

## **RESERVES REPORT**

### **Form 51-101F1**

Petro-Reef's proved plus probable net reserves, based on an independent engineering year-end evaluation, indicated a decrease of 5.4 percent to 1,272.1 MBOE from 1345.3 MBOE in the previous year, after extensions, technical revisions, and net production of 225 MBOE.

Reserves were 81.23% natural gas and 18.7% crude oil and natural gas liquids. Reserve replacement ratio was negative by a small margin.

Of the total net reserves reported (using forecast prices) Petro-Reef's reserves are 74.4% proved and 25.6% probable.

Reserves are classified according to the degree of certainty associated with the estimates.

#### **1) Proved Reserves**

Proved reserves are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.

#### **2) Probable Reserves**

Probable reserves are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

#### **3) Possible Reserves**

Possible reserves are those additional reserves that are less certain to be recovered than probable reserves. It is unlikely that the actual remaining quantities recovered will exceed the sum of the estimated proved plus probable plus possible reserves. Possible reserves have not been considered in this report.

## **RESERVES RECONCILIATION**

The December 31, 2007 evaluation was prepared using definitions in accordance with National Instrument 51-101. Estimates are prepared such that there is a 90% probability that at least the estimated proved reserves will be recovered and a 50% probability that at least the sum of the estimated proved reserves plus probable reserves will be recovered. The reserves reconciliation reflects current proved plus probable reserves. Both the December 31, 2006 and the December 31, 2007 reports were prepared by Sproule Associates Limited.

**1) Reserves Value**

Using a ten percent (10%) NPV, the value of proved plus probable reserves at forecast prices and Costs (before Income Taxes) decreased by five percent (5%) compared with last year's established reserves.

**2) Reserve Life Index (as at December 31, 2006).**

Based on established reserves and production volumes, Petro-Reef's reserve life index was 19 years at the end of 2007 compared with 23 years at the end of 2006. Petro-Reef's reserve life index (RLI) is an indication of the number of years it would take to deplete the Company's reserves. The RLI is obtained by dividing the year end reserves by the average daily production of oil, natural gas and natural gas liquids for a calendar year as estimated and determined by the independent reserves evaluator.

**3) Evaluation Standards**

This report has been prepared by Sproule Associates Limited using state-of-the-art geological and engineering knowledge and techniques. It has been prepared with the Code of Ethics of the Association of Professional Engineers, Geologists and Geophysicists of Alberta ("APEGGA"). Finally, this report adheres in all material aspects to the "best practices" recommended in the COGE Handbook which are in accordance with principals and definitions established by the Calgary Chapter of the Society of Petroleum Evaluation Engineers. The COGE Handbook is incorporated by reference in National Instrument 51-101.

**4) The Evaluation of the petroleum and natural gas**

The Evaluation of the petroleum and natural gas reserves of Petro-Reef Resources Ltd. has been approved by the company's reserve committee and the board of directors.

**5) Statement of Reserves Data**

Following is a detailed report on the reserves and future net revenue in six parts:

Part 1	Date of Statement
Part 2	Disclosure of Reserves Data
Part 3	Pricing Assumptions
Part 4	Reconciliation's of changes in Reserves and Future Net Revenue
Part 5	Additional Data Relating to Reserves Data
Part 6	Other Oil and Gas Information

**FORM 51-101F1**  
**STATEMENT OF RESERVES DATA**  
**AND OTHER OIL AND GAS INFORMATION**

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**PART 1 DATE OF STATEMENT**

**1.1 Relevant Dates**

- 1. Date the statement: April 04, 2008
- 2. Effective date: December 31, 2007
- 3. Preparation date: Between February 1 and April 2, 2008

