.0737
	West Seneca, New York	-	-	0.0620	-	0.0756
Regina Terminal, Saskatchewan	Clearbrook, Minnesota	-	-	0.0278	-	0.0339
	Superior, Wisconsin	-	-	0.0278	-	0.0339
	Lockport, Illinois	-	-	0.0278	-	0.0339
	Mokena, Illinois	-	-	0.0278	-	0.0339
	Flanagan, Illinois	-	-	0.0278	-	0.0339
	Griffith, Indiana	-	-	0.0278	-	0.0339
	Stockbridge, Michigan	-	-	0.0278	-	0.0339
	Rapid River, Michigan	-	-	-	-	-
	Marysville, Michigan	-	-	0.0278	-	0.0339
	Corunna or Sarnia Terminal, Ontario	-	-	0.0284	-	0.0347
	Nanticoke, Ontario	-	-	0.0423	-	0.0515
	West Seneca, New York	-	-	0.0438	-	0.0535

Schedule "F" (Part 2) - IJT Surcharges in U.S. Dollars per Barrel - continued

IJT - SURCHARGES
($USD PER BARREL)

FROM	TO	RATE				
		NGL	CND	LIGHT	MEDIUM	HEAVY
Cromer Terminal, Manitoba	Clearbrook, Minnesota	-	-	0.0147	0.0159	0.0179
	Superior, Wisconsin	0.0132	-	0.0147	0.0159	0.0179
	Lockport, Illinois	-	-	0.0147	0.0159	0.0179
	Mokena, Illinois	-	-	0.0147	0.0159	0.0179
	Flanagan, Illinois	-	-	0.0147	0.0159	0.0179
	Griffith, Indiana	-	-	0.0147	0.0159	0.0179
	Stockbridge, Michigan	-	-	0.0147	0.0159	0.0179
	Rapid River, Michigan	0.0132	-	-	-	-
	Marysville, Michigan	0.0132	-	0.0147	0.0159	0.0179
	Corunna or Sarnia Terminal, Ontario	0.0138	-	0.0153	0.0165	0.0187
	Nanticoke, Ontario	-	-	0.0291	0.0315	0.0356
	West Seneca, New York	-	-	0.0307	0.0332	0.0375

Schedule “F” (Part 3) - CLT Surcharges in Canadian Dollars per Cubic Meter

CLT - LIGHT CRUDE SURCHARGE
($CDN PER CUBIC METRE)

To (Delivery Points) ↓	←← From (Receipt Points) →→							
	Edmonton Terminal, AlB	Hardisty Terminal, AlB	Kerrobert Station, SK	Regina Terminal, SK	Cromer Terminal, MB	International Boundary near Sarnia, ON	Sarnia Terminal, ON	Westover, ON
Edmonton Terminal, AB	-	-	-	-	-	-	-	-
Hardisty Terminal, AB	0.057	-	-	-	-	-	-	-
Kerrobert Station, SK	0.113	0.057	-	-	-	-	-	-
Milden, SK	0.150	0.094	-	-	-	-	-	-
Stony Beach Take-off, SK	0.228	0.171	0.114	-	-	-	-	-
Regina Terminal, SK	0.228	0.171	0.114	-	-	-	-	-
Gretna Station, MB	0.402	-	-	0.174	-	-	-	-
International Boundary near Gretna, MB	0.403	0.346	0.289	0.175	0.092	-	-	-
Corunna or Sarnia Terminal, ON	0.406	0.350	0.293	0.179	0.096	0.004	-	-
Nanticoke, ON	0.493	0.437	0.380	0.266	0.183	0.091	0.087	0.025
International Boundary near Chippawa, ON	0.503	0.447	0.390	0.276	0.193	0.101	0.097	0.034

CLT - MEDIUM CRUDE SURCHARGE
($CDN PER CUBIC METRE)

To (Delivery Points) ↓	←← From (Receipt Points) →→				
	Edmonton Terminal, AB	Hardisty Terminal, AlB	Cromer Terminal, MB	International Boundary near Sarnia, ON	Westover, ON
Edmonton Terminal, AB	-	-	-	-	-
Hardisty Terminal, AB	0.061	-	-	-	-
Kerrobert Station, SK	-	0.061	-	-	-
Stony Beach Take-off, SK	0.246	0.185	-	-	-
Regina Terminal, SK	0.246	0.185	-	-	-
International Boundary near Gretna, MB	0.435	0.374	0.100	-	-
Corunna or Sarnia Terminal, ON	0.439	0.378	0.104	0.004	-
Nanticoke, ON	0.533	0.472	0.198	0.098	0.027
International Boundary near Chippawa, ON	0.544	0.483	0.209	0.109	0.037

Schedule "F" (Part 3) - CLT Surcharges in Canadian Dollars per Cubic Meter - continued

CLT - HEAVY CRUDE SURCHARGE
($CDN PER CUBIC METRE)

To (Delivery Points) ↓	← ← From (Receipt Points) → →					
	Edmonton Terminal, Alberta	Hardisty Terminal, Alberta	Kerrobert Station, Saskatchewan	Regina Terminal, Saskatchewan	Cromer Terminal, Manitoba	International Boundary near Sarnia, Ontario
Edmonton Terminal, AB	-	-	-	-	-	-
Hardisty Terminal, AB	0.069	-	-	-	-	-
Kerrobert Station, SK	0.138	0.069	-	-	-	-
Stony Beach Take-off, SK	0.278	0.209	0.139	-	-	-
Regina Terminal, SK	0.278	0.209	0.139	-	-	-
International Boundary near Gretna, MB	0.491	0.422	0.353	0.213	0.113	-
Corunna or Sarnia Terminal, ON	0.496	0.427	0.357	0.218	0.118	0.005
Nanticoke, ON	0.602	0.533	0.463	0.324	0.224	0.111
International Boundary near Chippawa, ON	0.614	0.545	0.476	0.336	0.236	0.123

CLT - GASOLINE AND CONDENSATE SURCHARGE
($CDN PER CUBIC METRE)

To (Delivery Points) ↓	← ← From (Receipt Points) → →				
	Edmonton Terminal, AlB	Hardisty Terminal, AlB	Regina Terminal, SK	International Boundary near Sarnia, ON	Sarnia Terminal, ON
Edmonton Terminal, AB	-	-	-	-	-
Hardisty Terminal, AB	0.052	-	-	-	-
Kerrobert Station, SK	0.104	0.052	-	-	-
Milden, SK	0.138	-	-	-	-
Stony Beach Take-off, SK	0.209	-	-	-	-
Regina Terminal, SK	0.209	-	-	-	-
Gretna Station, MB	0.369	-	0.160	-	-
International Boundary near Gretna, MB	0.370	-	-	-	-
Corunna or Sarnia Terminal, ON	0.374	-	-	0.004	-
Nanticoke, Ontario	0.454	-	-	0.084	0.080
International Boundary near Chippawa, Ontario	0.463	-	-	0.093	0.089

Schedule "F" (Part 3) - CLT Surcharges in Canadian Dollars per Cubic Meter - continued

CLT - NATURAL GAS LIQUIDS SURCHARGE
($CDN PER CUBIC METRE)

To (Delivery Points) ↓	← From (Receipt Points) →		
	Edmonton Terminal, AB	Kerrobert Station, SK	Cromer Terminal, MB
International Boundary near Gretna, MBnitoba	0.362	0.260	0.083
Corunna or Sarnia Terminal, Ontario	0.366	0.264	0.087

Schedule “F” (Part 4) - CLT Surcharges in Canadian Dollars per Barrel

CLT - LIGHT CRUDE SURCHARGE
($CDN PER BARREL)

	Edmonton Terminal, AlB	Hardisty Terminal, AlB	Kerrobert Station, SK	Regina Terminal, SK	Cromer Terminal, MB	International Boundary near Sarnia, ON	Sarnia Terminal, ON	Westover, ON
Edmonton Terminal, AB	-	-	-	-	-	-	-	-
Hardisty Terminal, AB	0.009	-	-	-	-	-	-	-
Kerrobert Station, SK	0.018	0.009	-	-	-	-	-	-
Milden, SK	0.024	0.015	-	-	-	-	-	-
Stony Beach Take-off, SK	0.036	0.027	0.018	-	-	-	-	-
Regina Terminal, SK	0.036	0.027	0.018	-	-	-	-	-
Gretna Station, MB	0.064	-	-	0.028	-	-	-	-
International Boundary near Gretna, MB	0.064	0.055	0.046	0.028	0.015	-	-	-
Corunna or Sarnia Terminal, ON	0.065	0.056	0.047	0.028	0.015	0.001	-	-
Nanticoke, ON	0.078	0.069	0.060	0.042	0.029	0.014	0.014	0.004
International Boundary near Chippawa, ON	0.080	0.071	0.062	0.044	0.031	0.016	0.015	0.005

CLT - MEDIUM CRUDE SURCHARGE
($CDN PER BARREL)

To (Delivery Points) ↓	**← ← From (Receipt Points) → →**				
	Edmonton Terminal, AlB	Hardisty Terminal, AB	Cromer Terminal, MB	International Boundary near Sarnia, ON	Westover, ON
Edmonton Terminal, AB	-	-	-	-	-
Hardisty Terminal, AB	0.010	-	-	-	-
Kerrobert Station, SK	-	0.010	-	-	-
Stony Beach Take-off, SK	0.039	0.029	-	-	-
Regina Terminal, SK	0.039	0.029	-	-	-
International Boundary near Gretna, MB	0.069	0.059	0.016	-	-
Corunna or Sarnia Terminal, ON	0.070	0.060	0.017	0.001	-
Nanticoke, ON	0.085	0.075	0.031	0.016	0.004
International Boundary near Chippawa, ON	0.086	0.077	0.033	0.017	0.006

Schedule “F” (Part 4) - CLT Surcharges in Canadian Dollars per Barrel - continued

CLT - HEAVY CRUDE SURCHARGE
($CDN PER BARREL)

To (Delivery Points) ↓	←← From (Receipt Points) →→					
	Edmonton Terminal, AlB	Hardisty Terminal, AlB	Kerrobert Station, SK	Regina Terminal, SK	Cromer Terminal, MB	International Boundary near Sarnia, ON
Edmonton Terminal, AB	-	-	-	-	-	-
Hardisty Terminal, AB	0.011	-	-	-	-	-
Kerrobert Station, SK	0.022	0.011	-	-	-	-
Stony Beach Take-off, SK	0.044	0.033	0.022	-	-	-
Regina Terminal, SK	0.044	0.033	0.022	-	-	-
International Boundary near Gretna, MB	0.078	0.067	0.056	0.034	0.018	-
Corunna or Sarnia Terminal, ON	0.079	0.068	0.057	0.035	0.019	0.001
Nanticoke, Ontario	0.096	0.085	0.074	0.052	0.036	0.018
International Boundary near Chippawa, ON	0.098	0.087	0.076	0.053	0.038	0.020

CLT - GASOLINE AND CONDENSATE SURCHARGE
($CDN PER BARREL)

To (Delivery Points) ↓	←← From (Receipt Points) →→				
	Edmonton Terminal, AB	Hardisty Terminal, AB	Regina Terminal, SK	International Boundary near Sarnia, ON	Sarnia Terminal, ON
Edmonton Terminal, AB	-	-	-	-	-
Hardisty Terminal, AB	0.008	-	-	-	-
Kerrobert Station, SK	0.017	0.008	-	-	-
Milden, SK	0.022	-	-	-	-
Stony Beach Take-off, SK	0.033	-	-	-	-
Regina Terminal, SK	0.033	-	-	-	-
Gretna Station, MB	0.059	-	0.025	-	-
International Boundary near Gretna, MB	0.059	-	-	-	-
Corunna or Sarnia Terminal, ON	0.059	-	-	0.001	-
Nanticoke, ON	0.072	-	-	0.013	0.013
International Boundary near Chippawa, ON	0.074	-	-	0.015	0.014

Schedule "F" (Part 4) - CLT Surcharges in Canadian Dollars per Barrel - continued

CLT - NATURAL GAS LIQUIDS SURCHARGE
($CDN PER BARREL)

To (Delivery Points) ↓	**← From (Receipt Points) →**		
	Edmonton Terminal, AB	Kerrobert Station, SK	Cromer Terminal, MB
International Boundary near Gretna, Manitoba	0.058	0.041	0.013
Corunna or Sarnia Terminal, ON	0.058	0.042	0.014

SCHEDULE "G" – ENBRIDGE MAINLINE REFERENCE CAPACITIES

As of December 31, 2010 excluding temporary capacity restrictions:

Upstream Pipeline Capacity

a) Line 1 – 240 kbpd
b) Line 2 – 440 kbdp
c) Line 3 – 390 kbpd
d) Line 4 – 800 kbpd
e) Line 67 – 450 kbpd
f) Line 65 – 185 kbpd

Downstream Pipeline Capacity:

a) Line 5 – 490 kbpd
b) Line 6A – 670 kbpd
c) Line 6B – 290 kbpd
d) Line 14/64 – 320 kbpd
e) Line 61 – 320 kbpd
f) Line 62 – 130 kbpd
g) Line 7 – 150 kbpd
h) Line 10 – 70 kbpd
i) Line 11 – 120 kbpd

SCHEDULE “H” - CANADIAN AGREEMENTS

	Agreement	Relevant Dates	Applicable Depreciation Term/End Date(s)
1	System Expansion Project (SEP) I	SEP I assets in-service December 1, 1996	Canadian Mainline Depreciation Truncation date of 2039
2	IPL/LPL and CAPP SEP II Risk Sharing Agreement dated December 8, 1998	Agreement begins January 1, 1999 and has 15 year term	Canadian Mainline Depreciation Truncation date of 2039
3	Terrace Toll Agreement Statement of Principles dated October 21, 1998	Terrace Surcharge ends December 31, 2013	Terrace Phases Depreciation Truncation date of Dec 31, 2024 (25 years)
4	Alberta Clipper Canada Settlement dated June 28, 2007	Alberta Clipper assets in-service April 1, 2010 and agreement has 15 year term	Depreciation calculated over 30 years
5	Line 4 Extension Settlement dated June 28, 2007	Line 4 Extension assets in-service April 1, 2009 and agreement has 15 year term	Depreciation calculated over 30 years
6	Southern Access Enbridge Pipelines Surcharge Terms (Appendix A of the Mainline Expansion Toll Mechanism dated January 31, 2008)	Southern Access assets in-service May 31, 2008 and agreement has 30 year term	Depreciation calculated over 30 years
7	2011 ITS dated April 1, 2011	Effective to tolls from April 1, 2011 to December 31, 2011	Canadian Mainline Depreciation Truncation date of 2039

