STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

PART 1 DATE OF STATEMENT

This statement of reserves data and other information (the "**Statement**") is dated April 8, 2009.

The Effective Date of this Statement is December 31, 2008.

The reserve data on the Corporation's natural gas properties in Alberta set forth below is derived from the Evaluation of the P&NG Reserves Report (the "Sproule Report") prepared by Sproule Associates Limited ("Sproule") dated April 8, 2009.

The future net revenue numbers presented throughout this Statement, whether calculated without discount or using a discount rate, are estimated values and do not represent fair market value.

PART 2 DISCLOSURE OF RESERVES DATA

The following reserves data and associated tables summarize the reserves of crude oil, natural gas and associated products and the estimated present worth of future net cash flows associated with natural gas reserves as evaluated by Sproule was prepared in accordance with the COGE Handbook and National Instrument 51-101 Standards of Disclosure for Oil and Gas Activities (NI-51-101). Sproule Associates Limited is an independently qualified reserves evaluator and auditor of Calgary, Alberta. The reserves are based on forecast price assumptions.

The tables summarize the data may contain rounding errors**.** The values in the Sproule Report do not include the value of undeveloped land holdings or the tangible value of the Corporation's interest in any associated plant and wellsite facilities. **It should not be assumed that the present values of estimated future net cash flows shown below are representative of the fair market value of the reserves. There is no assurance that such price and cost assumptions will be attained and variances could be material. Actual crude oil, natural gas and NGLs reserves may be greater than or less than the estimates provided herein.**

Boes may be misleading, particularly if used in isolation. A boe conversion ration of 6 Mcf to 1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. The estimates of reserves and future net revenue for individual properties may not reflect the same confidence level as estimates of reserves and future net revenue for all properties, due to the effects of aggregation.

All of the reserves held by the Corporation as at December 31, 2008 are located in Canada and, specifically, in the province of Alberta. As of December 31, 2008, the Corporation had no oil or gas reserves on any of its properties in Maritimes Canada. The values in the Sproule Report only include the value of the Corporation's reserves data in Alberta, Western Canada.

Reserves Data (Forecast Prices and Costs)

The following tables detail the aggregate gross and net reserves of the Corporation, as at December 31, 2008, using forecast prices and costs as well as the aggregate net present value of future net revenue attributable to the reserves estimated using forecast prices and costs, calculated without discount and using discount rates of 5%, 10%, 15% and 20%:

Table 1 NI 51-101 Summary of Oil and Gas Reserves as of December 31, 2008 Forecast Prices and Costs								
Reserves								
	Light and Medium Oil		Heavy Oil		Natural Gas (non-associated & associated)		Natural Gas Liquids	
Reserve Category	Gross (Mbbl)	Net (Mbbl)	Gross (Mbbl)	Net (Mbbl)	Gross (MMcf)	Net (MMcf)	Gross (Mbbl)	Net (Mbbl)
Proved								
Developed Producing	0.0	0.0	0.0	0.0	80	56	1.1	0.7
Developed Non-Producing	0.0	0.0	0.0	0.0	0	0	0.0	0.0
Undeveloped	0.0	0.0	0.0	0.0	0	0	0.0	0.0
Total Proved	**0.0**	**0.0**	**0.0**	**0.0**	**80**	**56**	**1.1**	**0.7**
Probable	0.0	0.0	0.0	0.0	86	57	1.2	0.7
Total Proved Plus Probable	**0.0**	**0.0**	**0.0**	**0.0**	**167**	**113**	**2.3**	**1.4**

