



Q2 2009

FINANCIAL & OPERATING HIGHLIGHTS

	Three months ended			Six months ended		
	June 30, 2009	2008	% change	June 30, 2009	2008	% change
Financial (\$000s, except where noted)						
Oil and natural gas revenue	224,396	247,479	(9)	415,182	426,770	(3)
Funds flow from operations ⁽¹⁾	150,350	177,923	(15)	275,506	301,411	(9)
Per share – basic (\$)	1.78	2.16	(18)	3.28	3.69	(11)
– diluted (\$)	1.64	1.92	(15)	3.03	3.28	(8)
Net income	34,667	57,636	(40)	33,125	93,173	(64)
Per share – basic (\$)	0.41	0.70	(41)	0.39	1.14	(66)
– diluted (\$)	0.40	0.64	(38)	0.39	1.04	(63)
Capital expenditures	144,422	172,356	(16)	317,416	372,626	(15)
Canadian Business Unit (“CBU”)	38,901	69,711	(44)	108,925	180,200	(40)
Latin American Business Unit (“LABU”)	93,203	80,637	16	174,763	149,383	17
Heavy Oil Business Unit (“HBU”)	12,318	22,008	(44)	33,728	43,043	(22)
Total assets	2,421,171	1,826,464	33	2,421,171	1,826,464	33
Net debt ⁽¹⁾	383,678	176,302	118	383,678	176,302	118
Common shares outstanding, end of period (000s)						
Basic	92,267	82,668	12	92,267	82,668	12
Diluted ⁽²⁾	99,270	98,023	1	99,270	98,023	1
Operations						
CBU operating netback (\$/boe except where noted) ⁽¹⁾⁽³⁾						
Oil and NGL revenue (\$/bbl) ⁽⁴⁾	62.22	117.64	(47)	54.88	106.19	(48)
Natural gas revenue (\$/mcf) ⁽⁴⁾	3.91	9.83	(60)	4.56	8.73	(48)
Oil, NGL and natural gas revenue ⁽⁴⁾	56.64	109.43	(48)	51.45	97.61	(47)
Royalties	7.40	11.70	(37)	6.30	9.43	(33)
Production expenses	6.52	8.88	(27)	6.67	9.10	(27)
Operating netback ⁽⁵⁾	42.72	88.85	(52)	38.48	79.08	(51)
LABU operating netback (\$/bbl) ⁽¹⁾						
Oil revenue ⁽⁴⁾	55.76	115.77	(52)	49.01	99.96	(51)
Royalties	5.02	11.11	(55)	4.81	9.56	(50)
Production expenses	7.86	10.86	(28)	7.63	10.86	(30)
Operating netback ⁽⁵⁾	42.88	93.80	(54)	36.56	79.54	(54)
Average daily production ⁽³⁾						
CBU – oil and NGL (bbls)	16,761	14,205	18	18,233	12,778	43
CBU – natural gas (mcf)	16,906	13,871	22	15,550	14,550	7
Total CBU (boe)	19,579	16,517	19	20,825	15,203	37
LABU – oil (bbls) ⁽⁶⁾	21,548	7,339	194	21,659	7,987	171
Total Company conventional (boe)	41,127	23,856	72	42,484	23,190	83

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

⁽²⁾ Assumes 0.2 million shares will be issued upon conversion of the Company’s remaining 3% convertible debentures.

⁽³⁾ 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.

⁽⁴⁾ Net of transportation expenses.

- ⁽⁵⁾ Excludes hedging activities. In the second quarter of 2009 the CBU realized gains of \$3.46/boe (2008 – realized loss of \$2.98/boe) and no gain or loss was recognized by the LABU (2008 – realized loss of \$6.38/bbl). In the first six months of 2009 the CBU realized gains of \$4.44/boe (2008 – realized loss of \$2.19/boe) and no gain or loss was recognized by the LABU (2008 – realized loss of \$4.21/bbl).
- ⁽⁶⁾ Actual production sold for the three and six months ended June 30, 2009 was 21,390 barrels of oil per day (“bopd”) and 21,399 bopd, respectively (2008 – 7,339 bopd and 7,987 bopd).

OPERATIONAL REVIEW

Petrobank reported strong funds flow from operations of \$150.4 million, or \$1.64 per diluted share, in the second quarter of 2009 as year over year sales volumes increased by 72% to 41,127 boepd. Funds flow from operations decreased by 15% from the prior year, primarily due to a 52% decrease in world oil prices. CBU infrastructure investments in 2008 helped reduce operating expenses to \$6.52/boe in the second quarter, preserving strong operating netbacks of \$42.72/boe, excluding hedging gains of \$3.46/boe. Similarly in Colombia, continued improvements in production operations resulted in operating expenses decreasing to \$7.86/bbl, leading to operating netbacks of \$42.88/bbl.

FINANCIAL AND OPERATING HIGHLIGHTS

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

- Petrobank’s production increased by 72% to 41,127 barrels of oil equivalent per day (“boepd”) in the second quarter of 2009.
- Canadian Business Unit (“CBU”) production increased 19% to 19,579 boepd.
- Latin American Business Unit (“LABU”) production increased 194% to 21,548 bopd.
- Our Heavy Oil Business Unit (“HBU”) produced 205 bopd in the second quarter and commenced drilling at our Kerrobert Project in July.
- Despite a sharp 52% drop in world oil prices, funds flow from operations only decreased by 15% to \$150.4 million (\$1.64 per diluted share).
- Petrobank achieved net income of \$34.7 million (\$0.40 per diluted share) in the second quarter compared to net income of \$57.6 million (\$0.64 per diluted share) in the same 2008 period.
- CBU production expenses decreased by 27% to \$6.52/boe and LABU production expenses decreased by 28% to \$7.86/bbl.
- CBU operating netbacks averaged \$42.72/boe excluding hedging gains of \$3.46/boe and LABU operating netbacks averaged \$42.88/bbl in the second quarter.
- On July 10, 2009, Petrobank issued US\$400 million of convertible debentures.
- On August 4, 2009, Petrobank and TriStar Oil and Gas Ltd. (“TriStar”) entered into an arrangement that will create a new publicly listed company, PetroBakken Energy Ltd. (“PetroBakken”).

PETROBAKKEN

On August 4, 2009, Petrobank and TriStar agreed to a strategic combination of TriStar Oil and Gas Ltd. (“TriStar”) and Petrobank’s CBU. The combination will create a new publicly listed company, PetroBakken, that will be a premier, Bakken-focused, light oil exploration and production company.

Petrobank will capitalize PetroBakken with its CBU assets and \$400 million of cash. PetroBakken will then acquire all the outstanding shares of TriStar. In return, Petrobank will receive 109.8 million common shares of PetroBakken which will represent approximately 64% of PetroBakken’s anticipated shares outstanding.

The transaction will be completed by way of plan of arrangement (the “Arrangement”) and is subject to TriStar shareholder approval. The information circular for the Arrangement is expected to be mailed to TriStar shareholders on or about August 31, 2009 and it is anticipated that the special meeting of TriStar’s shareholders will be held on or about September 30, 2009 with closing of the transaction to occur on or about October 1, 2009. The successful completion of the transaction is also subject to customary regulatory, stock exchange, court and other approvals.

PetroBakken will target significant production and reserves growth through an internally-funded capital program underpinned by strong cash flows which will also allow us to provide an attractive dividend yield to our shareholders. Based on the proposed dividend policy PetroBakken shares are expected to yield approximately 3% based on a \$0.96 annualized dividend and anticipated trading levels for PetroBakken.

Key Attributes of PetroBakken

PetroBakken will combine significant, high growth, long-life Bakken reserves and production with legacy conventional light oil assets, which provide high netbacks and a low production decline profile. PetroBakken will be the premier Bakken player in Canada with a greater proportion of its production coming from the Bakken than any other material producer, and will represent a compelling new investment opportunity for investors. In addition, PetroBakken will have significant future development opportunities in the Horn River and Montney gas resource plays in northeast BC that will add long-term growth to PetroBakken’s attractive light oil position. After planned Alberta asset dispositions of approximately 9,500 boepd, PetroBakken will have the following key attributes:

- 2009 exit production is expected to be above 37,000 boepd (greater than 95% light oil).
- More than 27,000 boepd from the Bakken (greater than 70% of total exit 2009 production).
- More than 127 mboe of high quality, primarily light oil, proved plus probable reserves with significant future reserve growth potential through revisions, additions, improved recoveries and the application of new technology.
- Proved plus probable reserve life index of more than 9 years.
- Significant land inventory of over 1.0 million net acres with more than 800,000 net acres in southeast Saskatchewan, making PetroBakken the single largest landholder in this region. Of this, over 280,000 net acres (440 net sections) are located in the Bakken play fairway with significant additional exposure to further Bakken exploration activity, including 80,000 net acres in Montana.
- Incremental reserve enhancement capabilities on 110 net sections of existing producing Bakken acreage.
- More than 1,300 future Bakken drilling locations using predominantly long-reach, bilateral horizontal wells.

