



Q1 2009

## FINANCIAL & OPERATING HIGHLIGHTS

Three months ended March 31,	2009	2008	% Change
<b>Financial</b>			
(\$000s, except where noted)			
Oil and natural gas revenue	<b>190,786</b>	179,291	6
Funds flow from operations <sup>(1)</sup>	<b>125,156</b>	123,488	1
Per share – basic (\$)	<b>1.50</b>	1.53	(2)
– diluted (\$)	<b>1.40</b>	1.36	3
Net income (loss)	<b>(1,542)</b>	35,537	-
Per share – basic (\$)	<b>(0.02)</b>	0.44	-
– diluted (\$)	<b>(0.02)</b>	0.40	-
Capital expenditures			
Canadian Business Unit (“CBU”)	<b>70,024</b>	110,489	(37)
Latin American Business Unit (“LABU”)	<b>81,560</b>	68,746	19
Heavy Oil Business Unit (“HBU”)	<b>21,410</b>	21,035	2
Total Company	<b>172,994</b>	200,270	(14)
Total assets	<b>2,414,146</b>	1,737,225	39
Net debt <sup>(1)</sup>	<b>418,079</b>	181,306	131
Common shares outstanding, end of period (000s)			
Basic	<b>83,598</b>	82,489	1
Fully diluted <sup>(2)</sup>	<b>99,214</b>	96,889	2
<b>Operations</b>			
CBU operating netback (\$/boe except where noted) <sup>(1)(3)</sup>			
Oil and NGL revenue (\$/bbl) <sup>(4)</sup>	<b>48.57</b>	91.87	(47)
Natural gas revenue (\$/mcf) <sup>(4)</sup>	<b>5.35</b>	7.73	(31)
Oil and natural gas revenue <sup>(4)</sup>	<b>46.81</b>	83.55	(44)
Royalties	<b>5.32</b>	6.74	(21)
Production expenses	<b>6.81</b>	9.35	(27)
Operating netback <sup>(5)</sup>	<b>34.68</b>	67.46	(49)
LABU operating netback (\$/bbl) <sup>(1)</sup>			
Oil revenue <sup>(4)</sup>	<b>42.18</b>	86.53	(51)
Royalties	<b>4.60</b>	8.25	(44)
Production expenses	<b>7.40</b>	10.86	(32)
Operating netback <sup>(5)</sup>	<b>30.18</b>	67.42	(55)
Average daily crude oil production <sup>(3)</sup>			
CBU – oil and NGL (bbls)	<b>19,722</b>	11,351	74
CBU – natural gas (mcf)	<b>14,179</b>	15,229	(7)
Total CBU (boe)	<b>22,085</b>	13,889	59
LABU – oil (bbls) <sup>(6)</sup>	<b>21,771</b>	8,635	152
Total Company conventional (boe)	<b>43,856</b>	22,524	95

<sup>(1)</sup> Non-GAAP measure. See “Non-GAAP Measures” section within Management’s Discussion and Analysis (“MD&A”).

<sup>(2)</sup> Assumes 8.8 million common shares will be issued upon conversion of the Company’s convertible debentures.

<sup>(3)</sup> Six mcf of natural gas is equivalent to one barrel of oil equivalent (“boe”). HBU bitumen volumes are excluded from average daily production as Whitesands operations are considered to be in the pre-operating stage and accordingly are capitalized.

<sup>(4)</sup> Net of transportation expenses.

<sup>(5)</sup> Excludes hedging activities. In the first quarter of 2009 the CBU realized gains of \$5.31/boe (2008 – realized loss of \$1.25/boe) and no gain or loss was recognized by the LABU (2008 – realized loss of \$2.36/bbl).

<sup>(6)</sup> Actual production sold for the three months ended March 31, 2009 was 21,409 barrels of oil per day (“bopd”) (2008 – 8,635 bopd).

## **OPERATIONAL REVIEW**

Petrobank reported strong funds flow from operations of \$125.2 million, or \$1.40 per diluted share, in the first quarter of 2009 as year over year sales volumes almost doubled to 43,856 boepd. Funds flow from operations increased 1% from the prior year, despite a 56% decrease in world oil prices. CBU infrastructure investments in 2008 reduced operating expenses to \$6.81/boe in the first quarter, preserving strong operating netbacks of \$34.68/boe, excluding hedging gains of \$5.31/boe. Similarly in Colombia, continued improvements in production operations also decreased operating expenses to \$7.40/bbl, leading to operating netbacks of \$30.18/bbl.

## **CANADIAN BUSINESS UNIT (CBU) OPERATIONAL UPDATE**

Following an aggressive drilling program through 2008, our first quarter 2009 production averaged 22,085 boepd, a 59% increase from the 13,889 boepd produced in the first quarter of 2008. In response to the lower oil price environment in early 2009 we reduced our drilling program to 20 (16.14 net) Bakken horizontal wells during the first quarter. Despite lower activity levels, production was down less than 1% from the fourth quarter of 2008. Our efforts in the field to continue optimizing well performance and operating efficiencies minimized the impact of the reduced activity on our production. Outside of the Bakken, our activities are targeted toward building our expertise and drilling inventory in other large resource accumulations, including the Montney and Horn River Basin.

In 2009, our primary focus will be to maintain our low-cost advantage through selective drilling in the Bakken. We are positioned for continued long term reserve and production growth, despite our reduced pace of development at the beginning of 2009. At current commodity prices we expect to drill a further 50 wells this year and if oil prices improve we are prepared to drill as many as 120 wells in 2009. All of our Bakken drilling emphasizes testing and refining different technologies that have the potential to increase ultimate resource recovery.

### *The Bakken Resource*

Petrobank pioneered the horizontal fracture stimulation techniques that opened up the true potential of this substantial resource, and we continue to find new ways to improve well performance and expected ultimate recoveries from the Bakken. Our recent efforts to further improve Bakken production have focused on increasing the intensity of fracture stimulation completions (fracs) by 38% in our long (1400 metre) horizontals, by 200% in our short (700 metre) horizontals, and by 400% in our short bilateral (two 700 metre horizontal legs from a single vertical well bore) horizontal wells. We continue to build on our innovative approach to maximizing value from the Bakken resource and we are monitoring production performance from these wells to optimize future drilling and fracture stimulation design. Our production and reserves are heavily weighted (over 85%) to high value Bakken light oil and associated gas and liquids. This allows Petrobank to achieve industry-leading netbacks and demonstrates our high quality asset base.

Of our year-end inventory of over 550 undrilled Bakken locations, only 162 have been assigned 2P reserves with an additional 19 assigned possible reserves. Our current drilling inventory is based on only four wells per section and could easily double with the advances being realized by increasing well density and frac intensity. We believe the 3P reserve estimates come closer to reflecting the true potential of our assets as our reserves are derived largely from low risk, extensive resource accumulations. CBU 3P reserves increased by 83% year-over-year to 86.2 million boe and reserve additions of 45.5 million boe replaced our 2008 production more than seven times. These 3P reserves have a net present value, discounted at 10%, before tax of \$2.0 billion, an 85% increase from 2007 despite steep declines in commodity prices.

Part of our strategy in the Bakken is to operate centralized facilities to capture additional value from the gas and natural gas liquids associated with the light oil, and to ensure field efficiencies that maintain low operating costs. To strengthen our infrastructure, three new facilities at Viewfield, Creelman, and Freestone were connected to our main Midale plant through 100 kilometres of new pipelines. Together our facilities are now conserving more than 7 mmcf/d of natural gas plus associated natural gas liquids, allowing us to maintain low operating costs while improving our overall project economics.

The enhanced operational efficiencies achieved through our extensive infrastructure investments resulted in a reduction of our Bakken production costs to \$6.03/boe. This brings the average first quarter production costs for all of our CBU operations down to \$6.81/boe, a 27% decrease from the \$9.35/boe recorded in the first quarter of 2008. Our future plans include two more pipeline-connected facilities that are scheduled to be built as drilling activity extends to the north. At our current drilling pace, construction is expected to commence in late 2009 or 2010.

### *Beyond Bakken*

Petrobank has also established strong positions in two massive natural gas resource plays; the Montney and the Horn River Basin. The key to unlocking the potential of these plays is through the use of horizontal wells and multi-stage fracture stimulation technologies, similar to those pioneered by Petrobank in the Bakken. We intend to capitalize on our evolving experience with advanced fracturing techniques, with the goal of building a substantial, long-term inventory of drilling locations at a low near-term cost.

In October 2008, through the acquisition of a private company, we acquired a highly prospective position in the Montney tight gas play at Monias in northeastern B.C. We now have a 100% working interest in 17 sections of land, and a 5.0 mmcf/d gas plant.

In December 2008, we drilled our first Montney horizontal well, and in February 2009 we performed a seven-stage fracture stimulation in the upper portion of the 135 metre thick Montney interval. The well flow tested at initial rates in excess of 7.5 mmcf/d plus 180 barrels of natural gas liquids per day. The well was put on production at the end of the first quarter at a restricted rate of 5.5 mmcf/d. This well is currently producing at approximately 2.2 mmcf/day showing a typical production profile where the rate drops quickly and then flattens at a much lower decline rate. The consistent geology across our 17 sections of land establishes a 67-well inventory of prolific Montney drilling locations. Our next steps will be to install additional compression to increase our plant capacity to 10.0 mmcf/d and then drill another well later in 2009 to test new technology ideas and improve our economics for the play. Our independent reserve evaluators have only assigned reserves to the first well in this multi-well development.

A second resource play where we can apply our innovative completion experience is in the Horn River Shale Basin in northeast B.C. As this emerging play developed we began to build an acreage position, which has now expanded to 82 B.C. sections (54,721 acres) of 100% working interest lands and 14 B.C. sections of 15.5% working interest lands. Our first horizontal evaluation well was drilled in the first quarter of 2009 in an area with all-season access close to the Alaska Highway. The majority of the basin is characterized by a short three-month operating season (January to March) due to the presence of thick muskeg. All-season access at this first location allowed us to complete the multi-stage fracture stimulation during the second quarter of 2009. Our immediate focus will be on drilling test wells and developing a multi-year inventory of drilling locations in the Muskwa and Evie shales. No reserves have been assigned to our Horn River asset base as at December 31, 2008.

### *Cornwall*

Late in 2007, we drilled an exploration well in the Cornwall area which tested gas at 6.5 mmcf/day with 200 barrels per day of condensate. We completed a short pipeline tie-in with compression installation during the quarter, and brought the well on production April 1<sup>st</sup> to take advantage of recently announced royalty incentives in the province of Alberta. Production from the well has been pipeline restricted at rates between 2.0 to 2.5 mmcf/day.

### **HEAVY OIL BUSINESS UNIT (HBU) OPERATIONAL UPDATE**

- Achieved stable production rates from our P3B well with air injection at one-third of design rates
- Effectively eliminated sand production with revised P3B liner design
- Produced at restricted rates of 248 bopd in March and 256 bopd in April
- Sustained P3B wellbore temperatures in the catalyst activation range
- Filed the Kerrobert project application with the Saskatchewan regulatory authorities
- Advanced the May River and Dawson project applications through the Alberta regulatory process

### *Whitesands Project*

During March and into the second quarter of 2009, P3B operations were stabilized and rateable production was achieved. In the first quarter, P3B operations were ramped up following the A3 injection well workover and the commissioning of new plant facilities. Production averaged 248 bopd in March and 256 bopd in April, these restricted production rates correspond to a reduced air injection rate required to balance P2 production operations. The highest daily oil rate from the P3B well was 378 bopd in March and 404 bopd in April. During April, production from the P1 well was suspended and maintenance work on the P3B wellhead and primary separator reduced on-stream factors.