SCHEDULE "I" - U.S. AGREEMENTS

A	Facility Surcharge Mechanism Agreement inclusive of the following:	Relevant Dates	Applicable Depreciation Term/End Date(s)
1	Superior Manifold Modification Project – FERC Docket No. 0R04-2	Assets included in 2004 filing	* Depreciation truncation date calculated as 2031 based on 2006 Lakehead System Depreciation Study
2	Griffith Hartsdale Transfer Lines Project – FERC Docket No, 0R04-02	Assets included in 2004 toll filing	* Depreciation truncation date calculated as 2031 based on 2006 Lakehead System Depreciation Study
3	Hartsdale Lease Tanks – FERC Docket No. 0R04-02	Lease tanks in-service in January 2004. Agreement expires December 31, 2012 with option to renew for 1 year	* Depreciation truncation date calculated as 2031 based on 2006 Lakehead System Depreciation Study
4	Southern Access Mainline Expansion Surcharge Terms (Exhibit III of Offers of Settlement) – FERC Docket No. 0R06-03	Southern Access assets in-service April 1, 2008 and agreement has a 30 year term	Depreciation calculated over 30 years per agreement
5	Tank 34 at Superior Terminal & Tank 79 at Griffith Terminal – FERC Docket No. 0R08-10	Assets included in 2008 filing	* Depreciation truncation date calculated as 2031 based on 2006 Lakehead System Depreciation Study
6	Clearbrook Manifold – FERC Docket No. 0R08-10	Assets included in 2008 filing	* Depreciation truncation date calculated as 2031 based on 2006 Lakehead System Depreciation Study
7	Tank 35 at Superior Terminal & Tank 80 at Griffith Terminal - FERC Docket No. 0R08-10	Assets included in 2008 filing	* Depreciation truncation date calculated as 2031 based on 2006 Lakehead System Depreciation Study

8	Alberta Clipper U.S. Expansion (U.S. Term Sheet dated June 28, 2007) – FERC Docket No, 0R08-10	Alberta Clipper assets in-service April 1, 2010 and agreement has 15 year term	Depreciation calculated over 30 years per agreement
9	Line 3 Conversion Project – FERC Docket No, 0R10-7	Assets included in 2010 filing	* Depreciation truncation date calculated as 2031 based on 2006 Lakehead System Depreciation Study
10	Line 6B Capital/ Integrity – FERC Docket No. 0R11-5-000	Assets included in 2011 filing	Depreciation calculated over 30 years per agreement
B	**The 1998 Offer of Settlement FERC Docket No. 0R99-2, subsequently approved by FERC by letter dated December 21, 1998 inclusive of the following:**	**Relevant Dates**	
1	SEP II Expansion Surcharge (1998 Offer of Settlement)	SEP II assets in-service January 1, 1998 and agreement has 15 year term	Remaining life of 7 years upon expiry of agreement in 2013
2	Terrace Toll Agreement Statement of Principles dated October 21, 1998	Terrace Surcharge ends December 31, 2013	Terrace Phases Depreciation Truncation date of Dec 31, 2024 (25 years)
3	350 Centistoke Agreement (1998 Offer of Settlement)	Assets included in 1998 filing	* Depreciation truncation date calculated as 2031 based on 2006 Lakehead System Depreciation Study
4	Southern Access Quality Guarantee	Assets included in 2008 filing	* Depreciation truncation date calculated as 2031 based on 2006 Lakehead System Depreciation Study
C	**The 1996 Offer of Settlement FERC Docket Nos. IS92-27, et al., subsequently approved by FERC by letter dated October 18, 1996 inclusive of the following:**	**Relevant Dates**	**Applicable Depreciation Term/End Date(s)**
1	Integrity Non-Routine Adjustments (Appendix E of 1996 Offer of Settlement)	Assets and costs which were included under the 1996 Settlement Agreement executed August 28, 1996	* Depreciation truncation date calculated as 2031 based on 2006 Lakehead System Depreciation Study
Note* - Subject to future FERC approved depreciation studies			

SCHEDULE "J" – ILLUSTRATIVE EXAMPLE OF APPLICATION OF CTS vs. CANADIAN AGREEMENT

Assumptions for Project A:

1. Project A agreement dated November 30, 2009 has a 30 year term commencing January 1, 2010 and ending December 31, 2040.
2. The Agreement stated straight line depreciation over 30 years at a depreciation rate of 3 1/3rd % annually.
3. Rate base is equal to the Net Book Value of Project A capital assets.
4. The capital cost of Project A at January 1, 2010 is $50,000,000.
5. All power and operating costs are flow through except as otherwise agreed.
6. The agreed to fixed operating costs charges to Project A were agreed to be $3,000,000 for the calendar year ending December 31, 2010 and are allowed to escalate at 50% of the GDPP Index annually.
7. The CTS supersedes the Project A agreement from July 1, 2011 to June 30, 2021.
8. From January 1, 2010 to December 31, 2021 $1 million of actual capital costs are spent on the Project A assets annually for maintenance and integrity – assume additions occur evenly throughout each year.
9. GDPP Index is 3% annually

Based on the above assumptions, at the end of the CTS on July 1, 2021, the following Project A terms would be relevant:

1) **The approximate rate base would be $40,150,538 based on the following schedule:**

PERIOD	Date	Rate Base at Period End	Additions for Period Ending	Depreciation for Period Ending
0	January 1, 2010	$50,000,000	N/A	N/A
1	December 31, 2010	49,318,350	$1,000,000	1,681,650
2	June 30, 2011	48,965,038	$500,000	853,313
3	June 30, 2012	48,233,438	$1,000,000	1,731,600
4	June 30, 2013	47,468,538	$1,000,000	1,764,900
5	June 30, 2014	46,670,338	$1,000,000	1,798,200
6	June 30, 2015	45,838,838	$1,000,000	1,831,500
7	June 30, 2016	44,974,038	$1,000,000	1,864,800
8	June 30, 2017	44,075,938	$1,000,000	1,898,100
9	June 30, 2018	43,144538	$1,000,000	1,931,400
10	June 30, 2019	42,179,838	$1,000,000	1,964,700
11	June 30, 2020	41,181,838	$1,000,000	1,998,800
12	June 30, 2021	40,150,538	$1,000,000	2,031,300
13	December 31, 2021	39,642,400	$500,000	1,028,138

2) The fixed operating cost charges that will be allocated to Project A for the period from July 1, 2021 to December 31, 2021 would be $1,766,923.40 ($3,533,846.80X 50%) based on the following schedule:

YEAR	Date	Fixed Operating Costs Allowed	50% of GDPP Index
0	December 31, 2010	$3,000,000	
1	December 31, 2011	$3,045,000	1.5%
2	December 31, 2012	$3,090,675	1.5%
3	December 31, 2013	$3,137,035.10	1.5%
4	December 31, 2014	$3,184,090.70	1.5%
5	December 31, 2015	$3,231,852	1.5%
6	December 31, 2016	$3,280,329.80	1.5%
7	December 31, 2017	$3,329,534.80	1.5%
8	December 31, 2018	$3,379,477.80	1.5%
9	December 31, 2019	$3,430,169.90	1.5%
10	December 31, 2020	$3,481,622.50	1.5%
11	December 31, 2021	$3,533,846.80	1.5%

SCHEDULE "K" – ILLUSTRATIVE EXAMPLES OF CAPITAL EXPENDITURES UNDER SECTION 16.3 & 16.4

Example #1 – Section 16.3

Assumptions:

1. The Representative Shipper Group has requested that Enbridge expand capacity on the Enbridge Mainline by 150,000 barrels per day by December 31, 2017.
2. Enbridge has completed a capital cost estimate that the project will cost approximately $500,000,000 – ½ in Canada and ½ in the U.S.

Per Section 16.3, the anticipated capital cost of the project will exceed $250,000,000. As a result, Enbridge would be required to work with the Representative Shipper Group to negotiate any adjustment to the applicable IJT and CLT.

Conclusion: Enbridge would negotiate with the Representative Shipper Group to determine if the IJT and CLT need to be adjusted.

Example #2 – Section 16.4

Assumptions:

1. One shipper, Shipper Z, has requested that Enbridge increase receipt tankage at the Edmonton terminal on the Canadian Mainline to accommodate incremental volumes of 15,000 barrels per day by June 30, 2015 from a new production area.
2. Enbridge has reviewed the service request details and is not confident that the 15,000 barrels per day of anticipated increased volumes will be required by June 30, 2015 and is uncertain, if such volumes are received on the Enbridge Mainline at the Edmonton Terminal, when the volumes would exit the Enbridge Mainline. As such, the economic benefit to Enbridge and the overall benefit of adding additional tanks into the Canadian Mainline rate base cannot be confirmed.
3. Shipper Z and Enbridge are prepared to enter into a Backstopping Agreement to support the tankage service request on the following terms, consistent with Section 16:
    a. 10 year term beginning July 1, 2015 to the earlier of June 30, 2025 or such time as all financial commitments of Shipper Z under the Backstopping Agreement have been fulfilled.
    b. Based on a capital structure of 45% equity
    c. Cost of debt of 6%
    d. Enbridge will accept a return of 13% return on equity based on the overall risks assumed
    e. Effectively amortize the cost of the capital over the 10 year term of the agreement; Revenue in Excess of the Revenue Requirement will be applied to the capital balance at the end of each year such excess is generated.
    f. Shipper Z will backstop based on 15,000 barrels per day – assumes that barrels enter the Enbridge Mainline in Edmonton and are transported to Chicago area with an initial toll of $4.50 per barrel increasing @ 2.25% per year, less incremental operating costs.

g. Incremental operating cost (power) is initially $1.00 per barrel escalating at 2.25% per year.
h. To accommodate the incremental volumes, Enbridge constructed a new tank at the Edmonton Terminal for a cost $80,000,000 with an in-service date of July 1, 2015
i. Annual incremental operating costs were $500,000 in the first year increasing at 3% per year.
j. The Tankage expenditures result in an 8% CCA class and the tax rate is 25% for all year.
k. Upon fulfillment of all commitments by Shipper Z under the Backstopping Agreement, the net present value of the future CCA will be paid as a credit to Shipper Z.

Conclusion:

Based on the above assumptions and the delivery profile outlined below, the following table outlines the annual financial outcome:

Year Ended	Average Daily Barrels	Revenue Requirement (including incremental asset operating costs)	Revenue Generated (less incremental transportation costs)	Excess Revenue (net of tax) / (Shortfall Payment) (grossed up for tax)	Cumulative Capital Recovered (including net Excess Revenue)
June 30, 2016	11,000	18,533	14,053	(5,972)	8,000
June 30, 2017	12,000	16,680	15,675	(1,339)	16,000
June 30, 2018	12,000	15,971	16,028	42	24,042
June 30, 2019	13,000	15,245	17,754	1,882	33,924
June 30, 2020	12,500	14,303	17,455	2,364	44,288
June 30, 2021	13,000	13,297	18,562	3,948	56,237
June 30, 2022	14,000	12,106	20,439	6,250	70,487
June 30, 2023	15,000	6,778	14,395	11,711	80,000
July 31, 2023	N/A	(5,000)*	N/A	N/A	N/A
June 30, 2024	N/A	N/A	N/A	N/A	N/A
June 30, 2025	N/A	N/A	N/A	N/A	N/A

***- Capital payout achieved at end of preceding contract year. Agreement is terminated and shipper is paid out present value of future capital cost allowance deductions.**

SCHEDULE “L” – ILLUSTRATIVE EXAMPLES OF CALCULATION OF MINIMUM THRESHOLD VOLUMES

Minimum Threshold Volumes Example #1

Assumptions:

1. Enbridge Mainline throughput ex-Gretna has been at 1,275,000 barrels per day on average for the 9 month period ending July 31, 2016.
2. The Enbridge Mainline has received 325,000 barrels per day of the Bakken/ Three Forks U.S. production on average for the same 9 month period ending July 31, 2016.
3. All the Bakken/ Three Forks U.S. production received on the Enbridge Mainline for the nine month period ending July 31, 2016 were delivered into Northern PADD II or Sarnia.
4. There are no other adjustments to the Minimum Threshold Volume.

Based on the above assumptions, the applicable Minimum Threshold Volume would be:

- 1,350,000 barrels per day (per Section 19.1 – after December 31, 2014)
- Less 20,000 barrels per day (per Section 19.2 – reduced by the amount that Bakken Three Forks US receipts exceed 305,000 barrels per day)

= **Minimum Threshold Volumes of 1,330,000 barrels per day**

Conclusion: Enbridge would be in a position to provide a Renegotiation Notice.

Minimum Threshold Volumes Example #2

Assumptions:

1. Enbridge Mainline throughput ex-Gretna has been at 1,200,000 barrels per day on average for the 9 month period ending December 31, 2012.
2. The Enbridge Mainline has received 385,000 barrels per day of the Bakken/ Three Forks U.S. production on average for the same 9 month period ending December 31, 2012.
3. 20,000 barrels per day of the Bakken/ Three Forks U.S. production received on the Enbridge Mainline for the nine month period ending December 31, 2012 were delivered into Mustang.
4. 365,000 barrels per day of the Bakken/ Three Forks U.S. production received on the Enbridge Mainline for the nine month period ending December 31, 2012 were delivered into Northern PADD II or Sarnia.
5. There are no other adjustments to the Minimum Threshold Volume.

Based on the above assumptions, the applicable Minimum Threshold Volume would be:

- 1,250,000 barrels per day (per Section 19.1 – before December 31, 2014)
- Less 60,000 barrels per day (per Section 19.2 – reduced by the amount that Bakken Three Forks U.S. receipts exceed 305,000 barrels per day delivered into PADD II or Sarnia

= **Minimum Threshold Volumes of 1,190,000 barrels per day**

Conclusion: Enbridge would NOT be in a position to provide a Renegotiation Notice.