- Significant upside gas potential in the Horn River and Montney plays in northeast BC, with more than 63,000 net undeveloped acres and over 400 potential drilling locations, providing an additional long-term growth platform.
- Industry leading operating netbacks estimated to be above \$57.00/boe based on US\$75.00 WTI.
- Expected operating costs of approximately \$8.00/boe.
- Approximately \$1.9 billion of tax pools.
- Run-rate cash flow of more than \$700 million based on US\$75 WTI oil price and 2009 exit production.
- 2010 capital budget of approximately \$550 million based on a US\$75 WTI oil price.
- Initial dividend of \$0.96 per share per annum, payable monthly, representing a payout ratio of 23% based on run rate cash flow.
- Excellent financial flexibility with a pro forma debt to cash flow ratio of less than one times.
- 172 million PetroBakken shares outstanding.
- Industry leading technical team.

Strategic Rationale

The combination of the Petrobank and TriStar assets is highly complementary as it creates a pure play investment opportunity for exposure to high-netback light oil and the continuing technical enhancements of the Bakken resource play. In the Bakken alone, the combined asset base creates a dominant, operationally complementary land position providing significant long-term development growth through the future drilling of 1,300+ identified locations.

The combined entity is expected to have an improved cost of capital as a result of the focused nature of the high netback light oil assets in southeast Saskatchewan.

Additionally, the strategic merger results in the combination of premier technical teams focused on unlocking the value embedded in this large resource base. Independently, TriStar and Petrobank have been industry leaders in applying new, leading-edge technologies to unlock the true potential of the Bakken resource play. Bringing these two teams together creates the preeminent Bakken development team, utilizing best practices to continually enhance and ultimately maximize recovery factors.

It is expected that PetroBakken's increased scale will provide superior operating efficiencies through complementary gathering systems, oil processing facilities, marketing arrangements and gas plant synergies.

PETROBANK FOLLOWING THE COMPLETION OF THE PETROBAKKEN TRANSACTION

Petrobank will capitalize PetroBakken with \$400 million, contribute all the Company's CBU assets and transfer all bank debt and working capital associated with the CBU. Net Canadian bank debt at June 30, 2009 totalled \$364 million and is expected to increase to approximately \$400 million by September 30, 2009 due to increasing third quarter activity levels and land acquisitions. After closing the PetroBakken transaction, Petrobank will have estimated cash, net of working capital balances, of approximately \$40 million, an undrawn operating line of credit estimated to initially be \$20 million and Petrobank will be receiving over \$105 million of dividends per year from PetroBakken, which together will be used to fund ongoing Heavy Oil Business Unit expenditures and obligations outstanding under Petrobank convertible bonds (principal amount US\$405.1 million).

Following the arrangement, an investment in one share of Petrobank (basic) will effectively represent 1.19 shares of PetroBakken, 0.71 shares of Petrominerales, and 100% of the Heavy Oil Business Unit assets, including our proprietary THAI™ and CAPRI™ technologies.

CANADIAN BUSINESS UNIT (“CBU”) OPERATIONAL UPDATE

(all comparisons are to the second quarter of 2008)

- CBU production increased 18.5% to 19,579 boepd.
- CBU production expenses decreased by 27% to \$6.52/boe.
- CBU operating netbacks were \$42.72/boe, excluding hedging gains of \$3.46/boe.
- We completed the first 20 stage fracture stimulation in Canada, using Packers Plus technology.
- Our new drilling and completion strategy for the Bakken play now focuses on dual leg horizontal wells with high intensity fracture stimulation, creating the most cost effective approach to increase Bakken production and reserves.
- On August 4th, 2009, Petrobank entered into a definitive agreement with TriStar to create PetroBakken.

Our aggressive drilling program through 2008 was followed by a dramatic slowdown in activity during the first half of 2009 in response to significantly lower commodity prices and field activity was further reduced during the second quarter due to spring break up. Our 2009 drilling program resulted in only 11 (7.3 net) wells being drilled in the second quarter and 32 (24.4 net) wells drilled in total during the first half of 2009. Production averaged 19,579 boepd, a 19% increase from the 16,517 boepd produced in the second quarter of 2008. Due to lower activity levels and field restrictions due to spring break-up, production was down 11% from the first quarter of 2009. We anticipate a return to strong production growth through the balance of the year as we dramatically increase our drilling activity in the Bakken. Through most of the first half of the year we operated with a maximum of only two rigs on the Bakken play. We now have five rigs operating and a sixth rig will be starting shortly. Outside of the Bakken, our activities are targeted toward building on our expertise and drilling inventory in other large resource accumulations, including the Montney and Horn River Basin.

The reduced drilling pace in early 2009 provided the opportunity to re-evaluate our Bakken drilling and completion strategies and to pioneer new techniques to maximize returns on our Bakken program. Our new strategy of drilling long-reach, bilateral horizontal wells provides improved production and reserves per-well by implementing the most cost effective approach for increasing the intensity of fracture stimulations along the length of the horizontal well bore while reducing the inter-well distance of the horizontal well bores, sub-surface. Furthermore, this new approach has immediate applications in our large inventory of existing producing wells, as we can re-enter these wells and add a second parallel horizontal leg with high intensity fracture stimulations (“re-entries”). TriStar’s complementary inventory of undeveloped lands, and existing producers, further increases the growth potential of PetroBakken.

Through the last half of 2009, our primary focus will be to increase Bakken drilling activity and continue to demonstrate our ability to maintain our low-cost advantage in developing this large resource base. We are positioned for continued long-term reserve and production growth as we increase our pace of development through the rest of the year. With current commodity prices we would expect to drill a further 70 wells in addition to another 20 re-entries through the balance of 2009, before taking into account the PetroBakken transaction.

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. This zone is a marginal reservoir that has been tested and analyzed for more than 50 years, yet only recently have advances in technology created the opportunity to produce significant oil from the Bakken. Recent, repeated testing has allowed us to conclude that every time we increase the number of fracture stimulations in a given section of land, we increase productivity and expected ultimate recoveries from the zone.

Our efforts through early 2009 to further improve Bakken production have focused on increasing the intensity of fracture stimulation completions (fracs) by 38% in our long (1,400 metre) horizontals, by 200% in our short (700 metre) horizontals, and then by 400% in our short bilateral (two 700 metre horizontal legs from a single vertical well bore) horizontal wells. Recently, Petrobank also completed the first 20-stage fracture stimulation in Canada using Packers Plus technology. Our first two 20-stage frac wells have materially improved production performance compared to offset competitor wells and were initially free-flowing at rates in excess of 400 bopd. These results further demonstrate the potential of our strategy to cost-effectively increase fracture stimulation intensity and ultimate recoveries from the Bakken. We continue to build on our innovative approach to maximizing value from the Bakken resource.

We are now implementing our new drilling and completion strategy which is to drill long bilateral horizontal wells (two 1,400 metre horizontal legs from a single vertical well bore) with a total of 30 fracture stimulations (15 fracture stimulations in each horizontal leg). These are the first wells to be drilled this way, and Petrobank has successfully executed all the unique elements of this approach in other wells. By combining our two most highly effective solutions for maximizing productivity and expected ultimate recoveries, we have developed the most capital efficient oil recovery method for the Bakken, to-date.

We are also applying this approach to our large inventory of existing well bores. We have started to re-enter these horizontal wells and drill second parallel horizontal legs from the same vertical well, and complete them with higher intensity multi-stage fracs. Initial re-entry results have resulted in production increases of 80 to 150 bopd from previous well production rates prior to the re-entries.

Another part of our strategy is to operate centralized facilities that capture additional value from the gas and natural gas liquids associated with our Bakken 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 through 2008. The future growth of our infrastructure will be timed to match our need with future drilling. PetroBakken's combined infrastructure will provide additional oil handling capabilities for Petrobank's current and future locations north of our Freestone facility as well as gas processing capabilities for TriStar wells and facilities.

Ongoing field efficiencies have resulted in a reduction of our Bakken production costs to \$5.75/boe. This brings the average second quarter production costs for all of our CBU operations down to \$6.52/boe, a 4% decrease from the \$6.81/boe recorded in the first quarter of 2009 and a remarkable 27% reduction from the second quarter of 2008.

Including the TriStar assets, PetroBakken will have 330 net undeveloped Bakken sections with a drilling inventory of over 1,300 bilateral wells, only 407 of which have been assigned 2P reserves. This substantial drilling inventory combined with our innovative approach to drilling and completing Bakken wells are expected to contribute to a multi-year growth profile for PetroBakken.

Beyond Bakken

Additional long-term growth will come from Petrobank's large land position in the Montney and Horn River natural gas resource plays located in northeast British Columbia. The company has 17 sections of land (100% working interest) in the Monias area with Montney potential and a further 97 (84 net) sections north of Fort Nelson in the Horn River Basin. Petrobank has, to-date, successfully operated over 270 horizontal wells with multi-stage fracture stimulations, more than any other operator in Canada. This experience positions Petrobank to be a leader in the development of these massive unconventional resource plays.