Table 2 NI 51-101 Summary of Net Present Values of Future Net Revenue as of December 31, 2008 Forecast Prices and Costs											
	Net Present Values of Future Net Revenue										
	Before Income Taxes Discounted at (%/Year)					After Income Taxes Discounted at (%/Year)					Future Net Val
Reserves Category	0 (M$)	5 (M$)	10 (M$)	15 (M$)	20 (M$)	0 (M$)	5 (M$)	10 (M$)	15 (M$)	20 (M$)	10%/yr ($/boe)
Proved											
Developed Producing	183	177	172	167	162	125	121	117	114	111	17.17
Developed Non-Producing	0	0	0	0	0	0	0	0	0	0	0.00
Undeveloped	0	0	0	0	0	0	0	0	0	0	0.00
Total Proved	**183**	**177**	**172**	**167**	**162**	**125**	**121**	**117**	**114**	**111**	**17.17**
Probable	270	242	219	199	182	202	181	163	148	135	21.34
Total Proved Plus Probable	**453**	**419**	**390**	**366**	**344**	**327**	**302**	**280**	**262**	**246**	**19.28**

Reference Item 2.2(2) of Form 51-101F1

Notes: NPV of FNR include all resource income:
- Sale of oil, gas, by-product reserves
- Processing third party reserves
- Other income

Income Taxes:
- Includes all resource income
- Apply appropriate income tax calculations
- Include prior tax pools

Unit Values are based on net reserve volumes

The following tables provide a breakdown of various elements of future net revenue attributable to proved reserves and proved plus probable reserves estimated using forecast prices and costs, calculated without *discount:*

Table 3
NI 51-101
Total Future Net Revenue
Undiscounted
as of December 31, 2008
Forecast Prices and Costs

Reserves Category	Revenue (M$)	Royalties (M$)	Operating Costs (M$)	Development Costs (M$)	Well Abandonment / Other Costs (M$)	Future Net Revenue Before Income Taxes (M$)	Income Taxes (M$)	Future Net Revenue After Income Taxes (M$)
Proved	686	160	309	17	17	183	59	125
Proved Plus Probable	1,506	369	649	17	18	453	127	327

The following tables detail by production group the net present value of future net revenue (before deducting future income tax expenses), estimated using forecast prices and costs, calculated using a discount rate of 10%:

Table 4
NI 51-101
Net Present Value of Future Net Revenue
by Production Group
as of December 31, 2008
Forecast Prices and Costs

Reserves Category	Production Group	Future Net Revenue Before Income Taxes (Discounted at 10%/Year) (M$)	Unit Value Before Income Taxes (Discounted at 10%/Year) ($/boe)
Proved	Light and Medium Crude Oil (including solution gas and associated by-products)	0	0
	Heavy Oil (including solution gas and associated by-products)	0	0
	Natural Gas (including associated by-products)*	172	17.17
Proved Plus Probable	Light and Medium Crude Oil (including solution gas and associated by-products)	0	0
	Heavy Oil (including solution gas and associated by-products)	0	0
	Natural Gas (including associated by-products)*	390	19.28

Reference Item 2.1(3)(c) of Form 51-101F1
* Includes corporate Capital GCA, if applicable
Unit Values are based on net reserve volumes

PART 3 PRICING ASSUMPTIONS

The following tables detail the reference prices as at December 31, 2008 in the Sproule Report for evaluating the net present values of future net revenues from reserves relating to Petroworth's reserves disclosed above.

Table 5
NI 51-101
Summary of Pricing and Inflation Rate Assumptions as of December 31, 2008
Forecast Prices and Costs