Since the initiation of production operations on P3B the well has exhibited negligible sand production, irrefutably proving the effectiveness of the new liner design. Produced gas volumes and rates are also in balance with the air injection rate, confirming the toe to heel process. Wellbore temperatures are now between 300 and 400°C, within the CAPRI™ catalyst activation range. Preliminary analysis of produced oil from P3B indicates upgrading to 12 degrees API, similar to the other wells. However, P3B oil has shown a significant reduction in asphaltene content, an increased volume of condensed light oil production and higher hydrocarbon content in the produced gas. Now that the well is operating in the optimum catalyst temperature range, conclusive, quantitative evidence confirming catalytic upgrading is expected with further testing. Associated water production continues to be high quality and is easily separated from the produced oil. Continuous upgrading and the composition of the produced gas indicate sustained high temperature combustion.

We have a drilling rig on-site and plan to have our P1 replacement well, P1B, drilled in the second quarter incorporating our new liner design. We have decided to cost-effectively convert Whitesands into a modified three well THAI™/CAPRI™ demonstration site, which will enable us to test any other new technology options, such as oxygen enrichment, using the existing facilities.

### *Kerrobert Project*

Pre-development work is currently underway on our two well, THAI™ conventional heavy oil project at Kerrobert. This third party THAI™ license project is located in west central Saskatchewan. We filed the Saskatchewan Ministry of Energy and Resources enhanced oil recovery regulatory application for the project on April 22<sup>nd</sup>. This filing begins the approximately one month approval process. Pending regulatory approval we expect to begin site preparation and drilling early in June, with the Pre-ignition Heating Cycle beginning in July and first production expected by the fourth quarter.

A public open house was held on April 17<sup>th</sup> in Kerrobert. A broad cross section of the local communities, land owners, and government representatives attended the open house. We received a positive response and encouragement for the project and its potential.

This joint project will highlight the applicability of the THAI™ technology in the conventional heavy oil resource base in Saskatchewan. We consider that a significant portion of the estimated 20 billion of barrels of unrecovered conventional heavy oil resources in Saskatchewan can be commercialized using THAI™. In addition, Saskatchewan is actively encouraging oil and gas development and the application of advanced technologies.

### *May River Project*

The May River Project is our first large-scale commercial THAI™ project on Petrobank's oil sands leases west of Conklin, Alberta. The May River project design builds on the experience gained from the Whitesands pilot. This project will be built in phases, with initial production capacity of 10,000 barrels of THAI™ oil per day, and an ultimate capacity of up to 100,000 bopd.

The regulatory application for May River's first phase was filed with the Energy Resources Conservation Board and Alberta Environment in December 2008. The application has been deemed complete and is now moving efficiently through the regulatory process. The front end engineering and design for the project began in the fourth quarter of 2008, and we expect to have completed this phase of engineering by the third quarter of 2009. The design incorporates self-sufficient power generation utilizing low-energy produced gas, sulphur recovery, is CO2 capture ready, and will be a net water producer rather than a water user. These designs contribute to making the May River project a leading environmentally sustainable process for oil sands and heavy oil development. The project is also designed to utilize a modular approach with direct applicability to heavy oil projects world-wide.

### *Dawson Project*

The Dawson Project is a joint project involving our first Alberta-based, third party THAI™ license. Our partner is now Shell Canada Limited who acquired Duvernay Oil Corp. in August 2008. The project is located near Peace River, Alberta and will be developed in the Bluesky formation. In August 2008, a stratigraphic well was drilled on the project site, which will be used as a thermal observation well during the project's operating phase. The regulatory application for the project was filed on April 2<sup>nd</sup>.

### *Business Development*

Our wholly-owned subsidiary, Archon Technologies Ltd., continues to evaluate a number of innovative engineering, environmental, and other value-added technology options to improve operational efficiency, increase product quality, and reduce the overall environmental impact of bitumen and heavy oil recovery. Technologies being assessed include enriched oxygen injection, power generation using produced lean gas, enhanced produced water quality, and incremental surface upgrading.

We continue to receive increasing world-wide interest in our technologies because of their superior economic and environmental benefits. Our joint project strategy is to demonstrate and commercialize THAI™ in a wide range of large global resource opportunities. Negotiations are ongoing and we expect to successfully conclude additional joint projects in the near term.

### **LATIN AMERICAN BUSINESS UNIT - PETROMINERALES LTD. (TSX: PMG – CURRENTLY 76.9% OWNED)**

A full operational update of our 76.9% owned Latin American Business Unit, Petrominerales Ltd., was published on May 6, 2009 and can be found at [www.petrominerales.com](http://www.petrominerales.com) and [www.sedar.com](http://www.sedar.com). Highlights of this release included:

- Significant production growth in the quarter; crude oil production increased 152% to 21,771 bopd due to drilling successes at Corcel, Mapache and Neiva.
- Strong operating netbacks resulted in cash flow of US\$41.8 million (US\$0.42 per share) and net income of US\$7.4 million (US\$0.07 per share) despite a sharp drop in world oil prices.
- Solid financial position with net working capital of US\$16.3 million, an undrawn US\$80 million credit facility, strong cash flows and operating netbacks combined with significant production growth.
- Continued drilling success has resulted in production averaging 25,252 bopd to date in May.
- Repurchased 802,200 common shares under a normal course issuer bid.

## **MANAGEMENT'S DISCUSSION AND ANALYSIS**

The following Management's Discussion and Analysis ("MD&A") is dated May 11, 2009 and should be read in conjunction with the unaudited consolidated financial statements and accompanying notes of Petrobank Energy and Resources Ltd. ("Petrobank", "we", "our" or the "Company") as at and for the three months ended March 31, 2009, MD&A for the year ended December 31, 2008, and the audited consolidated financial statements as at and for the year ended December 31, 2008. Additional information for the Company, including the Annual Information Form ("AIF"), can be found on SEDAR at [www.sedar.com](http://www.sedar.com) or at [www.petrobank.com](http://www.petrobank.com). All amounts are in Canadian dollars, unless otherwise stated and all tabular amounts are in thousands of Canadian dollars, except share amounts or as otherwise noted. Natural gas volumes have been converted to barrels of oil equivalent ("boe"). Six thousand cubic feet ("mcf") of natural gas is equal to one barrel based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Boes may be misleading, especially if used in isolation.

### **Forward-Looking Statements**

In addition to historical information, the MD&A contains forward-looking statements that are generally identifiable as any statements that express, or involve discussions as to, expectations, beliefs, plans, objectives, assumptions or future events of performance (often, but not always, through the use of words or phrases such as "will likely result," "expected," "is anticipated," "believes," "estimated," "intends," "plans," "projection" and "outlook"). These statements are not historical facts and may be forward-looking and may involve estimates, assumptions and uncertainties which could cause actual results or outcomes to differ materially from those expressed in such forward-looking statements. The reader is cautioned that assumptions used in the preparation of such information, although considered reasonable at the time of preparation, may prove to be incorrect. Actual results achieved during the forecast period will vary from the information provided herein as a result of numerous known and unknown risks and uncertainties and other factors. Such factors include, but are not limited to: general economic, market and business conditions; fluctuations in oil and gas prices; the results of exploration and development of drilling and related activities; costs and availability of services; fluctuation in foreign currency exchange rates; the uncertainty of reserve estimates; changes in environmental and other regulations; risks associated with oil and gas operations; the ability to economically test, develop and utilize the Company's patented technologies, the feasibility of the technologies; and other factors, many of which are beyond the control of the Company. Accordingly, there is no representation by Petrobank that actual results achieved during the forecast period will be the same in whole or in part as those forecasts. Except to the extent required by law, Petrobank assumes no obligation to publicly update or revise any forward-looking statements made in this MD&A or otherwise, whether as a result of new information, future events or otherwise. All subsequent forward-looking statements, whether written or oral, attributable to Petrobank or persons acting on the Company's behalf, are qualified in their entirety by these cautionary statements.

### **Non-GAAP Measures**

This report contains financial terms that are not considered measures under Canadian generally accepted accounting principles ("GAAP"), such as funds flow from operations, funds flow per share, EBITDA, net debt and operating netback. These measures are commonly utilized in the oil and gas industry and are considered informative for management and shareholders. Specifically, funds flow from operations and funds flow per share reflect cash generated from operating activities before changes in non-cash working capital. Management considers funds flow from operations and funds flow per share important as they help evaluate performance and demonstrate the Company's ability to generate sufficient cash to fund future growth opportunities and repay debt. EBITDA is defined as earnings before interest, taxes, depreciation, amortization, non-controlling interest and non-cash items. Net debt includes bank debt plus

accounts payable and accrued liabilities less current assets (excluding future income tax asset) and is used to evaluate the Company's financial leverage. Profitability relative to commodity prices per unit of production is demonstrated by an operating netback. Funds flow from operations, funds flow per share, EBITDA, net debt and operating netbacks may not be comparable to those reported by other companies nor should they be viewed as an alternative to cash flow from operations, net income or other measures of financial performance calculated in accordance with GAAP.

## **2009 Year to Date Highlights and Significant Transaction**

(Comparisons are first quarter of 2009 compared to the first quarter of 2008)

- Petrobank's production almost doubled to 43,856 barrels of oil equivalent per day ("boepd") in the first quarter of 2009.
- Canadian Business Unit ("CBU") production increased 59% to 22,085 boepd.
- Latin American Business Unit ("LABU") production increased 152% to 21,771 bopd.
- Our Heavy Oil Business Unit ("HBU") produced 248 bopd in March and 256 bopd in April.
- Despite a sharp drop in world oil prices funds flow from operations increased by 1% to \$125.2 million (\$1.40 per diluted share). We recorded a net loss of \$1.5 million (\$0.02 per diluted share) in the first quarter compared to net income of \$35.5 million (\$0.40 per diluted share) in the same 2008 period.
- CBU production expenses improved 27% to \$6.81/boe and LABU production expenses improved 32% to \$7.40/bbl.
- CBU operating netbacks averaged \$34.68/boe excluding hedging gains of \$5.31/boe and LABU operating netbacks averaged \$30.18/bbl in the first quarter.
- On April 27, 2009, Petrobank agreed to sell 9.9 million shares of our Petrominerales holdings for gross proceeds of \$101.5 million. The transaction is expected to be completed on or about May 15, 2009, at which time Petrobank's ownership interest will be reduced to 66.8%.

## **Financial and Operational Review**

(Comparisons are first quarter 2009 compared to the first quarter of 2008 unless otherwise noted)

Petrobank reported strong funds flow from operations of \$125.2 million, or \$1.40 per diluted share, in the first quarter of 2009 as year over year sales volumes almost doubled to 43,856 boepd. Funds flow from operations increased 1% from the prior year, despite a 56% decrease in world oil prices. CBU infrastructure investments in 2008 reduced operating expenses to \$6.81/boe in the first quarter, preserving strong operating netbacks of \$34.68/boe, excluding hedging gains of \$5.31/boe. Similarly in Colombia, continued improvements in production operations also decreased operating expenses to \$7.40/bbl, leading to operating netbacks of \$30.18/bbl.

### Average Daily Crude Oil Production

Three months ended March 31,	2009	2008	Change
<b>CBU</b>			
Oil and NGL (bbls)	<b>19,722</b>	11,351	74%
Natural gas (mcf)	<b>14,179</b>	15,229	(7%)
Total CBU (boe)	<b>22,085</b>	13,889	59%
LABU – light / medium oil (bbls) <sup>(1)</sup>	<b>21,771</b>	8,635	152%
Total Company conventional (boe)	<b>43,856</b>	22,524	95%

<sup>(1)</sup> Represents crude oil produced in the period. Actual sales volumes may be different due to crude oil in transit at the period end date. Sales volumes in the first quarter of 2009 were 21,409 bopd.

Strong production in the CBU and record production in the LABU in the first quarter helped Petrobank almost double production to 43,856 boepd. HBU bitumen volumes are excluded from average daily production as Whitesands operations are considered to be in the pre-operating stage and accordingly revenues are offset against capitalized costs as opposed to being recognized in net income.