Minimum Threshold Volumes Example #3

Assumptions:

1. On May 31, 2013 flooding of the Red River in Manitoba, significantly impacted the Canadian Mainline, in a manner that was beyond reasonable design or operational considerations and reduced throughput ex-Gretna to 1,000,000 barrels per day. Enbridge has undertaken its best efforts, which are considered reasonable by industry standards, between May 31, 2013 and February 28, 2014 to repair the damage and remove all pressure restrictions.
2. Enbridge Mainline throughput ex-Gretna was 1,500,000 barrels per day on average for the 9 month period ending May 30, 2013.
3. Enbridge Mainline throughput ex-Gretna was 1,000,000 barrels per day on average for the 9 month period ending February 28, 2014.
4. There are no other adjustments to the Minimum Threshold Volume.

Based on the above assumptions, the applicable Minimum Threshold Volume would be:

- 1,250,000 barrels per day (per Section 19.1 – before December 31, 2014)
- There is no adjustment to the Minimum Threshold Volume for capacity loss on the Enbridge Mainline pursuant to Section 19.5 since the capacity loss was due to a Force Majeure event.

= **Minimum Threshold Volumes of 1,250,000 barrels per day**

Conclusion: Enbridge would be in a position to provide a Renegotiation Notice.

SCHEDULE “M” – MAINLINE CAPITAL REPORTING TEMPLATE

	A	B	C	D
1	**Capital Project AFE Number**	**Capital Project Expenditure in Prior years**	**Capital Project Expenditure during Past Calendar Year**	**Capital Project Expenditure Forecast for Current Calendar Year**
2	Canadian Mainline: Each Project AFE in excess of $50 M in Canadian $			
3	Project A	CDN $ in 2010 & prior	CDN $ in 2011	CDN $ in 2012
4	Project B	CDN $ in 2010 & prior	CDN $ in 2011	CDN $ in 2012
5	Project C	CDN $ in 2010 & prior	CDN $ in 2011	CDN $ in 2012
6	Canadian Mainline: Total of Shipper Supported Capital Projects less than $50 M per project in Canadian $			
7	Sum of all other AFEs			
8	**Total**			
9	Lakehead System: Each Project AFE in excess of $50 M in US $			
10	Project X	US $ in 2010 & prior	US $ in 2011	US $ in 2012
11	Project Y	US $ in 2010 & prior	US $ in 2011	US $ in 2012
12	Project Z	US $ in 2010 & prior	US $ in 2011	US $ in 2012
13	Lakehead System: Total of Shipper Supported Capital Projects less than $50 M per project in US $			
14	Sum of all other AFEs			
15	**Total**			

Note: Example provided for reporting in February 2012.

Amounts in columns B & C will be actual results while amounts in columns D will be forecast and subject to amendment/change.

SCHEDULE “N” – ENBRIDGE SERVICE LEVELS

Enbridge Pipelines Inc.
Enbridge Energy Partners, L.P.
Enbridge Pipelines (Toledo) Inc.

Service Levels

April, 2011

1. INTRODUCTION

This document provides information respecting Enbridge's operation and service levels.

The Service Levels and system operation are based on the system configuration in place for the second quarter of 2011. The actual service of the pipeline on a day-to-day basis will depend on numerous variables. Enbridge will use reasonable efforts to operate the pipeline system in accordance with current Service Levels.

As changes occur to the pipeline system configuration and operation, or customer requirements, Service Level revisions will be undertaken to reflect such changes.

Enbridge is obligated to provide transportation service pursuant to the terms and conditions specified by the tariff Rules and Regulations, on file with the National Energy Board (NEB). Service Levels provided in this document are not intended to amend the tariff Rules and Regulations.

The Service Levels described encompass both the Enbridge Canadian and United States (U.S.) Mainline[1] transportation systems. The service references for Lakehead[2] are not intended to amend the service rules and regulations outlined in Lakehead's tariff, on file with the Federal Energy Regulatory Commission (FERC).

The Enbridge Service Levels described in this document are broken into three sections: Operations, Procedures and Reporting, and Communications. The Operations section describes movement associated with the current Mainline System operation. For the commodities shipped on the system this section describes normal line routings, transit times, tankage considerations and batch management. The Procedures and Reporting section outlines scheduling events, supply control activities and other general movement information. The Communication section provides a statement on the general principles around communication to Enbridge's customer base.

[1] Enbridge Pipelines Inc., Enbridge Energy Partners, L.P., and Enbridge Pipelines (Toledo) Inc.
[2] Enbridge Energy Partners, L.P.

2. OPERATIONS

A. General

Enbridge provides transportation service using a batched system to retain commodity integrity and shipper ownership for a wide variety of Crude Petroleum, Refined Products and Natural Gas Liquids (NGL). The Enbridge system is a supply driven system, with shippers (producers, marketers and refiners) nominating supplies onto the system on a monthly basis. These supplies are scheduled and routed through the system to identified delivery locations. Nominations for local transfers through an Enbridge terminal are routed as operating conditions allow. During the month supplies are received from feeder pipelines/transfer facilities into the various Enbridge receipt facilities where the supplies are aggregated for shipment and/or directly injected into the Mainline System. Subject to the operating conditions of the pipeline system, shippers may request changes to injection and delivery location, volume and commodity type on receipt and delivery and ownership, which may result in operational adjustments.

B. Ratability

Enbridge's objective is to operate its system so that nominations are pumped and delivered on a ratable and predictable basis. Delivery ratability and predictability are primarily dependent upon ratable supply into Enbridge. Supply ratability can affect Enbridge's ability to meet the Service Levels described below.

C. Commodity Receipt Summary (Tables 1A and 1B)

The Enbridge system transports a wide variety of commodities, including both Canadian and U.S. receipts. Tables 1A and 1B depict the current approved receipt commodities with their acronyms, receipt locations, and feeder pipeline/transfer facilities on both the Enbridge and Lakehead transportation systems. New commodities not in the table must be applied for through the applicable service request procedure. Commodities not shipped for a period of time or which revert to a commingled stream are subject to removal from the table, and will be required to be re-applied for to be re-instated.

D. Commodity Routing Summary by Pipeline Segment (Table 2)

Enbridge provides batch transportation service where commodities are segregated according to quality specifications and standards to minimize interfacial contamination between batches and track batch ownership.

Individual pipeline segments comprising the Enbridge Mainline System are used to transport specific commodities. Allocation of commodities to these pipelines is dependent upon several factors, including but not limited to petroleum quality, supply, tankage constraints, connectivity, receipt and delivery patterns, ratability, apportionment and power costs.

Enbridge reserves the right to revise commodity allocations to optimize pipeline operations in a fair and equitable manner.

The summary provided in Table 2 provides the base Service Level routings and permissible routing of commodities. A schematic system diagram is attached to this table (as Figure 1) and describes the general commodity slate for each pipeline segment.

E. General Pipeline Operations

The following outlines pipeline operations for each pipeline segment.

Upstream of Superior Pipelines

Line 1 (Edmonton to Superior)

Line 1 originates at Edmonton and extends to Superior, Wisconsin transporting natural gas liquids (NGL), refined products, synthetics and required synthetic buffers. There are six refined products cycles (three gasoline and three distillate cycles) and six NGL cycles per month. All NGL and refined product volumes are pumped as a direct receipt from feeder pipeline or connected refineries.

- Refined products are injected at Edmonton and Regina and are delivered at Milden Take-off, Regina and Gretna.
- NGL is injected at Edmonton, Kerrobert and Cromer and is transported to breakout facilities at Superior Terminal.

All crude volumes access breakout tankage at Superior before being re-pumped over Lines 5, 6, 14 or 61, or as tank transfer deliveries to Murphy. NGL advances through the NGL spheres to be re-pumped over Line 5 or as sphere transfer deliveries to BP-NGL.

Line 2 (Edmonton to Superior)

The pipeline segment from Edmonton to Cromer is referred to as Line 2A and the pipeline segment from Cromer to Superior is referred to as Line 2B. All Line 2A volumes breakout into Cromer tankage before being re-pumped on Line 2B.

Line 2A (Edmonton to Cromer)

- Line 2A originates at Edmonton and pumps condensate, light synthetic, sweet, light sour and high sour batches. Batches are scheduled to pump with compatible crude types adjacent to one another, if available.
- At Hardisty, deliveries of condensate, light synthetic, sweet, light sour and high sour crude batches may be scheduled to Express Pipeline, Hardisty Caverns, L.P., Gibsons, Husky, Flint Hills Resources, Enbridge Hardisty Contract Terminal, or Enbridge Mainline tankage. During deliveries, if possible, injections of light synthetic are scheduled simultaneously to optimize Line 2 operations.

- At Kerrobert, deliveries of condensate to Plains occur simultaneously, if possible, with sweet injections.
- At Regina, deliveries of condensate to Plains and light synthetic crudes to Consumers Co-op or Wascana Pipeline occur simultaneously, if possible, with light synthetic or high sour injections.
- At Cromer, all incoming Line 2A volumes access breakout tankage.

Line 2B (Cromer to Superior)

- At Cromer all Line 2A volumes along with sweet and light sour receipts entering the system at Cromer are rescheduled and reinjected on a daily cycle including condensate, light synthetic, sweet, light sour and high sour receipts.
- At Clearbrook, mostly light synthetic along with some sweet and high sour batches are delivered to Minnesota Pipeline. During these Line 2 deliveries "windows" U.S. sweet volumes are injected. There is also the ability to inject light sour and medium crude coming from Line 65 via Clearbrook tankage if necessary.
- At Superior, the volumes access breakout tankage and are scheduled to re-pump over Lines 5, 6, 14, or 61, or as tank transfer deliveries to Murphy.

Line 3 (Edmonton to Superior)

Line 3 originates at Edmonton and pumps condensate, light synthetic, sweet, light sour and high sour batches. Batches are scheduled to pump with compatible crude types adjacent to one another, if available.

At Hardisty, available deliveries of condensate, light synthetic, sweet, light sour and high sour batches may be scheduled to Express Pipeline, Gibsons, Husky and Flint Hills Resources. During these Line 3 deliveries “windows”, if possible, injections of high sour from Gibsons or light synthetic batches from Enbridge Mainline Tankage are scheduled to optimize Line 3 operations.

At Clearbrook, in the event that deliveries are scheduled off of Line 3, volumes coming from Line 65 via Clearbrook tankage may be injected. If required, U.S. sweet and/or volumes coming from Line 2B via Clearbrook tankage may also be injected. Line 3 cannot deliver to Clearbrook tankage.

At Superior, the volumes access breakout tankage and are scheduled to re-pump over Lines 5, 6, 14, or 61, or as tank transfer deliveries to Murphy.

Line 4 (Edmonton to Superior)

Line 4 originates at Edmonton and pumps heavy volumes received at Edmonton, Hardisty, Kerrobert and Regina. Some of the volumes originating at Hardisty and Kerrobert are scheduled for injection on a nominal 2-day cycle.

- At Edmonton available volumes of heavy are scheduled and pumped in each cycle. Sarnia Special volumes are pumped on an as-requested basis subject to the availability of receipt tankage.
- At Hardisty deliveries of heavy crude batches to Express Pipeline, Hardisty Caverns, L.P., Flint Hills Resources, Enbridge Hardisty Contract Terminal, and Gibsons are available off Line 4. Hardisty Line 4 injections from Gibsons, Husky, Flint Hills Resources, Hardisty Caverns, L.P., Enbridge Hardisty Contract Terminal, and Enbridge mainline tankage commence with Hardisty deliveries and are scheduled in a predetermined pattern each cycle. Upon completion of delivered and breakout volumes Line 4 is shutdown ex Edmonton.
- At Kerrobert, heavy volumes from Plains and Inter Pipeline are injected over Line 4. Available deliveries to Plains are scheduled simultaneous with injections.
- At Stoney Beach heavy crude side stream deliveries are made to Gibsons.
- At Regina deliveries of heavy crude oil batches to Consumers Co-op and Wascana Pipeline are available from Line 4. To the extent possible, heavy injections are scheduled to occur simultaneously with scheduled deliveries.
- At Clearbrook Line 4 volumes are delivered to Minnesota Pipeline. During these deliveries U.S. medium and volumes coming from Line 65 via Clearbrook tankage may be injected. If required, quality trains of U.S. sweet and/or some sweet, light sour or high sour batches coming from Line 2B via Clearbrook tankage may also be injected. Line 4 cannot deliver to Clearbrook tankage.
- At Superior Line 4 incoming volumes access breakout tankage. Line 4 volumes are scheduled to re-pump over Lines 6, 14 or 61 or as tank transfer deliveries to Murphy.

Line 67 (Hardisty to Superior)

Line 67 originates at Hardisty and can pump heavy, heavy high tan, heavy low resid or cracked material to Clearbrook or Superior. It can also pump Edmonton heavies should they deliver to Enbridge Hardisty Contract Terminal or Enbridge Mainline tankage.

At Clearbrook Line 67 volumes can be delivered to Minnesota Pipeline. Line 67 cannot deliver to Clearbrook tankage.

At Superior Line 67 incoming volumes access breakout tankage. Line 67 volumes are scheduled to re-pump over Lines 6, 14 or 61 or as tank transfer deliveries to Murphy.

Line 65 (Cromer to Clearbrook)

Line 65 transports medium and light sour crude from Cromer to Clearbrook. All volumes that are not delivered to Minnesota Pipeline, access breakout tankage and can be reinjected on Lines 3, 4 or 2B for shipment to Superior.

Downstream of Superior Pipelines

Line 5 (Superior to Sarnia)

Line 5 transports condensate, light synthetic, sweet, light sour and NGL volumes destined for Sarnia and east of Sarnia delivery points. When possible, compatible batches are scheduled to pump adjacent to one another.

At Rapid River scheduled NGL volumes are side-stream delivered for stripping of their required components. Concurrent with the side stream deliveries are side stream injections of stripped NGL.

At Lewiston scheduled U.S. sweet volumes are injected.

After the scheduled deliveries have been made at Marysville and Sarnia area refineries the balance of the Line 5 incoming volumes access breakout tankage at Sarnia for subsequent movement on Line 7. When necessary, Line 5 and Line 6B delivery conflicts at Sarnia are directed to Enbridge tankage prior to being delivered directly to the refinery.

Line 61 (Superior to Flanagan)

Line 61 can transport all approved mainline commodities except NGL, refined products and cracked material.

At Flanagan all volumes access breakout tankage and are either reinjected on the Line 55 contract pipeline for movement to Cushing, Oklahoma or are reinjected on Line 62 for movement to Griffith/Hartsdale.