Year	WTI Cushing Oklahoma ($US/bbl)	Edmonton Par Price 40° API ($Cdn/bbl)	Cromer Medium 29.3° API ($Cdn/bbl)	Natural Gas[1] AECO Gas Prices ($Cdn/MMBtu)	Pentanes Plus FOB Field Gate ($Cdn/bbl)	Butanes F.O.B. Field Gate ($Cdn/bbl)	Inflation Rate[2] (%/Yr)	Exchange Rate[3] ($US/$Cdn)
Historical								
2004	41.42	52.91	45.72	6.87	53.91	41.37	1.4	0.770
2005	56.46	69.29	45.62	8.58	69.13	45.20	1.3	0.826
2006	66.09	73.30	51.54	7.16	75.03	59.32	1.5	0.882
2007	72.27	77.06	53.16	6.65	77.33	63.71	2.0	0.935
2008 Est	99.59	102.85	84.31	8.15	104.70	75.10	1.0	0.943
Forecast								
2009	53.73	65.35	58.16	6.82	66.93	51.15	2.0	0.800
2010	63.41	72.78	66.23	7.56	74.54	54.25	2.0	0.850
2011	69.53	79.95	72.76	7.84	81.88	59.59	2.0	0.850
2012	79.59	86.57	79.65	8.38	88.66	64.53	2.0	0.900
2013	92.01	94.97	87.38	9.20	97.27	70.79	2.0	0.950
Thereafter	Various Escalation Rates							

(1) This summary table identifies benchmark reference pricing schedules that might apply to a *reporting issuer*.
(2) Inflation rates for forecasting prices and costs.
(3) Exchange rates used to generate the benchmark reference prices in this table.

Notes:
Product sale prices will reflect these reference prices with further adjustments for quality and transportation to point of sale.

PART 4 RECONCILIATIONS OF CHANGES IN RESERVES AND FUTURE NET REVENUE

Petroworth had no proved or probable reserves as at December 31, 2006. The following table represents the reconciliation of the Corporation's gross reserves by principal produce type as of December 31, 2008 using forecast prices and costs:

Table 6
NI 51-101
Reconciliation of Company Gross (1) Reserves (Before Royalty)
By Principal Product Type
As of December 31, 2008
Forecast Prices and Costs

	Associated and Non-Associated Gas			Natural Gas Liquids		
Factors	**Gross Proved (MMcf)**	**Gross Probable (MMcf)**	**Gross Proved Plus Probable (MMcf**	**Gross Proved (Mbbl)**	**Gross Probable (Mbbl)**	**Gross Proved Plus Probable (Mbbl)**
December 31, 2007	186	191	377	1.1	1.3	2.4
Extensions	-	-	-	-	-	-
Improved Recovery	-	-	-	-	-	-
Technical Revisions	(83)	(104)	(187)	0.2	(0.1)	0.1
Discoveries	-	-	-	-	-	-
Acquisitions	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-
Economic Factors	-	-	-	-	-	-
Production	(23)	0	(23)	(0.2)	0	(0.2)
December 31, 2008	80	86	167	1.1	1.2	2.3

(1) Gross Reserves means the Company's working interest reserves before calculation of royalities, and before consideration of the Company's royalty interests.

PART 5 ADDITIONAL INFORMATION RELATING TO RESERVES DATA

Undeveloped Reserves

The following table sets forth, for each product type, the volumes of proved undeveloped reserves that were first attributed in each of the periods indicated:

Timing of Initial Undeveloped Reserves Assignment

Company Gross Reserves First Attributed By Year				
Product Type	Units	2006	2007	**2008**
Proved Undeveloped				
Natural Gas	Mmcf	0	70.0	**0**
Natural Gas Liquids*	Mbbl	0	0.2	0
Total: Oil Equivalent	**Mboe**	0	11.9	0
Probable Undeveloped				
Natural Gas	Mmcf	0	58.0	0

* Values included with gas

The proved and probable undeveloped reserves attributable to Petroworth's reserves have been estimated by Sproule in the Sproule Report in accordance with the procedures and standards contained in the COGE Handbook and consistent with NI 51-101.

Significant Factors or Uncertainties

The process of evaluating reserves is inherently complex. It requires significant judgements and decisions based on available geological, geophysical, engineering and economic data. As circumstances change and additional data becomes available, reserve estimates also change. Estimates are reviewed and revised, either upward or downward, as warranted by the new information. Revisions are often required due to changes in well performance, prices, economic conditions and governmental restrictions. Revisions to reserve estimates can arise from changes in year-end prices, reservoir performance and geologic conditions or production. These revisions can be either positive or negative. See "Risk Factors".