The significant increases in oil and NGL production in the CBU are due to production increases from the Company's Bakken light oil properties in southeast Saskatchewan, which accounted for approximately 88% of the CBU's production in the first quarter. The increases were achieved through continued drilling activity and the acquisition of Peerless in the first quarter of 2008. The Company drilled 187.5 net Bakken wells in 2008 and drilled an additional 16 in the first quarter of 2009. We currently have two drilling rigs working in the area and will continue to monitor industry conditions and position ourselves to be able to ramp up or scale down drilling activity with minimal delay.

Natural gas production was lower in the first quarter primarily due to natural declines. In the first quarter we completed natural gas wells at Monias and Cornwall and brought on production at the end of the quarter. The Monias well had rate restricted initial production of approximately 5.5 mmcf per day and is the first on the Company's Montney formation lands acquired through the acquisition of Rocor Resources Inc. in the fourth quarter of 2008. This well is currently producing at approximately 2.2 mmcf per day showing the typical production pattern where the rates drop quickly and then flatten at a much lower decline rate. The Cornwall well has been on production since April 1, 2009 at pipeline restricted rates between 2.0 to 2.5 mmcf per day.

LABU oil production increased in the first quarter primarily due to drilling success at Corcel, Mapache and Neiva. Compared to fourth quarter of 2008 production of 15,344 bopd, the 2009 production levels represent 42% quarter over quarter production growth. At Corcel, the Company drilled and tied-in eight successful oil wells since the first quarter of 2008, resulting in six wells on production in 2009 compared to two in the comparable 2008 period. Orito production was 20% lower due to the effects of a general strike in the Putumayo region. Neiva production increased 194% due to the results of our recent drilling program that added six new producing wells in the quarter. The two exploration wells drilled on the Mapache block in 2008, Mapache-1 and Mirasol-1 were tested in the first quarter of 2009, resulting in two new discoveries. Production from the Mapache block commenced in March and averaged 2,022 bopd for the month.

### Average Benchmark and Realized Prices

Three months ended March 31,	2009	2008	Change
WTI (US\$/bbl)	<b>43.08</b>	97.82	(56%)
WTI (\$/bbl)	<b>53.69</b>	98.15	(45%)
NYMEX natural gas (US\$/mmbtu)	<b>4.48</b>	8.75	(49%)
US\$/\$ exchange rate	<b>0.80</b>	1.00	(20%)
<b>CBU – oil and NGL</b>			
Realized price per bbl (\$/bbl)	<b>49.93</b>	95.57	(48%)
US\$ discount as a % of WTI	<b>10%</b>	3%	233%
<b>CBU – natural gas</b>			
Realized price per mcf (\$/mcf)	<b>5.38</b>	7.73	(30%)
<b>LABU – light / medium oil</b>			
Realized price per bbl (\$/bbl)	<b>49.46</b>	88.91	(44%)
US\$ discount as a % of WTI	<b>8%</b>	9%	(11%)

The realized oil and NGL prices received by the CBU in the first quarter decreased as a result of lower average WTI prices and wider differentials. The differentials compared to WTI increased primarily due to larger benchmark crude differentials from WTI experienced by the industry in January and February before improving in March. A portion of the differential is also fixed which causes the percentage to increase as WTI decreases. Canadian dollar denominated realized prices benefited from a 20% devaluation of the Canadian dollar relative to the U.S. dollar.

In the first quarter, approximately 15% of natural gas production was sold under the Company's long-term physical natural gas sales contract at a price of \$5.43 per mcf (2008 – \$5.22 per mcf).

In Colombia, the realized oil prices also decreased as a result of lower average WTI prices offset by a smaller discount to WTI. The discount as a percentage of WTI decreased to 8% versus 9% in the 2008 period mainly due to positive quality premiums received for Corcel sales volumes.

### Revenue

The change in revenue in the first quarter of 2009 compared to the first quarter of 2008 is primarily due sales volumes that were 59% higher in the CBU and 148% higher in the LABU, offset by lower oil prices, as summarized below:

Reconciliation of Changes in Revenue	CBU	LABU	Total
Three months ended March 31, 2008	109,423	69,868	179,291
Sales volumes	34,769	56,435	91,204
Price variance	(48,706)	(31,003)	(79,709)
<b>Three months ended March 31, 2009</b>	<b>95,486</b>	<b>95,300</b>	<b>190,786</b>
\$ change in revenue	(13,937)	25,432	11,495
% change in revenue	(13%)	36%	6%

Three months ended March 31,	2009	2008	Change
CBU revenue	<b>95,486</b>	109,423	(13%)
LABU revenue	<b>95,300</b>	69,868	36%
Total revenue	<b>190,786</b>	179,291	6%
CBU transportation costs	<b>2,451</b>	3,817	(36%)
LABU transportation costs	<b>14,018</b>	1,870	650%
Total transportation costs	<b>16,469</b>	5,687	190%
CBU revenue, net of transportation costs	<b>93,035</b>	105,606	(12%)
LABU revenue, net of transportation costs	<b>81,282</b>	67,998	20%
Total revenue, net of transportation costs	<b>174,317</b>	173,604	-
CBU gross revenue (\$/boe)	<b>48.04</b>	86.57	(45%)
CBU transportation costs (\$/boe)	<b>1.23</b>	3.02	(59%)
CBU realized price, net of transportation costs (\$/boe)	<b>46.81</b>	83.55	(44%)
LABU gross revenue (\$/bbl)	<b>49.46</b>	88.91	(44%)
LABU transportation costs (\$/bbl)	<b>7.28</b>	2.38	206%
LABU realized price, net of transportation costs (\$/bbl)	<b>42.18</b>	86.53	(51%)

Total revenue, net of transportation remained relatively consistent in the first quarter of 2009 as higher production was offset by lower realized prices, in both the CBU and LABU.

In the CBU, transportation costs decreased in both dollar terms and on a per boe basis as an increasing number of our wells are tied into our southeast Saskatchewan facilities and we realized a reduction in trucking tariffs.

In the LABU, transportation costs relate to trucking sales oil from Corcel and Mapache to various offloading stations. Transportation costs increased in 2009 in both dollar terms and on a per barrel basis due to higher Corcel sales volumes that were trucked to more distant offloading stations. Access to pipeline and offloading infrastructure is critical to growing production in the region. Petrominerales has secured additional offloading capacity with the construction of the Monterrey facility that will give Petrominerales up to an initial 20,000 barrels per day of incremental offloading capacity. Initial start-up of this facility is planned for May 2009 with a capacity of 11,000 bopd, and the remaining capacity is expected to be available in the third quarter of 2009. Monterrey will be the closest offloading station to Corcel resulting in significant savings on trucking costs.

### Royalties

Three months ended March 31,	2009	2008	Change
CBU	<b>10,571</b>	8,523	24%
LABU	<b>8,870</b>	6,485	37%
Total royalties	<b>19,441</b>	15,008	30%
CBU – \$ per boe	<b>5.32</b>	6.74	(21%)
LABU – \$ per bbl	<b>4.60</b>	8.25	(44%)
CBU – royalties as a % of realized price, net of transportation	<b>11%</b>	8%	38%
LABU – royalties as a % of realized price, net of transportation	<b>11%</b>	10%	10%

CBU royalties include the Saskatchewan Resource Surcharge charged as a percentage of sales from our Saskatchewan Crown lands. As a percentage of realized prices, net of transportation, CBU royalties increased in the first quarter as a portion of the Company's Bakken wells no longer receive their royalty holidays. The first 37,740 barrels of production from horizontal Bakken wells drilled on Crown land incur a royalty rate of 2.5% plus Saskatchewan Resource Surcharge of 1.7%.

Colombian government royalties are fixed at a rate of eight percent until the Company's net production per field exceeds 5,000 bopd, and then increase by one percent for each incremental 10,000 bopd of production per field. In addition, there is an eight percent net profits interest ("NPI") applicable to the

Corcel Block. Royalties as a percentage of realized oil price, net of transportation, increased to 11% in the first quarter of 2009 as a higher proportion of production is coming from Corcel and is subject to the NPI.

#### Gain (Loss) on Risk Management Contracts

Three months ended March 31,	2009	2008	Change
CBU realized gain (loss)	<b>10,555</b>	(1,582)	-
LABU realized loss	-	(1,858)	-
CBU unrealized loss	<b>(8,328)</b>	(616)	1,252%
LABU unrealized loss	-	(284)	-
<b>Gain (loss) on risk management contracts</b>	<b>2,227</b>	(4,340)	-

The realized gain for actual monthly settlements incurred during the first quarter was \$5.31 per boe in the CBU. Unrealized gains and losses represent the change in fair value of the contracts related to expected future settlements.

At March 31, 2009, the Company had recorded a \$24.6 million asset related to the following risk management contract:

Business Unit	Term	Volume (Bopd)	Price (US\$/bbl)	Benchmark
CBU	Jan. 1, 2009 – Dec. 31, 2009	2,000	90.00 floor / 121.00 ceiling	WTI

#### Production Expenses

Three months ended March 31,	2009	2008	Change
CBU	<b>13,536</b>	11,818	15%
LABU	<b>14,260</b>	8,536	67%
Total production expenses	<b>27,796</b>	20,354	37%
CBU – \$ per boe	<b>6.81</b>	9.35	(27%)
LABU – \$ per bbl	<b>7.40</b>	10.86	(32%)

Consolidated production expenses increased in the first quarter of 2009 as a result of increased production. Production expenses per unit of production in the CBU decreased by 27% in the 2009 period, mainly due to Bakken production being handled through our two new facilities that were completed in the second half of 2008. In addition, these facilities have allowed Petrobank to add liquids rich natural gas production and reserves associated with Bakken light oil production.

Production expenses in the LABU increased in the first quarter of 2009 mainly due to higher Corcel production. Petrominerales completed the first-phase expansion of the Corcel central processing facilities in July 2008 to increase fluid handling capacity to 70,000 barrels of fluid per day. These permanent facilities replaced higher cost, less efficient temporary facilities resulting in improved U.S. dollar denominated production expenses through the last two quarters of 2008 and into 2009. In addition, as a portion of production expenses are fixed, when combined with higher production, has resulted in lower per barrel costs.

### General and Administrative Expenses

Three months ended March 31,	2009	2008	Change
CBU and HBU	3,940	3,033	30%
LABU	3,419	2,442	40%
Total general and administrative expenses	7,359	5,475	34%
CBU and HBU – \$ per CBU boe	1.98	2.40	(18%)
LABU – \$ per bbl	1.77	3.11	(43%)

Total general and administrative costs increased in the first quarter of 2009, primarily due to additional personnel as a result of expanding operations. On a unit of production basis, these costs have decreased due to higher production levels in both Canada and the LABU.

### Stock-Based Compensation Expenses

Three months ended March 31,	2009	2008	Change
CBU and HBU (Petrobank)	6,254	2,234	180%
LABU (Petrominerales)	1,422	412	245%
Total stock-based compensation expenses	7,676	2,646	190%

Stock-based compensation expenses relate to stock options and deferred common shares granted by Petrobank and Petrominerales. The calculation of this non-cash expense is based on the fair value of stock options and deferred common shares granted, amortized over the vesting period of the option, or immediately upon grant of the deferred common shares.

### Interest Expense

Three months ended March 31,	2009	2008	Change
CBU and HBU	6,209	3,613	72%
LABU	2,960	2,672	11%
Total interest expense	9,169	6,285	46%

Interest expense includes interest on bank debt and convertible debentures, fees on letters of credit and amortization of deferred financing costs. Interest expense includes non-cash accretion related to the convertible debentures of \$4.8 million in the first quarter (2008 – \$2.4 million). In addition, the depreciation of the Canadian dollar relative to the U.S. dollar in 2009 compared to the first quarter of 2008 resulted in higher Canadian dollar denominated interest expense as interest on the convertible debentures is payable in U.S. dollars. Interest expense was also higher in Canada as outstanding bank debt averaged \$315 million in the first quarter compared to approximately \$100 million a year earlier, offset somewhat by a decrease in interest rates.

