Westcoast Energy Inc.

2011 to 2013 Transmission Toll Settlement

WESTCOAST ENERGY INC.

2011 to 2013 TRANSMISSION TOLL SETTLEMENT

ARTICLE 1
INTRODUCTION

1.1 Negotiated Settlement

Westcoast Energy Inc. ("Westcoast") and the Canadian Association of Petroleum Producers, Terasen Gas Inc., the Export Users Group (comprising Avista Corporation, Cascade Natural Gas Corporation, Northwest Natural Gas Company and Puget Sound Energy, Inc.) and Powerex Corp. (collectively the "Stakeholders") have reached this Settlement Agreement (the "Agreement") regarding the determination of Westcoast's tolls for transmission service in Zones 3 and 4 for the 2011, 2012 and 2013 calendar years.

This Agreement is the result of negotiations between Westcoast and the Stakeholders and is entered into on the understanding that no single component of this Agreement is to be construed as representing the position of Westcoast or any of the Stakeholders on the appropriate tolls that would be obtained in the absence of this Agreement. Westcoast and the Stakeholders intend that this Agreement be viewed as a whole, and that no aspect of this Agreement should be considered as acceptable to Westcoast or any of the Stakeholders in isolation from all other aspects of this Agreement.

1.2 Objectives

Westcoast and the Stakeholders intend that this Agreement be interpreted and applied in good faith in a manner consistent with the spirit of the following objectives:

(a) to enhance the viability and competitiveness of the British Columbia natural gas basin by aligning more closely the interests of Westcoast and its shippers through a framework that encourages operating and capital efficiencies;

(b) to provide Westcoast's shippers with toll certainty and stability;

(c) to provide the lowest cost tolls possible while maintaining or improving pipeline service, efficiency, reliability, flexibility and utilization and without compromising safety or the environment;

(d) to maintain the financial integrity of Westcoast; and

(e) to reduce the resources used by Westcoast, its shippers and the National Energy Board (the "Board") in the traditional regulatory process.

1.3 Disclosure by Westcoast

Westcoast confirms that it has in the revenue requirement and toll information provided to the Stakeholders (including the information package provided on November 10, 2010), in its responses to information requests from the Stakeholders (including the responses provided on November 12, 2010 and revised on December 3, 2010) with respect to such revenue requirement and toll information and in its settlement proposals, negotiations and discussions with the Stakeholders, provided full and fair disclosure of all relevant financial and accounting information that will or Westcoast reasonably expects may have an impact on Westcoast's revenue requirement in Zones 3 and 4 for 2011, 2012 and 2013. The parties recognize that financial and accounting information provided up to the date of this Agreement is based on good faith estimates and forecasts consistent with Westcoast's rate making practices. Westcoast will continue to provide such full and fair disclosure for the remainder of the term of this Agreement. The Stakeholders have relied and will rely in good faith on Westcoast's full and fair disclosure of all such financial and accounting information. Any Stakeholder who subsequently believes that Westcoast has not made such full and fair disclosure of all relevant financial or accounting information, that Westcoast knew or reasonably ought to have known about at the time disclosure should have been made, and such lack of disclosure related to a matter that has a total impact of more than $100,000 per year on Westcoast's revenue requirement in Zones 3 and 4 combined in 2011, 2012 or 2013, may raise the matter with the Board and seek appropriate relief, which may include adjustments to the tolls or components of this Agreement.

1.4 Meaning of "Flow-Through"

Westcoast and the Stakeholders agree that the term "flow-through" as used in this Agreement with respect to certain components of Westcoast's revenue requirement means that the cost adjustments, positive or negative, including all associated tax impacts, to the revenue requirement with respect to such components, will be to the account of shippers. The revenue requirement impact of any difference between the forecast and actual cost of those components of the revenue requirement to be treated on a flow-through basis will be recorded in the appropriate deferral account as set out in this Agreement and flowed-through to the account of shippers.

1.5 2014 Information

Westcoast agrees to provide to the Stakeholders no later than November 1, 2013 an information package with respect to Westcoast's forecast revenue requirement and tolls in Zones 3 and 4 for 2014 in a form similar to the revenue requirement and toll information contained in the revenue requirement and toll information package provided by Westcoast to the Westcoast Toll and Tariff Task Force ("TTTF") on November 10, 2010.

ARTICLE 2
REVENUE REQUIREMENT

2.1 2011, 2012 and 2013 Revenue Requirement

Westcoast's tolls in Zones 3 and 4 will be based on a forecast revenue requirement of $321.872 million (including motor fuel and carbon taxes of $18.596 million) in 2011, $363.377 million (including motor fuel and carbon taxes of $24.743 million) in 2012 and $364.972 million (including motor fuel and carbon taxes of $26.013 million) in 2013, in each case as set out in Appendix A, based on the following and subject to the provisions of this Agreement:

(a) Operating and Maintenance (O&M) Expenses Excluding Pipeline Integrity O&M Expenses

The O&M expenses allocated to Zones 3 and 4 will be $62.382 million in 2011 (excluding pipeline integrity O&M expenses), $66.100 million in 2012 (excluding pipeline integrity O&M expenses) and $67.600 million in 2013 (excluding pipeline integrity O&M expenses), in each case as set out in Appendix B.

The 2012 and 2013 O&M expenses include forecast O&M expenses of $835,000 in each of 2012 and 2013 associated with the Transmission North expansion project that is the subject of Westcoast's application to the Board dated November 30, 2010 under Part III of the *National Energy Board Act* (the "2011 T-North Expansion Project"). O&M expenses associated with the 2011 T-North Expansion Project will be treated on a flow-through basis and the revenue requirement impact of any difference between the forecast and actual 2011 T-North Expansion Project O&M expenses incurred by Westcoast in 2012 and 2013 will be recorded in the 2011 T-North Expansion Project Deferral Account for amortization in 2013 and 2014, respectively.

The 2011, 2012 and 2013 O&M expenses also include forecast costs associated with those activities referred to in section 10.3(n) of this Agreement. If Westcoast decides or intends to defer, substitute other activities for, or not proceed with any of the activities referred to in section 10.3(n), then Westcoast will provide the TTTF with notice of that decision or intention as soon as practical and review the circumstances of such activities at the next meeting of the TTTF.

(b) Pipeline Integrity O&M Expenses

Pipeline integrity O&M expenses will be treated on a flow-through basis. For the purposes of this Agreement, pipeline integrity O&M expenses are those non-capitalized costs with respect to pipeline integrity programs which include, without limitation, programs related to stress corrosion cracking, corrosion and pipeline re-coating necessary to address existing, new or unanticipated pipeline integrity issues.

The pipeline integrity O&M expenses allocated to Zones 3 and 4 are forecast to be $15.577 million in 2011, $15.710 million in 2012 and $14.303 million in 2013, in each case as set out in Appendix B. The revenue requirement impact of any difference between the forecast and actual pipeline integrity O&M expenses incurred by Westcoast in 2011, 2012 and 2013 will be recorded in the Pipeline Integrity Deferral Account for amortization in 2012, 2013 and 2014, respectively.

(c) NEB Cost Recovery Expense

NEB Cost Recovery expense will be treated on a flow-though basis. The forecast of NEB Cost Recovery expense included in the revenue requirement is $0.746 million for 2011, $1.004 million for 2012 and $1.049 million for 2013. The revenue requirement impact of any difference between the forecast and actual NEB Cost Recovery expense incurred by Westcoast in each of 2011, 2012 and 2013 will be recorded in the NEB Cost Recovery Deferral Account for amortization in 2012, 2013 and 2014, respectively.

(d) Depreciation

For 2011, 2012 and 2013 Westcoast's depreciation expense in Zone 3 and 4 will be determined based on the depreciation rates set out in Appendix D. The 2012 and 2013 forecast of depreciation expense will be adjusted to reflect the adjustments to the rate base for 2012 and 2013, respectively, contemplated by this Agreement.