Line 62 (Flanagan to Griffith/Hartsdale)

Line 62 can transport heavy crude from Flanagan breakout tankage to Griffith / Hartsdale terminal. Volumes destined for delivery beyond Griffith/Hartsdale access breakout tankage for subsequent reinjection on Line 6B. Volumes can also access the BP Whiting refinery utilizing Griffith/Hartsdale delivery tankage.

Line 6 (Superior to Sarnia)

Line 6 transports volumes of heavy, heavy high tan and heavy low resid crudes for delivery in the Chicago area and those destined for delivery at Sarnia / Toronto / Buffalo area refineries. Quality trains of light synthetic and medium destined to Mustang Pipeline are also scheduled on Line 6 because it is the only line connected to Lockport terminal.

Line 6A (Superior to Griffith/Hartsdale)

- The pipeline segment from Superior to Griffith/Hartsdale is referred to as Line 6A.
- In the Chicago area, deliveries can be made at Lockport, Mokena and Griffith. Volumes delivered at Lockport can be pumped over Mustang Pipeline for subsequent movement from Lockport to Patoka.
- Volumes destined for delivery beyond the Chicago area access breakout tankage at Griffith/Hartsdale and are scheduled to pump ex Griffith. Deliveries destined for BP Whiting utilize Griffith/Hartsdale delivery tankage for subsequent transfers to the refinery.

Line 6B (Griffith/Hartsdale to Sarnia)

- The pipeline segment from Griffith/Hartsdale to Sarnia is referred to as Line 6B.
- At Stockbridge volumes destined for Samaria and Toledo access breakout tankage for subsequent movement over Line 17.
- Scheduled Line 6B deliveries occur at Marysville and the Sarnia area refineries. The remaining Line 6B volumes destined for delivery east of Sarnia access breakout tankage at Sarnia for subsequent movement over Line 7 to connecting lines through Westover Terminal. When necessary, Line 6B and Line 5 delivery conflicts at Sarnia are directed to Enbridge tankage prior to being delivered directly to the refinery.

Line 14/64 (Superior to Griffith/Hartsdale)

Line 14/64 transports volumes ranging between condensate and medium crudes for delivery at Mokena and Griffith respectively. It is also possible for volumes transported on Line 64 to access breakout tankage at Griffith/Hartsdale for subsequent movement on Line 6B.

Even though the summary provided in Table 2 of this document (Commodity Routing Summary by Pipeline Segment) allows heavier commodities into Line 14/64, in normal operations it is considered a light crude oil line.

Line 17 (Stockbridge to Toledo)

Line 17 transports volumes of light sour, high sour, medium, heavy, heavy high tan, heavy low resid crude for delivery at Samaria and Toledo.

Line 7 (*Sarnia to Westover)*
Line 10 *(Westover to Kiantone)*
Line 11 *(Westover to Nanticoke)*

Volumes pumped over Line 7 access breakout tankage at Westover. These volumes are subsequently rescheduled to pump over Line 10 for delivery to United Refining at Kiantone and Line 11 for delivery to Imperial Oil at Nanticoke.

F. Predicted Pipeline Transit Times (Table 3)

Predicted transit times associated with service offered by Enbridge are provided on the Oil Movement Manager / Shipper Information System (OM2/SIS) Portal. Proxy transit times are updated weekly, and are based on original Notices of Shipment (NOS) and Revised Notices of Shipment.

Table 3 provides instructions for using the OM2/SIS Transit Time Calculator.

G. Minimum Batch Size (Table 4)

The nominal batch size in the Enbridge system is 10,000 m^3 and is subject to nominations on each pipeline and feeder pipeline requests. Batch sizes are generally a function of the volume nominated, as well as the size and number of available receipt, break-out and delivery tanks for given commodities (both within the Enbridge Mainline System and with connected feeder pipelines and refineries).

Minimum Batch Size

A shipper's minimum monthly nomination volume, for any commodity, is typically restricted to the minimum batch sizes defined in Table 4. This table sets out batch size considerations for the base Service Levels. Minimum batch sizes are set based on the requirements of measurement, quality, tank utilization, capacity impact, pipeline integrity and administrative efficiency. The minimum batch size for movement on the Enbridge Mainline System is determined by the size indicated for the pipeline of delivery.

Maximum Batch Size

Maximum batch sizes are generally determined by terminal tankage availability or other operational considerations. Currently 12,000 m^3 is the largest typical batch size transported on the system; however larger batch sizes or double-batching of commodities can be reviewed by Enbridge on an individual basis with consideration to system and shipper constraints.

Enbridge and Shippers must ensure that nominated volumes can be divided into standard batch sizes within the minimum and maximum batch size parameters. Batch sizes may also be impacted by cycle sizes on each line to maintain overall system quality guidelines.

H. Tankage Operations and Utilization by Commodity Category (Table 5)

Receipt, breakout and delivery tankage is required for the transportation of specific commodities on the Enbridge System. Table 5 outlines the commodities that utilize tankage at various terminal locations associated with the base Service Levels. The tankage allocation in Table 5 is predicated on factors including but not limited to preserving the petroleum quality of batches transported on the Enbridge system. To the greatest extent possible, Enbridge will advise shippers prior to making any significant changes to tank utilization.

Actual time in tankage at each location will be dependent upon commodity allocations to each tank, system operating conditions and/or third party operations. As a result, tankage retention times at individual locations may vary significantly as detailed in Tankage Operation.

Tankage Operation

Tanks on the Enbridge / Lakehead system are an integral part of the physical pipeline system. There are four basic categories for tanks: receipt, breakout, delivery and operational as detailed below.

Receipt Tankage

Receipt tankage is designed to accumulate incoming volumes until such time that the volumes are scheduled to pump. In some cases a volume or batch may pump as soon as it is received. However at other times, especially for smaller volumes or equalized streams, volumes may be accumulated until such time that a batch is available to pump.

The Enbridge system has been historically designed such that receipt tankage is provided for a nominal retention time of 4 days. Regular operation and recent analysis indicate that retention times are moving below 4 days. Shippers and feeders should be aware of the retention times for their respective commodities.

Breakout Tankage

Breakout tankage is designed and built at locations where there is a substantial rate change, due to volumes entering or leaving the system, and may also be considered to preserve the quality of the streams. At these locations, volumes are received to breakout tankage and re-pumped on another line segment. At breakout locations the retention time in tankage is defined as the time between landing and re-pumping batches. The Enbridge system has been designed such that breakout tankage is provided for a nominal retention time of 2 days.

Breakout tankage is designed and built mainly to reduce power costs, pressure cycling and capital costs for new pipeline expansions. Below some examples are described where breakout tankage is required.

- Line 2A volumes currently access breakout tankage at Cromer, and these volumes along with other receipts entering the system at Cromer are subsequently rescheduled on Line 2B.

- At Superior there are 5 incoming pipelines and 4 outgoing pipelines, but none of the incoming rates match the outgoing rates. Therefore all volumes are required to access breakout tankage and volumes are rescheduled for subsequent movement on the various outgoing lines.

The actual time in tankage can vary from batch to batch depending on pipeline conditions with consideration given to but not limited to scheduling, petroleum quality or unplanned interruptions. Consideration will be given to shipper requests as operational conditions allow.

<u>Delivery Tankage</u>

At some delivery locations the receiving refinery is not able to receive crude volumes at the full Enbridge mainline rate. In these situations, the scheduled delivery volume will first access an Enbridge delivery tank and then be transferred over to the refinery at a lower transfer rate. Superior and Griffith are locations where this type of operation occurs.

<u>Operational Tankage</u>

Tankage may be utilized for operational considerations to "absorb" the flow rate change from operating to shut down mode, and vice versa. There is Mainline tankage available at Hardisty, Kerrobert, Regina, and Clearbrook that may be utilized as Operational tankage if required.

3. PROCEDURES AND REPORTING

A. Commodity Testing (Table 6)

Enbridge conducts various standard tests for commodities transported on the pipeline system. These standard tests are summarized for each commodity with respect to location, frequency, and type of test in Table 6, Commodity Testing Summary. Commodity quality measurement is also provided in Table 6.

B. Shipper Services Business Activities (Tables 7 & 8)

To manage the logistics of transporting commodities through its system, Enbridge and industry have developed a set of procedures and reporting requirements with respect to nominations, supply control and scheduling activities on its system. These are summarized in Table 7 (Scheduling Calendar) and Table 8 (Shipper Services Business Activities).

4. COMMUNICATIONS

An important component of Enbridge service is communication to its customers. Enbridge operations can have a material impact on oil markets and, in turn, on producers, marketers, shippers and refiners. As such, Enbridge will strive to provide these impacted parties with timely access to system related information on its commodity movements, operational decisions and events.

Where unscheduled and unplanned events impact, or potentially impact, Enbridge operations, these will be communicated to Enbridge customers as quickly as possible, subject to any commercial considerations. Ideally, changes to planned or scheduled events will be communicated with prior notice. Generally and where feasible, the objective will be to inform impacted parties of events or circumstances so that there are "no surprises" regarding system operations.

Enbridge also has a reciprocal expectation on its customers to provide accurate and timely information in order to fulfill the above noted communication obligations.

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ENBRIDGE SERVICE LEVELS

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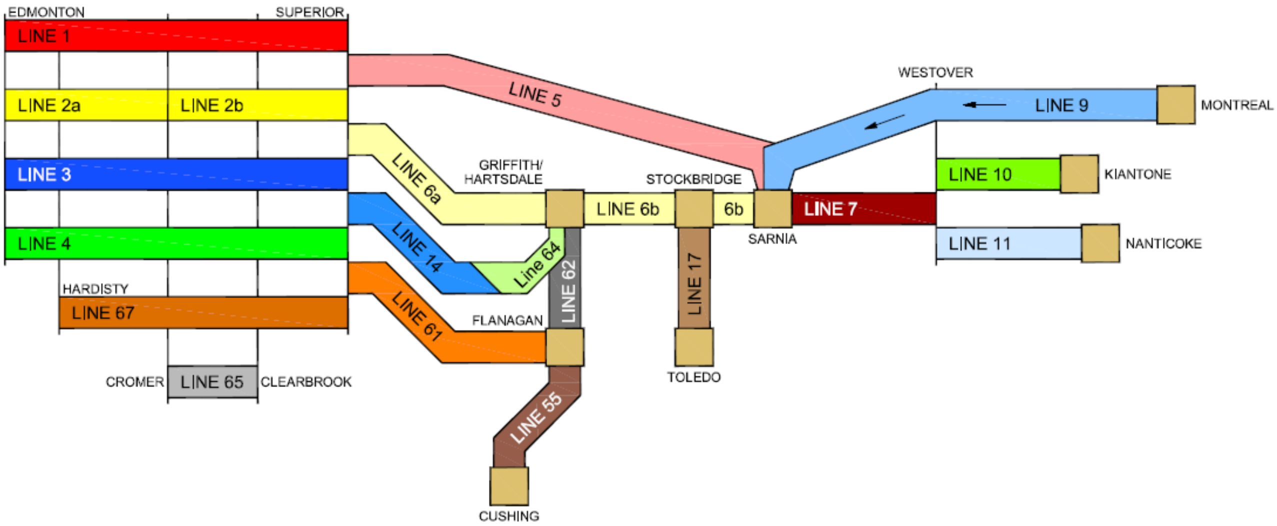
Figure 1
Pipeline System Configuration – Quarter 1, 2011



Line 1

37,600 m^3/d (236.5 kbpd)
18"/20" - 1098 miles
NGL
Refined Products
Light Synthetics

Line 2

Line 2a
70,300 m^3/d (442.2 kbpd)
24" - 596 miles
Line 2b
70,300 m^3/d (442.2 kbpd)
24"/26" - 502 miles
Condensates
Light Synthetics
Sweet
Light & High Sour

Line 3

80,000 m^3/d (503.2 kbpd)[1]
34" - 1098 miles
Light Synthetics
Sweet
Light & High Sour

Line 4

126,500 m^3/d (795.7 kbpd)
36"/48" - 1098 miles
Heavy
Medium (Ex-Clearbrook)
Light Sour (Ex-Clearbrook)

Line 5

78,100 m^3/d (491.2 kbpd)
30" - 645 miles
NGL
Condensates
Light Synthetics
Sweet
Light Sour

Line 6

Line 6a
106,000 m^3/d (666.7 kbpd)
34" - 467 miles
Line 6b
45,000 m^3/d (283.1 kbpd)
30" - 293 miles
Light Synthetics (Superior to Lockport)
Sweet (Superior to Lockport)
Light & High Sour
Medium
Heavy

Line 7

23,900 m^3/d (150.3 kbpd)
20" - 153 miles
Condensates
Light Synthetics
Sweet
Light & High Sour
Medium
Heavy

Line 9

38,200 m^3/d (240.3 kbpd)
30" - 524 miles
Condensates
Sweet
Light & High Sour

Line 10

11,800 m^3/d (74.2 kbpd)
12"/20" - 91 miles
Condensates
Light Synthetics
Sweet
Light & High Sour
Medium
Heavy

Line 11

18,600 m^3/d (117.0 kbpd)
16"/20" - 47 miles
Condensates
Light Synthetics
Sweet
Light & High Sour
Medium
Heavy

L 14 / L 64

50,500 m^3/d (317.6 kbpd)
24" - 467 miles
Condensates
Light Synthetics
Sweet
Light & High Sour
Medium
Heavy (Superior to Mokena)

Line 17

16,000 m^3/d (100.6 kbpd)
16" - 88 miles
Heavy

Line 55

30,700 m^3/d (193.3 kbpd)
22"/24" - 575 miles
Light Synthetics
Sweet
Light & High Sour
Medium
Heavy

Line 61

63,600 m^3/d (400.0 kbpd)
42" - 454 miles
Light Synthetics
Sweet
Light & High Sour
Medium
Heavy

Line 62

20,700 m^3/d (130.2 kbpd)
22" - 75 miles
Heavy

Line 65

29,500 m^3/d (185.6 kbpd)
20" - 313 miles
Light Sour
Medium

Line 67

71,500 m^3/d (449.7 kbpd)
36" - 999 miles
Heavy

NOTES:

- Capacities provided are Annual Capacities
- [1]Current pressure restrictions limit capacity to 62,000 m^3/d (390.0kbpd)
- Updated: January 2011