At Monias, our first Montney horizontal well was drilled in the fourth quarter of 2008 adjacent to our 5.0 mmcfpd gas plant. Based on that successful result, a second well is currently drilling. This well is a multi-leg horizontal with high density fracture stimulation designed to further increase production rates and expected ultimate gas recoveries. Our first horizontal well gas well in the Horn River Basin was drilled in the first quarter of 2009 in an area that offers multi-season access due to our proximity to the Alaska Highway. Based on that successful result, a second well is planned for later this year, building on what we learned from the first well as well as testing additional geological concepts.

Our immediate operational goal for both of these prolific resource plays is to identify optimal technology applications that lower our internal hurdle for a gas price necessary to provide a competitive rate of return that will ultimately allow us to initiate a major full-scale development.

HEAVY OIL BUSINESS UNIT (“HBU”) OPERATIONAL UPDATE

- Production averaged 205 bopd of partially upgraded oil.
- P1B was drilled as a THAI™ well, replacing P1.
- P2B was drilled as the second THAI™/CAPRI™ well, replacing P2.
- We have confirmed the CAPRI™ in-situ catalytic upgrading effect.
- The Kerrobert project was approved on July 9, 2009, and drilling has commenced.

Whitesands Project

During the second quarter production averaged 205 bopd, down 43 barrels per day compared to the previous quarter as operations were ramped down and stabilized in preparation for drilling the P1B and P2B wells. As previously reported, P1 was shut-in on March 31, 2009 and P2 was subsequently shut-in on July 24, 2009 to facilitate the drilling of the replacement wells for P1 and P2. Concurrent with the preparation for drilling the new wells, P3B air injection was reduced and production was stabilized at 100 bopd per day prior to and during the drilling and completion operations.

We commenced drilling P1B on July 5, 2009 and we completed drilling on July 16, 2009. This well is completed as a THAI™ well with a FacsRite™ liner utilizing cartridge screens designed for superior downhole sand control, liner integrity and increased flow area. The FacsRite™ liner is manufactured by Absolute Completion Technologies in Alberta and internationally distributed by Schlumberger. This liner configuration has been used in projects worldwide but P1B is the first well in North America to be completed with the FacsRite™ design.

P2B is our second THAI™/CAPRI™ well and drilling was completed on August 7, 2009. P2B has the same liner design as our successful P3B well. Both wells are expected to be completed, tied in and operational by the end of August, with production expected near the end of the third quarter.

P3B wellbore temperatures have been operating between 400 and 500 degrees Celsius, well within the CAPRI™ catalyst range. Produced light hydrocarbons from the P3B secondary separator averaged 36 degrees API and the combined P3B THAI™/CAPRI™ production from the primary and secondary separators ranged from 12 to 15 degrees API, compared to a reservoir quality of 8 degrees API. The

CAPRI™ upgrading effect has been measured at as much as 3 degrees API higher than THAI™ production, confirming a direct in-situ upgrading effect of the catalyst.

In the second quarter, we commenced a routine regulatory inspection of the surface facilities starting with the P1 production train. During the current drilling and completion operations, we will be able to complete the majority of the inspections prior to resuming full operations on all three wells. To-date, the facilities inspections have shown no evidence of any corrosion in the vessels and associated equipment.

Whitesands is now configured as a modified three well THAI™/CAPRI™ demonstration site, which will allow us to continue to test new technology enhancements, such as oxygen enrichment, CO₂ co-injection, and partial surface upgrading.

Kerrobert Project

Regulatory applications for the Kerrobert Project were filed on April 22, 2009 and approval was received on July 9, 2009. In our environmental application we completed additional work to enable expansion of the project which resulted in a slightly longer initial regulatory process but will facilitate a shorter time frame for expansion projects. Drilling operations began on July 18, 2009 and the first production well KP1 completed drilling on August 5, 2009. KP2 commenced drilling on August 7, 2009 and drilling is expected to be completed next week. Both of these wells will utilize FacsRite™ liners. The air injection wells are planned to be completed by the end of August, and the pre-ignition heating cycle (PIHC) will be initiated simultaneously. Air injection is planned to begin in early October and first production is expected to occur at about the same time. This two well project applies the THAI™ technology in a conventional heavy oil reservoir at Kerrobert and is a 50/50 joint venture with Baytex Energy Trust, who purchased True Energy Trust's Saskatchewan assets. With the approval of the Kerrobert project Petrobank earned a 50% percent interest in an initial four sections of land.

This joint project will highlight the applicability of the THAI™ technology in Saskatchewan's conventional heavy oil resource base. 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 through government royalty incentive programs.

May River Project

The May River Project is our first large-scale commercial THAI™ application on Petrobank's oil sands leases west of Conklin, Alberta. The May River design builds on the experience gained from Whitesands. The 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 by the regulatory authorities and is now moving through the regulatory process. We expect to receive approval for the project near the end of the year.

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 in the fourth quarter of 2009. The design incorporates self-sufficient power generation utilizing low-BTU produced gas, produced gas sweetening, simplified CO₂ capture add-on capability, and the project will be a net water producer rather than a water user. These design elements 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 and immediate 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, 2009 and we expect to receive approval by the end of 2009. This project will be virtually the same as the Kerrobert Project and will demonstrate the THAI™ technology in a more mobile oil sands reservoir.

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 production efficiencies, and reduce the overall environmental impact of bitumen and heavy oil recovery. The utilization of the FacsRite™ liner is another example of our ability to evaluate new technologies and rapidly deploy them in the field. Additional technologies being assessed include; elemental sulphur recovery, enriched oxygen injection, carbon dioxide co-injection, power generation using produced lean gas, enhanced produced water quality, and incremental surface upgrading.

We have been in active discussions and negotiations on potential licensing arrangements opportunities and there is a great deal of interest in our technologies because of their superior economic and environmental benefits. Our business strategy is to license and apply THAI™ and related technologies in a wide range of large global resource opportunities.

LATIN AMERICAN BUSINESS UNIT – PETROMINERALES LTD. (TSX: PMG – CURRENTLY 67% OWNED)

A full operational update of our 67% owned Latin American Business Unit, Petrominerales Ltd., was published on August 5, 2009 and can be found at www.petrominerales.com and www.sedar.com. Highlights of this release included:

- Crude oil production increased 194% to 21,548 bopd due to drilling successes in Corcel, Mapache and Neiva.
- July production averaged 21,922 bopd.
- Funds flow from operations increased by 20% to US\$64.1 million (US\$0.63 per share diluted) despite significantly lower world oil prices.
- Petrominerales recorded net income of US\$15.3 million (US\$0.15 per share diluted).
- Phase I of Monterrey offloading facility was operational at first-phase capacity of 11,000 bopd and crude oil deliveries commenced on July 9, 2009.

MANAGEMENT'S DISCUSSION AND ANALYSIS

The following Management's Discussion and Analysis ("MD&A") is dated August 12, 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 and six months ended June 30, 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 or at 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 attributable 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.

Net Income

Throughout this MD&A reference is made to net income, which represents “Net income attributable to Petrobank” on the Company’s consolidated financial statements.

FINANCIAL AND OPERATING REVIEW

(Comparisons are second quarter of 2009 compared to the second quarter of 2008 and the first six months of 2009 compared to the first six months of 2008 unless otherwise noted)

Petrobank reported strong funds flow from operations of \$150.4 million, or \$1.64 per diluted share, in the second quarter of 2009 as year over year sales volumes increased by 72% to 41,127 boepd. Funds flow from operations decreased by 15% from the prior year, primarily due to a 52% decrease in world oil prices. CBU infrastructure investments in 2008 helped reduce operating expenses to \$6.52/boe in the second quarter, preserving strong operating netbacks of \$42.72/boe, excluding hedging gains of \$3.46/boe. Similarly in Colombia, continued improvements in production operations resulted in operating expenses decreasing to \$7.86/bbl, leading to operating netbacks of \$42.88/bbl.

Average Daily Production

	Three months ended June 30,			Six months ended June 30,		
	2009	2008	Change	2009	2008	Change
CBU						
Oil and NGL (bbls)	16,761	14,205	18%	18,233	12,778	43%
Natural gas (mcf)	16,906	13,871	22%	15,550	14,550	7%
Total CBU (boe)	19,579	16,517	19%	20,825	15,203	37%
LABU – light / medium oil (bbls) ⁽¹⁾	21,548	7,339	194%	21,659	7,987	171%
Total Company conventional (boe)	41,127	23,856	72%	42,484	23,190	83%

⁽¹⁾ 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 both the CBU and LABU in the second quarter helped Petrobank average 41,127 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 84% of the CBU’s production in the second quarter. The Company drilled 187.5 net Bakken wells in 2008 and drilled an additional 7.3 wells in the second quarter bringing the 2009 year to date total to 22.4 wells. Until the end of June we primarily had only two drilling rigs working in the area but since the end of June, activity levels have started to ramp back up and we are now utilizing five rigs with plans to increase to eight in the near future.