(e) Amortization

Westcoast's amortization expense in Zones 3 and 4 will be $4.082 million in 2011, $4.082 million in 2012 and $4.082 million in 2013. Amortization expense includes Southern Mainline Expansion Project Costs being amortized to the end of 2014 of $4.399 million per year (Board Orders TG-05-2004 and TG-04-2007) and forecast toll settlement expenses of $100,000 being amortized over three years commencing January, 2011, offset by the amortization of contributions in aid of construction. Westcoast's toll settlement expenses will consist of all reasonable third party costs and disbursements incurred by Westcoast in connection with the negotiation, settlement and obtaining Board approval of this Agreement. Westcoast's amortization expense in 2012 and 2013 will be adjusted to reflect any difference between the forecast and actual toll settlement expenses rounded to the nearest $10,000 incurred by Westcoast.

(f) Property Taxes

Property taxes will be treated on a flow-through basis. The forecast of property taxes included in the revenue requirement is $52.898 million for 2011, $54.743 million for 2012 and $55.823 million for 2013. The revenue requirement impact of any difference between the forecast and actual property tax expense incurred by Westcoast in each of 2011, 2012 and 2013 will be recorded in the Property Tax Deferral Account for amortization in 2012, 2013 and 2014, respectively. Westcoast will continue to work with governmental authorities in British Columbia in an effort to reduce property taxes.

(g) Motor Fuel Taxes

Motor fuel taxes will be treated on a flow-through basis and charged and recovered by Westcoast in accordance with the existing methodology. Westcoast will continue to work with governmental authorities in British Columbia in an effort to reduce motor fuel taxes.

(h) British Columbia Carbon Taxes

Carbon taxes will be treated on a flow-through basis and recovered by Westcoast in accordance with the same methodology used by Westcoast to charge and recover motor fuel tax.

(i) Income Tax Expense and Other Taxes

Westcoast's income tax expense in Zones 3 and 4 will be $15.655 million in 2011 and is forecast to be $18.261 million in 2012 and $15.178 million in 2013. The 2012 and 2013 forecast will be adjusted to reflect the adjustments to the rate base for 2012 and 2013, respectively, contemplated by this Agreement, the income tax impacts in 2012 and 2013 associated with the 2011 and 2012 deferral account balances that flow-through in 2012 and 2013, respectively, and any other adjustments to the forecast required as a result of this Agreement.

Any changes in Westcoast's tax expense for the 2011, 2012 or 2013 tax years resulting from changes in federal or provincial tax regimes including, without limitation:

(i) the introduction of new taxes, including taxes related to greenhouse gases and other air emissions, or the elimination of existing taxes;

(ii) changes in income tax rates, corporate capital tax rates or sales tax rates;

(iii) changes in legislation, regulations, rules, policies, procedures or case law affecting the application or interpretation of tax law, including changes in rules, policies or procedures of the Canada Revenue Agency; or

(iv) reassessments, regardless of whether they are initiated by the competent governmental authority or by Westcoast;

will be treated on a flow-through basis. The revenue requirement impact of any such changes for 2011, 2012 or 2013 will be recorded in the Income Tax Deferral Account for amortization in 2012, 2013 and 2014, respectively, provided that if any such change occurs after the term of this Agreement then the revenue requirement impact of such change, positive or negative, will flow-through to shippers in the toll year in which such change occurs.

Westcoast will not draw down its booked deferred income taxes in 2011, 2012 or 2013.

(j) Gas Substitution Costs

Gas substitution costs, which consist of Aitken Creek system gas management costs and swing gas costs, will be treated on a flow-through basis as follows:

(i) For each of 2011, 2012 and 2013 Aitken Creek system gas management costs are forecast to be $1.2 million. The revenue requirement impact of any difference between the forecast and actual Aitken Creek system gas management costs incurred by Westcoast in 2011, 2012 and 2013 will be recorded in the System Gas Management Deferral Account for amortization in 2012, 2013 and 2014, respectively.

(ii) For each of 2011, 2012 and 2013 swing gas costs are forecast to be zero. The revenue requirement impact of any swing gas costs incurred in 2011, 2012 or 2013 will be recorded in the Swing Gas Deferral Account for amortization in 2012, 2013 and 2014, respectively.

(k) Return on Rate Base

For 2011, 2012 and 2013 the deemed capital structure in Zones 3 and 4 will be as follows (subject to any adjustment to the funded and unfunded debt ratios required as a result of any expansion facility expenditures in Zone 3 or 4, as set out in Article 7):

	2011	2012	2013
Common Equity	40.00%	40.00%	40.00%
Funded Debt	53.01%	57.41%	58.41%
Unfunded Debt	6.99%	2.59%	1.59%
	100.00%	100.00%	100.00%

The rate of return on rate base, including the calculation of the funded debt rate and the unfunded debt rate, will be calculated in accordance with the existing Board approved methodology.

The rate of return on common equity for each of 2011, 2012 and 2013 will be 9.70%. Westcoast and the Stakeholders reserve the right to participate in any generic or pipeline specific cost of capital proceeding that is initiated by the Board or others that may affect or be relevant to the determination of Westcoast's cost of capital after the term of this Agreement. For greater certainty, Westcoast and the stakeholders agree that they will not pursue or support any change to the 9.70% rate of return on common equity or the 40% common equity component of the deemed capital structure that would take effect during the term of this Agreement.

The cost rate for the new $125 million long-term debt issue included in the unfunded debt component of the Zones 3 and 4 capital structure in 2011 and in the funded debt component of the Zones 3 and 4 capital structure in 2012 and 2013 will be deemed to be equal to what the cost rate would be on November 1, 2011 (the date on which this new long-term debt is assumed to be issued) for a new long-term debt issue assuming Westcoast's debt is rated BBB+ by Standard & Poor's. For each of 2011, 2012 and 2013 the forecast revenue requirement reflects a forecast deemed long-term rate of 4.35% for this new long-term debt issue. The revenue requirement impact associated with any change in the 2011 unfunded debt rate as a result of any difference between the forecast and actual timing, principal amount or deemed long-term rate of the assumed November 1, 2011 new long-term debt issue will be recorded in the Debt Rate Deferral Account for amortization in 2012. The 2012 and 2013 funded debt rate and the 2012 and 2013 revenue requirement will be updated to reflect the actual deemed long-term rate for the assumed November 1, 2011 new long-term debt issue.

There are no new long-term issues included in the unfunded or funded debt component of the Zones 3 and 4 capital structure in 2012 or 2013.

The cost rate for short-term debt included in the unfunded debt component of the Zones 3 and 4 capital structure in 2011, 2012 and 2013 will be equal to Westcoast's actual commercial paper rate each month, provided that if in any month Westcoast does not issue commercial paper then the short-term debt rate for that month will be equal to the average for that month of the yield on 30 day Canadian Bankers' Acceptances for each day of that month as reported by Bloomberg Financial Services, plus 20 basis points. The revenue requirement reflects a forecast short-term debt rate of 1.70% for 2011, 2.00% for 2012 and 2.40% for 2013. The revenue requirement impact associated with any change in the 2011, 2012 or 2013 unfunded debt rate as a result of any difference between the forecast and actual short-term debt rate in each of 2011, 2012 and 2013 will be recorded in the Debt Rate Deferral Account for amortization in 2012, 2013 and 2014, respectively.