The reserve estimates contained herein are based on current production forecasts, prices and economic conditions. These factors and assumptions include among others: (i) historical production in the area compared with production rates from analogous producing areas; (ii) initial production rates; (iii) production decline rates; (iv) ultimate recovery of reserves; (v) success of future development activities; (vi) marketability of production; (vii) proximity to existing pipelines and tied in costs especially with regard to the properties in Maritimes Canada.

The evaluated oil and natural gas properties have no material extraordinary risks or uncertainties beyond those which are inherent in an oil and natural gas producing company.

Future Development Costs

There are no planned future development costs attributable to the reserve categories noted in this report. All seven wells located in Alberta have been completed. Petroworth has no plans to further the development of the five wells in Alberta that are currently not in production. Petroworth is of the view that its net interests in these 5 wells are too small to warrant further expenditure.

PART 6 OTHER OIL AND GAS INFORMATION

Oil an Gas Properties and Wells

PetroWorth has oil and gas properties in the Provinces of New Brunswick, Prince Edward Island, Nova Scotia, and Alberta. As of December 31, 2007, the Corporation had natural gas reserves in its wells only in Alberta and no oil or gas reserves on any of its properties in Maritimes Canada. All the Corporation's properties are onshore.

Alberta

As of December 31, 2008, Petroworth had working interest in 7 wells completed in Alberta of which two commenced production in 2007. During the year 2008, the Company conducted an analysis of all 7 wells and concluded that the merits of the following wells do not warrant any further expenditure and declined further participation:

1. 40% working interest in 160 acres gross (64 acres net) at Bruce, Alberta Sec. 29 Tp 45-18W4M;
2. 50% working interest in 160 acres gross (80 acres net) at Bruce, Alberta, Sec. 31 Tp 45-17W4M;
3. 5% working interest in 160 acres gross (8 acres net) at Wetaskawin, Sec 6 Tp 46-24W4M;
4. 5% working interest in 160 acres gross (8 acres net) at Wetaskawin, Sec 17 Tp 46-24W4M;
5. 5% working interest in 160 acres gross (8 acres net) at Wetaskawin, Sec 6 Tp 47-24 W4M.

The Company continued to maintain its working interest in the following natural gas wells:

1. 50% working interest in 160 acres gross (80 acres net) at Bruce, Alberta, Sec. 21 Tp 46-18W4M;
2. 55% working interest in 160 acres gross (88 acres net) at Ferrybank, Alberta, Sec. 32 Tp 44-27W4M;

The following table sets forth the number and status of wells as at December 31, 2008 in which the Corporation has a working interest and which are producing or are considered by the Corporation to be capable of production. All of these wells are located in Alberta. The stated interests are subject to land-owners and other royalties, where applicable, in addition to the customary Crown royalties and mineral taxes.

	Natural Gas Wells			
	Producing		Non-Producing	
	Gross(1)	Net(2)	Gross(1)	Net(2)
Alberta	2	1.05	0	0
New Brunswick	0	0	4	4
Prince Edward Island	0	0	1	0.1
Nova Scotia	0	0	0	0
Total	**2**	**1.05**	**5**	4.1

Notes:

(1) "Gross" refers to all oil and gas wells in which Petroworth has a working interest.

(2) "Net" refers to the aggregate of the percentage working interests of Petroworth in the gross wells, before the deduction of any royalty interests.

Properties with no Attributed Reserves:

Information relating to the Corporation's principal properties with no attributed reserves is set out below.

New Brunswick

As of December 31, 2008, Petroworth had the following onshore land holdings in New Brunswick:

1. 100% interest in the New Brunswick Licence No. ONG 04-06 consisting of approximately 33,754 acres in southern New Brunswick (the "Rosevale" property);

2. 100% interest in two additional and adjacent permits in southern New Brunswick (the "Stoney Creek" property):

    a. ONG 06-05 consisting of approximately 1,773 acres; and

    b. ONG 06-06 consisting of approximately 5,319 acres.