Natural gas production was higher in the second quarter primarily due to wells at Monias and Cornwall which were brought on production at the end of the first quarter.

LABU oil production for the three and six months ended June 30, 2009 increased significantly over the comparable 2008 periods, 194% and 171%, respectively. Production increases in 2009 are primarily due to drilling successes in Corcel, Mapache and Neiva. In Corcel, Petrominerales had a total of eight wells on production in the second quarter of 2009 compared to the two wells that were on production in the

second quarter of 2008. In Mapache, two successful exploration wells, Mapache-1 and Mirasol-1, were brought on production in March of 2009. In Neiva, production increased 435% due to the results of Petrominerales' recent drilling program that added 10 new production wells in the second quarter of 2009, and 17 wells this year. Production for the second quarter of 2009 was negatively affected by work-overs performed on three Corcel wells in June. The Corcel-C3, D1 and E1 wells were off production for 25, 8 and 21 days, respectively.

Average Benchmark and Realized Prices

	Three months ended June 30,			Six months ended June 30,		
	2009	2008	Change	2009	2008	Change
WTI (US\$/bbl)	59.79	123.80	(52%)	51.68	111.12	(53%)
WTI (\$/bbl)	68.32	125.03	(45%)	60.27	111.91	(46%)
AECO natural gas (\$/mcf)	3.47	10.20	(66%)	4.21	9.09	(54%)
US\$ per C\$1	0.86	0.99	(13%)	0.83	0.99	(16%)
CBU – oil and NGL						
Realized price per bbl (\$/bbl)	63.21	120.95	(48%)	56.00	108.03	(48%)
US\$ discount as a % of WTI	8%	6%	25%	9%	5%	80%
CBU – natural gas						
Realized price per mcf (\$/mcf)	3.93	9.83	(60%)	4.59	8.73	(47%)
LABU – light / medium oil						
Realized price per bbl (\$/bbl)	62.65	117.56	(47%)	56.09	101.51	(45%)
US\$ discount as a % of WTI	10%	6%	67%	9%	9%	-

The realized oil and NGL prices received by the CBU in the second quarter and first six months decreased as a result of lower average WTI prices and wider differentials as a percentage of WTI. A portion of the differential is fixed which causes the percentage to increase as WTI decreases. In the second quarter and first six months, Canadian dollar denominated realized prices benefited from a respective 13% and 16% devaluation of the Canadian dollar relative to the U.S. dollar.

In the second quarter and first six months approximately 12% and 13% respectively, 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 and by a larger discount to WTI in the second quarter. The price differential as a percentage of WTI increased in the second quarter of 2009 as a portion of the differential is fixed while 2009 WTI prices were at lower levels than 2008.

Revenue

The change in revenue in the second quarter of 2009 compared to the second quarter of 2008 is primarily due to sales volumes that were 19% higher in the CBU and 191% higher in the LABU, offset by lower oil prices, as summarized below:

Reconciliation of Changes in Revenue	CBU	LABU	Total
Three months ended June 30, 2008	168,757	78,722	247,479
Sales volumes	16,023	80,104	96,127
Price variance	(82,328)	(36,882)	(119,210)
Three months ended June 30, 2009	102,452	121,944	224,396
\$ change in revenue	(66,305)	43,222	(23,083)
% change in revenue	(39%)	55%	(9%)

The change in revenue in the first six months of 2009 compared to the first six months of 2008 is primarily due to sales volumes that were 37% higher in the CBU and 168% higher in the LABU, offset by lower oil prices, as summarized below:

Reconciliation of Changes in Revenue	CBU	LABU	Total
Six months ended June 30, 2008	278,180	148,590	426,770
Sales volumes	50,792	136,539	187,331
Price variance	(131,034)	(67,885)	(198,919)
Six months ended June 30, 2009	197,938	217,244	415,182
\$ change in revenue	(80,242)	68,654	(11,588)
% change in revenue	(29%)	46%	(3%)

Revenue	Three months ended June 30,			Six months ended June 30,		
	2009	2008	Change	2009	2008	Change
CBU revenue	102,452	168,757	(39%)	197,938	278,180	(29%)
LABU revenue	121,944	78,722	55%	217,244	148,590	46%
Total revenue	224,396	247,479	(9%)	415,182	426,770	(3%)
CBU transportation expenses	1,541	4,283	(64%)	3,992	8,100	(51%)
LABU transportation expenses	13,404	1,405	854%	27,422	3,275	737%
Total transportation expenses	14,945	5,688	163%	31,414	11,375	176%
CBU revenue, net of transportation costs	100,911	164,474	(39%)	193,946	270,080	(28%)
LABU revenue, net of transportation costs	108,540	77,317	40%	189,822	145,315	31%
Total revenue, net of transportation costs	209,451	241,791	(13%)	383,768	415,395	(8%)
CBU gross revenue (\$/boe)	57.50	112.82	(49%)	52.51	100.54	(48%)
CBU transportation costs (\$/boe)	0.86	3.39	(75%)	1.06	2.93	(64%)
CBU realized price, net of transportation costs (\$/boe)	56.64	109.43	(48%)	51.45	97.61	(47%)
LABU gross revenue (\$/bbl)	62.65	117.56	(47%)	56.09	101.51	(45%)
LABU transportation costs (\$/bbl)	6.89	1.79	285%	7.08	2.25	215%
LABU realized price, net of transportation costs (\$/bbl)	55.76	115.77	(52%)	49.01	99.26	(51%)

Total revenue, net of transportation decreased by 57% from the second quarter of 2008 as higher production was offset by significantly 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 in both the three and six month periods as an increasing number of our wells are tied into our southeast Saskatchewan facilities and we realized a significant 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 mainly 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 additional 20,000 bopd of incremental offloading capacity. Phase I of the facility (11,000 bopd capacity net to Petrominerales) was completed in the second quarter and oil deliveries commenced on July 9, 2009. The additional offloading capacity is expected to be available in the fourth quarter of 2009. Monterrey is the closest offloading station to Corcel and has now reduced our trucking costs for volumes delivered to Monterrey to under US\$3.00 per barrel.

Royalties	Three months ended June 30,			Six months ended June 30,		
	2009	2008	Change	2009	2008	Change
CBU	13,195	17,581	(25%)	23,766	26,104	(9%)
LABU	9,771	7,421	32%	18,641	13,906	34%
Total royalties	22,966	25,002	(8%)	42,407	40,010	6%
CBU – \$ per boe	7.40	11.70	(37%)	6.30	9.43	(33%)
LABU – \$ per bbl	5.02	11.11	(55%)	4.81	9.56	(50%)
CBU – royalties as a % of realized price, net of transportation costs	13%	11%	18%	12%	10%	20%
LABU – royalties as a % of realized price, net of transportation costs	9%	10%	(10%)	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 costs, CBU royalties increased in the second quarter and first six months 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 can 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") attributable to the Corcel Block.

Loss on Risk Management Contracts

	Three months ended June 30,			Six months ended June 30,		
	2009	2008	Change	2009	2008	Change
CBU realized gain (loss)	6,172	(4,476)	-	16,727	(6,058)	-
LABU realized loss	-	(4,262)	-	-	(6,120)	-
CBU unrealized loss	(16,392)	(29,664)	(45%)	(24,720)	(30,280)	(18%)
LABU unrealized loss	-	(5,527)	-	-	(5,811)	-
Loss on risk management contracts	(10,220)	(43,929)	(77%)	(7,993)	(48,269)	(83%)

The realized gain for actual monthly settlements incurred during the second quarter and first six months in the CBU were \$3.46 and \$4.44 per boe, respectively. Unrealized gains and losses represent the change in fair value of the contracts related to expected future settlements.

At June 30, 2009, the Company had recorded an \$8.2 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 June 30,			Six months ended June 30,		
	2009	2008	Change	2009	2008	Change
CBU	11,610	13,343	(13%)	25,146	25,161	-
LABU	15,299	7,251	111%	29,559	15,787	87%
Total production expenses	26,909	20,594	31%	54,705	40,948	34%
CBU – \$ per boe	6.52	8.88	(27%)	6.67	9.10	(27%)
LABU – \$ per bbl	7.86	10.86	(28%)	7.63	10.86	(30%)

Consolidated production expenses increased in the second quarter and first six months of 2009 as a result of increased production. Production expenses per unit of production in the CBU decreased by 27% in the second quarter and first six months of 2009, mainly due to Bakken production being handled through two new facilities that were completed in the second half of 2008. These facilities have also allowed

Petrobank to add liquids rich natural gas production and reserves associated with Bakken light oil production. In addition, we completed salt water disposal facilities at the end of 2008 which further reduced our expenses on a per boe basis.