(l) Waste Heat Project

The Zone 4 revenue requirement will be credited (the "Waste Heat Project Credit") with the shippers' share of any amounts received by Westcoast from Enpower Green Energy Generation Inc. ("Enpower") in 2011, 2012 and 2013 in respect of Enpower's waste heat electrical generation projects installed at Compressor Stations 6A and 7 on the T-South system, such share being one half, pre tax, of the "Energy Recovery Fee", all of the "Contract Operating Fee", site lease rent and the monitized value of any "Direct GHG Benefits", all as outlined in TTTF IRS 2006-01 dated March 16, 2006 and TTTF IRS 2006-01-1 dated

June 16, 2006. For 2011, 2012 and 2013 the amount of the Waste Heat Project Credit is forecast to be $489,000, $499,000 and $511,000, respectively. The revenue requirement impact of any difference between the forecast and actual Waste Heat Project Credit in 2011, 2012 and 2013 will be recorded in the Waste Heat Project Credit Deferral Account for amortization in 2012, 2013 and 2014, respectively.

2.2 Pipeline Abandonment Costs

Westcoast agrees that it will not during the term of this Agreement collect or accrue terminal negative salvage costs (such cost in general being the future costs associated with pipeline abandonments in excess of the salvage value of the abandoned pipeline) unless directed to do so by the Board. Notwithstanding the foregoing, Westcoast and the Stakeholders will not in any way be restricted in the positions they may take in the Board's ongoing Land Matters Consultation Initiative, including positions regarding the amount and means of collection of terminal negative salvage costs and other abandonment costs by Westcoast from tollpayers commencing after the term of this Agreement. Westcoast will from time to time provide the TTTF with an update on the positions that Westcoast intends to take in the Land Matters Consultation Initiative. All reasonable third party costs and disbursements incurred by Westcoast in connection with its participation in the Land Matters Consultation Initiative will be recorded in the Land Matters Consultation Initiative Deferral Account for amortization in the year following the year in which the costs and disbursements are incurred.

ARTICLE 3
RATE BASE

3.1 Rate Base and Maintenance Capital

The forecast average rate base is $1,094.664 million for 2011, $1,321.898 million for 2012 and $1,303.951 million for 2013. These amounts include forecast maintenance capital expenditures transferred to Gas Plant In-Service of $36.885 million ($35.472 million, excluding AFUDC) in 2011, $31.929 million ($30.920 million, excluding AFUDC) in 2012 and $32.319 million ($31.251 million, excluding AFUDC) in 2013 (including in the case of each year, forecast general plant additions, AFUDC and ODC and excluding forecast capital expenditures for pipeline integrity). The 2011, 2012 and 2013 revenue requirement will not be adjusted for any difference between the forecast and actual maintenance capital expenditures.

3.2 Pipeline Integrity Capital

Pipeline integrity capital costs will be treated on a flow-through basis. For purposes of this Agreement, pipeline integrity capital expenditures are those capital expenditures with respect to pipeline integrity programs which include, without limitation, programs related to stress corrosion cracking, corrosion and pipeline re-coating necessary to address existing, new or unanticipated pipeline integrity issues.

The forecast average rate base and revenue requirement includes forecast pipeline integrity capital expenditures transferred to Gas Plant In-Service, including AFUDC, of $15.213 million

($15.00 million, excluding AFUDC) in 2011, $15.204 million ($15.00 million, excluding AFUDC) in 2012 and $15.710 million ($15.50 million, excluding AFUDC) in 2013. The revenue requirement impact of any difference between the forecast and actual pipeline integrity capital expenditures incurred by Westcoast in 2011, 2012 and 2013 will be recorded in the Pipeline Integrity Deferral Account for amortization in 2012, 2013 and 2014, respectively.

3.3 <u>2011 T-North Expansion Project</u>

2011 T-North Expansion Project capital costs will be treated on a flow-through basis. The forecast average rate base and revenue requirement includes forecast 2011 T-North Expansion Project capital expenditures transferred to Gas Plant In-Service, including AFUDC, of $260 million ($250 million, excluding AFUDC) in 2012. The revenue requirement impact of any difference between the forecast and actual 2011 T-North Expansion Project capital expenditures incurred by Westcoast in 2011, 2012 and 2013, and the revenue requirement impact of any difference between the forecast and actual timing of such expenditures and in-service date of the 2011 T-North Expansion Project, will be recorded in the 2011 T-North Expansion Project Deferral Account for amortization in 2012, 2013 and 2014, respectively.

3.4 <u>Update of 2012 and 2013 Rate Base and Revenue Requirement</u>

The forecast average rate base and revenue requirement for 2012 and 2013 will be updated to reflect (i) actual pipeline integrity capital expenditures, 2011 T-North Expansion Project capital expenditures, any other expansion facility capital expenditures, any compressor upgrade capital expenditures and any shipper requested capital expenditures in 2011 and 2012, respectively, (ii) the 2011 and 2012 year-end deferral account balances, respectively, (iii) an updated forecast of 2011 T-North Expansion Project capital expenditures and a forecast of any other expansion facility capital expenditures, any compressor upgrade capital expenditures and any shipper requested capital expenditures in 2012 and 2013, respectively, and (iv) any other adjustments to the forecast required as a result of this Agreement.

3.5 <u>AFUDC Rate</u>

For 2011 the AFUDC rate will be 7.81%. The AFUDC rate for 2012 and 2013 will be the rate of return on rate base for 2012 and 2013, respectively.

3.6 <u>Material Asset Divestitures</u>

The revenue requirement impact associated with any Zone 3 or 4 asset divestitures by Westcoast in 2011, 2012 or 2013 that have the effect of decreasing net plant in service by an aggregate amount of $5 million or more in any such year will be treated on a flow-through basis and recorded in the Material Asset Divestiture Deferral Account for amortization in 2011, 2012 and 2013, respectively. Westcoast confirms that as of the date of this Agreement it has no plans for any material Zone 3 or 4 asset divestitures.

ARTICLE 4
DEFERRAL ACCOUNTS

4.1 Deferral Accounts

Westcoast will maintain for accounting and toll-making purposes the cost of service and revenue deferral accounts in 2011, 2012 and 2013 set out in sections 4.2 and 4.3. It is the intent of the parties that the year end balance of each deferral account will, together with interest thereon, flow-through to the account of shippers (and thus be reflected in the calculation of the revenue requirement and the final tolls) for 2012, 2013 and 2014, respectively, in accordance with the existing methodology, provided that the Stakeholders will not be precluded from reviewing and making submissions to the Board concerning the reasonableness of the year-end balance of any of the deferral accounts set out in sections 4.2 and 4.3. Interest on the deferral balances will be calculated monthly based on Westcoast's rate of return on rate base.

4.2 Cost of Service Deferral Accounts

The cost of service deferral accounts will be as follows:

(a) Pipeline Integrity: This deferral account will record the revenue requirement impact of any difference between forecast and actual pipeline integrity O&M expenses and capital expenditures, as set out in sections 2.1(b) and 3.2.

(b) NEB Cost Recovery: This deferral account will record the revenue requirement impact of any difference between forecast and actual NEB Cost Recovery expense, as set out in section 2.1(c).

(c) Property Taxes: This deferral account will record the revenue requirement impact of any difference between forecast and actual property tax expense, as set out in section 2.1(f).

(d) Income Tax Expense and Other Taxes: This deferral account will record the revenue requirement impact of any changes in Westcoast's tax expense resulting from changes in federal or provincial tax regimes, as set out in section 2.1(i).

(e) System Gas Management Costs: This deferral account will record the revenue requirement impact of any difference between forecast and actual Aitken Creek system gas management costs, as set out in section 2.1(j)(i).

(f) Swing Gas Costs: This deferral account will record the revenue requirement impact of any difference between forecast and actual swing gas costs, as set out in section 2.1(j)(ii).

(g) Debt Rate: This deferral account will record the revenue requirement impact associated with any difference between the forecast and actual long-term and short-term debt rates, as set out in section 2.1(k).