### Foreign Exchange Loss (Gain)

Three months ended March 31,	2009	2008	Change
CBU and HBU (Canada)	6,994	7,713	(9%)
LABU (Colombia)	(3,510)	2,329	-
Total foreign exchange loss (gain)	3,484	10,042	(65%)

The Company recognized foreign exchange losses primarily due to the depreciation of the Canadian dollar relative to the U.S. dollar. An unrealized foreign exchange loss of \$7.3 million in the first quarter of 2009 (2008 – \$7.7 million) was recorded on Petrobank's U.S. dollar denominated convertible debentures, offset by an unrealized foreign exchange gain of \$3.2 million (2008 – nil) in the LABU relating to Colombian peso denominated working capital and future income tax liabilities.

**Depletion, Depreciation and Accretion (“DD&A”) Expense**

Three months ended March 31,	2009	2008	Change
CBU	58,894	37,527	57%
LABU	49,851	15,744	217%
Total DD&A expense	108,745	53,271	104%
CBU – \$ per boe	29.63	29.69	-
LABU – \$ per bbl	25.87	20.04	29%

Higher production caused DD&A expense to increase in the first quarter of 2009. The DD&A rate per unit of production in the CBU remained relatively consistent, while the LABU rate remained relatively consistent on a U.S. dollar basis but increased on a Canadian dollar basis due to the depreciation of the Canadian dollar relative to the U.S. dollar.

**Current Taxes**

Three months ended March 31,	2009	2008	Change
Current taxes	1,477	938	57%

Current taxes consist of income, presumptive income and equity taxes in Colombia. Equity tax is based on equity capitalization levels in Colombia, while presumptive income tax is charged in periods where taxable income is below certain thresholds, and when paid, can be carried forward for five years and be recovered against income taxes in future periods. Petrominerales’ pre-tax income is subject to the Colombian statutory income tax rate of 33%.

**Future Income Taxes (Recovery)**

Three months ended March 31,	2009	2008	Change
CBU and HBU (Canada)	(1,682)	10,919	-
LABU (Colombia)	(7,671)	4,895	-
Total future income taxes (recovery)	(9,353)	15,814	-

The Company’s future tax recovery in Canada is consistent with the Company’s change in Canadian income after adjustments for non-deductible items. A future income tax recovery was also recorded in the LABU in the first quarter due to an estimated taxable loss in Colombia.

**Income Applicable to Non-Controlling Interest (“NCI”)**

Three months ended March 31,	2009	2008	Change
Income applicable to NCI	2,421	5,338	(55%)

The income applicable to NCI represents the 23.3% non-controlling interest share (2008 – 23.6%) of Petrominerales’ net income. The income applicable to NCI decreased in the first quarter due to the decrease in Petrominerales’ income.

Petrominerales announced a normal course issuer bid on August 14, 2008 authorizing Petrominerales to purchase up to 5,032,718 common shares by August 17, 2009. To March 31, 2009, Petrominerales had repurchased a total of 2,128,200 common shares. For every share purchased on the open market one share is also purchased from Petrobank; accordingly, Petrobank’s ownership interest is increasing as a result of the bid as it is participating for less than its prorated ownership interest.

On April 27, 2009, the Company announced a bought-deal secondary offering whereby Petrobank agreed to sell 9.9 million shares of our Petrominerales holdings for gross proceeds of \$101.5 million. The transaction is expected to be completed on or about May 15, 2009, at which time Petrobank’s ownership interest will be reduced to approximately 66.8%.

## Net Income (Loss)

The change in net income (loss) in the first quarter of 2009 is primarily due to lower commodity prices and higher DD&A expense and transportation costs, offset by higher production and a future income tax recovery, as summarized below:

<b>Reconciliation of Changes in Net Income (Loss)</b>	<b>Amount</b>	<b>Per share, diluted</b>
Three months ended March 31, 2008	35,537	0.40
Increase (decrease) due to:		
Sales volumes	91,204	1.09
Realized prices	(79,709)	(0.95)
Royalties	(4,433)	(0.05)
Risk management contracts	6,567	0.08
Operating expenses	(7,442)	(0.09)
Transportation expenses	(10,782)	(0.13)
Stock based compensation expenses	(5,030)	(0.06)
Foreign exchange	6,558	0.08
DD&A expense	(55,474)	(0.66)
Future income taxes	25,167	0.30
Other <sup>(1)</sup>	(3,705)	(0.03)
<b>Three months ended March 31, 2009</b>	<b>(1,542)</b>	<b>(0.02)</b>

<sup>(1)</sup> Includes interest income, general and administrative expenses, interest expense, current taxes and income applicable to non-controlling interest.

## Funds Flow From Operations

The increase in funds flow from operations is primarily due to higher production offset by lower commodity prices, as summarized below:

<b>Reconciliation of Changes in Funds Flow From Operations</b>	<b>Amount</b>	<b>Per share, diluted</b>
Three months ended March 31, 2008	123,488	1.36
Increase (decrease) due to:		
Sales volumes	91,204	1.09
Realized prices	(79,709)	(0.95)
Royalties	(4,433)	(0.05)
Realized portion of risk management contracts	13,995	0.17
Operating expenses	(7,442)	(0.09)
Transportation expenses	(10,782)	(0.13)
Other <sup>(1)</sup>	(1,165)	-
<b>Three months ended March 31, 2009</b>	<b>125,156</b>	<b>1.40</b>

<sup>(1)</sup> Includes interest income, general and administrative expenses, cash interest expense, realized foreign exchange, current taxes and asset retirement obligations settled.

The following table shows the reconciliation of funds flow from operations to cash flow from operating activities for the periods noted:

Three months ended March 31,	<b>2009</b>	2008	Change
Funds flow from operations: Non-GAAP	<b>125,156</b>	123,488	1%
Changes in non-cash working capital	<b>(13,892)</b>	(53,791)	(74%)
Cash flow from operating activities: GAAP	<b>111,264</b>	69,697	60%

## Capital Expenditures

Three months ended March 31,	2009	2008	Change
CBU	<b>70,024</b>	110,489	(37%)
LABU	<b>81,560</b>	68,746	19%
HBU	<b>21,410</b>	21,035	2%
<b>Total capital expenditures</b>	<b>172,994</b>	200,270	(14%)

<b>Q1 2009 Capital Expenditures By Type</b>	<b>CBU</b>	<b>LABU</b>	<b>HBU</b>	<b>Total</b>
Drilling, completions and workovers	45,783	56,351	3,557	105,691
Facilities	14,726	14,889	5,474	35,089
Land	3,057	-	49	3,106
Seismic	338	7,591	916	8,845
Pilot capital	-	-	8,759	8,759
Other <sup>(1)</sup>	6,120	2,729	2,655	11,504
<b>Total capital expenditures</b>	<b>70,024</b>	<b>81,560</b>	<b>21,410</b>	<b>172,994</b>

<sup>(1)</sup> CBU and LABU include health, safety and environmental, capitalized salaries and office furniture. HBU includes \$2.6 million of capitalized cash interest and \$0.1 million of non-cash accretion.

CBU expenditures in the first quarter were mainly focused on drilling, completions and workovers, primarily at the Company's southeast Saskatchewan light oil properties as we drilled 16 net Bakken wells in the quarter, in addition to wells at Monias and Horn River. Facilities costs include expenditures on tying in wells and gathering systems to two major facilities that were completed in the latter half of 2008.

The Company's first quarter LABU expenditures focused on continuing exploration and development at Corcel, including drilling the D3 well, initial drilling operations on the E1 well, completing two wells, facilities costs to tie-in D structure production and related civil works. Orito expenditures included drilling three wells, completing two wells, and infrastructure and equipment costs to tie-in new wells. Neiva expenditures included drilling nine oil wells and completing eight wells. Mapache expenditures included completing two wells, the construction of temporary production facilities, and the commencement of a 91 square kilometre 3D seismic program. Exploration activity included costs associated with seismic acquisition programs and infrastructure work preparing heavy oil block drilling locations.

HBU expenditures in the first quarter included drilling oil sands exploration wells to further define the resource for the May River project, facility modifications, workovers, operating expenses, and capitalized interest. Currently, Whitesands operations are considered to be in the pre-operating stage and as a result, operating expenses net of revenues are capitalized.

## SUMMARY OF QUARTERLY RESULTS

	2009	2008				2007		
	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2
<b>Financial</b> (\$000s except where noted)								
Oil and natural gas revenue	<b>190,786</b>	206,161	317,137	247,479	179,291	127,308	63,006	37,577
Funds flow from operations	<b>125,156</b>	147,813	216,709	177,923	123,488	92,733	42,316	21,580
Per share – basic (\$)	<b>1.50</b>	1.78	2.62	2.16	1.53	1.20	0.55	0.28
– diluted (\$)	<b>1.40</b>	1.63	2.36	1.92	1.36	1.05	0.48	0.26
Net income	<b>(1,542)</b>	28,083	123,226	57,636	35,537	40,146	20,978	16,564
Per share – basic (\$)	<b>(0.02)</b>	0.34	1.49	0.70	0.44	0.52	0.27	0.22
– diluted (\$)	<b>(0.02)</b>	0.34	1.35	0.64	0.40	0.45	0.25	0.22
EBITDA	<b>130,884</b>	138,529	235,377	182,349	126,998	94,200	44,168	22,475
Capital expenditures	<b>172,994</b>	279,982	257,305	172,356	200,270	136,528	135,417	165,707
<b>Operations</b>								
<i>CBU operating netbacks by product</i>								
Light/medium oil and NGL sales price, net of transportation (\$/bbl)	<b>48.57</b>	57.71	115.11	117.64	91.87	80.83	76.56	67.53
Royalties	<b>5.39</b>	8.90	13.36	11.83	6.44	5.70	5.09	5.35
Production expenses	<b>6.98</b>	8.68	9.56	9.55	10.25	8.94	10.13	10.64
Operating netback	<b>36.20</b>	40.13	92.19	96.26	75.18	66.19	61.34	51.54
Natural gas sales price, net of transportation (\$/mcf)	<b>5.35</b>	6.86	7.94	9.83	7.73	6.05	5.25	6.77
Royalties	<b>0.78</b>	1.06	1.38	1.81	1.35	0.43	0.36	0.54
Production expenses	<b>0.90</b>	0.77	0.66	0.83	0.89	0.64	0.68	1.06
Operating netback	<b>3.67</b>	5.03	5.90	7.19	5.49	4.98	4.21	5.17
Oil equivalent sales price, net of transportation (\$/boe)	<b>46.81</b>	55.90	106.51	109.43	83.55	72.42	62.68	54.65
Royalties	<b>5.32</b>	8.62	12.72	11.70	6.74	5.11	4.18	4.35
Production expenses	<b>6.81</b>	8.24	8.84	8.88	9.35	7.99	8.26	8.60
Operating netback	<b>34.68</b>	39.04	84.95	88.85	67.46	59.32	50.24	41.70
<i>LABU operating netback (\$/bbl)</i>								
Oil sales price, net of transportation	<b>42.18</b>	54.93	110.53	115.77	86.53	76.53	72.74	63.29
Royalties	<b>4.60</b>	4.68	11.71	11.11	8.25	7.74	6.32	5.09
Production expenses	<b>7.40</b>	7.80	8.38	10.86	10.86	7.34	7.42	6.74
Operating netback	<b>30.18</b>	42.45	90.44	93.80	67.42	61.45	59.00	51.46
<i>Average daily production</i>								
CBU – light/medium oil and NGL (bbls)	<b>19,722</b>	19,841	16,024	14,205	11,351	6,691	3,745	2,132
CBU – conventional heavy oil (bbls)	-	-	-	-	-	-	-	-
CBU – natural gas (mcf)	<b>14,179</b>	14,598	14,047	13,871	15,229	9,379	10,006	11,771
Total CBU conventional (boe)	<b>22,085</b>	22,274	18,365	16,517	13,889	8,254	5,413	4,094
LABU – oil (bbls)	<b>21,771</b>	15,344	12,485	7,339	8,635	9,575	4,522	2,848
Total Company conventional (boe)	<b>43,856</b>	37,618	30,850	23,856	22,524	17,829	9,935	6,942

Significant factors influencing quarterly results were:

- Record production in both the CBU and LABU and high benchmark oil prices in the first three quarters of 2008 resulted in dramatic increases in operating netbacks, revenue and funds flow from operations. In the fourth quarter of 2008 and first quarter of 2009 benchmark crude oil prices declined significantly, which negatively affected profitability, despite higher production levels in both the CBU and LABU.
- Light oil production in the CBU in the first quarter of 2009 increased by 59% over the first quarter of 2008, reflecting the acquisition of Peerless in January 2008.
- The Company's industry leading drilling activity on the Bakken light oil resource play in southeast Saskatchewan contributed to continued CBU production increases throughout 2008.
- LABU production increased significantly in the last half of 2007 due to additions from the Corcel-A1 discovery well in the third quarter of 2007 and the follow up Corcel-A2 well in the fourth quarter of 2007.
- LABU production increased further in the third quarter of 2008 due to production additions from the Corcel-A4 and C1 wells.
- LABU production increased again in the fourth quarter of 2008 due to production additions from the Corcel-C3 and D1 wells, offset by a temporary suspension of operations at the Orito field from November 20, 2008 to January 5, 2009 due to a general strike in the region.
- First quarter 2009 LABU production increased further due to additions from Corcel-D2 and D1 recompletion, two wells on the Mapache block and six wells at Neiva.