Production expenses in the LABU increased in the second quarter and first six months 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 June 30,			Six months ended June 30,		
	2009	2008	Change	2009	2008	Change
CBU and HBU	4,440	3,435	29%	8,380	6,468	30%
LABU	3,173	2,710	17%	6,592	5,152	28%
Total general and administrative expenses	7,613	6,145	24%	14,972	11,620	29%
CBU and HBU – \$ per CBU boe	2.49	2.29	9%	2.22	2.34	(5%)
LABU – \$ per bbl	1.63	4.06	(60%)	1.70	3.54	(52%)

Total general and administrative costs increased in the second quarter and first six months of 2009, primarily due to additional personnel as a result of expanding operations. On a unit of production basis, the LABU costs have decreased significantly in the 2009 periods due to higher production levels while CBU costs have remained relatively consistent.

Stock-Based Compensation Expenses

	Three months ended June 30,			Six months ended June 30,		
	2009	2008	Change	2009	2008	Change
CBU and HBU (Petrobank)	5,554	3,348	66%	11,808	5,582	112%
LABU (Petrominerales)	1,434	675	112%	2,856	1,087	163%
Total stock-based compensation expenses	6,988	4,023	74%	14,664	6,669	120%

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 June 30,			Six months ended June 30,		
	2009	2008	Change	2009	2008	Change
CBU and HBU	4,649	3,551	31%	10,858	7,164	52%
LABU	2,587	2,773	(7%)	5,547	5,445	2%
Total interest expense	7,236	6,324	14%	16,405	12,609	30%

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 \$4.0 million in the second quarter (2008 – \$3.1 million) and \$8.8 million in the first six months of 2009 (2008 – \$5.5 million). In addition, the depreciation of the Canadian dollar relative to the U.S. dollar in 2009 compared to the first half 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 approximately \$325 million in the first half of 2009 compared to approximately \$130 million a year earlier, offset somewhat by a decrease in interest rates.

Foreign Exchange Loss (Gain)	Three months ended June 30,			Six months ended June 30,		
	2009	2008	Change	2009	2008	Change
CBU	(29,797)	(1,894)	1,473%	(22,803)	5,819	-
LABU	7,290	(931)	-	3,780	1,398	170%
Total foreign exchange loss (gain)	(22,507)	(2,825)	697%	(19,023)	7,217	-

The Company recognized foreign exchange gains in 2009 primarily due to the appreciation of the Canadian dollar relative to the U.S. dollar since the end of 2008. An unrealized foreign exchange gain of \$29.3 million (2008 – \$1.8 million) in the second quarter of 2009 and \$22.0 million in the first six months of 2009 (2008 – \$5.9 million loss) was recorded on Petrobank’s U.S. dollar denominated convertible debentures, offset primarily by foreign exchange losses 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 June 30,			Six months ended June 30,		
	2009	2008	Change	2009	2008	Change
CBU	53,394	43,079	24%	112,288	80,606	39%
LABU	44,860	14,125	218%	94,711	29,869	217%
Total DD&A expense	98,254	57,204	72%	206,999	110,475	87%
CBU – \$ per boe	29.97	28.66	5%	29.79	29.13	2%
LABU – \$ per bbl	23.05	21.15	9%	24.45	20.55	19%

Higher production caused DD&A expense to increase in the second quarter and first six months of 2009. The DD&A rate per unit of production in the CBU remained relatively consistent compared to the prior year periods, while the LABU rates decreased slightly 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 June 30,			Six months ended June 30,		
	2009	2008	Change	2009	2008	Change
Current taxes	1,391	1,784	(22%)	2,868	2,722	5%

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	Three months ended June 30,			Six months ended June 30,		
	2009	2008	Change	2009	2008	Change
CBU and HBU (Canada)	5,769	14,326	(60%)	4,087	25,245	(84%)
LABU (Colombia)	4,740	734	546%	(2,931)	5,629	-
Total future income taxes	10,509	15,060	(30%)	1,156	30,874	(96%)

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 expense was also recorded in the LABU in the second quarter resulting in a smaller recovery for the first six months of 2009.

Net Income Attributable to Non-Controlling Interest (“NCI”)

	Three months ended June 30,			Six months ended June 30,		
	2009	2008	Change	2009	2008	Change
Net income attributable to NCI	5,466	7,425	(26%)	7,887	12,763	(38%)

The net income attributable to NCI represents the 30.0% and 27.7% non-controlling interest share (2008 – 23.7% and 23.6%) of Petrominerales’ net income for the three and six month periods ending June 30, 2009, respectively. The net income attributable to NCI decreased in the second quarter and first six months of 2009 due to lower net income recorded by Petrominerales.

On May 15, 2009, Petrobank sold 9.9 million shares of our Petrominerales holdings for gross proceeds of \$101.5 million. The transaction reduced Petrobank’s ownership interest which is currently approximately 67%.

Net Income

The change in net income in the second quarter and first six months of 2009 is primarily due to lower commodity prices and higher DD&A and transportation expenses, offset by higher production, gains on risk management contracts and foreign exchange, and lower future income taxes, as summarized below:

Reconciliation of Changes in Net Income	Three months ended June 30,		Six months ended June 30,	
	(\$000s)	Per share, diluted	(\$000s)	Per share, diluted
Net income: June 30, 2008	57,636	0.64	93,173	1.04
Increase (decrease) due to:				
Sales volumes	96,127	1.03	187,331	2.12
Realized prices	(119,210)	(1.28)	(198,919)	(2.25)
Royalties	2,036	0.02	(2,397)	(0.03)
Risk management contracts	33,709	0.36	40,276	0.46
Production expenses	(6,315)	(0.07)	(13,757)	(0.16)
Transportation expenses	(9,257)	(0.10)	(20,039)	(0.23)
Stock-based compensation expenses	(2,965)	(0.03)	(7,995)	(0.09)
Foreign exchange	19,682	0.22	26,240	0.30
DD&A expense	(41,050)	(0.44)	(96,524)	(1.08)
Future income taxes	4,551	0.05	29,718	0.34
Other ⁽¹⁾	(277)	-	(3,982)	(0.03)
Net income: June 30, 2009	34,667	0.40	33,125	0.39

⁽¹⁾ Includes interest income, general and administrative expenses, interest expense, current taxes and net income attributable to non-controlling interest.

Funds Flow From Operations

The decrease in funds flow from operations is primarily due to lower commodity prices and higher transportation expenses offset by higher production and realized hedging gains, as summarized below:

Reconciliation of Changes in Funds Flow From Operations

	Three months ended June 30,		Six months ended June 30,	
	(\$000s)	Per share, diluted	(\$000s)	Per share, diluted
Funds flow from operations: June 30, 2008	177,923	1.92	301,411	3.28
Increase (decrease) due to:				
Sales volumes	96,127	1.03	187,331	2.12
Realized prices	(119,210)	(1.28)	(198,919)	(2.25)
Royalties	2,036	0.02	(2,397)	(0.03)
Realized portion of risk management contracts	14,910	0.18	28,905	0.35
Production expenses	(6,315)	(0.07)	(13,757)	(0.16)
Transportation expenses	(9,257)	(0.10)	(20,039)	(0.23)
Other ⁽¹⁾	(5,864)	(0.06)	(7,029)	(0.05)
Funds flow from operations: June 30, 2009	150,350	1.64	275,506	3.03

⁽¹⁾ 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 June 30,			Six months ended June 30,		
	2009	2008	Change	2009	2008	Change
Funds flow from operations: Non-GAAP	150,350	177,923	(15%)	275,506	301,411	(9%)
Changes in non-cash working capital	(29,216)	(22,615)	29%	(43,108)	(76,406)	(44%)
Cash flow from operating activities: GAAP	121,134	155,308	(22%)	232,398	225,005	3%

Capital Expenditures	Three months ended June 30,			Six months ended June 30,		
	2009	2008	Change	2009	2008	Change
CBU	38,901	69,711	(44%)	108,925	180,200	(40%)
LABU	93,203	80,637	16%	174,763	149,383	17%
HBU	12,318	22,008	(44%)	33,728	43,043	(22%)
Total capital expenditures	144,422	172,356	(16%)	317,416	372,626	(15%)

Q2 2009 Capital Expenditures By Type	CBU	LABU	HBU	Total
Drilling, completions and workovers	25,815	49,483	1,481	76,779
Facilities	2,790	23,013	3,522	29,325
Land	6,045	-	204	6,249
Seismic	255	17,591	39	17,885
Pilot capital	-	-	4,988	4,988
Other ⁽¹⁾	3,996	3,116	2,084	9,196
Total capital expenditures	38,901	93,203	12,318	144,422

YTD 2009 Capital Expenditures By Type	CBU	LABU	HBU	Total
Drilling, completions and workovers	71,598	105,834	5,038	182,470
Facilities	17,516	37,902	8,996	64,414
Land	9,102	-	253	9,355
Seismic	593	25,182	955	26,730
Pilot capital	-	-	13,747	13,747
Other ⁽¹⁾	10,116	5,845	4,739	20,700
Total capital expenditures	108,925	174,763	33,728	317,416

⁽¹⁾ CBU and LABU include health, safety and environmental, capitalized salaries and office furniture and fixtures. HBU includes \$4.7 million of capitalized cash interest.