(h) Material Asset Divestitures: This deferral account will record the revenue requirement impact associated with any material asset divestitures, as set out in section 3.6.

(i) Customer Incentive Program: The 2011 revenue requirement includes the forecast recovery by Westcoast of $1,000,000 on account of Westcoast's performance in 2010 under the customer service incentive program introduced pursuant to Article 8 of Westcoast's 2008 to 2010 Transmission Toll Settlement. This deferral account will record any difference between the $1,000,000 forecast and the actual amount that Westcoast is entitled to recover in 2011 with respect to its performance in 2010 under the customer service incentive program.

(j) Material Changes in Costs: This deferral account will record any changes in costs resulting from:

(i) changes in legislation, regulations or ordinances or the issuance of orders or directives that result in changes to safety, health or environmental requirements (including those relating to greenhouse gases and other air emissions), practices or procedures for Westcoast, to the extent that the aggregate costs exceed $100,000 in any year;

(ii) changes in applicable accounting standards of the Canadian Institute of Chartered Accountants (the "CICA"), if approved by the Board for Westcoast's accounting and toll-making purposes; or

(iii) orders or directives issued by a regulatory authority having jurisdiction, including the Board, to the extent that the aggregate costs exceed $100,000 in any year.

(k) Land Matters Consultation Initiative: This deferral account will record the revenue requirement impact of all reasonable third party costs and disbursements incurred by Westcoast in connection with its participation in the Board's ongoing Land Matters Consultation Initiative, as set out in section 2.2.

(l) Shipper Requested Programs: This deferral account will record the revenue requirement impact (and any incremental revenue) associated with programs implemented or to be implemented by Westcoast that are voted on by the TTTF and for which the vote result is unanimous or unopposed.

(m) SRED Consulting: This deferral account will record any amount payable by Westcoast to the tax consultant retained by Westcoast to pursue Scientific Research and Experimental Development tax credits. Any tax credits themselves will be recorded in the Income Tax Expense and Other Taxes deferral account in section 4.2(d).

(n) T-North Expansion Project: This deferral account will record the revenue requirement impact of any difference between forecast and actual 2011 T-North Expansion Project expenditures, as set out in section 7.1.

(o) Expansion Facilities: This deferral account will record the revenue requirement impact associated with any expansion facility expenditures in Zone 3 or 4, as set out in section 7.2.

(p) Compressor Upgrade/Replacement: This deferral account will record the revenue requirement impact associated with any compressor upgrade/replacement expenditures in Zones 3 or 4, as set out in section 8.2.

(q) Enhanced T-South Service: This deferral account will record the revenue requirement impact of any difference between the forecast and actual amount payable by Westcoast to Terasen Gas Inc. ("TGI") under the transportation of gas by others (TBO) agreement between Westcoast and TGI and entered into by Westcoast in order to provide Enhanced T-South Service under Westcoast's Tariff Supplement for Enhanced T-South Service filed with the Board.

4.3 Revenue Deferral Accounts

The revenue deferral accounts will be as follows:

(a) Contract Demand: This deferral account will record the impact on fixed cost collection resulting from differences between the forecast and actual contract demand allocation units that are used to fix the term differentiated firm service tolls, separately for each of Zone 3 and Zone 4, as set out in section 5.4.

(b) Discretionary Revenue: This deferral account will record any difference between the forecast and actual revenue from interruptible service and short-term firm service credited in calculating the 2011, 2012 and 2013 demand tolls, separately for each of Zone 3 and Zone 4, as set out in sections 5.2 and 5.3.

(c) Waste Heat Project Credit: This deferral account will record any difference between the forecast and actual Waste Heat Project Credit credited in calculating the Zone 4 revenue requirement for 2011, 2012 and 2013, as set out in section 2.1(l).

ARTICLE 5
TOLLS

5.1 Toll Design

Westcoast's tolls in Zones 3 and 4 will be calculated in accordance with the toll design approved by the Board for Zones 3 and 4, including the changes approved by the Board in its RHW-1-2005 Reasons for Decision. Westcoast or any Stakeholder may make any toll design proposals for consideration by the TTTF or make toll design applications to the Board for changes in the toll design to become effective during the term of this Agreement.

Westcoast will not offer short-term firm service in Zone 3 or Zone 4 during the term of this Agreement unless such proposals are discussed and voted on by the TTTF and for which the vote result is unanimous or unopposed.

For each of 2011, 2012 and 2013, all revenue collected by Westcoast from interruptible and short-term firm service in Zone 3 will be for the account of shippers in Zone 3.

For each of 2011, 2012 and 2013, all revenue collected by Westcoast from interruptible and short-term firm service in Zone 4 will be for the account of shippers in Zone 4.

5.2 2011 Tolls

Westcoast's tolls in Zones 3 and 4 for 2011, as determined pursuant to this Agreement, are set out in Appendix E. Westcoast applied to the Board on November 23, 2010 for approval of the tolls set out in Appendix E as interim tolls for Zones 3 and 4 effective January 1, 2011. Westcoast will as soon as reasonably practicable after Westcoast's actual results are available for 2010 update the tolls set out in Appendix E to reflect the actual 2010 year-end cost of service and revenue deferral account balances and apply to the Board to have such updated tolls made final for 2011. Westcoast will consult with and provide the Stakeholders with the opportunity to review and comment on the updated 2011 tolls with the intention that Westcoast and the Stakeholders will agree on the update.

The tolls in Zone 3 for 2011 reflect a credit of $1.43 million for forecast revenue from interruptible service in Zone 3 in 2011. The tolls in Zone 4 for 2011 reflect a credit of $12.898 million for forecast revenue from interruptible service in 2011. Any difference between the forecast and actual revenue from interruptible and short-term firm service in 2011 in Zones 3 and 4 will be recorded in the Discretionary Revenue Deferral Account for amortization in 2012.

5.3 2012 and 2013 Tolls

Westcoast will by December 1, 2011 and December 1, 2012 apply to the Board for approval of interim tolls for Zones 3 and 4 for 2012 and 2013, respectively, based on a forecast of the tolls for 2012 and 2013, respectively, having regard for the adjustments, including changes in allocation units and the forecast revenue from interruptible service, contemplated by this Agreement. Each application will include sufficient supporting schedules and explanatory information necessary to establish that the tolls have been determined in accordance with this Agreement. Westcoast will consult with and provide the Stakeholders with the opportunity to review and comment on the 2012 and 2013 toll filings with the intention that Westcoast and the Stakeholders will agree on the filing. The final form of the 2012 and 2013 toll filings will be at Westcoast's discretion, but any Stakeholder may make submissions to the Board regarding appropriate amendments. In preparing each application Westcoast will also consult with the Stakeholders to determine whether the forecast of 2012 or 2013, as the case may be, pipeline integrity O&M and capital expenditures, NEB cost recovery expense, property taxes and short-term and long-term debt rates, expansion facility or compressor upgrade/replacement capital expenditures and O&M and other expenses, and any other flow-through items should be updated to reflect current information at that time.

Unless Westcoast and the Stakeholders agree otherwise, the tolls for each of 2012 and 2013 will include a credit of $1.43 million in Zone 3 and $12.898 million in Zone 4 for forecast revenue from interruptible service in each such year. Westcoast will review the 2012 and 2013 forecast revenue from interruptible service with the Stakeholders prior to filing each of the 2012 and 2013 toll filings to determine whether the forecast should be updated to reflect current information at that time. Any difference between the forecast and actual revenue from interruptible and short-term firm service in 2012 and 2013 in Zones 3 and 4 will be recorded in the Discretionary Revenue Deferral Account for amortization in 2013 and 2014, respectively.