File: 2011_Q1 System Config.dwg

Revised by: CDS
Drawn by: DRD

Table 1A
Commodity Receipt Summary – Canada

Receipt Location	Quality Category	Transport Commodity	Feeder Pipeline or Transfer Facility Company Name [Facility Name]
Edmonton	NGL	Natural Gas Liquids (NGL)	BP [Fort Saskatchewan Facility]
	Refined Products	Gasoline	Imperial Oil [Strathcona Refinery], Suncor [Edmonton Refinery], Shell [Scotford Refinery]
		Distillate	Imperial Oil [Strathcona Refinery], Suncor [Edmonton Refinery], Shell [Scotford Refinery]
	Condensate	Condensate Blend (CRW)[1]	BP [Coed Pipeline], Gibsons [Edmonton Terminal], Keyera [Fort Saskatchewan Pipeline], Pembina [Peace Pipeline, Drayton Valley Pipeline, Swanhills Pipeline], Suncor [Edmonton Refinery, Oil Sands Pipeline], Plains [Rainbow Pipeline, Rangeland Pipeline, Joarcam Pipeline], Kinder Morgan [North 40 Terminal], Enbridge [Southern Lights Pipeline]
	Light Synthetic	Suncor A (OSA)	Suncor [Oil Sands Pipeline]
		Suncor C (OSC)	Suncor [Oil Sands Pipeline]
		Syncrude (SYN)	Pembina [Alberta Oil Sands Pipeline], Kinder Morgan [North 40 Terminal], Plains [Rangeland Pipeline]
		Premium Albian Synthetic (PAS)	Inter Pipeline [Corridor Pipeline], Kinder Morgan [North 40 Terminal]
		Shell Premium Synthetic (SPX)	Inter Pipeline [Corridor Pipeline]
		Shell Synthetic Light (SSX)	Inter Pipeline [Corridor Pipeline]
		CNRL Light Sweet Synthetic Blend (CNS)	Pembina [Horizon Pipeline]
		CNRL Synthetic Custom Blend (CNC)	Pembina [Horizon Pipeline]
	Sweet	Mixed Blend Sweet (SW)[1]	Plains [Rainbow Pipeline, Joarcam Pipeline], Gibsons [Edmonton Terminal], Pembina [Bonnie Glen Pipeline, Peace Pipeline, Drayton Valley Pipeline, Swanhills Pipeline], Kinder Morgan [North 40 Terminal]
	Light Sour	Low Sulphur Sour (SLE)[1]	Gibsons [Edmonton Terminal], Inter Pipeline [Central Alberta Pipeline], Pembina [Drayton Valley], Plains [Joarcam Pipeline, Rangeland Pipeline], Kinder Morgan [North 40 Terminal]
	High Sour	High Sulfur Sour (SHE)[1]	Gibsons [Edmonton Terminal], Pembina [Peace Pipeline], Kinder Morgan [North 40 Terminal]
	Heavy	Albian Heavy Synthetic (AHS)	Kinder Morgan [North 40 Terminal], Inter Pipeline [Corridor Pipeline]
		Albian Residual Blend (ARB)	Kinder Morgan [North 40 Terminal], Inter Pipeline [Corridor Pipeline]
		Cold Lake (CL)	Inter Pipeline [Cold Lake Pipeline West], Kinder Morgan [North 40 Terminal]
		Wabasca Heavy (WH)	Plains [Rainbow Pipeline], Kinder Morgan [North 40 Terminal]
	Heavy High Tan	Peace Heavy (PH)	Plains [Rainbow Pipeline], Kinder Morgan [North 40 Terminal]
		Seal Heavy (SH)	Plains [Rainbow Pipeline]
		Access Western Blend (AWB)	Devon & MEG [Access Pipeline]
		Albian Muskeg River Heavy (AMH)	Inter Pipeline [Corridor Pipeline]
		Statoil Cheecham Blend (SCB)	Enbridge [Waupisoo Pipeline]
		Surmont Heavy Blend (SHB)	Enbridge [Waupisoo Pipeline]
	Heavy Low Resid	Suncor H (OSH)	Enbridge [Waupisoo Pipeline]
		Albian Vacuum Blend (AVB)	Inter Pipeline [Corridor Pipeline], Kinder Morgan [North 40 Terminal]
	Cracked	CNRL Heavy Sour Synthetic Blend (CNH)	Pembina [Horizon Pipeline]
	Other	Caroline Condensate (CCA)	Plains [Rangeland Pipeline]
		Sarnia Special (SSS)	Imperial Oil [Strathcona Refinery]

[1] Component streams indicated represent the current feeder components for each stream respectively.

Table 1A Continued
Commodity Receipt Summary – Canada

Receipt Location	Quality Category	Transport Commodity	Feeder Pipeline or Transfer Facility Company Name [Facility Name]
Hardisty	Light Synthetic	Suncor A (OSA)	Enbridge [Athabasca Pipeline]
		Suncor C (OSC)	Enbridge [Athabasca Pipeline]
		Husky Synthetic Blend (HSB)	Husky [Hardisty Terminal]
		BP Sweet Synthetic Blend (BSS)	Enbridge [Hardisty Caverns]
		Long Lake Light Synthetic Blend (PSC)	Enbridge [Athabasca Pipeline]
	Sweet	Long Lake Sweet Blend (PSW)	Enbridge [Athabasca Pipeline]
	Light Sour	BP Sour Blend (BSO)	Enbridge [Hardisty Caverns]
		Long Lake Sour Blend (PSO)	Enbridge [Athabasca Pipeline]
	High Sour	Hardisty Sour (SO)	Gibsons [Hardisty Terminal]
	Heavy	Cold Lake (CL)	Inter Pipeline [Cold Lake Pipeline South], Flint Hills [Hardisty Terminal], Gibsons [Hardisty Terminal], Enbridge [Hardisty Caverns]
		BP Synthetic Heavy Blend (BSH)	Enbridge [Hardisty Caverns]
		BP Conventional Heavy Blend (BCH)	Enbridge [Hardisty Caverns]
		Western Canadian Blend (WCB)	Husky [Hardisty Terminal]
		Western Canadian Select (WCS)	Husky [Hardisty Terminal], Enbridge [Hardisty Caverns]
		Bow River (BR)	Gibsons [Hardisty Terminal]
		Lloydminster Hardisty (LLB)	Husky [Hardisty Terminal], Enbridge [Hardisty Caverns]
	Heavy High Tan	MacKay River Heavy (MKH)	Enbridge [Athabasca Pipeline], Flint Hills [Hardisty Terminal], Gibsons [Hardisty Terminal]
		Long Lake Heavy SynBit Blend (PSH)	Enbridge [Athabasca Pipeline]
		Christina SynBit (CSB)	Gibsons [Hardisty Terminal]
		Borealis Heavy Blend (BHB)	Enbridge [Athabasca Pipeline], Flint Hills [Hardisty Terminal], Gibsons [Hardisty Terminal]
	Heavy Low Resid	Suncor H (OSH)	Enbridge [Athabasca Pipeline], Flint Hills [Hardisty Terminal], Gibsons [Hardisty Terminal]
	Cracked	Pine Bend Special (PBS)	Flint Hills [Hardisty Terminal]
		Suncor Cracked C (OCC)	Enbridge [Athabasca Pipeline]
Kerrobert	NGL	Natural Gas Liquids (NGL)	BP [Kerrobert Caverns]
	Sweet	Mixed Blend Sweet (SW)	Inter Pipeline [Mid-Saskatchewan Pipeline]
	Heavy	Lloydminster Kerrobert (LLK)	Plains [Manito Pipeline]
		Smiley Coleville (SC)	Inter Pipeline [Mid-Saskatchewan Pipeline]
Regina	Refined Products	Gasoline	Consumers Co-operative [Regina Refinery]
		Distillate	Consumers Co-operative [Regina Refinery]
	Light Synthetic	Newgrade Synthetic Blend A (NSA)	Consumers Co-operative [Regina Upgrader]
		Newgrade Synthetic Blend X (NSX)	Consumers Co-operative [Regina Upgrader]
	High Sour	Moose Jaw Tops (MJT)	Plains [South Saskatchewan Pipeline]
	Heavy	Fosterton (F)	Plains [South Saskatchewan Pipeline]
Cromer	NGL	Natural Gas Liquids (NGL)	Enbridge [Westspur Pipeline]
	Sweet	Mixed Blend Sweet (SW)	Tundra [Tundra Pipeline]
	Light Sour	Light Sour Blend (LSB)[1]	Enbridge [Virden Pipeline, Westspur Pipeline], Penn West [Waskada Pipeline], Tundra [Tundra Pipeline]
	Medium	Midale (M)[1]	Enbridge [Virden Pipeline, Westspur Pipeline]
Sarnia	Condensate	BP Condensate Blend (ACB)	BP [Sarnia Extraction Plant]

[1] Component streams indicated represent the current feeder components for each stream respectively.

Table 1B
Commodity Receipt Summary – United States

Receipt Location	Quality Category	Transport Commodity	Feeder Pipeline or Transfer Facility Company Name [Facility Name]
Clearbrook	Sweet	U.S. Sweet - Clearbrook (UHC)	Enbridge Energy Partners [North Dakota]
Mokena	Sweet	U.S. Sweet - Mokena (UHM)	Chicap Pipeline Company [Chicap Pipeline]
	High Sour	U.S. High Sour - Mokena (UOM)	Chicap Pipeline Company [Chicap Pipeline]
	Heavy	U.S. Heavy - Mokena (UVM)	Chicap Pipeline Company [Chicap Pipeline]
Rapid River	NGL	Natural Gas Liquids (NGL)	BP [Rapid River]
Lewiston	Sweet	U.S. Sweet - Lewiston (UHL)	Markwest Pipelines [Michigan Crude Pipeline]

Table 2
Commodity Routing Summary by Pipeline Segment

Receipt Location	Quality Category	Transport Commodity	Line 1	Line 2	Line 3	Line 4	Line 67	Line 65	Line 5	Line 14/64	Line 6A	Line 6B	Line 61	Line 62	Line 17	Line 7	Line 10	Line 11
Edmonton	NGL	Natural Gas Liquids (NGL)	√						√									
	Refined Products	Gasoline	√															
		Distillate	√															
	Condensate	Condensate Blend (CRW)		√	√				♦	♦	♦		♦			♦	♦	♦
	Light Synthetic	Suncor A (OSA)	√	√	√				√	√	√		√			♦	♦	♦
		Suncor C (OSC)	♦	√	√				√	♦	♦		♦			♦	♦	♦
		Syncrude (SYN)	√	√	√				√	√	√		√			√	√	√
		Premium Albian Synthetic (PAS)	♦	√	√				√	√	♦		♦			♦	♦	♦
		Shell Premium Synthetic (SPX)		√	√				√	√	♦		♦			♦	♦	♦
		Shell Synthetic Light (SSX)		√	√				√	√	♦		♦			♦	♦	♦
		CNRL Synthetic Custom Blend (CNC)		√														
		CNRL Light Sweet Synthetic Blend (CNS)		√	√				√	√	√					√	√	√
	Sweet	Mixed Blend Sweet (SW)		√	√				√	√	♦		√			√	√	√
	Light Sour	Low Sulphur Sour (SLE)		√	√	♦			√	√	♦	♦	√			♦	♦	♦
	High Sour	High Sulfur Sour (SHE)		♦	√	♦				√	♦	√	√		♦	√	√	♦
	Heavy	Albian Heavy Synthetic (AHS)				√				♦	√	√	√	√	√	♦	♦	♦
		Albian Residual Blend (ARB)				♦				♦	√	√	√	√	√	♦	♦	♦
		Cold Lake (CL)				√				√	√	√	√	√	√	√	√	√
		Wabasca Heavy (WH)				√				♦	√	√	√	√	√	♦	♦	♦
	Heavy High Tan	Peace Heavy (PH)				√				♦	√	√	√	♦	√	♦	♦	♦
		Seal Heavy (SH)				√				♦	√	√	√	♦	√	√	√	√
		Access Western Blend (AWB)				√				♦	√	√	√	♦	√	√	√	√
		Albian Muskeg River Heavy (AMH)				♦				♦	√	√	√	♦	√	√	√	√
		Statoil Cheecham Blend (SCB)				√				♦	√	√	√	♦	√	√	√	√
		Surmont Heavy Blend (SHB)				√				♦	√	√	√	♦	√	√	√	√
	Heavy Low Resid	Suncor H (OSH)				♦				√	√	√	√	♦	√			
		Albian Vacuum Blend (AVB)				♦				√	√	√	√	♦	√			
	Cracked	CNRL Heavy Sour Synthetic Blend (CNH)				√												
	Other	Caroline Condensate (CCA)		√	√													
		Sarnia Special (SSS)				♦				√	√	√				♦		♦

Table 2 Continued
Commodity Routing Summary by Pipeline Segment

Receipt Location	Quality Category	Transport Commodity	Line 1	Line 2	Line 3	Line 4	Line 67	Line 65	Line 5	Line 14/64	Line 6A	Line 6B	Line 61	Line 62	Line 17	Line 7	Line 10	Line 11
Hardisty	Light Synthetic	Suncor A (OSA)		√	√				√	√	√		√			♦	♦	♦
		Suncor C (OSC)		√	√				√	♦	♦		♦			♦	♦	♦
		Husky Synthetic Blend (HSB)		√	√				√	√	√		√			√	√	√
		BP Sweet Synthetic Blend (BSS)		√	√				♦	√	♦					♦	♦	♦
		Long Lake Light Synthetic Blend (PSC)		√	√				√	√	♦		√			√	√	√
	Sweet	Long Lake Sweet Blend (PSW)		√	√				√	√	♦		♦			√	√	√
	Light Sour	BP Sour Blend (BSO)		♦	√	♦	♦		♦	√	♦	♦	♦		♦	♦	♦	♦
		Long Lake Sour Blend (PSO)		♦	√	♦	♦		♦	√	√	√	♦		♦	√	√	√
	High Sour	Hardisty Sour (SO)		♦	√	♦	♦			√	♦	√	√		♦	√	√	√
	Heavy	Cold Lake (CL)				√	√			♦	√	√	√	√	√	√	√	√
		BP Synthetic Heavy Blend (BSH)				√	♦			♦	√	√	♦	♦	√	♦	♦	♦
		BP Conventional Heavy Blend (BCH)				√	♦			♦	√	√	♦	♦	√	♦	♦	♦
		Western Canadian Blend (WCB)				√	♦			♦	√	√	♦	♦	√	√	√	√
		Western Canadian Select (WCS)				√	√			♦	√	√	√	√	√	√	√	√
		Bow River (BR)				√	♦			♦	√	√	√	√	√	√	√	√
		Lloydminster Hardisty (LLB)				√	√			♦	√	√	√	√	√	√	√	√
	Heavy High Tan	MacKay River Heavy (MKH)				√	♦			♦	√	√	√	♦	♦	√	√	√
		Long Lake Heavy SynBit Blend (PSH)				√	♦			♦	√	√	√	♦	♦	√	√	√
		Christina SynBit (CSB)				√	♦			♦	√	√	√	♦	♦	√	√	√
		Borealis Heavy Blend (BHB)				√	♦			♦	√	√	√	♦	♦	√	√	√
	Heavy Low Resid	Suncor H (OSH)				√	♦			√	√	√	√	♦	√			
	Cracked	Pine Bend Special (PBS)				√	♦											
		Suncor J (OSJ)				√	♦											
		Suncor Cracked C (OCC)				√	♦											