3. 100% interest in Westmorland County of New Brunswick Licence No. 07-01 consisting of 88,737 acres located immediately east of the Stoney Creek oil and gas field.

During the year ending December 31, 2008, Petroworth drilled two exploratory wells known as A-08 and A-63. Exploratory drilling commenced on these wells in June 2008. A-08 was drilled and cased, following logging operations, to a total depth of 1,932 metres. The well is located on the northeast part of the 37,000-acre Rosevale lease, which is situated between the Stoney Creek field to the east and the McCully field to the southwest. Drilling at A-63 was terminated at a depth of 1,340 metres. Preliminary log interpretations indicate that the well encountered extremely hard metamorphosed Hiram Brook formation rock. A63 is located in the southwestern part of PetroWorth's Rosevale license.

The Company also conducted fracture stimulation on the E-08 well in four zones. Following a four-zone comingled flow test over a continuous 120-hour period, E-08 flowed at a final rate of 1.058 MMscfe/day at a flowing tubing pressure of 155 psi and a casing pressure of 347 psi prior to shut-in for pressure build-up measurements.

Prince Edward Island

As of December 31, 2008, Petroworth had the following onshore land holdings in Price Edward Island (PEI):

1. 100% interest in two contiguous permits in north-eastern PEI:

    a. Permit #03-01 consisting of approximately 88,090 acres; and

    b. Permit #03-02 consisting of approximately 177,985 acres.

2. 100% interest in Permit #04-05 of approximately 133,286 acres in central PEI.

3. 100% interest in three additional properties in King's County, PEI:

    a. Permit #04-06 consisting of approximately 21,360 acres;

    b. Permit #04-07 consisting of approximately 21,420 acres;

    c. Permit #04-08 consisting of approximately 3,418 acres; and

4. 10% working interest in Green Gables license 04-03, PEI.

During the year 2008, Corridor completed testing operations in one zone in New Harmony #1 well pursuant to the data exchange and farm-in option agreement after the well was drilled to a total depth of 3,403 meters. The well encountered several significant gas shows in the Bradelle Formation below a depth of approximately 2,700 meters but subsequent fracture stimulation did not result in the generation of commercial hydrocarbons. In December, one zone in New Harmony #1 underwent a fracture stimulation test, which did not result in the generation of commercial hydrocarbons. In order to earn a 50% interest on Exploration License 03-02, Corridor must drill two more wells on this property before October 1, 2008. Corridor did not exercise their option to drill the additional two wells and the option expired. During the year, PetroWorth re-negotiated the data exchange and farm-in option agreement with Corridor. Under the revised agreement PetroWorth will finance 100% of the costs of fracturing and testing the initial two zones in the Green Gables #3 well to a maximum cost of $2 million to earn a 10% working interest in Corridor's Green Gables license 04-03.

<u>Nova Scotia</u>

As of December 31, 2008, Petroworth holds two Exploration Agreements in Nova Scotia being 04-07-15-01 and 04-07-15-03 totalling approximately 383,727 acres (the "Ainslie" property). Under the Exploration Agreements, Petroworth has to complete exploratory work commitment of $1,500,000 prior to July 15, 2009 and a further $1,500,000 for each of the following two years totalling $4,500,000. Petroworth has put up a deposit of $300,000 for this agreement and is planning a seismic program on the property is being planned.

Forward Contracts

As at December 31, 2008, the Corporation did not, and currently does not, have any future material commitments to buy, sell, exchange or transport oil or natural gas.

Additional Information Concerning Abandonment and Reclamation Costs

According to the Sproule Report, Petroworth was expected to incur reclamation and abandonment of $30,000 for the wells in Alberta to which reserves were assigned. No abandonment or reclamation costs were allocated to the properties in the Maritimes.