Westcoast will as soon as reasonably practicable after Westcoast's 2011 and 2012 actual results are available apply to the Board for final 2012 and 2013 tolls, respectively, and will make any necessary amendments to the 2012 and 2013 toll applications to reflect the actual 2011 and 2012 results, respectively. Westcoast will consult with and provide the Stakeholders with the opportunity to review and comment on the amendments with the intention that Westcoast and the Stakeholders will agree on the amendments.

5.4 Allocation Units

The Contract Demand allocation units used to calculate the tolls for 2011 set out in Appendix E are the forecast of allocation units in Zones 3 and 4 for 2011 set out in Appendix F. Any variance in Contract Demand revenue in 2011 arising from any difference between the forecast and actual Contract Demand allocation units in Zones 3 and 4 that are used to fix the term differentiated firm service tolls for 2011 will be recorded in the Contract Demand Deferral Account for amortization in 2012.

The Contract Demand allocation units used to calculate the tolls for 2012 and 2013 will be forecast by Westcoast at the time it applies to the Board for approval of the 2012 and 2013 tolls, respectively. Westcoast will review the 2012 and 2013 forecast of Contract Demand allocation units with the Stakeholders with the intention that Westcoast and the Stakeholders will agree on the forecast. Any variance in Contract Demand revenue in 2012 or 2013 arising from any difference between the forecast and actual Contract Demand allocation units in Zones 3 and 4 that are used to fix the term differentiated firm service tolls for 2012 and 2013 will be recorded in the Contract Demand Deferral Account for amortization in 2013 and 2014, respectively.

ARTICLE 6
NEW SERVICES AND PRODUCTS

6.1 New Services and Products

New services and products, if any, proposed by Westcoast or any of the Stakeholders in 2011, 2012 or 2013 and the treatment of the associated costs and revenues will be considered by the TTTF prior to implementation. Westcoast will implement those new services and products that are voted on by the TTTF and for which the vote result is unanimous or unopposed. Westcoast or any of the Stakeholders may apply to the Board for approval to implement those new services and products for which the TTTF vote result is not unanimous or unopposed, and Westcoast or any of the Stakeholders may oppose such applications to the Board.

ARTICLE 7
EXPANSION FACILITIES

7.1 2011 T-North Expansion Project

Capital expenditures and O&M and other expenses incurred by Westcoast in 2011, 2012 and 2013 on account of the 2011 T-North Expansion Project will be treated on a flow-through basis and the revenue requirement impact associated with any difference between the forecast and actual expenditures and expenses incurred by Westcoast in 2011, 2012 and 2013 on account of the 2011 T-North Expansion Project, and the revenue requirement impact of any difference between the forecast and actual timing of such expenditures and expenses and in-service date of the 2011 T-North Expansion Project, will be recorded in the 2011 T-North Expansion Project Deferral Account for amortization in 2012, 2013 and 2014, respectively.

7.2 Other Expansion Facilities

Other than the 2011 T-North Expansion Project, the forecast revenue requirement for 2011, 2012 and 2013 does not include any capital expenditures or O&M or other expenses by Westcoast on account of any facilities (“Expansion Facilities”) designed to increase the physical and contractable capacity of the Pipeline System in Zone 3 or 4.

Any capital expenditures or O&M or other expenses incurred by Westcoast in 2011, 2012 or 2013 on account of any Expansion Facilities will be treated on a flow-through basis and the revenue requirement impact associated with any difference between the forecast and actual expenditures and other expenses incurred by Westcoast in 2011, 2012 and 2013 on account of any such Expansion Facilities, and the revenue requirement impact of any difference between the forecast and actual timing of such expenditures and in-service date of any such Expansion Facilities, will be recorded in the Expansion Facilities Deferral Account for amortization in 2012, 2013 and 2014, respectively.

7.3 Rolled-in Tolling

All Expansion Facilities that are placed into service during the term of this Agreement, including the 2011 T-North Expansion Project, will be tolled on a rolled-in basis.

ARTICLE 8
COMPRESSOR UPGRADE/REPLACEMENT PROGRAM

8.1 Annual Status Report

Westcoast will by the end of the third quarter of each year of the term of this Agreement report to the TTTF on the status of Westcoast’s compressor upgrade/replacement program for Zones 3 and 4. This report will include a presentation to the TTTF outlining the status of work on the upgrade program.

8.2 Compressor Upgrades/Replacements

The forecast revenue requirement for 2011, 2012 and 2013 does not include any capital expenditures or O&M or other expenses by Westcoast on account of any compressor upgrades/replacements in Zone 3 or 4, other than the replacement of one of the LM 1500 units (Unit 1) at Compressor Station N4 on the Fort Nelson Mainline that is part of the 2011 T-North Expansion Project.

Any capital expenditures or O&M or other expenses incurred by Westcoast in 2011, 2012 or 2013 on account of any compressor upgrades/replacements in Zone 3 or 4 will be treated on a flow-through basis and the revenue requirement impact associated with any difference between the forecast and actual expenditures incurred by Westcoast in 2011, 2012 and 2013 on account of any such compressor updates/replacements, and any revenue requirement impact of any difference between the forecast and actual timing of such expenditures and in-service date of any such compressor replacement/upgrade, will be recorded in the Compressor Upgrade/Replacement Deferral Account for amortization in 2012, 2013 and 2014, respectively.

8.3 Emission Reduction Requirements Plan

If during the term of this Agreement the federal or provincial government imposes or announces an intention to impose mandatory emission reduction requirements or other compliance obligations associated with air emissions (including an emission cap and tradeable permit system) on Westcoast, then Westcoast will, within six months of such imposition or announcement, provide to the TTTF a detailed emission reduction or compliance obligation plan (which plan will include consideration of a compressor upgrade/replacement program) covering a minimum period of five years describing how Westcoast intends to comply with such mandatory emission reduction requirements or compliance obligations. If Westcoast decides to proceed to implement such plan commencing during the term of this Agreement, then Westcoast will make the necessary applications to the Board (including, if necessary, an application for a deferral account to record any costs incurred by Westcoast during the term of this Agreement) and the Stakeholders will be free to take whatever positions they wish to take with respect to Westcoast's application.

ARTICLE 9
OTHER INITIATIVES

9.1 Capacity Benchmarking

Westcoast will report to the TTTF in a timely fashion any positive or negative changes in the contractible capacity of any pipeline segment in Zones 3 and 4 of more than 20 MMcf/d on a cumulative basis compared to the contractible capacity of that segment as of the date of this Agreement. Westcoast will also post any such cumulative change on its bulletin board as a critical notice together with a brief explanation for the change.

Westcoast will also make a presentation to the TTTF by November 30 of each year of the term of this Agreement of the relevant parameters that go into Westcoast's decision making process for setting contractible and daily capacities in Zones 3 and 4. Westcoast confirms that it will at the time of such presentation act in good faith to implement reasonable suggestions from the TTTF as to ways to enhance the decision making process for setting contractible and daily available capacities in Zones 3 and 4.

ARTICLE 10
GENERAL

10.1 Board Approval

This Agreement is subject to Board approval and Westcoast and the Stakeholders agree that this Agreement will terminate if it is not approved in its entirety by the Board. Westcoast and the Stakeholders also acknowledge that all matters respecting Westcoast's tolls, including the tolls under this Agreement and the ultimate adjudication of any disputes which arise out of this Agreement which cannot be resolved by Westcoast and the Stakeholders in accordance with the terms of this Agreement, will be determined by the Board.

10.2 Application to the Board

Westcoast will, as soon as practicable, prepare an application to the Board to give effect to the terms and conditions of this Agreement. Westcoast will consult with and provide the Stakeholders with the opportunity to review and comment on the application with the intention that Westcoast and the Stakeholders will agree on the application prior to filing with the Board. Each of the Stakeholders agrees to actively support or not oppose the application and the approval of this Agreement and the tolls determined under this Agreement by the Board.