## Commitments

The following is a summary of the estimated costs required to fulfill the Company's remaining contractual commitments as at March 31, 2009:

Type of Obligation	< 1 Year	1-3 Years	3-5 Years	Thereafter	Total
<i>CBU</i>					
Canadian bank debt (\$)	-	315,000	-	-	<b>315,000</b>
Petrobank convertible debentures (US\$) <sup>(1)</sup>	-	-	250,000	-	<b>250,000</b>
Office operating leases (\$)	3,600	7,500	10,200	25,400	<b>46,700</b>
Flow-through expenditures (\$)	8,000	-	-	-	<b>8,000</b>
<i>LABU</i>					
Petrominerales convertible debentures (US\$) <sup>(2)</sup>	-	81,700	-	-	<b>81,700</b>
Exploration contracts (US\$)	34,550	37,065	-	-	<b>71,615</b>
Offloading facility (US\$)	11,800	-	-	-	<b>11,800</b>
<b>Total Company</b> <sup>(3)</sup>	70,010	472,168	325,250	25,400	<b>892,828</b>

<sup>(1)</sup> The debentures are convertible into common shares of Petrobank at a conversion price of US\$28.4902 per share.

<sup>(2)</sup> The debentures are convertible into common shares of Petrominerales at a conversion price of US\$27.3485 per Petrominerales share.

<sup>(3)</sup> US\$ amounts have been converted using the March 31, 2009 exchange rate of \$1.2602.

## **Liquidity and Capital Resources**

The current economic slowdown and recent volatile financial and commodity markets have impacted the Company's operations and plans for 2009. The Company intends to balance capital spending with existing cash balances, expected future cash flows and prudent use of its credit facilities to execute its capital plans. As a result, the Company has slowed the pace of capital expenditures from what was incurred in 2008. The Company believes it is well positioned financially with cash on hand in Colombia, available capacity through our credit facilities, assets that are providing strong production platforms, operating netbacks and an inventory of prospects. The current economic environment, while challenging, is opening up opportunities and has resulted in lower costs and more availability of equipment and services.

At March 31, 2009, the Company had \$314.6 million of bank debt and accounts payable and accrued liabilities in excess of current assets of \$103.5 million, resulting in net debt of \$418.1 million. The ratio of debt to annualized EBITDA was 0.6 to 1.0, within a range acceptable to the Company, especially considering the commodity prices realized during the first quarter. On April 27, 2009, Petrobank agreed to sell 9.9 million shares of our Petrominerales holdings for gross proceeds of \$101.5 million which will provide additional cash, lower our net debt and increase our financial flexibility.

The Company's secured Canadian credit facilities combined borrowing limit totals \$380 million. The facilities are comprised of a \$320 million reserve-based revolver and a \$60 million oil sands resource-based revolver with terms ending on July 2009, extendable by the lenders for an additional year. If the lenders were to not extend the term, the drawn amounts would be due in July 2010. The syndicate of lenders of the Canadian facilities assess the borrowing bases semi-annually. The borrowing base under this facility is currently being reviewed by the syndicate of lenders to reflect the December 31, 2008 reserve evaluation.

The Company is in compliance with the covenants on its convertible debenture and credit facility agreements. Petrobank's convertible debenture agreement stipulates the Company maintain a ratio of equity to total assets of at least 30% and to limit the amount of security and encumbrances the Company has on its total assets to 27.5%. The Company is not subject to restrictive financial covenants under its Canadian credit facilities.

Petrominerales also has a revolving credit facility with an US\$80 million borrowing base that is undrawn. The borrowing base is reviewed with the lender semi-annually. Petrominerales is in compliance with the covenants contained in its convertible debenture and credit facility agreements. Petrominerales also maintains local Colombian operating lines of credit that are primarily used to issue letters of credit to support exploration agreements. Advances under the facility are collateralized by a promissory note provided by Petrominerales. Petrominerales has issued letters of credit totalling US\$12.2 million from their US\$16.9 million operating line of credit and pledged US\$3.2 million in restricted cash to guarantee exploration work commitments.

## **Outstanding Share Data**

The number of Petrobank shares outstanding at March 31, 2009 of 83,598,369 was unchanged as of the date of this MD&A.

## **Risks and Uncertainties**

There have been no significant changes in the three months ended March 31, 2009 to the risks and uncertainties identified in the MD&A for the year ended December 31, 2008.

## Sensitivities

The Company's earnings and cash flow are sensitive to changes in crude oil and natural gas prices, exchange rates and interest rates.

The following factors demonstrate the expected impact on annualized before tax cash flow:

<b>Change of:</b>		<b>(millions)</b>
<b>Crude oil</b>	US\$1.00/bbl WTI reference price (assuming 42,500 bopd)	<b>\$12.8</b>
	500 bopd of CBU production @ US\$50/bbl WTI	<b>\$7.9</b>
	500 bopd of LABU production @ US\$50/bbl WTI	<b>\$8.8</b>
<b>Natural gas</b>	\$1.00/mcf AECO reference price (assuming 15 mmcf per day)	<b>\$3.5</b>
	1.0 mmcf per day of CBU production @ \$4.00/mcf AECO	<b>\$1.0</b>
<b>Currency</b>	US\$0.01 in exchange rate	<b>\$7.2</b>
<b>Interest rate</b>	1% change in interest rate	<b>\$2.2</b>

## Critical Accounting Policies and Estimates

There have been no changes to the Company's critical accounting policies and estimates in the three months ended March 31, 2009.

## Changes in Accounting Policies

### *New Accounting Policies*

On January 1, 2009, the Company retrospectively adopted the Canadian Institute of Chartered Accountants ("CICA") Handbook Section 3064, *Goodwill and Intangible Assets* issued by the Canadian Accounting Standards Board ("AcSB"). The new section replaces the previous goodwill and intangible asset standard and revises the requirement for recognition, measurement, presentation and disclosure of intangible assets. The adoption of this standard had no impact on the Company's consolidated financial statements.

### *Recent and Pending Accounting Pronouncements*

In January 2009, the AcSB issued Section 1582, *Business Combinations*, which replaces former guidance on business combinations. Under the new standard, the purchase price used in a business combination is based on the fair value of consideration at the date of exchange. Currently the purchase price used is based on the fair value of the consideration for a reasonable period before and after the date of acquisition is agreed upon and announced. The new standard generally requires all acquisition costs be expensed, which are currently capitalized as part of the purchase price. In addition, the new standard modified the accounting for contingent consideration and negative goodwill. Section 1582 is effective for Petrobank on January 1, 2011 with prospective application and early adoption permitted. Once adopted, this standard will impact the accounting treatment of future business combinations.

In January 2009, the AcSB issued Sections 1601, *Consolidated Financial Statements*, and 1602, *Non-controlling Interests*, which replaces existing guidance. Section 1601 establishes standards for the preparation of consolidated financial statements and Section 1602 provides guidance on accounting for a non-controlling interest in a subsidiary subsequent to a business combination. These sections are effective for Petrobank on January 1, 2011 with prospective application and early adoption permitted. The adoption of these standards should not have a material impact on the Company's consolidated financial statements.

### *International Financial Reporting Standards*

The Canadian Accounting Standards Board has confirmed that International Financial Reporting Standards (“IFRS”) will replace Canadian GAAP effective January 1, 2011, including comparatives for 2010, for Canadian publicly accountable enterprises. The Company has completed its high-level IFRS impact study and established a preliminary timeline for the execution and completion of the conversion project. The impact of IFRS on the Company’s consolidated financial statements is not reasonably determinable at this time. Key information will be disclosed as it becomes available during the transition period.

### **Regulatory Policies**

#### *Certification of Disclosures in Interim Filings*

In accordance with Multilateral Instrument 52-109 of the Canadian Securities Administrators, the Company quarterly issues a “Certification of Interim Filings” (“Certification”). The Certification requires certifying officers to state that they are responsible for establishing and maintaining disclosure controls and procedures (“DC&P”) and internal control over financial reporting (“ICFR”).

The Certification requires certifying officers to state that they designed DC&P, or caused it to be designed under their supervision, to provide reasonable assurance that: (i) material information relating to Petrobank is made known to the certifying officers by others; (ii) information required to be disclosed by Petrobank in reports filed with, or submitted to, securities regulatory authorities is recorded, processed, summarized and reported within the time periods specified under Canadian securities legislation. In addition, the Certification requires certifying officers to state that they have designed ICFR, or caused it to be designed under their supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes.

During the quarter ended March 31, 2009, there has been no change in the Company’s ICFR that has materially affected, or is reasonably likely to materially affect, the Company’s ICFR. The Company has continually had in place systems relating to DC&P and ICFR and will continue to monitor such procedures as the Company’s business evolves.

### **Outlook**

In addition to the plans discussed in this MD&A, please see the Company’s first quarter 2009 Operational Update and 2008 Annual Report.

## CONSOLIDATED BALANCE SHEETS

(Unaudited, thousands of Canadian dollars)

As at	March 31, 2009	Dec. 31, 2008
<b>Assets</b>		
Current assets		
Cash and cash equivalents	\$ 40,862	\$ 102,181
Restricted cash (Note 3)	4,018	5,487
Accounts receivable and other current assets	120,259	81,702
Risk management asset	24,391	32,904
	<b>189,530</b>	222,274
Other assets	7,608	3,256
Capital assets	2,153,837	2,073,006
Goodwill	63,171	63,171
<b>Total assets</b>	<b>\$ 2,414,146</b>	<b>\$ 2,361,707</b>
<b>Liabilities and Shareholders' Equity</b>		
Current liabilities		
Accounts payable and accrued liabilities	\$ 293,008	\$ 262,777
Future income tax liability	7,364	9,860
	<b>300,372</b>	272,637
Bank debt (Note 3)	314,601	315,162
Convertible debentures	352,362	337,574
Obligations under gas sale contract	2,966	3,170
Asset retirement obligations	23,352	22,100
Future income tax liabilities	188,076	194,685
	<b>1,181,729</b>	1,145,328
Non-controlling interest (Note 5)	181,215	181,177
Commitments and contingencies (Note 10)		
Shareholders' equity		
Convertible debentures	64,089	64,089
Common shares (Note 4)	571,836	574,060
Contributed surplus (Note 4)	25,989	19,795
Accumulated other comprehensive income (Note 4)	56,420	42,848
Retained earnings	332,868	334,410
	<b>1,051,202</b>	1,035,202
<b>Total liabilities and shareholders' equity</b>	<b>\$ 2,414,146</b>	<b>\$ 2,361,707</b>

Subsequent events (Notes 5 and 8)

See accompanying notes to these consolidated financial statements.