CBU expenditures in the second quarter were mainly focused on drilling, completions and workovers, primarily at the Company's southeast Saskatchewan light oil properties as we drilled 7.3 net Bakken wells bringing our six month total to 22.4 net wells. We also drilled one well in the Horn River Basin in northeast British Columbia in the second quarter. The majority of the facilities costs in the first six months include costs to tie-in additional wells and gathering systems to two major facilities that were completed in the latter half of 2008.

Second quarter LABU expenditures focused on continuing exploration and development at Corcel, including drilling the E1 and F1 wells, along with initial drilling operations on the Boa-1 well. We also continued on from our first quarter activity at Orito and Neiva, completing two wells at Orito, drilling eight wells at Neiva, completing 10 wells at Neiva and initiated the drilling of the Chiguero Este well, all in the second quarter. Facilities costs in the second quarter continued to include costs to tie-in the Corcel D structure production and related civil works, early production facilities at Mapache and preparation work on future exploration drilling locations. Seismic activity in 2009 includes the acquisition of 288 square kilometres of 3D seismic and 14 kilometres of 2D seismic over our exploration blocks.

HBU expenditures in the second quarter included preparation work on the Kerrobert and May River projects, preparation work for drilling the P1B well, 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	
	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3
Financial (\$000s except where noted)								
Oil and natural gas revenue	224,396	190,786	206,161	317,137	247,479	179,291	127,308	63,006
Funds flow from operations	150,350	125,156	147,813	216,709	177,923	123,488	92,733	42,316
Per share – basic (\$)	1.78	1.50	1.78	2.62	2.16	1.53	1.20	0.55
– diluted (\$)	1.64	1.40	1.63	2.36	1.92	1.36	1.05	0.48
Net income	34,667	(1,542)	28,083	123,226	57,636	35,537	40,146	20,978
Per share – basic (\$)	0.41	(0.02)	0.34	1.49	0.70	0.44	0.52	0.27
– diluted (\$)	0.40	(0.02)	0.34	1.35	0.64	0.40	0.45	0.25
EBITDA	152,885	130,884	138,529	235,377	182,349	126,998	94,200	44,168
Capital expenditures	144,422	172,994	279,982	257,305	172,356	200,270	136,528	135,417
Operations								
<i>CBU operating netbacks by product</i>								
Light/medium oil and NGL sales price, net of transportation (\$/bbl)	62.22	48.57	57.71	115.11	117.64	91.87	80.83	76.56
Royalties	7.97	5.39	8.90	13.36	11.83	6.44	5.70	5.09
Production expenses	6.66	6.98	8.68	9.56	9.55	10.25	8.94	10.13
Operating netback	47.59	36.20	40.13	92.19	96.26	75.18	66.19	61.34
Natural gas sales price, net of transportation (\$/mcf)	3.91	5.35	6.86	7.94	9.83	7.73	6.05	5.25
Royalties	0.67	0.78	1.06	1.38	1.81	1.35	0.43	0.36
Production expenses	0.95	0.90	0.77	0.66	0.83	0.89	0.64	0.68
Operating netback	2.29	3.67	5.03	5.90	7.19	5.49	4.98	4.21
Oil equivalent sales price, net of transportation (\$/boe)	56.64	46.81	55.90	106.51	109.43	83.55	72.42	62.68
Royalties	7.40	5.32	8.62	12.72	11.70	6.74	5.11	4.18
Production expenses	6.52	6.81	8.24	8.84	8.88	9.35	7.99	8.26
Operating netback	42.72	34.68	39.04	84.95	88.85	67.46	59.32	50.24
<i>LABU operating netback (\$/bbl)</i>								
Oil sales price, net of transportation	55.76	42.18	54.93	110.53	115.77	86.53	76.53	72.74
Royalties	5.02	4.60	4.68	11.71	11.11	8.25	7.74	6.32
Production expenses	7.86	7.40	7.80	8.38	10.86	10.86	7.34	7.42
Operating netback	42.88	30.18	42.45	90.44	93.80	67.42	61.45	59.00
<i>Average daily production</i>								
CBU – light/medium oil and NGL (bbls)	16,761	19,722	19,841	16,024	14,205	11,351	6,691	3,745
CBU – natural gas (mcf)	16,906	14,179	14,598	14,047	13,871	15,229	9,379	10,006
Total CBU conventional (boe)	19,579	22,085	22,274	18,365	16,517	13,889	8,254	5,413
LABU – oil (bbls)	21,548	21,771	15,344	12,485	7,339	8,635	9,575	4,522
Total Company conventional (boe)	41,127	43,856	37,618	30,850	23,856	22,524	17,829	9,935

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 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.
- CBU capital expenditures have decreased in the first and second quarter of 2009 in response to lower crude oil prices and as a result, we have experienced anticipated production declines.

Commitments

The following is a summary of the estimated costs required to fulfill the Company's remaining contractual commitments as at June 30, 2009:

Type of Obligation	< 1 Year	1-3 Years	3-5 Years	Thereafter	Total
<i>CBU</i>					
Canadian bank debt (\$)	-	335,000	-	-	335,000
Petrobank convertible debentures (US\$) ⁽¹⁾	-	-	5,100	-	5,100
Office operating leases (\$)	3,700	7,900	10,200	24,100	45,900
Flow-through expenditures (\$)	3,600	-	-	-	3,600
<i>LABU</i>					
Petrominerales bank debt (US\$)	10,000	-	-	-	10,000
Petrominerales convertible debentures (US\$) ⁽²⁾	-	81,700	-	-	81,700
Exploration contracts (US\$)	30,700	31,100	-	-	61,800
Offloading facility (US\$)	3,833	-	-	-	3,833
Total Company ⁽³⁾	59,070	474,030	16,129	24,100	573,329

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

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

⁽³⁾ US\$ amounts have been converted using the June 30, 2009 exchange rate of \$1.1625.

Liquidity and Capital Resources

The recent economic slowdown and 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 June 30, 2009, the Company had \$346.6 million of bank debt and accounts payable and accrued liabilities in excess of current assets of \$37.1 million, resulting in net debt of \$383.7 million. The ratio of debt to annualized EBITDA was 0.5 times, within a range acceptable to the Company. In July 2009, Petrobank completed a US\$400 million convertible bond issuance which has allowed us to repay all outstanding Canadian bank debt and significantly increase our financial flexibility.

The Company's secured Canadian credit facilities combined borrowing limit totals \$400 million. The facilities are comprised of a \$380 million reserve-based revolver and a \$20 million oil sands resource-based revolver with terms ending on July 2010, 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 2011. The syndicate of lenders of the Canadian facilities assess the borrowing bases semi-annually.

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. 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\$10.2 million from their US\$29.4 million operating line of credit and pledged US\$3.5 million in restricted cash to guarantee exploration work commitments.

Outstanding Share Data

The number of Petrobank shares outstanding at June 30, 2009 of 92,267,019 was unchanged as of the date of this MD&A.

Risks and Uncertainties

There have been no significant changes in the three and six months ended June 30, 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 estimated as at June 30, 2009:

Change of:		(millions)
Crude oil	US\$1.00/bbl WTI reference price (assuming 42,500 bopd)	\$13.3
	500 bopd of CBU production @ US\$70/bbl WTI	\$10.8
	500 bopd of LABU production @ US\$70/bbl WTI	\$11.4
Natural gas	\$1.00/mcf AECO reference price (assuming 15 mmcf per day)	\$4.1
	1.0 mmcf per day of CBU production @ \$3.00/mcf AECO	\$0.7
Currency	US\$0.01 in exchange rate (assuming US\$0.86 / C\$1.00)	\$9.5
Interest rate	1% change in interest rate	\$2.5

Critical Accounting Policies and Estimates

There have been no changes to the Company's critical accounting policies and estimates in the three and six months ended June 30, 2009.

Changes in Accounting Policies

New Accounting Policies

Crude oil inventory, consisting of production in transit or in storage tanks at the balance sheet date, is valued at the lower of cost, using the weighted average cost method, or net realizable value. Costs include direct and indirect expenditures incurred in bringing the crude to its existing condition and location.

Changes in 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.

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.

On January 1, 2009, the Company adopted CICA Handbook 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. Previously the purchase price was based on the fair value of the consideration for a reasonable period before and after the date of acquisition was agreed upon and announced. The new standard generally requires all acquisition costs be expensed, which were previously capitalized as part of the purchase price. In addition, the new standard modified the accounting for contingent consideration and negative goodwill. The adoption of this standard will impact the accounting treatment of future business combinations.

On January 1, 2009, the Company adopted CICA Handbook Sections 1601, *Consolidated Financial Statements*, and 1602, *Non-controlling Interests*, which replace 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. The adoption of these standards did not have a material impact on our results of operations or financial position. The retrospective presentation changes have been included in the Company's consolidated financial statements.