10.3 Surveillance Reports

Westcoast will file quarterly and year-end surveillance reports with the Board with respect to Zones 3 and 4 in accordance with the Board's requirements for Group 1 pipeline companies, subject to such modifications as may be agreed to by the TTTF, supplemented with the following information:

(a) revenue requirement/cost of service summary, together with an explanation of material variances (quarterly and year-end);

(b) revenue requirement/cost of service summary by Zones 3 and 4 (year-end);

(c) income tax expense (year-end);

(d) status of tax assessments and any reassessments (year-end);

(e) UCC/capital cost allowance (year-end);

(f) long-term debt (year-end);

(g) short-term debt (year-end);

(h) average rate base summary (year-end);

(i) average rate base summary by Zones 3 and 4 (year-end);

(j) Section 58 Applications (quarterly and year-end):

  (i) reference;

  (ii) description;

  (iii) amount;

  (iv) Board approval;

  (v) allocations to G&P and Transmission; and

  (vi) forecast date in service;

(k) capital expenditures shown on Rate Base page 2.2 of the information package provided by Westcoast to the TTTF on July 15, 2010 and the equivalent page for 2012 and 2013 provided by Westcoast to the Stakeholders (year-end):

  (i) forecast versus actual costs;

  (ii) material changes in scope and cost of forecast projects;

  (iii) summary of projects deferred and new projects added;

  (iv) explanation of any cost overruns of greater than 10% from original forecast of projects transferred to gas plant in service; and

  (v) designation of each project as either a maintenance, integrity, compressor upgrade or expansion project;

(l) revenue deferral account balances;

(m) forecast versus actual activities and costs for pipeline integrity activities (O&M and capital) (semi-annual);

(n) forecast versus actual activities and costs for the following O&M activities (semi-annual): (i) aerial crossing maintenance; (ii) vegetation management; and (iii) compressor overhauls;

(o) actual and approved return on rate base (year-end);

(p) actual and approved return on common equity (year-end);

(q) actual and deemed composite depreciation rate used in this Agreement (year-end);

(r) the following metrics (year-end) in addition to the Board's required annual surveillance report metrics:

(i) compressor fuel use per throughput-km; and

(ii) integrity (O&M and capital) costs per km of pipe;

(s) number of any full time equivalent positions contracted out to third parties (year-end); and

(t) forecast versus actual costs associated with repairs to buildings and associated facilities, environmental remediation and insurance.

10.4 <u>TTTF Reports</u>

Westcoast will also provide monthly reports to the TTTF covering each of the following with respect to Zones 3 and 4:

(a) discretionary revenue, interruptible volumes and daily volumes;

(b) changes between forecast and actual allocation units and deferral account balances;

(c) any information presented to the Board regarding pipeline integrity activities (one month following each presentation); and

(d) existing Westcoast gas quality and unplanned outages performance measures and such other non-financial performance measures to be discussed and voted on by the TTTF and for which the vote result is unanimous or unopposed.

10.5 <u>Audit</u>

If the TTTF votes to conduct an audit and the vote result is unanimous or unopposed (with Westcoast abstaining), then an independent compliance audit(s) by a qualified firm of nationally recognized chartered accountants will be conducted at any time up to the end of 2014 with respect to the determination of final tolls under this Agreement for 2011, 2012 and 2013. The external costs of the audit(s) will flow-through to the account of shippers. Westcoast will provide the auditors selected to conduct the audit(s) with reasonable access to the source data necessary for the conduct of the audit(s), provided that the auditors will be required to execute and deliver to Westcoast a confidentiality agreement in a form satisfactory to Westcoast pursuant to which the auditors agree to maintain confidential any of the source data identified by Westcoast as confidential.

10.6 <u>Dispute Resolution</u>

In the event of any dispute under this Agreement, including a dispute respecting the determination of tolls and a dispute respecting the application of this Agreement, Westcoast and the Stakeholders will in good faith attempt to resolve the dispute. If a satisfactory resolution cannot be achieved within 30 days, Westcoast or any of the Stakeholders or any shipper may file an application with the Board requesting the Board to adjudicate the matter in dispute. Any such application must also contain a request that the Board deal with the matter in dispute on an expedited basis and may contain a request that tolls be made interim pending the Board's decision with respect to the matter.

10.7 Right to Initiate Review

The Stakeholders may initiate a review of this Agreement and the determination of Westcoast's tolls in Zones 3 and 4 under this Agreement if as a result of a corporate reorganization, restructuring, financing, acquisition or sale involving Westcoast there is the potential for a material impact on Westcoast's costs or levels or quality of service in Zones 3 and 4 during the term of this Agreement.

10.8 Further Assurances

Westcoast and each of the Stakeholders will do all such further acts and things as may be reasonably necessary to give full effect to the intent and meaning of this Agreement.

10.9 Compliance with Board Orders

Nothing in this Settlement is intended to preclude Westcoast from complying with any directives or orders of the Board applicable to Westcoast, including any matters currently before the Board.

The undersigned hereby agree that the foregoing establishes the basis on which Westcoast's tolls for transmission service in Zones 3 and 4 will be determined for the 2011, 2012 and 2013 calendar years.

Dated December 6, 2010

Westcoast Energy Inc.

per: ______________________ **R.L. (Rob) Whitwham**
Vice President, Pipeline

Canadian Association of Petroleum Producers

per: ______________________

cannot be achieved within 30 days, Westcoast or any of the Stakeholders or any shipper may file an application with the Board requesting the Board to adjudicate the matter in dispute. Any such application must also contain a request that the Board deal with the matter in dispute on an expedited basis and may contain a request that tolls be made interim pending the Board's decision with respect to the matter.

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Dated December 6, 2010

Westcoast Energy Inc.

per: ____________________ ____________________

Canadian Association of Petroleum Producers

per: Barry J Jardine

Terasen Gas Inc.

per: ______________________________
Roger Dall'Antonia
Terasen Gas Inc.
Vice President, Finance & CFO, Treasurer

Members of the Export Users Group:

Avista Corporation

per: ______________________________

Cascade Natural Gas Corporation

per: ______________________________

Northwest Natural Gas Company

per: ______________________________

Puget Sound Energy, Inc.

per: ______________________________

Powerex Corp.

per: ______________________________

Terasen Gas Inc.

per: ______________________________

Members of the Export Users Group:

Avista Corporation

per: ______________________________

Cascade Natural Gas Corporation

per: ______________________________

Northwest Natural Gas Company

per: ______________________________

Puget Sound Energy, Inc.

per: ______________________________

Powerex Corp.

per: ______________________________

Terasen Gas Inc.

per: ______________________________

Members of the Export Users Group:

Avista Corporation

per: ________________________

Cascade Natural Gas Corporation

per: ________________________
Dennis L. Haider

Northwest Natural Gas Company

per: ________________________

Puget Sound Energy, Inc.

per: ________________________

Powerex Corp.

per: ______________________________

Terasen Gas Inc.

per: ______________________________

Members of the Export Users Group:

Avista Corporation

per: ________________________

Cascade Natural Gas Corporation

per: ________________________

Northwest Natural Gas Company

per: ________________________

Puget Sound Energy, Inc.

per: ________________________

Powerex Corp.

per: ______________________________

Terasen Gas Inc.

per: ______________________________

Members of the Export Users Group:

Avista Corporation

per: ________________________

Cascade Natural Gas Corporation

per: ________________________

Northwest Natural Gas Company

per: ________________________

Puget Sound Energy, Inc.

per: ________________________

Powerex Corp.

per: ______________________________

Terasen Gas Inc.

per: ______________________________

Members of the Export Users Group:

Avista Corporation

per: ______________________________

Cascade Natural Gas Corporation

per: ______________________________

Northwest Natural Gas Company

per: ______________________________

Puget Sound Energy, Inc.