## CONSOLIDATED STATEMENTS OF OPERATIONS AND RETAINED EARNINGS

(Unaudited, thousands of Canadian dollars, except per share amounts)

Three months ended March 31,	2009	2008
<b>Revenues</b>		
Oil and natural gas	\$ 190,786	\$ 179,291
Royalties	(19,441)	(15,008)
Gain (loss) on risk management contracts	2,227	(4,340)
Interest income	129	1,444
	<b>173,701</b>	<b>161,387</b>
<b>Expenses</b>		
Production	27,796	20,354
Transportation	16,469	5,687
General and administrative	7,359	5,475
Stock-based compensation	7,676	2,646
Interest (Note 6)	9,169	6,285
Foreign exchange loss	3,484	10,042
Depletion, depreciation and accretion	108,745	53,271
	<b>180,698</b>	<b>103,760</b>
<b>Income (loss) before taxes and non-controlling interest</b>	<b>(6,997)</b>	<b>57,627</b>
Current taxes	1,477	938
Future income taxes (recovery)	(9,353)	15,814
<b>Income before non-controlling interest</b>	<b>879</b>	<b>40,875</b>
Income applicable to non-controlling interest (Note 5)	2,421	5,338
<b>Net income (loss)</b>	<b>(1,542)</b>	<b>35,537</b>
<b>Retained earnings, beginning of period</b>	<b>334,410</b>	<b>100,457</b>
<b>Retained earnings, end of period</b>	<b>\$ 332,868</b>	<b>\$ 135,994</b>
<b>Basic earnings (loss) per share (Note 4)</b>	<b>\$ (0.02)</b>	<b>\$ 0.44</b>
<b>Diluted earnings (loss) per share (Note 4)</b>	<b>\$ (0.02)</b>	<b>\$ 0.40</b>

See accompanying notes to these consolidated financial statements.

## CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(Unaudited, thousands of Canadian dollars)

Three months ended March 31,	2009	2008
<b>Net income (loss)</b>	<b>\$ (1,542)</b>	<b>\$ 35,537</b>
Other comprehensive income:		
Unrealized gain on translation of financial statements of self-sustaining foreign operations (Note 4)	13,757	11,112
Unrealized loss on interest rate contracts (Note 8)	(185)	-
<b>Comprehensive income</b>	<b>\$ 12,030</b>	<b>\$ 46,649</b>

See accompanying notes to these consolidated financial statements.

## CONSOLIDATED STATEMENTS OF CASH FLOW

(Unaudited, thousands of Canadian dollars)

Three months ended March 31,	2009	2008
<b>Operating Activities</b>		
Net income (loss)	\$ (1,542)	\$ 35,537
Depletion, depreciation and accretion	108,745	53,271
Future income taxes (recovery)	(9,353)	15,814
Unrealized foreign exchange loss	4,092	7,713
Unrealized loss on risk management contracts	8,328	900
Stock-based compensation	7,676	2,646
Income applicable to non-controlling interest	2,421	5,338
Accretion on convertible debentures	4,835	2,371
Amortization of deferred financing costs	258	211
Asset retirement obligations settled	(304)	(313)
	<b>125,156</b>	123,488
Changes in non-cash working capital (Note 9)	(13,892)	(53,791)
	<b>111,264</b>	69,697
<b>Financing Activities</b>		
Issuance (repayment) of bank debt	(658)	122,993
Equity issued (repurchased) by Petrominerales – net of costs	(7,902)	240
Financing costs relating to bank debt	(234)	-
Issuance of common shares – net of costs	185	1,121
Amortization of obligations under gas sale contract	(204)	(206)
	<b>(8,813)</b>	124,148
<b>Investing Activities</b>		
Expenditures on capital assets	(172,994)	(200,270)
Corporate acquisition	-	(67,248)
Sale of interest in subsidiary (Note 5)	4,097	-
Changes in restricted cash	1,469	-
Expenditures on other assets	(4,147)	-
Changes in non-cash working capital (Note 9)	6,438	24,376
	<b>(165,137)</b>	(243,142)
Effect of exchange rate changes on cash and cash equivalents	1,367	4,688
<b>Net change in cash and cash equivalents</b>	<b>(61,319)</b>	<b>(44,609)</b>
<b>Cash and cash equivalents, beginning of period</b>	<b>102,181</b>	<b>171,439</b>
<b>Cash and cash equivalents, end of period</b>	<b>\$ 40,862</b>	<b>\$ 126,830</b>
Cash and cash equivalents consist of:		
Cash	\$ 8,631	\$ 9,701
Cash equivalents	\$ 32,231	\$ 117,129
Other cash flow information:		
Cash taxes paid	\$ -	\$ 1,112
Cash interest paid	\$ 3,369	\$ 2,033
Cash interest received	\$ 101	\$ 1,391

See accompanying notes to these consolidated financial statements.

## NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

As at and for the three months ended March 31, 2009 and 2008

(Unaudited, all tabular amounts are expressed in thousands of Canadian dollars, except share amounts or as otherwise noted)

### Note 1 – Significant Accounting Policies

The interim consolidated financial statements for Petrobank Energy and Resources Ltd. (“Petrobank” or the “Company”) as at and for the three months ended March 31, 2009 should be read in conjunction with the audited consolidated financial statements as at and for the year ended December 31, 2008. The notes to these interim consolidated financial statements do not conform in all respects to the note disclosure requirements of generally accepted accounting policies (“GAAP”) for annual consolidated financial statements. These interim consolidated financial statements are prepared using the same accounting policies and methods of computation as disclosed in the annual consolidated financial statements as at and for the year ended December 31, 2008, except for those disclosed in Note 2 below. The disclosures provided within are incremental to those included with the annual financial statements.

### Note 2 – Changes in Accounting Policies

#### *Goodwill and Other Intangibles*

On January 1, 2009, the Company retrospectively adopted the Canadian Institute of Chartered Accountants (“CICA”) Handbook Section 3064, *Goodwill and Intangible Assets* issued by the Canadian Accounting Standards Board (“AcSB”). The new section replaces the previous goodwill and intangible asset standard and revises the requirement for recognition, measurement, presentation and disclosure of intangible assets. The adoption of this standard had no impact on the Company’s consolidated financial statements.

#### *Credit Risk and Fair Value of Financial Assets and Liabilities*

On January 1, 2009, the Company adopted the CICA’s EIC-173, *Credit Risk and the Fair Value of Financial Assets and Financial Liabilities*. The EIC provides guidance on how to take into account credit risk of an entity and counterparty when determining the fair value of financial assets and financial liabilities, including derivative instruments. The adoption of this EIC had no impact on the Company’s consolidated financial statements.

#### *Recent and Pending Accounting Pronouncements*

In January 2009, the AcSB issued Section 1582, *Business Combinations*, which replaces former guidance on business combinations. Under the new standard, the purchase price used in a business combination is based on the fair value of consideration at the date of exchange. Currently the purchase price used is based on the fair value of the consideration for a reasonable period before and after the date of acquisition is agreed upon and announced. The new standard generally requires all acquisition costs be expensed, which are currently capitalized as part of the purchase price. In addition, the new standard modified the accounting for contingent consideration and negative goodwill. Section 1582 is effective for Petrobank on January 1, 2011 with prospective application and early adoption permitted. Once adopted, this standard will impact the accounting treatment of future business combinations.

In January 2009, the AcSB issued Sections 1601, *Consolidated Financial Statements*, and 1602, *Non-controlling Interests*, which replaces existing guidance. Section 1601 establishes standards for the preparation of consolidated financial statements and Section 1602 provides guidance on accounting for a non-controlling interest in a subsidiary subsequent to a business combination. These sections are effective for Petrobank on January 1, 2011 with prospective application and early adoption permitted. The adoption of these standards are not expected to have a material impact on the Company’s consolidated financial statements.

The Canadian Accounting Standards Board has confirmed that International Financial Reporting Standards (“IFRS”) will replace Canadian GAAP effective January 1, 2011, including comparatives for 2010, for Canadian publicly accountable enterprises. The Company has completed its high-level IFRS impact study and established a preliminary timeline for the execution and completion of the conversion project. The impact of IFRS on the Company’s consolidated financial statements is not reasonably determinable at this time. Key information will be disclosed as it becomes available during the transition period.

### Note 3 – Bank Debt and Restricted Cash

The Company’s secured Canadian credit facilities combined borrowing limit totals \$380 million. Petrominerales Ltd. (“Petrominerales”) has a credit facility with a US\$80 million borrowing base which was undrawn as at March 31, 2009, and also has a US\$16.9 million operating line of credit.

At March 31, 2009, Petrominerales had restricted cash of US\$3.2 million (December 31, 2008 – US\$4.5 million), consisting of cash deposited to guarantee work commitments under exploration contracts and as collateral for a letter of credit.

### Note 4 – Share Capital

As at March 31, 2009, the Company had 83,598,369 common shares, 6,646,475 stock options and 193,935 deferred common shares outstanding. Upon conversion of the Petrobank convertible debentures, a total of 8,774,947 additional shares could be issued.

#### *Common Shares*

<b>Common Share Continuity</b>	<b>Number</b>	<b>Amount</b>
Balance at December 31, 2008	83,525,394	\$ 574,060
Exercise of stock options	72,975	185
Transfer from contributed surplus related to stock options and deferred common shares exercised	-	60
Tax benefit renounced to shareholders <sup>(1)</sup>	-	(2,469)
<b>Balance at March 31, 2009</b>	<b>83,598,369</b>	<b>\$ 571,836</b>

<sup>(1)</sup> In December 2008, the Company issued 285,795 flow-through common shares at a price of \$33.00 and renounced \$9.4 million of resource expenditures to flow-through investors in the first quarter of 2009.

#### *Contributed Surplus*

<b>Changes in Contributed Surplus</b>	<b>Amount</b>
Balance at December 31, 2008	\$ 19,795
Stock-based compensation	6,254
Transfer from contributed surplus related to stock options and deferred common shares exercised	(60)
<b>Balance at March 31, 2009</b>	<b>\$ 25,989</b>

*Accumulated Other Comprehensive Income*

<b>Changes in Accumulated Other Comprehensive Income</b>	<b>Amount</b>
Balance at December 31, 2008	\$ 42,848
Unrealized gain on translation of financial statements of self-sustaining foreign operations	13,757
Unrealized loss on interest rate contracts	(185)
<b>Balance at March 31, 2009</b>	<b>\$ 56,420</b>

*Stock Option Continuity*

	<b>Stock Options</b>	<b>Weighted-Avg Exercise Price</b>
Balance at December 31, 2008	6,596,076	22.37
Granted	171,749	22.39
Exercised	(72,975)	2.53
Forfeited	(48,375)	24.58
<b>Balance at March 31, 2009</b>	<b>6,646,475</b>	<b>\$ 22.57</b>

*Deferred Common Share Continuity*

	<b>Number</b>
Balance at December 31, 2008	146,810
Granted	47,125
<b>Balance at March 31, 2009</b>	<b>193,935</b>

*Stock-Based Compensation*

The fair value of Petrobank stock options and deferred common shares granted have been estimated on their respective grant dates using the Black-Scholes option-pricing model using the following assumptions:

<b>Three months ended March 31,</b>	<b>2009</b>
Risk free interest rate	<b>1.75%</b>
Dividend rate	<b>0%</b>
Expected life – options (years)	<b>3.75 to 4</b>
Expected life – deferred common shares (years)	<b>8</b>
Expected volatility	<b>47.5%</b>

The average fair value per stock option granted during the first three months of 2009 was \$8.44 (2008 – \$16.24) as at the date of grant. The average fair value per deferred common share granted during the first three months of 2009 was \$22.31 (2008 – \$46.30) as at the date of grant.

Stock-based compensation expense for the three months ended March 31, 2009 totalled \$7.7 million (2008 – \$2.6 million), of which \$1.4 million (2008 – \$0.4 million) related to Petrominerales.

### Earnings Per Share

The following tables summarize the net income and weighted average number of common shares used in calculating basic and diluted earnings per share.