Recent and Pending Accounting Pronouncements

In June 2009, the CICA issued amendments to CICA Handbook Section 3862, *Financial Instruments — Disclosures*. The amendments include enhanced disclosures related to the fair value of financial instruments and the liquidity risk associated with financial instruments. The amendments will be effective for annual financial statements for fiscal years ending after September 30, 2009. The amendments are consistent with recent amendments to financial instrument disclosure standards in International Financial Reporting Standards ("IFRS"). The Company will include these additional disclosures in its annual consolidated financial statements for the year ending December 31, 2009.

The Canadian Accounting Standards Board has confirmed that 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 June 30, 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.

Highlights of PetroBakken Transaction

- On August 4, 2009, Petrobank and TriStar Oil and Gas Ltd. (“TriStar”) entered into an arrangement that will create a new publicly listed company, PetroBakken Energy Ltd. (“PetroBakken”), which will be a Bakken-focused, light oil exploration and production company. PetroBakken is expected to trade on the TSX upon completion of the transaction under the symbol PBN.
- Petrobank will capitalize PetroBakken with its Canadian Business Unit assets and \$400 million of cash. PetroBakken will then acquire all the outstanding shares of TriStar. In return, Petrobank will receive 109.8 million common shares of PetroBakken which will represent approximately 64% of PetroBakken’s anticipated shares outstanding. Consideration to TriStar shareholders will consist of a combination of PetroBakken common shares and cash. In aggregate, TriStar shareholders will receive approximately \$580 million in cash and 61,762,500 shares of PetroBakken, representing 36% of PetroBakken’s anticipated shares outstanding.
- Following completion of the transaction, PetroBakken plans to divest a package of Alberta-based assets consisting of approximately 9,500 boepd (44% light oil, 56% natural gas), and 40.1 mmboc of proved plus probable reserves to further enhance the focus of PetroBakken on southeast Saskatchewan light oil resource plays. Proceeds from the disposition will be used to further solidify the strong PetroBakken balance sheet. Following the divestitures, PetroBakken will primarily be a pure-play, southeast Saskatchewan, light oil-focused company with 2009 exit production of more than 37,000 boepd, more than 95% light oil, more than 70% of which will be from the Bakken.
- Based upon the underlying strength of PetroBakken’s high-netback light oil asset base and flexible balance sheet, PetroBakken intends to adopt a dividend policy initially targeting payments of \$0.96 per share per annum, payable monthly, with the first dividend expected to be paid in November to shareholders of record on October 30, 2009. This dividend policy will allow PetroBakken shareholders to benefit in the Company’s industry leading high netback production on a monthly basis.

Outlook

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

CONSOLIDATED BALANCE SHEETS

(Unaudited, thousands of Canadian dollars)

As at	June 30, 2009	Dec. 31, 2008
Assets		
Current assets		
Cash and cash equivalents	\$ 24,049	\$ 102,181
Restricted cash (Note 3)	4,036	5,487
Accounts receivable and other current assets	149,268	81,702
Risk management assets	8,697	32,904
	186,050	222,274
Other assets	17,458	3,256
Capital assets	2,154,492	2,073,006
Goodwill	63,171	63,171
Total assets	\$ 2,421,171	\$ 2,361,707
Liabilities and Shareholders' Equity		
Current liabilities		
Accounts payable and accrued liabilities	\$ 223,103	\$ 262,777
Bank debt (Note 3)	11,625	-
Future income tax liabilities	2,606	9,860
	237,334	272,637
Bank debt (Note 3)	333,190	315,162
Convertible debentures (Note 5)	91,619	337,574
Obligations under gas sale contract and deferred credit	4,462	3,170
Asset retirement obligations	22,665	22,100
Future income tax liabilities	195,658	194,685
Total liabilities	884,928	1,145,328
Commitments and contingencies (Note 11)		
Shareholders' equity		
Petrobank shareholders' equity		
Common shares (Note 4)	861,737	574,060
Convertible debentures (Note 5)	1,307	64,089
Contributed surplus (Note 4)	31,350	19,795
Accumulated other comprehensive income (Note 4)	19,028	42,848
Retained earnings	343,390	334,410
Total Petrobank shareholders' equity	1,256,812	1,035,202
Non-controlling interest (Note 6)	279,431	181,177
Total shareholders' equity	1,536,243	1,216,379
Total liabilities and shareholders' equity	\$ 2,421,171	\$ 2,361,707

Subsequent events (Notes 5, 9 and 12)

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 June 30,		Six months ended June 30,	
	2009	2008	2009	2008
Revenues				
Oil and natural gas	\$ 224,396	\$ 247,479	\$ 415,182	\$ 426,770
Royalties	(22,966)	(25,002)	(42,407)	(40,010)
Loss on risk management contracts	(10,220)	(43,929)	(7,993)	(48,269)
Interest income	261	510	390	1,954
	191,471	179,058	365,172	340,445
Expenses				
Production	26,909	20,594	54,705	40,948
Transportation	14,945	5,688	31,414	11,375
General and administrative	7,613	6,145	14,972	11,620
Stock-based compensation	6,988	4,023	14,664	6,669
Interest	7,236	6,324	16,405	12,609
Foreign exchange loss (gain)	(22,507)	(2,825)	(19,023)	7,217
Depletion, depreciation and accretion	98,254	57,204	206,999	110,475
	139,438	97,153	320,136	200,913
Income before taxes	52,033	81,905	45,036	139,532
Current taxes	1,391	1,784	2,868	2,722
Future income taxes	10,509	15,060	1,156	30,874
Net income	40,133	65,061	41,012	105,936
Less: Net income attributable to non-controlling interest (Note 6)	5,466	7,425	7,887	12,763
Net income attributable to Petrobank	34,667	57,636	33,125	93,173
Retained earnings, beginning of period	332,868	135,994	334,410	100,457
Conversion of convertible debentures, net of tax (Note 5)	(24,145)	-	(24,145)	-
Retained earnings, end of period	\$ 343,390	\$ 193,630	\$ 343,390	\$ 193,630
Basic earnings per share (Note 4)	\$ 0.41	\$ 0.70	\$ 0.39	\$ 1.14
Diluted earnings per share (Note 4)	\$ 0.40	\$ 0.64	\$ 0.39	\$ 1.04

See accompanying notes to these consolidated financial statements.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(Unaudited, thousands of Canadian dollars)

	Three months ended June 30,		Six months ended June 30,	
	2009	2008	2009	2008
Net income attributable to Petrobank	\$ 34,667	\$ 57,636	\$ 33,125	\$ 93,173
Other comprehensive income:				
Unrealized gain (loss) on translation of financial statements of self-sustaining foreign operations (Note 4)	(38,089)	(2,413)	(24,332)	8,699
Unrealized gain on interest rate contracts (Note 9)	697	-	512	-
Comprehensive income attributable to Petrobank	\$ (2,725)	\$ 55,223	\$ 9,305	\$ 101,872

See accompanying notes to these consolidated financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOW

(Unaudited, thousands of Canadian dollars)

	Three months ended		Six months ended	
	June 30,		June 30,	
	2009	2008	2009	2008
Operating Activities				
Net income attributable to Petrobank	\$ 34,667	\$ 57,636	\$ 33,125	\$ 93,173
Depletion, depreciation and accretion	98,254	57,204	206,999	110,475
Unrealized loss on risk management contracts	16,392	35,191	24,720	36,091
Unrealized foreign exchange loss (gain)	(25,584)	(1,788)	(21,492)	5,925
Stock-based compensation	6,988	4,023	14,664	6,669
Accretion on convertible debentures	3,968	3,148	8,803	5,519
Net income attributable to non-controlling interest	5,466	7,425	7,887	12,763
Future income taxes	10,509	15,060	1,156	30,874
Amortization of deferred financing costs	248	296	506	507
Asset retirement obligations settled	(558)	(272)	(862)	(585)
	150,350	177,923	275,506	301,411
Changes in non-cash working capital (Note 10)	(29,216)	(22,615)	(43,108)	(76,406)
	121,134	155,308	232,398	225,005
Financing Activities				
Issuance (repayment) of bank debt	31,509	(37,167)	30,851	(85,826)
Conversion inducement of convertible debentures – including costs (Note 5)	(36,244)	-	(36,244)	-
Equity issued (repurchased) by Petrominerales – net of costs	(10,694)	1,247	(18,596)	1,487
Financing costs relating to bank debt	(1,534)	(781)	(1,768)	(781)
Issuance (repurchase) of common shares – net of costs	532	1,343	717	2,464
Amortization of obligations under gas sale contract	(206)	(206)	(410)	(412)
	(16,637)	(35,564)	(25,450)	(88,584)
Investing Activities				
Expenditures on capital assets	(144,422)	(172,356)	(317,416)	(372,626)
Expenditures on other assets	(10,752)	-	(14,899)	-
Sale of interest in subsidiary (Note 6)	102,010	-	106,107	-
Changes in restricted cash	(18)	-	1,451	-
Corporate acquisition	-	-	-	(67,248)
Changes in non-cash working capital (Note 10)	(67,957)	(1,001)	(61,519)	23,375
	(121,139)	(173,357)	(286,276)	(416,499)
Effect of exchange rate changes on cash and cash equivalents	(171)	(1,657)	1,196	3,031
Net change in cash and cash equivalents	(16,813)	(55,270)	(78,132)	(99,879)
Cash and cash equivalents, beginning of period	40,862	126,830	102,181	171,439
Cash and cash equivalents, end of period	\$ 24,049	\$ 71,560	\$ 24,049	\$ 71,560
Cash and cash equivalents consist of:				
Cash	\$ 5,619	\$ 10,615	\$ 5,619	\$ 10,615
Cash equivalents	\$ 18,430	\$ 60,945	\$ 18,430	\$ 60,945
Other cash flow information:				
Cash taxes paid	\$ 1,055	\$ 1,060	\$ 1,055	\$ 2,172
Cash interest paid	\$ 10,273	\$ 8,005	\$ 13,642	\$ 10,038
Cash interest received	\$ 211	\$ 416	\$ 312	\$ 1,807