Table 2 Continued
Commodity Routing Summary by Pipeline Segment

Receipt Location	Quality Category	Transport Commodity	Line 1	Line 2	Line 3	Line 4	Line 67	Line 65	Line 5	Line 14/64	Line 6A	Line 6B	Line 61	Line 62	Line 17	Line 7	Line 10	Line 11
Kerrobert	NGL	Natural Gas Liquids (NGL)	√						√									
	Sweet	Mixed Blend Sweet (SW)		√					√	√	♦		√			√	√	√
	Heavy	Lloydminster Kerrobert (LLK)				√				♦	√	√	√	√	√	√	√	√
		Smiley Coleville (SC)				√				♦	√	√	√	√	√	√	√	√
Regina	Refined Products	Gasoline	√															
		Distillate	√															
	Light Synthetic	Newgrade Synthetic Blend A (NSA)		√	♦				√	√	♦		√			√	√	√
		Newgrade Synthetic Blend X (NSX)		♦	♦	√												
	High Sour	Moose Jaw Tops (MJT)		√	♦				√									
	Heavy	Fosterton (F)				√				♦	√	√	√	√	√	√	√	√
Cromer	NGL	Natural Gas Liquids (NGL)	√						√									
	Sweet	Mixed Blend Sweet (SW)		√				♦	√	√	♦		√			√	√	√
	Light Sour	Light Sour Blend (LSB)		√	♦			√	√	√	√	♦	√	♦	♦	√	√	√
	Medium	Midale (M)		♦	♦			√		√	√	√	√	♦	♦	√	♦	√
Clearbrook	Sweet	U.S. Sweet - Clearbrook (UHC)		√	√	♦			√	√	♦		√			√	√	√
Mokena	Sweet	U.S. Sweet – Mokena (UHM)									√	√				√	♦	√
	High Sour	U.S. High Sour – Mokena (UOM)									√	√			♦	√	♦	√
	Heavy	U.S. Heavy - Mokena (UVM)									√	√			√	√	♦	√
Rapid River	NGL	Natural Gas Liquids (NGL)							√									
Lewiston	Sweet	U.S. Sweet - Lewiston (UHL)							√									
Sarnia	Condensate	BP Condensate Blend (ACB)														√	√	

5/2/2011

Commodity Routing Legend

Routing	Receipt	Definition
Existing Routing	√	"Existing Routing" reflects the expected nominal crude routing for each commodity by pipeline.
Permissible Routing	♦	"Permissible Routing" reflects the nominal crude routing for each commodity by pipeline that is not typical and is at the discretion of Enbridge.
No Routing Indicated		Movements not indicated as Existing Routing require prior authorization from Enbridge.

5/2/2011

Table 2 Disclaimer

1. The Commodity Routing Summary by Pipeline Segment Table is intended for reference only and is based on typical movements by commodity at the moment this document is issued.

2. The Commodity Routing Summary by Pipeline Segment Table considers only the injection of commodities at the Original Approved Receipt Locations and it does not cover injections from Commercial Storage Facilities, Merchant Tankage or Breakout Tankage.

3. The Commodity Routing Summary by Pipeline Segment Table does not include commodity routings that Enbridge can adopt during abnormal or extraordinary operational conditions.

4. Confirmation on specific commodity routings please contact your Enbridge pipeline scheduler.

Table 3
Instructions for Using the OM2/SIS Transit Time Calculator

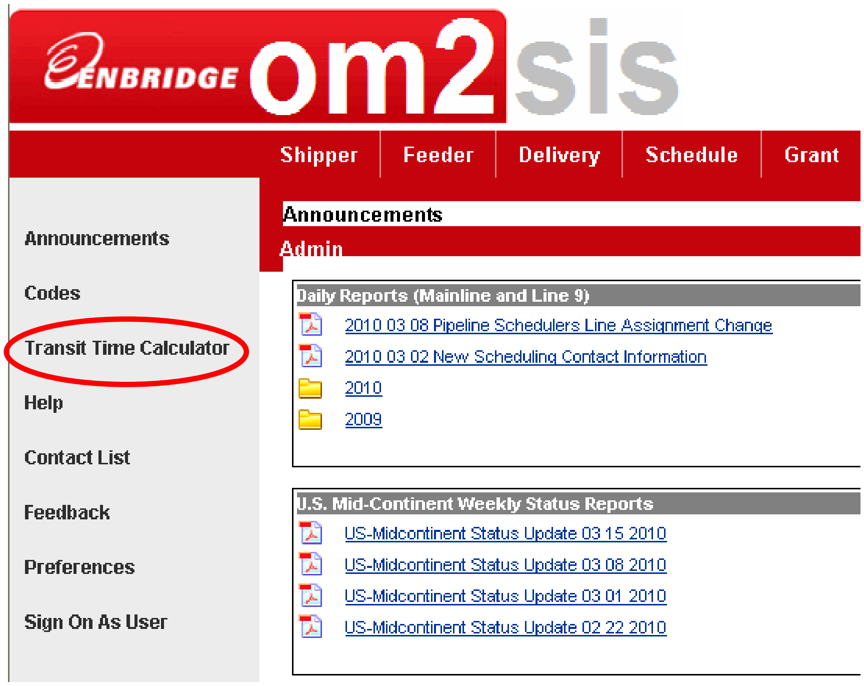
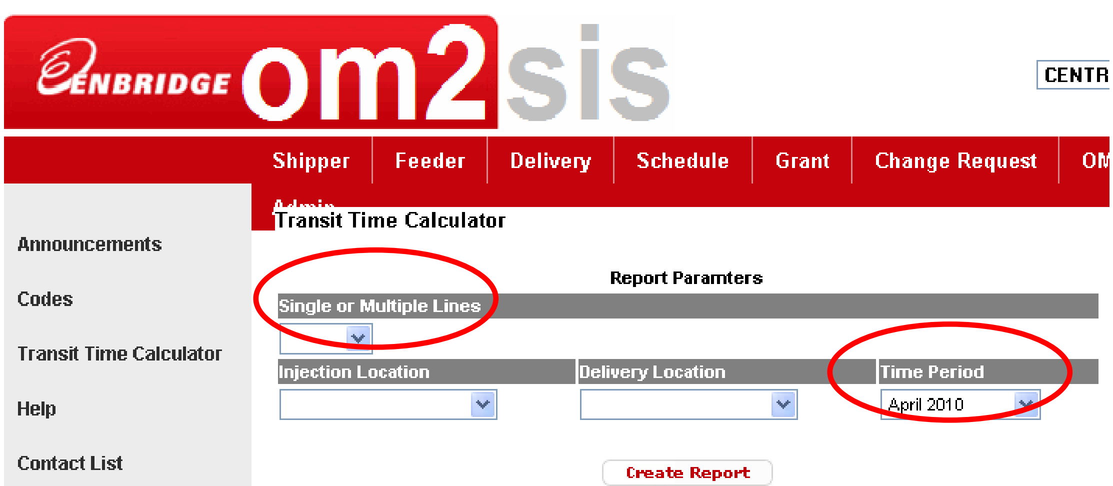
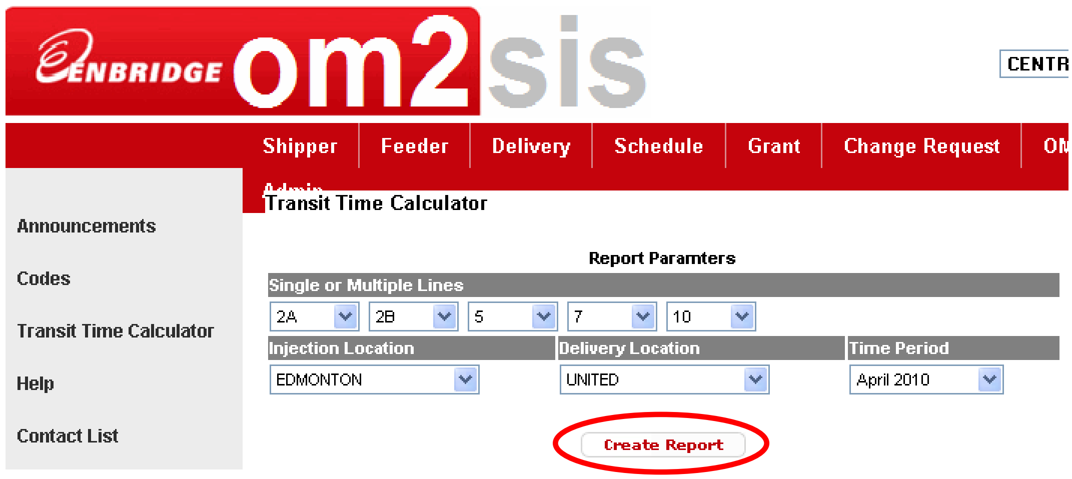
1	Internet connection and privilege to access into the OM2/SIS Portal
2	On the OM2/SIS home page click "Transit Time Calculator" at up left corner 
3	Select “Single or Multiple Lines” depending on the section of the Mainline that you want to check and “Time Period” (NOS month in which you want to calculate the transit time) 

Table 3 Continued
Instructions for Using the SIS Transit Time Calculator

4	For example, to calculate the transit time from Edmonton to United for a particular commodity in the month of April 2010, you must know the routing: lines 2A / 2B / 5 / 7 / 10 (see commodity routing on Table 2) and click on "Create Report" 
5	See the report

ENBRIDGE om2sis

Transit Time Calculator Report

Injection Location: EDMONTON
Delivery Location: UNITED
Report Period: April 2010

Line Number: 2A
Last Updated Date: April 2 2010 18:00:00 PM

From/To	HARDISTY	KERROBERT	REGINA	CROMER
EDMONTON	1.2	2.3	4.5	6.1
HARDISTY		1.1	3.3	4.9
KERROBERT			2.2	3.8
REGINA				1.6

Line Number: 2B
Last Updated Date: April 2 2010 18:00:00 PM

From/To	CLEARBROOK	SUPERIOR
CROMER	3.3	5.0
CLEARBROOK		1.7

Table 3 Continued
Instructions for Using the SIS Transit Time Calculator

5 See the report (Continued)

Line Number: 5
Last Updated Date: April 2 2010 18:00:00 PM

From/To	RAPID RIV	LEWISTON	BAY CITY	MARYSVILLE	SARNIA
SUPERIOR	2.3	4.0	4.8	5.7	6.0
RAPID RIV		1.7	2.5	3.4	3.7
LEWISTON			0.8	1.7	2.0
BAY CITY				0.9	1.2
MARYSVILLE					0.3

Line Number: 7
Last Updated Date: April 2 2010 18:00:00 PM

From/To	WESTOVER
SARNIA	1.7

Line Number: 10
Last Updated Date: April 2 2010 18:00:00 PM

From/To	UNITED
WESTOVER	1.6

Total Transit Time: 28.4 Days

Export to Excel **Exit**

Transit Time Report Disclaimer

1. Transit times are intended for reference only and are based on average flow rates. The total transit estimate includes a default breakout tankage estimate and does not consider unplanned maintenance, or other system upsets.
2. Any change in nominations or deliveries may alter transit times.

Contact Information

1. If you have any questions related to this Transit Time Calculator Report please contact: Laureano Martinez at laureano.martinez@enbridge.com or (403) 266-7977at
2. Contact your Enbridge pipeline scheduler to determine the specific transit time for a particular batch at a given time.

6 "Export to Excel" or "Exit" to start a new calculation

Table 4
Minimum Batch Size

Shippers are requested to supply a certain minimum volume to the Enbridge/Lakehead system such that the volume of the commodity tendered will be equal to or exceed the minimum batch size set for the required transportation route of the batch. The nominal batch size on the Enbridge system is 10,000 m3, however the minimum batch volume for each pipeline segment is provided below.