per: ______________________________

Powerex Corp.

per: ______________________________

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Appendix A

2011, 2012 and 2013 Revenue Requirement

COST OF SERVICE
SUMMARY
($000)

LINE NO.	PARTICULARS	2011 Test Year	Adjustments	2012 Test Year	Adjustments	2013 Test Year
		(A)	(B)	(C)	(D)	(E)
1	OPERATING AND MAINTENANCE EXPENSES	77,959	3,851	81,810	93	81,903
2	N.E.B COST RECOVERY	746	257	1,004	45	1,049
3	DEPRECIATION	60,373	10,168	70,541	2,718	73,260
4	AMORTIZATION	4,082	-	4,082	-	4,082
5	TAXES OTHER THAN INCOME TAXES	71,494	7,993	79,487	2,350	81,836
6	GAS SUBSTITUTION COSTS	1,200	-	1,200	-	1,200
7	MISCELLANEOUS OPERATING REVENUE	(828)	(17)	(845)	(17)	(863)
8	TRANSPORTATION BY OTHERS	5,195	-	5,195	-	5,195
9	INCOME TAX EXPENSE	15,655	2,606	18,261	(3,083)	15,178
10	RETURN ON RATE BASE	85,607	17,035	102,642	(510)	102,132
11	COST OF SERVICE	321,484	41,893	363,377	1,596	364,972
12	DEFERRALS	389	(389)	-	-	-
13	REVENUE REQUIREMENT	321,872	41,504	363,377	1,596	299,404
14	FIXED COSTS	303,276	35,357	338,633	325	338,959
15	VARIABLE COSTS [1]	18,596	6,147	24,743	1,270	26,013
16	REVENUE REQUIREMENT	321,872	41,504	363,377	1,596	364,972

NOTES:

1) Variable costs consist of Motor Fuel Tax and Carbon Tax on compressor fuel which is included in line 5.

Appendix B

2011, 2012 and 2013 Operating and Maintenance Expenses

OPERATING AND MAINTENANCE EXPENSES
SUMMARY
($000)

Line No.	Particulars	2011 Test Year (A)	Adjustment (B)	2012 Test Year (C)	Adjustment (D)	2013 Test Year (E)
1	Transmission North - Operations	11,468	1,831	13,299	43	13,342
2	Transmission North - Integrity	2,220	622	2,842	(36)	2,806
3	Transmission Central - Operations	9,281	326	9,607	(496)	9,111
4	Transmission Central - Integrity	3,572	2,173	5,745	807	6,552
5	Transmission South - Operations	9,221	(189)	9,032	871	9,903
6	Transmission South - Integrity	8,565	(2,662)	5,903	(2,178)	3,725
7	Area Management and Other Services	1,373	16	1,389	64	1,453
8	Shared Services - Operations	4,823	31	4,854	223	5,077
9	Shared Services - Integrity	1,220	-	1,220	-	1,220
10	Vancouver & Calgary Operations	19,243	551	19,793	462	20,255
11	General and Administrative	6,973	318	7,291	333	7,624
12	Transmission North - 2011 Expansion	-	835	835	-	835
13	Total	77,959	3,851	81,810	93	81,903
14	Integrity	15,577	133	15,710	(1,407)	14,303
15	Total excluding Integrity	62,382	3,718	66,100	1,500	67,600

Appendix C

2011, 2012 and 2013 Rate Base

AVERAGE RATE BASE
($000)

Line No.	Particulars	2011 Test Year	Adjustments	2012 Test Year	Adjustments	2013 Test Year
		(A)	(B)	(C)	(D)	(E)
1	GAS PLANT IN SERVICE	2,046,908	290,411	2,337,319	54,023	2,391,342
2	ACCUMULATED DEPRECIATION	(965,961)	(58,850)	(1,024,810)	(68,856)	(1,093,666)
3	NET PLANT IN SERVICE	1,080,947	231,562	1,312,508	(14,833)	1,297,676
4	CONTRIBUTIONS IN AID OF CONSTRUCTION	(5,357)	366	(4,991)	366	(4,625)
5	COST RECOVERY	15,395	(4,399)	10,996	(4,399)	6,598
6	PLANT INVESTMENT	1,090,984	227,530	1,318,514	(18,865)	1,299,649
7	MATERIALS AND SUPPLIES	20,121	(765)	19,356	(765)	18,590
8	LINE PACK GAS	4,089	-	4,089	-	4,089
9	PREPAID EXPENSES	(11,231)	837	(10,393)	1,654	(8,740)
10	DEFERRALS	194	(194)	-	-	-
11	DEFERRED INCOME TAXES	(10,926)	-	(10,926)	-	(10,926)
12	AVERAGE RATE BASE EXCLUSIVE OF CASH WORKING CAPITAL	1,093,232	227,407	1,320,639	(17,976)	1,302,663
13	CASH WORKING CAPITAL	1,432	(173)	1,259	29	1,289
14	AVERAGE RATE BASE	1,094,664	227,234	1,321,898	(17,947)	1,303,951

Appendix D

2011, 2012 and 2013 Transmission Depreciation Rates

TRANSMISSION AND GENERAL PLANT
DEPRECIATION AMOUNTS AND RATES
($000)

Line No.		Rate Base Section	Net Plant (C)	Reserve Life Index YRS (D)	Depreciation Amount (E)	Depreciation Rate - % (F)	Currently Approved Rate - %
1	RB 1	M/L, Station 2 to Huntingdon					
2		a) Obsolete Equipment '02 Pool	17,612		3,522	4.43%	4.43%
3		b) Obsolete Equipment '08 Pool	6,620		662	4.45%	
4		c) Balance	802,893	24.4	32,880	2.73%	2.42%
5			827,124		37,065	2.85%	2.56%
6	RB 2 & 2A	FN Mainline & Aitken Transmission					
7		a) Obsolete Equipment	0	10.0	0	0.00%	0.00%
8		b) Balance	185,761	18.4	10,123	3.38%	3.11%
9			185,761		10,123	3.38%	3.11%
10	RB 7	M/L, Station 1 to 2	36,977	24.2	1,530	2.41%	1.92%
11	RB 10A	16" Pipeline System	5,974	40.0	149	1.00%	1.65%
12	RB 10A	a) Obsolete Equipment '08 Pool	671		67	3.93%	
13	RB 10B & 12	26" Pipeline System	6,927	24.2	287	1.99%	1.57%
14	RB 13C	Grizzly Transmission System	8,766	37.0	237	1.46%	1.31%
15	RB 14B	Sikanni Pipeline & Meter Station	1,589	5.8	273	4.14%	2.03%
16	RB 15	Alces Pipeline & Meter Station	36	40.0	1	0.13%	0.18%
17	Subtotal		1,073,824		49,731	2.90%	2.60%
18	Miscellaneous	(a) Franchises and Consents	0		4	2.90%	2.60%
19		(b) Intangible	1		0	0.00%	0.00%
20		(c) Other Structures	1,051		58	2.90%	2.60%
21	Subtotal		1,052		62	2.89%	2.60%
22	General Plant	(a) Structures	1,808		102	2.90%	2.60%
23		(b) Leaseholds	1,800		306	10.00%	10.00%
24		(c) Houses	0		0	2.50%	2.50%
25		(d) Computer Equipment	3,003		624	20.00%	20.00%
26		(e) Office Furniture	703		122	5.00%	5.00%
27		(f) Transportation under 5 tonnes	1,227		939	15.40%	15.40%
28		(g) Transportation over 5 tonnes	153		98	7.00%	7.00%
29		(h) Heavy Work Equipment	525		244	4.70%	4.70%
30		(i) Tools and Work Equipment	183		230	5.00%	5.00%
31		(j) Communications Equipment	23		2	10.00%	10.00%
32		(k) Other Equipment	165		37	5.00%	5.00%
33	Subtotal		9,591		2,705	8.95%	14.05%
34	Total of Lines 17, 21 and 33		1,084,467		52,498	3.000%	3.075%