**PART 2 DISCLOSURE OF RESERVES DATA**

**2.1 Reserves Data (Forecast Prices and Costs)**

**2.1.1 Reserves Gross and Net (Forecast Prices and Costs)**

<b>N1 51-101</b> <b>Summary of Oil and Gas Reserves</b> <b>as of December 31, 2007</b> <b>Forecast Prices and Costs</b>										
<b>Reserves</b>										
	<b>Light and Medium Oil</b>		<b>Heavy Oil</b>		<b>Natural Gas (non-associated &amp; associated)</b>		<b>Natural Gas (solution)</b>		<b>Natural Gas Liquids</b>	
<b>Reserves Category</b>	<b>Gross (Mbbl)</b>	<b>Net (Mbbl)</b>	<b>Gross (Mbbl)</b>	<b>Net (MMcf)</b>	<b>Gross (MMcf)</b>	<b>Net (MMcf)</b>	<b>Gross (MMcf)</b>	<b>Net (MMcf)</b>	<b>Gross (Mbbl)</b>	<b>Net (Mbbl)</b>
<b>Proved</b>										
Developed Producing	96.9	85.7	0	0	2,690	2,011	192	154	6.0	4.4
Developed Non-Producing	0	0	0	0	855	727	0	0	0	0
Undeveloped	71.4	63.9	0	0	2,134	1,771	114	89	0	0
<b>Total Proved</b>	<b>168.3</b>	<b>149.6</b>	<b>0</b>	<b>0</b>	<b>5,679</b>	<b>4,509</b>	<b>306</b>	<b>243</b>	<b>6.0</b>	<b>4.4</b>
Probable	119.1	102.0	0	0	1,473	1,175	199	162	1.6	1.2
<b>Total Proved Plus Probable</b>	<b>287.3</b>	<b>251.6</b>	<b>0</b>	<b>0</b>	<b>7,152</b>	<b>5,683</b>	<b>505</b>	<b>405</b>	<b>7.6</b>	<b>5.6</b>

## 2.1.2 Net Present Value of Future Net Revenue (Forecast Prices and Costs)

<b>N1 51-101</b> <b>Summary of Net Present Values of</b> <b>Future Net Revenue</b> <b>as of December 31, 2007</b> <b>Forecast Prices and Costs</b>											
<b>Net Present Values of Future Net Revenue</b>											
<b>Reserves Category</b>	<b>Before Income Taxes</b> <b>Discounted at (% / Year)</b>					<b>After Income Taxes</b> <b>Discounted at (% / Year)</b>					<b>Future</b> <b>Net</b> <b>Value</b>
	<b>0</b> <b>(M\$)</b>	<b>5</b> <b>(M\$)</b>	<b>10</b> <b>(M\$)</b>	<b>15</b> <b>(M\$)</b>	<b>20</b> <b>(M\$)</b>	<b>0</b> <b>(M\$)</b>	<b>5</b> <b>(M\$)</b>	<b>10</b> <b>(M\$)</b>	<b>15</b> <b>(M\$)</b>	<b>20</b> <b>(M\$)</b>	
<b>Proved</b>											
Developed Producing	17,740	15,410	13,742	12,491	11,516	17,008	14,854	13,306	12,139	11,226	30.46
Developed Non-Producing	4,291	3,289	2,630	2,170	1,835	3,184	2,433	1,942	1,603	1,357	21.71
Undeveloped	11,953	8,814	6,723	5,262	4,200	8,821	6,415	4,812	3,691	2,877	17.98
<b>Total Proved</b>	<b>33,984</b>	<b>27,513</b>	<b>23,095</b>	<b>19,923</b>	<b>17,551</b>	<b>29,014</b>	<b>23,702</b>	<b>20,059</b>	<b>17,433</b>	<b>15,460</b>	<b>24.41</b>
Probable	12,730	9,359	7,352	6,043	5,126	9,425	6,859	5,346	4,366	3,685	22.55
<b>Total Proved Plus Probable</b>	<b>46,714</b>	<b>36,872</b>	<b>30,447</b>	<b>25,966</b>	<b>22,677</b>	<b>38,439</b>	<b>30,561</b>	<b>25,405</b>	<b>21,799</b>	<b>19,145</b>	<b>23.93</b>