Line	Minimum Batch Size (m^3)	Comments
1	3,500	Refined Products deliveries. NGLs and buffers have their own set of guidelines
2A	5,000	All deliveries
2B	8,000	All deliveries
3	8,000	All deliveries except Hardisty, which is allowed 5,000 m^3
4	10,000	All deliveries
67	8,000	All deliveries
65	8,000	All deliveries
5	8,000	All deliveries except NGLs, which have their own set of guidelines
6A	8,000	All deliveries
14	8,000	All deliveries
61	8,000	All deliveries
62	8,000	All deliveries
6B	8,000	All deliveries
7	8,000	All deliveries
10	8,000	All deliveries
11	8,000	All deliveries
17	8,000	All deliveries

4/19/2011

Table 5
Tank Utilization by Commodity Type

Transport Commodity	Crude Quality Category	Edmonton	Hardisty	Regina	Cromer	Clearbrook	Superior	Flanagan	Griffith	Stockbridge	Sarnia	Westover
Condensate Blend (CRW)	Condensate	Note 2			B/B$^{G, F}$		B/B$^{G, F}$	B/B$^{G, F}$	B/B$^{G, F}$		B/B$^{G, F}$	
BP Condensate Blend (ACB)											R/B	B/B$^{G, F}$
Suncor A (OSA)	Light Synthetic	R/S	R/S		B/B^{G}		B/B^{G}	B/B$^{G, F, H}$	B/B^{G}			B/B$^{G, F, H}$
Suncor C (OSC)		R/B	R/B		B/B^{G}		B/B^{G}	B/B$^{G, F, H}$	B/B^{G}			B/B$^{G, F, H}$
Syncrude (SYN)		R/S			B/B^{G}		B/B^{G}	B/B$^{G, F, H}$	B/B^{G}		B/B$^{G, H}$	B/B$^{G, F, H}$
Premium Albian Synthetic (PAS)		R/S			B/B^{G}		B/B^{G}	B/B$^{G, F, H}$	B/B^{G}		B/B$^{G, H}$	B/B$^{G, F, H}$
Shell Premium Synthetic (SPX)		R/S			B/B^{G}		B/B^{G}	B/B$^{G, F, H}$	B/B^{G}		B/B$^{G, H}$	B/B$^{G, F, H}$
Shell Synthetic Light (SSX)		R/S			B/B^{G}		B/B^{G}	B/B$^{G, F, H}$	B/B^{G}		B/B$^{G, H}$	B/B$^{G, F, H}$
CNRL Light Sweet Synthetic Blend (CNS)		R/S			B/B^{G}		B/B^{G}	B/B$^{G, F, H}$	B/B^{G}		B/B$^{G, H}$	B/B$^{G, F, H}$
CNRL Synthetic Custom Blend (CNC)		R/B										
Husky Synthetic Blend (HSB)			R/S		B/B^{G}		B/B^{G}	B/B$^{G, F, H}$	B/B^{G}		B/B$^{G, H}$	B/B$^{G, F, H}$
BP Sweet Synthetic Blend (BSS)					B/B^{G}		B/B^{G}		B/B^{G}			
Long Lake Light Synthetic Blend (PSC)			R/S		B/B^{G}		B/B^{G}	B/B$^{G, F, H}$	B/B^{G}		B/B$^{G, H}$	B/B$^{G, F, H}$
Newgrade Synthetic Blend A (NSA)				R/S	B/B^{G}		B/B^{G}	B/B$^{G, F, H}$	B/B^{G}		B/B$^{G, H}$	B/B$^{G, F, H}$
Newgrade Synthetic Blend X (NSX)				R/B								
Mixed Blend Sweet (SW)	Sweet	Note 2			B/C		B/B^{F}	B/B$^{F, G, H}$	B/B^{F}		B/B$^{F, G, H}$	B/B$^{F, G, H}$
Long Lake Sweet Blend (PSW)			R/S		B/B^{F}		B/B^{F}	B/B$^{F, G, H}$	B/B^{F}		B/B$^{F, G, H}$	B/B$^{F, G, H}$

As a first option, a commodity will cross bottoms with the same commodity. Second, third, and fourth choices are noted in superscript in preferential order.

Commodity Group Codes – **A**-Heavy, **B**-Heavy High Tan, **C**-Cracked, **D**-Medium, **E**-High Sour, **F**-Sweet, **G**-Light Synthetic, **H**-Condensate, **I**-Light Sour, **J**-Heavy Low Resid

4/18/2011

Table 5 Continued
Tank Utilization by Commodity Type

Transport Commodity	Crude Quality Category	Edmonton	Hardisty	Regina	Cromer	Clearbrook	Superior	Flanagan	Griffith	Stockbridge	Sarnia	Westover
U.S. Sweet - Clearbrook (UHC) U.S. Sweet - Lewiston (UHL) U.S. Sweet - Mokena (UHM)	Sweet					Note 5						
Edmonton Light Sour (SLE)	Light Sour	Note 2			B/B		B/B	B/B$^{I, E, D}$	B/B$^{I, E, D}$		B/B$^{I, E}$	B/B$^{I, E, D, A}$
BP Sour Blend (BSO)					B/B		B/B	B/B$^{I, E, D}$	B/B$^{I, E, D}$			
Long Lake Sour Blend (PSO)			R/S		B/B^{I}		B/B^{I}	B/B$^{I, E, D}$	B/B$^{I, E, D}$		B/B$^{I, E, D}$	B/B$^{I, E, D, A}$
Light Sour Blend (LSB)					Note 2	B/B^{I}	B/B^{I}	B/B$^{I, E, D}$	B/B$^{I, E, D}$		B/B$^{I, E, D}$	B/B$^{I, E, D, A}$
High Sulfur Sour (SHE)	High Sour	Note 2			B/C		B/C	B/B$^{E, I, D}$	B/B$^{E, I, D}$		B/B$^{E, I, D}$	B/B$^{E, I, D, A}$
Moose Jaw Tops (MJT)				R/S	B/B^{E}		B/B^{E}	B/B$^{E, I, D}$				
Hardisty Sour (SO)					B/C		B/C	B/B$^{E, I, D}$	B/B$^{E, I, D}$		B/B$^{E, I, D}$	B/B$^{E, I, D, A}$
U.S. High Sour - Mokena (UOM)									Note 5			
Midale (M)	Medium				Note 2	B/S	B/B$^{D, E, A}$	B/B$^{D, E, A}$	B/B$^{D, E, A}$		B/B$^{D, E, A}$	B/B$^{D, E, A, I}$
Albian Heavy Synthetic (AHS)	Heavy	R/S					B/B$^{A, B}$	B/B$^{A, B}$	B/B$^{A, B}$	B/B$^{A, B}$	B/B^{A}	B/B$^{A, D, E, I}$
Albian Residual Blend (ARB)		R/B					B/B$^{A, B}$	B/B$^{A, B}$	B/B$^{A, B}$	B/B$^{A, B}$	B/B^{A}	B/B$^{A, D, E, I}$
Cold Lake (CL)		R/S	R/S			B/B$^{A, B}$	B/B$^{A, B}$	B/B$^{A, B}$	B/B$^{A, B}$	B/B$^{A, B}$	B/B^{A}	B/B$^{A, D, E, I}$
Wabasca Heavy (WH)		R/S					B/B$^{A, B}$	B/B$^{A, B}$	B/B$^{A, B}$	B/B$^{A, B}$	B/B^{A}	B/B$^{A, D, E, I}$
BP Synthetic Heavy Blend (BSH)							B/B$^{A, B}$		B/B$^{A, B}$	B/B$^{A, B}$	B/B^{A}	B/B$^{A, D, E, I}$
BP Conventional Heavy Blend (BCH)							B/B$^{A, B}$		B/B$^{A, B}$	B/B$^{A, B}$		
Western Canadian Blend (WCB)							B/B$^{A, B}$	B/B$^{A, B}$	B/B$^{A, B}$	B/B$^{A, B}$	B/B^{A}	B/B$^{A, D, E, I}$
Western Canadian Select (WCS)							B/B$^{A, B}$	B/B$^{A, B}$	B/B$^{A, B}$	B/B$^{A, B}$	B/B^{A}	B/B$^{A, D, E, I}$

As a first option, a commodity will cross bottoms with the same commodity. Second, third, and fourth choices are noted in superscript in preferential order.

Commodity Group Codes – **A**-Heavy, **B**-Heavy High Tan, **C**-Cracked, **D**-Medium, **E**-High Sour, **F**-Sweet, **G**-Light Synthetic, **H**-Condensate, **I**-Light Sour, **J**-Heavy Low Resid

Table 5 Continued
Tank Utilization by Commodity Type

Transport Commodity	Crude Quality Category	Edmonton	Hardisty	Regina	Cromer	Clearbrook	Superior	Flanagan	Griffith	Stockbridge	Sarnia	Westover
Bow River (BR)	Heavy						B/B$^{A, B}$	B/B$^{A, B}$	B/B$^{A, B}$	B/B$^{A, B}$	B/B^{A}	B/B$^{A, D, E, I}$
Lloydminster Hardisty (LLB)							B/B$^{A, B}$	B/B$^{A, B}$	B/B$^{A, B}$	B/B$^{A, B}$	B/B^{A}	B/B$^{A, D, E, I}$
Lloydminster Kerrobert (LLK)							B/B$^{A, B}$	B/B$^{A, B}$	B/B$^{A, B}$	B/B$^{A, B}$	B/B^{A}	B/B$^{A, D, E, I}$
Smiley Coleville (SC)							B/B$^{A, B}$	B/B$^{A, B}$	B/B$^{A, B}$	B/B$^{A, B}$	B/B^{A}	B/B$^{A, D, E, I}$
Fosterton (F)				R/S			B/B$^{A, B}$	B/B$^{A, B}$	B/B$^{A, B}$	B/B$^{A, B}$	B/B^{A}	B/B$^{A, D, E, I}$
US Heavy - Mokena (UVM)									Note 5			
Peace Heavy (PH)	Heavy High Tan	R/S					B/B^{B}, B/C^{B}	B/B$^{B, A}$	B/B$^{B, A}$	B/B$^{B, A}$	B/B$^{B, A}$	B/B$^{B, A, D, E, I}$
Seal Heavy (SH)		R/C					B/B^{B}, B/C^{B}	B/B$^{B, A}$	B/B$^{B, A}$	B/B$^{B, A}$	B/B$^{B, A}$	B/B$^{B, A, D, E, I}$
Access Western Blend (AWB)		R/S					B/B^{B}, B/C^{B}	B/B$^{B, A}$	B/B$^{B, A}$	B/B$^{B, A}$	B/B$^{B, A}$	B/B$^{B, A, D, E, I}$
Albian Muskeg River Heavy (AMH)		R/B					B/B^{B}, B/C^{B}	B/B$^{B, A}$	B/B$^{B, A}$	B/B$^{B, A}$	B/B$^{B, A}$	B/B$^{B, A, D, E, I}$
Surmont Heavy Blend (SHB)		R/S					B/B^{B}, B/C^{B}	B/B$^{B, A}$	B/B$^{B, A}$	B/B$^{B, A}$	B/B$^{B, A}$	B/B$^{B, A, D, E, I}$
MacKay River Heavy (MKH)			R/S				B/B^{B}, B/C^{B}	B/B$^{B, A}$	B/B$^{B, A}$	B/B$^{B, A}$	B/B$^{B, A}$	B/B$^{B, A, D, E, I}$
Long Lake Heavy SynBit Blend (PSH)			R/S				B/B^{B}, B/C^{B}	B/B$^{B, A}$	B/B$^{B, A}$		B/B$^{B, A}$	B/B$^{B, A, D, E, I}$
Christina Syn-Bit (CSB)							B/B^{B}, B/C^{B}	B/B$^{B, A}$	B/B$^{B, A}$	B/B$^{B, A}$	B/B$^{B, A}$	B/B$^{B, A, D, E, I}$
Borealis Heavy Blend (BHB)							B/B^{B}, B/C^{B}	B/B$^{B, A}$	B/B$^{B, A}$		B/B$^{B, A}$	B/B$^{B, A, D, E, I}$
Statoil Cheecham Blen (SCB)		R/S, R/B^{B}, R/C^{B}					B/B^{B}, B/C^{B}	B/B$^{B, A}$	B/B$^{B, A}$		B/B$^{B, A}$	B/B$^{B, A, D, E, I}$
Suncor H (OSH)	Heavy Low Resid	R/S	R/S				B/ B$^{J, B, A}$	B/ B$^{J, B, A}$	B/ B$^{J, B, A}$	B/ B$^{J, B, A}$	B/ B$^{J, B, A}$	
Albian Vacuum Blend (AVB)		R/B					B/ B$^{J, B, A}$	B/ B$^{J, B, A}$	B/ B$^{J, B, A}$	B/ B$^{J, B, A}$	B/ B$^{J, B, A}$	
Pine Bend Special (PBS)	Cracked		Note 3									
Suncor Cracked C (OCC)			R/S Note 3									
CNRL Heavy Sour Synthetic Blend (CNH)		R/S Note 3										
Caroline Condensate (CCA)	Other	R/S Note 3										
Sarnia Special (SSS)		R/B^{A}					B/B$^{D, A, B}$		B/B$^{D, A, B}$	B/B$^{D, A, B}$		

As a first option, a commodity will cross bottoms with the same commodity. Second, third, and fourth choices are noted in superscript in preferential order.

Commodity Group Codes – **A**-Heavy, **B**-Heavy High Tan, **C**-Cracked, **D**-Medium, **E**-High Sour, **F**-Sweet, **G**-Light Synthetic, **H**-Condensate, **I**-Light Sour, **J**-Heavy Low Resid

Table 5 Continued
Tank Utilization by Commodity Type

Tank Service Legend

Service	Receipt	Breakout	Tank Service Definitions
Segregated	R/S	B/S	Crude streams that does not share tankage with other crude streams.
Share Common Bottoms	R/B	B/B	Crude streams that can share tank bottoms with other crude types; - As a first option, a commodity will cross bottoms with the same commodity. - As second option, a commodity will cross bottoms within its identified Commodity Group. - Third, fourth, and fifth choices are noted in superscript in preferential order.
Commingled	R/C	B/C	Crude components that share tankage with other like-crude components to form single commingled streams e.g. SW, SLE, SHE, SO, CRW, LSB, M. Crude streams that can be commingled with a given commodity are noted in superscript in preferential order.
No Tankage Requirement			

General Notes

1. Above tankage references Enbridge facilities only.
2. The CRW, SW, SLE, SHE, LSB and M commodities are blended from their individual components and are combined on receipt and segregated receipt service is provided for these streams.
3. OCC, PBS, CNH and CCA require buffering.
4. SHE and SO will be commingled as required at breakout locations. Once commingled, they are treated as a single commodity and may cross bottoms with compatible sours.
5. US and Foreign crude is received at Clearbrook, Mokena, and Lewiston on the Enbridge system.
   - US sweet crude will cross bottoms with commodity group "F".
   - US Sour crude will cross bottoms with commodity groups, in the order of "E", "D", and "I".
   - US medium crudes will move through the system the same as Midale.
   - US heavy crude streams will move through the system the same as heavy streams.
6. Natural Gas Liquids, Gasoline, and Distillate do not utilize Enbridge tankage and are therefore not included in this table.