Three months ended March 31,	2009	2008
<b>Net income adjustments</b>		
Net income (loss), basic	\$ (1,542)	\$ 35,537
Interest expense on Petrobank's convertible debentures	-	2,023
Tax effect	-	(597)
Impact of Petrominerales dilution on net income	-	(527)
Net income (loss), diluted	\$ (1,542)	\$ 36,436
<b>Weighted average common share adjustments</b>		
Weighted average common share outstanding, basic	83,531,853	80,723,360
Effect of convertible debentures	-	8,774,947
Effect of stock options and deferred common shares	-	2,251,613
Weighted average common share outstanding, diluted	83,531,853	91,749,920

### Note 5 – Non-Controlling Interest

The components of the Company's non-controlling interest in Petrominerales, the Company's 76.7% owned subsidiary as at March 31, 2009 are as follows:

	Amount
Balance at December 31, 2008	\$ 181,177
Attributable income	2,421
Common shares issued by Petrominerales	308
Common shares repurchased by Petrominerales <sup>(1)</sup>	(8,210)
Common shares repurchased from Petrobank <sup>(1)</sup>	4,097
Stock-based compensation	1,422
<b>Balance at March 31, 2009</b>	<b>\$ 181,215</b>

<sup>(1)</sup> Petrominerales repurchased a total of 802,200 Petrominerales common shares during the first three months of 2009 under a Normal Course Issuer Bid ("NCIB") which authorizes Petrominerales to purchase up to 5,032,718 common shares until August 17, 2009. To March 31, 2009, Petrominerales had repurchased 2,128,200 common shares under their NCIB. For every share purchased on the open market one share was also purchased from Petrobank, accordingly, Petrobank's ownership interest increased as a result as it is participating for less than its prorated ownership interest.

On April 27, 2009 the Company announced a bought-deal arrangement where Petrobank agreed to sell 9.9 million shares of our Petrominerales holdings for gross proceeds of \$101.5 million. The transaction is expected to be completed on or about May 15, 2009, at which time Petrobank's ownership interest will be reduced to approximately 66.8%. The Company does not expect to record a gain or loss on this transaction.

## Note 6 – Interest Expense

Interest expense includes the following:

Three months ended March 31,	2009	2008
Cash interest	\$ 6,731	\$ 5,355
Accretion on Petrobank convertible debentures	3,606	2,668
Accretion on Petrominerales convertible debentures	1,310	1,182
Amortization of deferred financing costs	258	211
Capitalized interest related to Whitesands project <sup>(1)</sup>	(2,736)	(3,131)
Interest expense	\$ 9,169	\$ 6,285

<sup>(1)</sup> Capitalized interest includes \$2.6 million of cash and \$0.1 million of non-cash accretion (2008 – \$1.6 million and \$1.5 million, respectively).

## Note 7 – Capital Management

The Company's policy is to maintain a strong capital base in order to provide flexibility in the future development of the business and maintain investor, creditor and market confidence.

The Company manages its capital structure and makes adjustments to it in light of changes in economic conditions and the risk characteristics of the underlying assets. The Company considers its capital structure to include common share capital, convertible debentures, bank debt and working capital deficiency (a non-GAAP measure defined as accounts payable and accrued liabilities less current assets). In order to maintain or adjust the capital structure, from time to time the Company may issue common shares or other securities, obtain project financing on its heavy oil projects, sell assets or adjust its capital spending to manage current and projected debt levels. Petrobank is also able to raise funds by selling a portion of its ownership interest in Petrominerales or by issuing debt secured by this interest.

Petrominerales manages its capital structure independently and generates its own cash flows, and has the ability to fund its operations through the issuance of secured and unsecured debt as well as equity financing.

As at	March 31, 2009	Dec. 31, 2008
Bank debt – Petrobank	\$ 314,601	\$ 315,162
Bank debt – Petrominerales	-	-
Total bank debt	\$ 314,601	\$ 315,162
Working capital deficiency (surplus)	\$ 103,478	\$ 40,503
Convertible debentures – Petrobank principal amount (US\$)	250,000	250,000
Convertible debentures – Petrominerales principal amount (US\$)	81,700	81,700
Total convertible debentures (US\$)	\$ 331,700	\$ 331,700
Common share capital	\$ 571,836	\$ 574,060

The Company monitors leverage and adjusts its capital structure based on the ratio of Canadian bank debt to annualized Canadian earnings before interest, taxes and non-cash items. This ratio is based solely on Canadian bank debt and Canadian cash earnings as Petrominerales manages its leverage and capital structure independently. At March 31, 2009, the ratio of debt to annualized Canadian earnings before interest, taxes and non-cash items was 1 to 1, within a range acceptable to the Company. Petrobank uses the ratio of debt to annualized Canadian earnings before interest, taxes and non-cash items as a key indicator of the Company's leverage and to monitor the strength of the balance sheet. In order to facilitate the management of this ratio, the Company prepares annual budgets, which are updated as necessary depending on varying factors including current and forecast commodity prices, changes in capital

structure, execution of the Company's business plan and general industry conditions. The annual budget is approved by the Board of Directors and updates are prepared and reviewed as required.

The Petrobank convertible debentures are considered to be equity as opposed to debt. If Petrobank's share price is below the prevailing conversion price at maturity, Petrobank can elect to redeem the principal amount in common shares or re-pay the remaining principal with new debt, equity and / or accumulated cash. The Company has an option to force conversion of the debentures at the prevailing conversion price commencing in May 2010, should the price of the Company's common shares exceed 120% of the prevailing conversion price of the debentures over a specified period. If conversion of the debentures is forced, or if the Company's share price is in excess of the prevailing conversion price upon maturity in May 2012, the debentures will be converted into equity.

The Company is in compliance with the covenants on its convertible debenture and credit facility agreements. Petrobank's and Petrominerales' convertible debenture agreements stipulate they each maintain a ratio of equity to total assets of at least 30% and to limit the amount of security and encumbrances the Company has on its total assets to 27.5%. The Company is not subject to restrictive financial covenants under its Canadian credit facilities.

Neither the Company nor its subsidiaries has paid or declared any dividends since the date of incorporation.

There have been no changes to the Company's capital management during 2009 except the sale of a portion of Petrobank's ownership in Petrominerales.

Credit markets throughout the world have tightened recently which could limit the Company's ability to access incremental debt. The Company has positive cash flow from operations, \$44.9 million of cash and cash equivalents and restricted cash, a Canadian credit facility with \$65.0 million of available capacity, a US\$80 million credit facility available to Petrominerales and, in April 2009, Petrobank announced the sale of a portion of our Petrominerales shares for gross proceeds of \$101.5 million which will provide additional cash, lower our net debt and increase our financial flexibility.

## **Note 8 – Financial Instruments and Financial Risk Management**

The Company has exposure to the following risks from its use of financial instruments: credit risk, liquidity risk and market risk. This note presents information about the Company's exposure to each of these risks and the Company's objectives, policies and processes for measuring and managing risk. Further quantitative disclosures are included throughout these consolidated financial statements.

The Board of Directors has overall responsibility for the establishment and oversight of the Company's financial risk management framework and monitors risk management activities. The Company identifies and analyzes the risks faced by the Company and may utilize financial instruments to mitigate these risks.

### *Credit Risk*

A substantial portion of the Company's accounts receivable are with customers and joint-venture participants in the oil and natural gas industry and are subject to normal industry credit risks. The carrying amount of accounts receivable reflects management's assessment of the credit risk associated with these customers and participants. At March 31, 2009 the majority of the Company's Canadian oil production was being sold to a large international marketing company. To help mitigate the risk associated with the significant amount of Canadian oil production being sold to one purchaser, the Company arranged for early payments and / or letters of credit. Furthermore, in May 2009 the Company will commence selling a portion of our Canadian oil production to an additional purchaser. Colombian oil production is sold, as determined by market based prices adjusted for quality differentials, to three main counterparties: Ecopetrol, the Colombian national oil company, and the remainder to two international oil companies. Colombian oil revenue is received in Bermuda and is denominated in United States dollars. Typically,

Petrominerales' maximum credit exposure to customers is up to two months' sales revenue. Petrominerales does not anticipate non-performance by these counterparties.

The composition of the Company's accounts receivable are as follows:

As at	<b>March 31, 2009</b>	Dec. 31, 2008
Oil and natural gas customers	\$ 98,025	\$ 57,085
Tax receivable	10,999	10,088
Other	9,977	14,529
Total	\$ 119,001	\$ 81,702

Receivables from oil and natural gas marketers are normally collected 25 to 45 days after the month following production. The Company's policy to mitigate credit risk associated with these balances is to establish marketing relationships with large purchasers and, where practical, obtain support in the form of guarantees or letters of credit. Receivables from joint-venture partners related to capital and operating expenses are generally collected between 45 and 90 days after the month of billing. The Company historically has not experienced any material collection issues with its oil and natural gas customers or joint interest partners.

Cash and cash equivalents and restricted cash consist of cash bank balances and short term deposits maturing in less than 90 days. The Company manages the credit exposure related to short term investments by selecting counter parties based on credit ratings and by monitoring all investments to ensure a stable return, avoiding investment vehicles with higher risk such as asset backed commercial paper.

The carrying amount of accounts receivable, cash and cash equivalents and restricted cash represent the Company's maximum credit exposure. The Company had a \$0.8 million allowance for doubtful accounts as at March 31, 2009, and did not provide for any doubtful accounts nor was it required to write-off any receivables during the three months ended March 31, 2009.

The Company's accounts receivable are aged as follows:

As at	<b>March 31, 2009</b>	Dec. 31, 2008
Not past due	\$ 116,607	\$ 78,697
Past due	2,394	3,005
Total	\$ 119,001	\$ 81,702

### *Liquidity Risk*

The Company's approach to managing liquidity is to ensure, as far as possible, that it will have sufficient liquidity to meet its liabilities when due, under both normal and unusual conditions without incurring unacceptable losses or jeopardizing the Company's business objectives.

The Company prepares annual capital expenditure budgets, which are monitored and updated as considered necessary. Production is monitored regularly to provide current cash flow estimates and the Company utilizes authorizations for expenditures on projects to manage capital expenditures. To facilitate the capital expenditure program, the Company has revolving asset based credit facilities, as outlined in Note 3, that are reviewed semi-annually by the lenders.

The following are the contractual maturities of financial liabilities at March 31, 2009:

<b>Financial Liability</b>	<b>&lt; 1 Year</b>	<b>1-3 Years</b>	<b>3-5 Years</b>	<b>Total</b>
Accounts payable and accrued liabilities	\$ 293,008	\$ -	\$ -	\$ 293,008
Canadian bank debt – principal	-	315,000	-	315,000
Petrobank convertible debentures – principal (US\$)	-	-	250,000 <sup>(1)</sup>	250,000
Petrominerales convertible debentures – principal (US\$)	-	81,700 <sup>(2)</sup>	-	81,700
<b>Total</b> <sup>(3)</sup>	<b>\$ 293,008</b>	<b>\$ 417,958</b>	<b>\$ 315,050</b>	<b>\$ 1,026,016</b>

<sup>(1)</sup> The debentures are convertible to common shares of Petrobank at a conversion price of US\$28.4902 per share. Upon conversion, a total of 8,774,947 common shares may be issued. At maturity, the Company has the option to redeem the principal amount in cash or common shares if the debentures have not been converted.

<sup>(2)</sup> The debentures are convertible to common shares of Petrominerales at a conversion price of US\$27.3485 per Petrominerales share. Upon conversion, 2,987,367 Petrominerales common shares may be issued. At maturity, Petrominerales will redeem the principal amount in cash if the debentures have not been converted.

<sup>(3)</sup> US\$ amounts have been converted using a period end exchange rate of 1.2602.

### *Market Risk*

Market risk is the risk that changes in market factors, such as foreign exchange rates, commodity prices, and interest rates will affect the Company's cash flows, net income, liquidity or the value of financial instruments. The objective of market risk management is to mitigate market risk exposures where considered appropriate and maximize returns.

The Company may utilize derivative instruments to manage market risk. The Board of Directors periodically reviews the results of all risk management activities and all outstanding positions.