Appendix E

Transmission Tolls

$\$/10^3m^3$/month	2010	2011 Interim	2012 Forecast	2013 Forecast
Firm Transportation Service - North				
Shorthaul	8.05	7.74	10.79	10.82
Longhaul	115.87	111.44	155.39	155.82
Firm Transportation Service - South				
Pacific Northern Gas Delivery Point	105.24	116.43	115.22	115.23
Inland Delivery Area	252.73	303.92	300.78	300.81
Huntingdon Delivery Area	464.50	513.90	508.59	508.65
Terasen Kingsvale to Huntingdon	211.77	209.98	207.81	207.84

¢/Mcf/day	2010	2011 Interim	2012 Forecast	2013 Forecast
Firm Transportation Service - North				
Shorthaul	0.75	0.72	1.00	1.01
Longhaul	10.79	10.38	14.43	14.51
Firm Transportation Service – South				
Pacific Northern Gas Delivery Point	9.80	10.84	10.70	10.73
Inland Delivery Area	23.54	28.30	27.94	28.02
Huntingdon Delivery Area	43.26	47.86	47.24	47.37
Terasen Kingsvale to Huntingdon	19.72	19.56	19.30	19.36

Transmission Tolls with Term Differentiated Rates
(10^3m^3/month)

Firm Transportation Service - North								
Segment	2010 Annualized	2010 Annualized TDR	2011 Interim	2011 Interim TDR	2012 Forecast	2012 Forecast TDR	2013 Forecast	2013 Forecast TDR
Shorthaul								
1 Year		8.53		8.21		11.46		11.49
2 Year	8.05	8.29	7.74	7.97	10.79	11.13	10.82	11.16
3 Year		8.04		7.73		10.80		10.82
4 Year		7.95		7.65		10.68		10.71
5 Year +		7.87		7.57		10.57		10.60
Longhaul								
1 Year		122.90		118.17		165.07		165.52
2 Year	115.87	119.32	111.44	114.73	155.39	160.26	155.82	160.70
3 Year		115.74		111.29		155.45		155.88
4 Year		114.54		110.14		153.85		154.27
5 Year +		113.35		108.99		152.25		152.67

Firm Transportation Service - South								
Segment	2010 Annualized	2010 Annualized TDR	2011 Interim	2011 Interim TDR	2012 Forecast	2012 Forecast TDR	2013 Forecast	2013 Forecast TDR
Pacific Northern Gas Delivery Point								
1 Year		108.52		124.45		123.16		123.18
2 Year	105.24	105.36	116.43	120.82	115.22	119.57	115.23	119.59
3 Year		102.20		117.20		115.99		116.00
4 Year		101.15		115.99		114.79		114.80
5 Year +		100.09		114.78		113.60		113.61
Inland Delivery Area								
1 Year		260.62		324.86		321.50		321.54
2 Year	252.73	253.03	303.92	315.40	300.78	312.14	300.81	312.17
3 Year		245.44		305.94		302.77		302.81
4 Year		242.91		302.78		299.65		299.69
5 Year +		240.38		299.63		296.53		296.57
Huntingdon Delivery Area								
1 Year		479.00		549.32		543.64		543.70
2 Year	464.50	465.05	513.90	533.32	508.59	527.80	508.65	527.86
3 Year		451.10		517.32		511.97		512.03
4 Year		446.45		511.98		506.69		506.75
5 Year +		441.80		506.65		501.41		501.47
Terasen Kingsvale to Huntingdon								
1 Year		218.38		224.46		222.14		222.16
2 Year	211.77	212.02	209.98	217.92	207.81	215.67	207.84	215.69
3 Year		205.66		211.38		209.20		209.22
4 Year		203.54		209.20		207.04		207.06
5 Year +		201.42		207.02		204.88		204.91

Transmission Tolls with Term Differentiated Rates
(¢/mcf/day)

Firm Transportation Service - North								
Segment	2010 Annualized	2010 Annualized TDR	2011 Interim	2011 Interim TDR	2012 Forecast	2012 Forecast TDR	2013 Forecast	2013 Forecast TDR
Shorthaul								
1 Year		0.79		0.76		1.06		1.07
2 Year	0.75	0.77	0.72	0.74	1.00	1.03	1.01	1.04
3 Year		0.75		0.72		1.00		1.01
4 Year		0.74		0.71		0.99		1.00
5 Year +		0.73		0.70		0.98		0.99
Longhaul								
1 Year		11.45		11.01		15.33		15.42
2 Year	10.79	11.11	10.38	10.69	14.43	14.88	14.51	14.97
3 Year		10.78		10.36		14.44		14.52
4 Year		10.67		10.26		14.29		14.37
5 Year +		10.56		10.15		14.14		14.22

Firm Transportation Service - South								
Segment	2010 Annualized	2010 Annualized TDR	2011 Interim	2011 Interim TDR	2012 Forecast	2012 Forecast TDR	2013 Forecast	2013 Forecast TDR
Pacific Northern Gas Delivery Point								
1 Year		10.11		11.59		11.44		11.47
2 Year	9.80	9.81	10.84	11.25	10.70	11.11	10.73	11.14
3 Year		9.52		10.92		10.77		10.80
4 Year		9.42		10.80		10.66		10.69
5 Year +		9.32		10.69		10.55		10.58
Inland Delivery Area								
1 Year		24.27		30.26		29.86		29.95
2 Year	23.54	23.57	28.30	29.37	27.94	28.99	28.02	29.07
3 Year		22.86		28.49		28.12		28.20
4 Year		22.62		28.20		27.83		27.91
5 Year +		22.39		27.91		27.54		27.62
Huntingdon Delivery Area								
1 Year		44.61		51.16		50.49		50.64
2 Year	43.26	43.31	47.86	49.67	47.24	49.02	47.37	49.16
3 Year		42.01		48.18		47.55		47.69
4 Year		41.58		47.68		47.06		47.19
5 Year +		41.15		47.19		46.57		46.70
Terasen Kingsvale to Huntingdon								
1 Year		20.34		20.90		20.63		20.69
2 Year	19.72	19.75	19.56	20.30	19.30	20.03	19.36	20.09
3 Year		19.15		19.69		19.43		19.49
4 Year		18.96		19.48		19.23		19.28
5 Year +		18.76		19.28		19.03		19.08

Appendix F

Transmission Allocation Units

$10^3 m^3$/day	2010 Annualized	2011 Forecast	2012 Forecast	2013 Forecast
Firm Transportation Service - North				
Shorthaul	16,509.8	15,518.7	15,518.7	15,518.7
Longhaul	48,179.1	53,238.2	58,031.3	58,031.3
Firm Transportation Service - South				
Pacific Northern Gas Delivery Point	788.3	663.0	663.0	663.0
Inland Delivery Area	4,797.3	4,612.1	4,612.1	4,612.1
Huntingdon Delivery Area	31,012.4	30,821.3	30,821.3	30,821.3
Terasen Kingsvale to Huntingdon	2,974.4	2,974.4	2,974.4	2,974.4

MMcf/day	2010 Annualized	2011 Forecast	2012 Forecast	2013 Forecast
Firm Transportation Service - North				
Shorthaul	583	548	548	548
Longhaul	1,701	1,879	2,049	2,049
Firm Transportation Service - South				
Pacific Northern Gas Delivery Point	28	23	23	23
Inland Delivery Area	169	163	163	163
Huntingdon Delivery Area	1,095	1,088	1,088	1,088
Terasen Kingsvale to Huntingdon	105	105	105	105