Tax Horizon

Based on Petroworth's existing tax pools, estimated capital program for 2009 and current production levels, no income taxes are expected to be payable for the foreseeable future.

Capital Expenditures

The following table summarizes capital expenditures incurred by Petroworth and property acquisitions added to oil and natural gas properties and equipment with respect to Petroworth's reserves for the period ended December 31, 2008.

Expenditures	Year Ended December 31, 2008 ($000s)
Property acquisition costs-Unproved properties	-
Property acquisition costs-Proved properties	-
Exploration costs	10,835
Development costs	169
Total Expenditures	11,004

Exploration and Development Activities

The following table sets forth the gross and net exploratory and development wells drilled during the period ended December 31, 2008.

	Period Ended December 31, 2008			
	Exploratory Wells		Development Wells	
	Gross[1]	Net[2]	Gross[1]	Net[2]
Oil	0	0	0	0
Gas	5	4.1	2	1.05
Total	**5**	**4.1**	**2**	**1.05**

Notes:

(1) "Gross" means the total number of wells comprising the Corporation's reserves.

(2) "Net" means the number of wells obtained by aggregating the working interest in each of the gross wells comprising the Corporation's reserves.

For details on the important current and planned exploration and development activities during 2008, see "Principal Properties".

Production History

The following table sets forth the production history in respect of production, product prices received, royalties paid, operating expenses and resulting netback of Petroworth's production for the periods indicated. Petroworth commenced natural gas production in June 2007.

	2008 First Quarter	**2008 Second Quarter**	**2008 Third Quarter**	**2008 Fourth Quarter**	**Year-to-Date December 31, 2008**
Average Daily Production[1]					
Natural Gas (mcf/d) [2]	48	95	53	81	69
Average Price Received[1]					
Natural Gas ($/mcf) [2]	$7.91	$10.40	$8.71	$5.80	$5.78
Royalties Paid					
Natural Gas ($/mcf) [2]	$2.05	$2.99	$1.13	$0.95	$1.88
Operating Expenses[3]					
Natural Gas ($/mcf) [2]	$6.84	$4.58	$9.11	$6.35	$6.35
Netback Received[4]					
Natural Gas ($/mcf) [2]	$(0.98)	$2.83	$(1.53)	$(1.51)	$(0.65)

Notes:

(1) Before deduction of royalties.

(2) Natural Gas includes associated and non-associated gas and all other marketable gas.

(3) Operating expenses are composed of direct costs incurred to operate gas wells.

(4) Netbacks are calculated by subtracting royalties, operating costs and transportation expenses from revenues.

The following table indicates the net average daily production volumes from each important field for the year ended December 31, 2008.

	Light Oil and NGLs (bbls/d)	Natural Gas (mcf/d)
Bruce	0	30.3
Ferrybank	0	38.8
Wetaskawin	0	0
Total*	0	**69.1**

Production Estimates

The following table sets out the total volume of production estimated by Sproule for 2009 in the estimates of future net revenue from gross proved and gross probable reserves:

2009 Estimated Average Daily Production – Forecast Dollar Pricing

	Natural Gas (mcf/d)	Oil Equivalent (boe/d)
Gross Proved		
Bruce	0	0
Ferrybank	149	27
Wetaskiwin	0	0
Total Gross Proved	**149**	**27**
Gross Probable		
Bruce	0	0
Ferrybank	41	7
Wetaskiwin	0	0
Total Gross Probable	**41**	**7**
Gross Proved Plus Probable		
Bruce	0	0
Ferrybank	190	34
Wetaskiwin	0	0
Total Gross Proved Plus Probable	**190**	**34**

Marketing

Crude oil, natural gas and NGLs will be priced based on daily spot prices adjusted for quality and transportation. See "Forward Contracts".