### Notes:

- 1) NPV of FNR include all resource income:
  - Sale of oil, gas, by-product reserves
  - Processing third party reserves
  - Other income
  
- 2) Income Taxes
  - Includes all resource income
  - Apply appropriate income tax calculations
  - Include prior tax pools

### 2.1.3 Future Net Revenue Undiscounted (Forecast Prices and Costs)

<b>N1 51-101 Total Future Net Revenue Undiscounted as of December 31, 2007 Forecast Prices and Costs</b>								
<b>Reserves Category</b>	<b>Revenue (M\$)</b>	<b>Royalties (M\$)</b>	<b>Operating Costs (M\$)</b>	<b>Development Costs (M\$)</b>	<b>Well Abandonment/ Other Costs (M\$)</b>	<b>Future Net Revenue Before Income Taxes (M\$)</b>	<b>Income Taxes (M\$)</b>	<b>Future Net Revenue After Income Taxes (M\$)</b>
Proved	62,838	11,747	13,882	2,857	367	33,984	4,971	29,014
Proved Plus Probable	86,159	16,036	18,973	3,978	458	46,714	8,276	38,439

### 2.1.4 By Production Group-Future Net Revenue before Income Tax (Using Forecast Prices and Costs – Using a discount rate of 10%)

<b>N1 51-101 Net Present Value of Future Net Revenue By Production Group as of December 31, 2007 Forecast Prices and Costs</b>			
<b>Reserves Category</b>	<b>Production Group</b>	<b>Future Net Revenue Before Income Taxes Discounted at 10% Year M\$</b>	<b>Unit Value Before Income Taxes Discounted at 10% Year \$/BOE</b>
Proved	Light and Medium Crude Oil (including solution gas and associated by-products)	4,542	23.89
	Heavy Oil (including solution gas and associated by-products)	0	0
	Natural Gas (including associated by-products) <sup>8*</sup>	18,553	24.54
Proved Plus Probable Reserves	Light and Medium Crude Oil (including solution gas and associated by-products)	7,405	23.20
	Heavy Oil (including solution gas and associated by-products)	0	0
	Natural Gas (including associated by-products)*	23,042	24.18

**PART 3 PRICING ASSUMPTIONS**

**3.1 FORECAST PRICES USED IN ESTIMATES**

<p align="center"><b>N1 51-101</b>  <b>Summary of Pricing and</b>  <b>Inflation Rate Assumptions</b>  <b>as of December 31, 2007</b>  <b>Forecast Prices and Costs</b></p>								
	Oil							
Year	WTI Cushing Oklahoma (\$US/bbl)	Edmonton Par Price 40° API (\$Cdn/bbl)	Cromer Medium 29.3° API (\$Cdn/bbl)	Natural Gas <sup>1</sup> AECO Gas Prices (\$Cdn/MMBtu)	Pentanes Plus F.O.B Field Gate (\$Cdn/bbl)	Butanes F.O.B. Field Gate (\$Cdn/bbl)	Inflation Rate <sup>2</sup> (%/Yr)	Exchange Rate <sup>3</sup> (\$US/\$Cdn)
<b>Historical</b>								
2003	31.14	43.23	37.53	6.66	44.16	34.55	2.5	0.716
2004	41.42	52.91	45.72	6.67	53.91	41.37	1.3	0.770
2005	56.46	69.29	57.36	8.58	69.13	45.20	1.6	0.826
2006	66.09	73.30	62.35	7.16	75.03	59.32	1.5	0.882
2007	72.27	77.06	65.33	6.65	77.33	63.71	2.0	0.935
<b>Forecast</b>								
2008	89.61	88.17	75.83	6.51	90.30	65.72	2.0	1,000
2009	86.01	84.54	72.71	7.22	86.58	63.01	2.0	1,000
2010	84.65	83.16	71.52	7.69	85.17	61.98	2.0	1,000
2011	82.77	81.26	69.89	7.70	83.23	60.57	2.0	1,000
2012	82.26	80.73	69.43	7.61	82.68	60.17	2.0	1,000
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.