### Foreign Currency Risk

The Company is exposed to foreign currency fluctuations as Colombian revenues are denominated in United States dollars and Colombian expenses are denominated primarily in United States dollars and Colombian pesos. The Company is also exposed as Petrobank's convertible debentures are denominated in United States dollars and Canadian revenues are strongly linked to United States dollar denominated benchmark prices. At March 31, 2009, if the Canadian dollar had depreciated five percent against the United States dollar with all other variables held constant, net income would have been \$10.4 million lower for the three months ended March 31, 2009 (2008 – \$12.5 million lower), due to Petrobank's United States dollar denominated convertible debentures, offset by the risk management contracts related to Canadian production. Other comprehensive income would have been \$14.4 million higher (2008 – \$2.4 million higher) due to the foreign currency balances of Petrominerales that are translated into Petrobank's consolidated financial statements and risk management contracts related to Canadian production, offset by the Petrobank convertible debentures.

The Company had no forward exchange rate contracts in place as at or during the three months ended March 31, 2009.

### Commodity Price Risk

Changes in commodity prices may significantly impact the results of the Company's operations and cash generated from operating activities, and can also impact the Company's borrowing base under its secured credit facilities. Lower commodity prices can also reduce the Company's ability to raise capital. Crude oil prices are impacted by world economic events that dictate the levels of supply and demand. Natural gas prices in Canada are influenced primarily by North American supply and demand. From time to time the Company may attempt to mitigate commodity price risk through the use of financial derivatives. The

Company's policy is to only enter into commodity contracts considered appropriate to a maximum of 50% of forecasted production volumes.

The Company had the following risk management contract outstanding at March 31, 2009:

Country	Term	Volume (Bopd)	Price (US\$/bbl)	Benchmark
Canada	Jan. 1, 2009 – Dec. 31, 2009	2,000	90.00 floor / 121.00 ceiling	WTI

Three months ended March 31,	2009	2008
Realized gain (loss) on risk management contracts	\$ 10,555	\$ (3,440)
Unrealized gain (loss) on risk management contracts	(8,328)	(900)
Gain (loss) on risk management contracts	\$ 2,227	\$ (4,340)

The unrealized gain (loss) represents the change in fair value of the risk management contracts related to expected future settlements. The fair value of the remaining risk management asset at March 31, 2009 was \$24.6 million (December 31, 2008 – \$32.9 million). If crude oil prices had been 10% lower on March 31, 2009, with all other variables held constant, the change in the fair value of the risk management contracts would have resulted in net income and other comprehensive income that was \$2.6 million higher for the three months then ended (2008 – \$4.8 million higher).

#### Interest Rate Risk

The Company is exposed to interest rate cash flow risk on floating interest rate bank debt due to fluctuations in market interest rates and interest rate price risk on fixed rate convertible debentures. The remainder of the Company's financial assets and liabilities are not exposed to interest rate risk.

The Company had the following interest rate swap contracts in place at March 31, 2009:

Term	Notional Principal	Fixed Annual Rate (%)
April 2009 – April 2011	\$50 million	1.05%
April 2009 – April 2012	\$50 million	1.30%

The fair value of the interest rate swaps at March 31, 2009 was \$0.2 million. Had interest rates been 1% higher for the three months ended March 31, 2009 net income would have decreased by \$0.3 million (2008 – \$0.1 million) due to interest charged on the Company's floating rate bank debt. If interest rates had been 1% higher at March 31, 2009, net income would be unchanged and other comprehensive income would have increased by \$1.9 million (2008 – \$nil) due to the change in fair value of the interest rate swaps.

### *Fair Value of Financial Instruments*

The Company's financial instruments are classified as cash and cash equivalents, restricted cash, accounts receivable, risk management asset, accounts payable and accrued liabilities, bank debt and convertible debentures on the balance sheet. The carrying value and fair value of these financial instruments at March 31, 2009 is disclosed below by financial instrument category, as well as any related gain, loss, expense or revenue for the three months ended March 31, 2009:

<b>Financial Instrument</b>	<b>Carrying Value</b>	<b>Fair Value</b>	<b>Gain / (Loss)</b>	<b>Interest Expense</b>	<b>Revenue</b>
<i>Assets Held For Trading</i>					
Cash and cash equivalents <sup>(1)</sup>	40,862	40,862	-	-	-
Restricted cash	4,018	4,018	-	-	-
Risk management contracts	24,391	24,391	2,227 <sup>(2)</sup>	-	-
<i>Loans and Receivables</i>					
Accounts receivable and other current assets	120,259	120,259	-	-	-
<i>Other Liabilities</i>					
Accounts payable and accrued liabilities	293,008	293,008	-	-	-
Bank debt	314,601	315,000	-	1,236 <sup>(3)</sup>	-
Convertible debentures	352,362	330,288 <sup>(4)</sup>	(7,279) <sup>(5)</sup>	7,933 <sup>(6)</sup>	-
Obligations under gas sale contract	2,966	1,152	-	-	204 <sup>(7)</sup>

<sup>(1)</sup> The effective yield on cash equivalents at March 31, 2009 was 0.6% (December 31, 2008 – 0.6%).

<sup>(2)</sup> Included in gain on risk management contracts on the statement of operations and retained earnings, and statement of comprehensive income. In addition, an unrealized loss of \$0.2 million is included in the statement of comprehensive income related to the Company's interest rate hedges. The unrealized loss of \$8.3 million representing the change in fair value of the contracts is added back on the statement of cash flow.

<sup>(3)</sup> Included in interest expense net of capitalized interest on the statement of operations and retained earnings and statement of comprehensive income. The amortization of deferred financing costs is included on the statement of cash flow. The effective yield on bank debt before capitalized interest at March 31, 2009 was 2.5% (December 31, 2008 – 3.5%).

<sup>(4)</sup> The Company estimated the fair value of the convertible debentures based on market transactions close to March 31, 2009. The principal amounts of the Petrobank and Petrominerales convertible debentures at March 31, 2009 are US\$250 million and US\$81.7 million, respectively.

<sup>(5)</sup> Included in foreign exchange loss on the statement of operations and retained earnings, statement of comprehensive income and statement of cash flow.

<sup>(6)</sup> Included in interest expense net of capitalized interest on the statement of operations and retained earnings and statement of comprehensive income. The non-cash interest expense relating to the accretion of the initial discounts and transaction costs that are netted against the liabilities are included in accretion on convertible debentures on the statement of cash flow. The effective yields on the convertible debentures issued by Petrobank and Petrominerales are 9.4% and 9.7%, respectively.

<sup>(7)</sup> Included in oil and natural gas revenues on the statement of operations and retained earnings and statement of comprehensive income. The amortization of obligations under gas sale contract is included on the statement of cash flow.

The risk management contracts are recorded at their fair value based on quoted market prices in the futures market on the balance sheet date; accordingly, there is no difference between fair value and carrying value. The fair value of the obligations under gas sale contract is based on the estimated cash payment necessary to settle the contract at the balance sheet date. Cash payments are calculated based on discounted cash flow analysis using prevailing market prices at the time. Bank debt is recorded on the balance sheet net of deferred financing costs which results in a difference between the carrying value and the fair value. Due to the short term nature of: cash and cash equivalents, restricted cash, accounts receivable and other current assets, and accounts payable and accrued liabilities their carrying values approximate their fair values.

#### Note 9 – Changes in Non-Cash Working Capital

Three months ended March 31,	2009	2008
Change in:		
Accounts receivable and other current assets	\$ (38,557)	\$ (77,815)
Accounts payable and accrued liabilities	30,231	63,121
Depletion related to other current assets	872	(363)
	<b>(7,454)</b>	(15,057)
Working capital deficiencies acquired	-	(14,358)
	<b>\$ (7,454)</b>	\$ (29,415)
Changes relating to:		
Attributable to operating activities	\$ (13,892)	\$ (53,791)
Attributable to financing activities	\$ -	\$ -
Attributable to investing activities	\$ 6,438	\$ 24,376

#### Note 10 – Commitments and Contingencies

The information contained within this note summarizes significant changes in the Company's commitments since December 31, 2008.

At March 31, 2009, the Company has flow-through share expenditures of \$8.0 million (December 31, 2008 – \$15.3 million) remaining to be spent in 2009.

Pursuant to exploration contracts, Petrominerales has work commitments totalling US\$71.6 million (December 31, 2008 – US\$48.6 million) to be completed during the next two years. The work commitments are normal course of business exploration activities that include acquisition and processing of seismic data and drilling exploration wells in Colombia (US\$62.1 million) and property acquisition and seismic in Peru (US\$9.5 million). Petrominerales has issued letters of credit totalling US\$12.2 million and pledged US\$3.2 million in restricted cash to guarantee the obligations under these exploration contracts.

At March 31, 2009 Petrominerales has remaining costs of US\$11.8 million (December 31, 2008 – US\$15.3 million) to be incurred in 2009 for the construction of a crude oil offloading facility in Colombia.

## Note 11 – Segmented Information

Three months ended March 31,	2009			2008		
	Canada and Other <sup>(1)</sup>	Colombia	Total	Canada and Other <sup>(1)</sup>	Colombia	Total
<b>Revenues</b>						
Oil and natural gas	\$ 95,486	\$ 95,300	\$ 190,786	\$ 109,423	\$ 69,868	\$ 179,291
Royalties	(10,571)	(8,870)	(19,441)	(8,523)	(6,485)	(15,008)
Gain (loss) on risk management contracts	2,227	-	2,227	(2,198)	(2,142)	(4,340)
Interest income	30	99	129	134	1,310	1,444
	<b>87,172</b>	<b>86,529</b>	<b>173,701</b>	<b>98,836</b>	<b>62,551</b>	<b>161,387</b>
<b>Expenses</b>						
Production	13,536	14,260	27,796	11,818	8,536	20,354
Transportation	2,451	14,018	16,469	3,817	1,870	5,687
General and administrative	3,940	3,419	7,359	3,033	2,442	5,475
Stock-based compensation	6,254	1,422	7,676	2,234	412	2,646
Interest	6,209	2,960	9,169	3,613	2,672	6,285
Foreign exchange loss (gain)	6,994	(3,510)	3,484	7,713	2,329	10,042
Depletion, depreciation and accretion	58,894	49,851	108,745	37,527	15,744	53,271
	<b>98,278</b>	<b>82,420</b>	<b>180,698</b>	<b>69,755</b>	<b>34,005</b>	<b>103,760</b>
<b>Income (loss) before taxes and non-controlling interest</b>						
	(11,106)	4,109	(6,997)	29,081	28,546	57,627
Current taxes	-	1,477	1,477	-	938	938
Future income taxes (recovery)	(1,682)	(7,671)	(9,353)	10,919	4,895	15,814
<b>Income (loss) before non-controlling interest</b>						
	(9,424)	10,303	879	18,162	22,713	40,875
Income applicable to non-controlling interest	-	2,421	2,421	-	5,338	5,338
<b>Net income (loss)</b>	<b>\$ (9,424)</b>	<b>\$ 7,882</b>	<b>\$ (1,542)</b>	<b>\$ 18,162</b>	<b>\$ 17,375</b>	<b>\$ 35,537</b>
Identifiable assets	\$1,692,572	\$ 721,574	\$2,414,146	\$1,272,656	\$ 464,569	\$1,737,225
Goodwill	\$ 63,171	\$ -	\$ 63,171	\$ 54,860	\$ -	\$ 54,860
Capital expenditures	\$ 91,434	\$ 81,560	\$ 172,994	\$ 131,524	\$ 68,746	\$ 200,270

<sup>(1)</sup> Canada includes Heavy Oil Business Unit capital expenditures of \$21.4 million in 2009 (2008 – \$21.0 million), identifiable assets at March 31, 2009 of \$383.4 million (2008 – \$305.8 million) including goodwill of \$28.1 million (2008 – \$28.1 million), and negligible revenues and expenses as operations are considered to be in the pre-operating stage and accordingly are capitalized.