5/31/2010

Table 6
Commodity Testing Summary

Transport Commodity	Quality Category	Test
Refined Products (Gasoline and Distillate)	Products	2
Condensate Blend (CRW)	Condensate	3, 6, 7
Amoco Condensate (ACB)		1, 2, 3
Suncor A, Suncor C (OSA, OSC)	Light Synthetic	1, 2, 3, 8*
Syncrude (SYN)		1, 2, 3, 8*
Premium Albian Synthetic (PAS)		1, 2, 3
Shell Premium Synthetic (SPX)		1, 2, 3
Shell Synthetic Light (SSX)		1, 2, 3
CNRL Light Sweet Synthetic Blend (CNS)		1, 2, 3
CNRL Synthetic Custom Blend (CNC)		1, 2, 3
Husky Synthetic Blend (HSB)		1, 2, 3
BP Sweet Synthetic Blend (BSS)		1, 2, 3
Long Lake Light Synthetic Blend (PSC)		1, 2, 3
Newgrade Synthetic Blend (NSA, NSX)		1, 2, 3
Mixed Blend Sweet (SW)	Sweet	1, 2, 3, 4
Long Lake Sweet Blend (PSW)		1, 2, 3, 4
U.S. Sweet – Clearbrook (UHC)		1, 2, 3, 4
U.S. Sweet – Lewiston (UHL)		1, 2, 3, 4
U.S. Sweet – Mokena (UHM)		1, 2, 3, 4
Low Sulphur Sour (SLE)	Light Sour	1, 2, 3, 5
BP Sour Blend (BSO)		1, 2, 3, 5
Long Lake Sour Blend (PSO)		1, 2, 3
Light Sour Blend (LSB)		1, 2, 3, 5
High Sulfur Sour (SHE)	High Sour	1, 2, 3, 5
Moose Jaw Tops (MJT)		1, 2, 3
Hardisty Sour (SO)		1, 2, 3, 5
U.S. Sour - Mokena (UOM)		1, 2, 3
Midale (M)	Medium	1, 2, 3

General Notes:

Crude tests referenced in Table 6 are detailed in Tables 6A through 6E respectively. Test 3A on Table 6A and phosphorus testing listed under Test 4 on table 6B are incremental to base Service Levels and the testing costs are being recovered separately.

* Test only performed when commodity used as Line 1 buffer.

4/18/2011

Table 6 Continued
Commodity Testing Summary

Transport Commodity	Quality Category	Test
Albian Heavy Synthetic (AHS)	Heavy	1, 2, 3
Albian Residual Blend (ARB)		1, 2, 3
Cold Lake (CL)		1, 2, 3
Wabasca Heavy (WH)		1, 2, 3
BP Synthetic Heavy Blend (BSH)		1, 2, 3
BP Conventional Heavy Blend (BCH)		1, 2, 3
Western Canadian Blend (WCB)		1, 2, 3
Western Canadian Select (WCS)		1, 2, 3
Bow River (BR)		1, 2, 3
Lloydminster Hardisty (LLB)		1, 2, 3
Lloydminster Kerrobert (LLK)		1, 2, 3
Smiley Coleville (SC)		1, 2, 3
Fosterton (F)		1, 2, 3
U.S. Heavy - Mokena (UVM)		1, 2, 3
Peace Heavy (PH)	Heavy High Tan	1, 2, 3
Seal Heavy (SH)		1, 2, 3
Access Western Blend (AWB)		1, 2, 3
Albian Muskeg River Heavy (AMH)		1, 2, 3
Surmont Heavy Blend (SHB)		1, 2, 3
MacKay River Heavy (MKH)		1, 2, 3
Long Lake Heavy SynBit Blend (PSH)		1, 2, 3
Christina Syn-Bit (CSB)		1, 2, 3
Borealis Heavy Blend (BHB)		1, 2, 3
Statoil Cheecham Blend (SCB)		1, 2, 3
Suncor H (OSH)	Heavy Low Resid	1, 2, 3
Albian Vacuum Blend (AVB)		1, 2, 2
Pine Bend Special (PBS)	Cracked	1, 2, 3
CNRL Heavy Sour Synthetic Blend (CNH)		1, 2, 3
Suncor Cracked C (OCC)		1, 2, 3
Caroline Condensate (CCA)	Other	1, 2, 3
Sarnia Special (SSS)		1, 2, 3

General Notes:

Crude tests referenced in Table 6 are detailed in Tables 6A through 6E respectively. Test 3A on Table 6A and phosphorus testing listed under Test 4 on table 6B are incremental to base Service Levels and the testing costs are being recovered separately.

* Test only performed when commodity used as Line 1 buffer.

Table 6A – General Testing

Test	Frequency	Crude Types	Tests	Reporting
1	On Receipt	All	S&W, density	Reported by receipt ticket to feeder pipeline.
		All heavy crudes	Viscosity	Reported to feeder on exception basis only on violation of tariff quality specifications.
		Select light and medium crudes	Viscosity – tested during winter months to determine tariff category	Reported to feeder on exception basis only on violation of tariff quality specifications.
2	On Delivery	All	S&W, density	Reported by delivery ticket to delivery facility.
	On Receipt and Delivery	Refined products and NGL	Testing and reporting are in accordance with Enbridge's Line 1 Operations Manual.	
3	Annual Crude Characteristics	All	Density, RVP, sulphur, viscosity (10°C, 20°C, 30°C, 40°C, 45°C), pour point every two years	Annual crude characteristics report.
3A	Annual	Random	Organic Chloride, Olefinic content	Reported to feeder on exception basis only on violation of quality specifications.

4/15/2011

Table 6B – Sweet Streams Testing

Test	Location	Frequency	Test	Comments	Reporting
4	Receipt	All receipt batches	Density, sulphur, phosphorus	Selected batch receipt composite for SW components (SW component feeders defined in Table 1)	• Reported to feeder on exception basis only on violation of stream quality specifications per SW Receipt Quality Standard procedures • Enbridge issues monthly Crude Equalization Program report by the 15th day of the following month
		Selected receipt batches	Density, sulphur	U.S. Sweet (UHC, UHL)	Reported to feeder on exception basis only on violation of stream quality specifications per SW Receipt Sulphur Standard procedures
		All receipt batches	Density, sulphur	U.S. Sweet (UHM)	Reported to feeder on exception basis only on violation of stream quality specifications per SW Receipt Sulphur Standard procedures

Table 6C – Sour Streams Testing

Test	Location	Frequency	Test	Comments	Reporting
5	Receipt	Weekly	Density, sulphur	Selected batch receipt composite for Edmonton SLE & SHE and Cromer LSB feeder components	• Reported to feeder on exception basis only on violation of respective stream quality specifications per SLE Receipt Sulphur Standard procedures • Enbridge issues monthly Crude Equalization Program report by the 15th day of the following month

4/15/2011

Table 6D – Condensate Sampling Procedures and Testing – Edmonton Terminal

		Composite Sample		Monthly Testing		Bimonthly Testing		Quarterly Testing		
Test	**Location**	Collection Frequency	Tests	Sample Type	Test	Sample Type	Test	Sample Type	Test	**Reporting**
6	Receipts	1 / week – continuous & batched feeders	S&W density and Sulfur	1 spot/mo	Vapour pressure	Select weekly composite	Butane	Random Composite per CRW component stream	Viscosity, Olefins, Organic Chlorides, Aromatics, Meracptans, H_2S, Benzene, Mercury, Oxygenates, Total Suspended Solids, Phosphorous (Volatile)	Enbridge issues monthly Condensate Equalization Program report by the 15th day of the following
						1 spot / mo	Sulphur			
7	Delivery at Edmonton	1 / week	S&W and density	1 spot/mo	Vapour pressure	1 spot / mo	Butane			S& W and density reported by delivery ticket to delivery facility

Table 6E – Line 1 Synthetic Buffer Testing

Test	Location	Frequency	Test	Reporting
8	Edmonton	Batch pump out	Density, copper strip and sediment content	Reported to feeder on exception basis only on violation of Line 1 Quality Guidelines

Table 7
Scheduling Calendar

Business Day	Activity IF NO Apportionment	Activity IF Apportionment
1	Notices of shipment due to Enbridge (Notice of shipment dates issued by Enbridge per COLC calendar)	Notices of shipment due to Enbridge (Notice of shipment dates issued by Enbridge per COLC calendar)
1	If no apportionment is determined, so announced	If apportionment is determined, verification procedures commence
2	Commence compiling new month's schedule	Twenty-four (24) hours after feeder verification procedures commence, apportionment announced and revised notices of shipment requested
3		Revised notices of shipment received
4	Complete scheduling sequence for Lines 1, 2, 3, 4, 67 and 65 and issue via OM2/SIS	Commence compiling new months schedule
5	Complete scheduling sequence for Lines 5, 6, 14, 61, 62, 16 and 17 and issue via OM2/SIS	
6	Complete scheduling sequence for Lines 7, 10 and 11 and issue via OM2/SIS	Complete scheduling sequence for Lines 1, 2, 3, 4, 67 and 65 and issue via OM2/SIS
7		Complete scheduling sequence for Lines 5, 6, 14, 61, 62, 16 and 17 and issue via OM2/SIS
8		Complete scheduling sequence for Lines 7, 10 and 11 and issue via OM2/SIS

5/4/2010

Table 7 Continued
Scheduling Calendar

Scheduling Notes

1. Schedule Updates and Changes

Pipeline schedules are updated on a daily basis, including the processing of changes resulting from shipper requests and due to varying operating conditions. All changes submitted through OM2/SIS affecting pump orders (next 48 hours) will be promted to give proper notification to the Pipeline Schedulers as per the Line Space Queue rules.

- Any changes or updates that directly affect the next 48 hours of business must be received no later than 2:00 pm MST.

- Changes as a result of emergency may be accepted after 2:00 pm MST if accompanied by a direct telephone communication, and must be acknowledged by Enbridge.

2. Accepting Increases in Nominations

<u>Pipeline Initially Apportioned</u>
Batch requests located in the line space queue will be honored if the pipeline, or any segment thereof, was initially apportioned, and space has become available either due to shippers reducing volumes or an increase in capacity occurs. When either condition occurs, the first shipper in the queue will be contacted and given notification there is spare capacity and option of adding a batch. In all cases prior to being accepted by Enbridge, the feeder pipeline must verify any extra volumes tendered. If the total remains less than the available capacity, the volumes will be accepted. If spare capacity still remains, the next shipper in the queue will be contacted.

<u>Pipeline At or Below Capacity</u>
If nominations for the pipeline, or any segment thereof, indicates that space is available for the month, or in the case of a pipeline initially at capacity and space becomes available, shippers may increase volumes, on a first come basis, at any time up to the point that the increase brings that segment to capacity. Any volume increases that cannot be accommodated at this time should be submitted to our line space queue. When space becomes available on a pipeline that is initially at capacity shippers will be notified through the Oil Movement Manager/Shipper Information System (OM2/SIS) Portal that increases to nominations will be accepted.

5/4/2010

Table 8A
Supply Management

Process	Activity	Reporting
Nominations	Due on a specific date and time as specified on the Crude Oil Logistics Committee (COLC) Forecast Reporting Calendar.	Enbridge issues letter to all shippers, feeders and interested parties by November 30 each year for the following year's nomination calendar.
Apportionment	• All nomination information is compiled to determine if apportionment required. • If required, announced by the end of first business day after initial nominations are due (as outlined in the COLC forecast-reporting calendar). Revised Notices of Shipment due back 24 hours from time of announcement. • If not required, announcement is made the afternoon of the day Notices of Shipment are due.	Enbridge issues letter to all shippers, feeders and interested parties in accordance with Scheduling Calendar (Table 7).
Ticketing	Tickets are pulled each Monday morning or as specified per COLC forecast reporting calendar.	No Enbridge reporting for this activity.
Weekly Splits	Weekly splits are required to be provided to Enbridge by 12:00 pm each Tuesday or as specified by the COLC forecast reporting calendar.	Enbridge issues Splits Reports to all shippers by end of respective week.
Month-end Splits	• Feeders notified of month-end total deliveries to Enbridge by end of day on 2nd working day of the new month for the previous month. • Feeders provide to Enbridge month-end splits (within 24 hours after notified by Enbridge) 3rd working day of new month for previous month.	No Enbridge reporting for this activity.
Month-end Close	Supply management month-end close occurs on the 4th working day of the new month for the previous month. **Note:** Timely completion is dependent on all industry information being provided to Enbridge on time.	Enbridge issues reports to all shippers and feeders with information pertaining to previous month's activities by 12:00 pm on the 6th working day of the following month.
Non-Performance Penalty (NPP) Process	Refer to tariff Rules and Regulations under Non-Performance.	• Enbridge issues Shipper Nomination and Actual Supply Report to all shippers and interested parties. • For a shipper(s) in violation of NPP, Detail of Shipper Performance Report issued after month end close.

5/31/2010

Table 8B
Carriers Inventory

Process	Activity	Reporting
Supply Control Shippers Position Report	• Summarizes shipper activity in the system. • Sent out at month-end after close off is completed. **Note:** Timely completion is dependent on all industry information being provided to Enbridge on time.	Reporting for this activity is included in Month-end Close reporting.
Retention Stock	Calculated quarterly using a combination of 2 months actual receipts and 1 month nominations.	Enbridge issues Retention Stock Report to shippers quarterly via OM2/SIS.
Balancing Shipper's Positions	• Automatic Balancing procedure available in the Tariffs and Tolls section at www.enbridge.com • Performed on an on going basis.	No Enbridge reporting for this activity.

Table 8C
Oil Accounting

Process	Activity	Reporting
Monthly Shippers Balance	Preliminary statements issued the 6th / 7th working day, with final statements including Automatic Balancing transactions and pricing by the 15th working day. **Note:** Timely completion is dependent on all industry information being provided to Enbridge on time.	Enbridge issues Monthly Shippers Balance Statement.
Tariff Invoicing	Issued on the 4th working day after the 15th; and the 4th working day after the last working day of each month.	Enbridge issues Tariff Invoices.

SCHEDULE "O" – LINE 9 CAPITAL REPORTING TEMPLATE

	A	B	C	D
1	**Capital Project AFE Number**	**Capital Project Expenditure in Prior years**	**Capital Project Expenditure during Past Calendar Year**	**Capital Project Expenditure Forecast for Current Calendar Year**
2	Line 9: Each Project AFE in excess of $5 M in Canadian $			
3	Project A	CDN $ in 2010 & prior	CDN $ in 2011	CDN $ in 2012
4	Project B	CDN $ in 2010 & prior	CDN $ in 2011	CDN $ in 2012
5	Project C	CDN $ in 2010 & prior	CDN $ in 2011	CDN $ in 2012
6	Line 9: Total of Line 9 Shipper Supported Capital Projects less than $5 M per project in Canadian $			
7	Sum of all other AFEs			
8	**Total**			