Reference Item 3.1 of Form 51-101F1

**PART 4 RECONCILIATIONS OF CHANGES IN RESERVES AND FUTURE NET REVENUE**

**4.1 Reserves Reconciliation**

**N1 51-101  
Reconciliation of Company Gross <sup>(1)</sup> Reserves (Before Royalty)  
By Principal Product Type  
As of December 31, 2007  
Forecast Prices and Costs**

Factors	Light and Medium Oil			Associated and Non-Associated Gas			Natural Gas Solution			Natural Gas Liquids		
	Gross Proved (Mbbbl)	Gross Probable (Mbbbl)	Gross Proved Plus Probable (Mbbbl)	Gross Proved (MMcf)	Gross Probable (MMcf)	Gross Proved Plus Probable (MMcf)	Gross Proved (MMcf)	Gross Probable (MMcf)	Gross Proved Plus Probable (MMcf)	Gross Proved (Mbbbl)	Net Probable (Mbbbl)	Net Proved Plus Probable (Mbbbl)
<b>December 31, 2006</b>	<b>74.1</b>	<b>22.3</b>	<b>96.4</b>	<b>8,159</b>	<b>992</b>	<b>9,151</b>	<b>0</b>	<b>0</b>	<b>0</b>	<b>9.2</b>	<b>1.6</b>	<b>10.8</b>
Extensions	95.1	35.9	131.0	1,027	544	1,571	-	-	-	4.7	1.2	5.9
Improved Recovery	-	52.3	52.3	-	-	-	308	199	507	-	-	-
Technical Revisions	4.0	8.4	12.4	-2,277	-120	-2,397	-	-	-	-3.4	-1.1	-4.5
Discoveries	-	-	-	43	63	106	-	-	-	-	-	-
Acquisitions	-	-	-	-	-	-	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-	-	-	-	-	-	-
Economic Factors	1.0	0.1	1.1	37	-6	31	-	-	-	-	-0.1	-0.1
Production	-5.9	-	-5.9	-1,310	-	-1,310	-2	-	-2	-4.5	-	-4.5
<b>December 31, 2007</b>	<b>168.3</b>	<b>119.0</b>	<b>287.3</b>	<b>5,679</b>	<b>1,473</b>	<b>7,152</b>	<b>306</b>	<b>199</b>	<b>505</b>	<b>6.0</b>	<b>1.6</b>	<b>7.6</b>

**4.2 Additional changes were due to changes used in the Forecast Price for December 31, 2006 and December 31, 2007 as follows:**

	<b>December 31, 2006 Price (\$)</b>	<b>December 31, 2007 Price (\$)</b>
Oil : Edmonton Par	\$74.10/stb	\$88.17/stb
Natural Gas (AECO-C)	\$7.72/mcf	\$6.51/mcf
Natural Gas By Products:		
Butanes	\$55.23/stb	\$65.72/stb
Pentanes Plus	\$75.88/stb	\$90.30/stb
Exchange Rate	\$0.870 US/CDN	\$1.000 US/CDN

**4.3 The change in future net development costs of proved undeveloped reserves from December 31, 2006 to December 31, 2007 is as a result of increased cost in drilling, completions and facilities.**

**4.4 The net change in income taxes are due to increases or decreases in projected net revenues effective December 31, 2007, versus the projected net reserves effective December 31, 2006 and the increase in capital expenditures on properties during fiscal year 2006.**

**PART 5 ADDITIONAL INFORMATION RELATING TO RESERVES DATA**

**5.1 Undeveloped Reserves**

**5.1.1 Proved Undeveloped Reserves**

Proved Undeveloped Reserves are those reserves expected to be recovered from known accumulations where a significant expenditure is required to render them capable of production and meet the proved developed or proved developed producing reserves classification. Total net capital expenditures for 2008 are anticipated to be \$2,552,000.

**5.1.2 Probable Undeveloped Reserves**

Probable Undeveloped Reserves are those reserves expected to be recovered from known accumulations where a significant expenditure is required to render them capable of production to meet the proved developed or proved developed producing reserves classification from the current probable undeveloped classification. Capital expenditures for 2008 are anticipated to be \$1,119,000.

**5.2 Significant Factors or Uncertainties**

There are no economic factors or significant uncertainties that affect particular components of the reserves data.

### 5.3 Future Development Costs

#### 5.3.1 Development Costs of Future Net Revenue

Proved Reserves (Forecast Prices and Costs)		Proved Plus Probable Reserves (Forecast Prices and Costs)	
Undiscounted	Discount @ 10%	Undiscounted	Discount @ 10%
\$2,853,000	\$2,631,000	\$3,978,000	\$3,749,000

**Note:** Development costs are all incurred in fiscal year 2006.

#### 5.3.2 Development Costs of Future Net Revenue (by year)

a) Proved Reserves (Forecast Prices and Costs)

2008	\$2,761,000
2009	0
2010	\$92,000
2011	0
2012	0

b) Proved Plus Probable Reserves (Forecast Prices and Costs)

2008	\$3,880,000
2009	0
2010	0
2011	\$93,000
2012	0

**Note:** Development costs are funded by cash flow, and available bank credit

## PART 6 OTHER OIL AND GAS INFORMATION

### 6.1 Oil and Gas Properties and Wells

Petro-Reef's Alexander main property representing 98.0% of its net present value (for proved plus probable reserves using 10% discounted values – before income taxes) is located in Central Alberta.

#### 6.1.1 Producing Versus Non-Producing Reserves

Following is the Alexander property to which reserves have been attributed and are capable of producing but which are not producing as of the effective date, the percentage of those reserves to the total reserves, and the percentage of those reserves that are non-producing as of the dates indicated.

##### a) (i) Alexander

##### Total Proved plus Probable Reserves (@ December 31, 2007)

CRUDE OIL & NATURAL GAS LIQUIDS			NATURAL GAS *		
	Company			Company	
Gross MBbl	Gross MBbl	Net MBbl	Gross MMCF	Gross MMCF	Net MMCF
667.9	294.9	257.2	15,026	7,581	6,006

##### (ii) Total Proved plus Probable Developed Non-Producing Reserves and Undeveloped Reserves (as at December 31, 2007)

CRUDE OIL & NATURAL GAS LIQUIDS			NATURAL GAS *		
	Company			Company	
Gross MBbl	Gross MBbl	Net MBbl	Gross MMCF	Gross MMCF	Net MMCF
372.3	163.8	142.3	6,638	4,011	3,345
Percentage of Total Reserves Non-Producing	57.0%	56.5%	44.2%	52.9%	55.7%

\* Includes solution gas

##### b) Other Properties

Other properties represent 2.0% of the total net present value (before income tax) with approximately 95% of those properties producing. The other properties are all non-operated.

### 6.1.2 Producing Versus Non-Producing Oil & Gas Wells:

Following is a list of oil and gas wells (gross and net) which are producing and non-producing (@ December 31, 2007). All the oil and gaswells are in Central Alberta, Canada.

#### Production is as of December 31, 2007

	Oilwells		Gaswells	
	Gross	Net	Gross	Net
Producing	2.0	0.88	15	6.962
Non-Producing @ December 31, 2007	4.0	1.76	4	0.861

**Note:** Only wells which have reserves assigned by the qualified independent reserves evaluator have been reported.

### 6.1 Properties With No Attributed Reserves

#### 6.2.1 Unproved Properties <sup>(1)</sup>

Location	Gross (Acres)	Net (Acres)
Total Unproved Properties	16,404	11,751

Note 1: Unproved Properties are those lands which have no reserves assigned by the independent reserves evaluator.

There are no work commitments required for fiscal year 2008.

#### 6.2.2 The net area of unproved property which is expected to expire in fiscal year 2008 is 512.4 acres.

### 6.3 Forward Contracts

The Company is not bound by any agreement (including any transportation agreement) which would preclude it from fully realizing future market prices for oil or gas.

### 6.4 Additional Information Concerning Abandonment and Reclamation Costs.

- a) Petro-Reef estimates abandonment and reclamation cost based on historical average costs for the area net of salvage value at \$30,000 per well.
- b) Undiscounted cost to the Company is estimated at \$458,000 for reclamation and abandonment as determined by the independent engineering evaluators.

## 6.5 Tax Horizon

The Company does not expect to be required to pay income taxes for its 2007 financial year. It is anticipated that taxes will become payable for fiscal year 2009.

## 6.6 Costs Incurred (for fiscal year 2007)

### 6.6.1 Cost for COGPE, CEE, and CDE (\$)

- a) Property acquisition costs (COGPE) = \$1,840,105
- b) Exploration costs (CEE) = \$4,858,191
- c) Development costs (CDE) = \$1,896,940
- d) Class 39 & 41 = \$5,567,873
- e) Other = \$60,734
- f) Total = \$14,224,946

## 6.7 Exploration and Development Activities

### 6.7.1 Wells for fiscal year 2007

Exploration wells	6	Gross	(3.47 net)
Development wells	6	Gross	(3.04 net)

### 6.7.2 Wells for fiscal year 2007

Gaswells	5	Gross	(2.86 net)
Oilwells	3	Gross	(1.57 net)
Dry Holes	4	Gross	(2.08 net)

## 6.8 Production Estimates

### 6.8.1 Production estimates for 2008 (based on Company Interest) are:

- a) Using Forecast Prices and Costs (Proved plus Probable)
  - Oil 67 BBLs / D
  - Gas 4,211 MCF / D
  - NGL 13 BBLs / D

**Of the above referenced production 98% is represented by One (1) property:**

- a) Alexander

## 6.9 Production History for fiscal year 2007

The following table summarizes certain information in respect of production, product prices received, royalties paid, operating expenses, and resulting netbacks for the periods indicated.

### QUARTER ENDED 2007

	<u>MARCH 31</u>	<u>JUNE 30</u>	<u>SEPT. 30</u>	<u>DEC. 31</u>
<b>Production per Quarter (BOE)</b>				
- Crude Oil and NGL's (BBL /day)	26	25	27	37
- Natural Gas (MCF/day) <sup>(3)</sup>	3,426	3,274	3,406	4,401
- Combined (BOE/day)	594	571	595	771
<b>Average Price Received</b>				
- Crude Oil and NGL's (\$/BBL)	\$51.67	\$60.37	\$65.90	\$67.72
- Natural Gas (\$/MCF)	\$7.90	\$7.42	\$5.12	\$6.11
- Combined (\$/BOE)	\$47.45	\$45.14	\$32.79	\$38.40
<b>Royalties Paid <sup>(4)</sup></b>				
- Crude Oil and NGL's (\$/BBL)	\$9.18	\$8.39	\$5.45	\$9.77
- Natural Gas (\$/MCF)	\$1.53	\$1.40	\$0.91	\$1.63
- Combined (\$/BOE)	\$9.18	\$8.39	\$5.45	\$9.77
<b>Operating Expenses</b>				
Combined (\$/BOE)	\$7.80	\$8.33	\$7.65	\$7.91
<b>Netback Received <sup>(2)</sup></b>				
Combined (\$/BOE)	\$30.57	\$28.42	\$19.70	\$20.72

#### Notes:

- 1) Production is stated after BTU adjustment.
- 2) Before deduction of royalties
- 3) Netbacks are calculated by subtracting royalties and operating costs from revenues.
- 4) Natural gas production is reported as part of the combined BOE/ day by converting at 6 MCF per 1 BBL.