See accompanying notes to these consolidated financial statements.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

As at and for the three and six months ended June 30, 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 and six months ended June 30, 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 – New Accounting Policies and Changes in Accounting Policies

New Accounting Policies

Crude oil inventory, consisting of production in transit or in storage tanks at the balance sheet date, is valued at the lower of cost, using the weighted average cost method, or net realizable value. Costs include direct and indirect expenditures incurred in bringing the crude to its existing condition and location.

Changes in 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.

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.

On January 1, 2009, the Company adopted CICA Handbook 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. Previously the purchase price was based on the fair value of the consideration for a reasonable period before and after the date of acquisition was agreed upon and announced. The new standard generally requires all acquisition costs be expensed, which were previously capitalized as part of the purchase price. In addition, the new standard modified the accounting for contingent consideration and negative goodwill. The adoption of this standard will impact the accounting treatment of future business combinations.

On January 1, 2009, the Company adopted CICA Handbook Sections 1601, *Consolidated Financial Statements*, and 1602, *Non-controlling Interests*, which replace 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. The adoption of these standards did not have a material impact on our results of operations or financial position. The retrospective presentation changes have been included in the Company’s consolidated financial statements.

Recent and Pending Accounting Pronouncements

In June 2009, the CICA issued amendments to CICA Handbook Section 3862, *Financial Instruments — Disclosures*. The amendments include enhanced disclosures related to the fair value of financial instruments and the liquidity risk associated with financial instruments. The amendments will be effective for annual financial statements for fiscal years ending after September 30, 2009. The amendments are consistent with recent amendments to financial instrument disclosure standards in International Financial Reporting Standards (“IFRS”). The Company will include these additional disclosures in its annual consolidated financial statements for the year ending December 31, 2009.

The Canadian Accounting Standards Board has confirmed that 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 \$400 million, of which \$335 million was drawn at June 30, 2009. Petrominerales Ltd. (“Petrominerales”) had US\$10 million of bank debt outstanding under its secured credit facility. The borrowing base under this facility is US\$80 million and is currently set to mature in December 2009. Petrominerales also has an US\$18.6 million operating line of credit.

At June 30, 2009, Petrominerales had restricted cash of US\$3.5 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 June 30, 2009, the Company had 92,267,019 common shares, 6,619,500 stock options and 204,310 deferred common shares outstanding. Upon conversion of Petrobank's remaining 3% convertible debentures, a total of 179,022 additional shares could be issued.

Common Shares

Common Share Continuity	Number	Amount
Balance at December 31, 2008	83,525,394	\$ 574,060
Issued upon conversion of debentures (Note 5)	8,595,925	291,246
Costs associated with conversion of debentures	-	(2,863)
Tax effect of share issue costs	-	792
Exercise of stock options	145,700	717
Transfer from contributed surplus related to stock options and deferred common shares exercised	-	253
Tax benefit renounced to shareholders	-	(2,468)
Balance at June 30, 2009	92,267,019	\$ 861,737

Contributed Surplus

Changes in Contributed Surplus	Amount
Balance at December 31, 2008	\$ 19,795
Stock-based compensation	11,808
Transfer from contributed surplus related to stock options and deferred common shares exercised	(253)
Balance at June 30, 2009	\$ 31,350

Accumulated Other Comprehensive Income

Changes in Accumulated Other Comprehensive Income	Amount
Balance at December 31, 2008	\$ 42,848
Unrealized gain on translation of financial statements of self-sustaining foreign operations	(24,332)
Unrealized gain on interest rate contracts	512
Balance at June 30, 2009	\$ 19,028

Stock Option Continuity

	Stock Options	Weighted-Avg Exercise Price
Balance at December 31, 2008	6,596,076	22.37
Granted	261,249	25.93
Exercised	(145,700)	4.92
Forfeited	(62,125)	23.79
Cancelled	(30,000)	48.57
Balance at June 30, 2009	6,619,500	\$ 22.76

Deferred Common Share Continuity

	Number
Balance at December 31, 2008	146,810
Granted	57,500
Balance at June 30, 2009	204,310

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:

Six months ended June 30,	2009
Risk free interest rate	1.75 - 2.25%
Dividend rate	0%
Expected life – options (years)	3.75 to 4
Expected life – deferred common shares (years)	8
Expected volatility	37.5 - 47.5%

The average fair value per stock option granted during the three and six months ended June 30, 2009 were \$12.84 (2008 – \$17.84) and \$9.95 (2008 – \$16.88) respectively, as at the date of grant. The average fair value per deferred common share granted during the three and six months ended June 30, 2009 were \$32.68 (2008 – \$56.45) and \$24.18 (2008 – \$48.00) respectively, as at the date of grant.

Stock-based compensation expense for the three and six months ended June 30, 2009 totalled \$7.0 million (2008 – \$4.0 million) and \$14.7 million (2008 – \$6.7 million), of which \$1.4 million (2008 – \$0.7 million) and \$2.9 million (2008 – \$1.1 million) related to Petrominerales.

Earnings Per Share

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

	Three months ended June 30,		Six months ended June 30,	
	2009	2008	2009	2008
Net income adjustments				
Net income attributable to Petrobank, basic	\$ 34,667	\$ 57,636	\$ 33,125	\$ 93,173
Interest expense on Petrobank's convertible debentures	4,374	3,235	2,199	5,258
Tax effect	(1,291)	(955)	(649)	(1,552)
Impact of Petrominerales dilution on net income	(249)	(586)	(125)	(1,113)
Net income attributable to Petrobank, diluted	\$ 37,501	\$ 59,330	\$ 34,550	\$ 95,766
Weighted average common share adjustments				
Weighted average common shares outstanding, basic	84,668,160	82,559,089	84,103,145	81,641,225
Effect of convertible debentures	7,232,099	8,774,947	3,636,028	8,774,947
Effect of stock options and deferred common shares	1,016,906	1,755,968	511,262	2,003,790
Weighted average common shares outstanding, diluted	92,917,165	93,090,004	88,250,435	92,419,962

Note 5 – Convertible Debentures

In June 2009, Petrobank convertible debentures with a face value of US\$244.9 million were converted into common shares. Petrobank paid \$36.2 million (including costs) as an incentive to debenture holders to convert their holdings into common shares. As a result, the Company recorded a \$24.1 million, net of tax, reduction in retained earnings relating to the conversion inducement.

The following table summarizes the liability component of the debentures at June 30, 2009:

	Petrobank	Petrominerales	Total
Balance of liability component, December 31, 2008	\$ 248,909	\$ 88,665	\$ 337,574
Accretion	6,554	2,581	9,135
Conversion into common shares ⁽¹⁾	(228,464)	-	(228,464)
Change in exchange rate	(22,038)	(4,588)	(26,626)
Balance of liability component, June 30, 2009	\$ 4,961	\$ 86,658	\$ 91,619

⁽¹⁾ The conversion amount of \$228.5 million represents the carrying amount of the liability portion on the conversion date.

In July 2009, Petrobank issued US\$400 million of convertible debentures maturing in July 2015. The debentures are convertible into common shares of Petrobank and have an annual coupon rate of 5.125% and a conversion price of US\$38.08 (Cdn\$44.01) per debenture. Upon conversion, a total of 10,504,202 common shares may be issued.

Note 6 – Non-Controlling Interest

The components of the Company's non-controlling interest in Petrominerales, the Company's 66.6% owned subsidiary as at June 30, 2009 are as follows:

	Amount
Balance at December 31, 2008	\$ 181,177
Attributable income	7,887
Stock-based compensation	2,856
Common shares sold by Petrobank ⁽¹⁾	96,736
Common shares repurchased by Petrominerales ⁽²⁾	(20,302)
Common shares repurchased from Petrobank ⁽²⁾	9,371
Common shares issued by Petrominerales ⁽³⁾	1,706
Balance at June 30, 2009	\$ 279,431

⁽¹⁾ On May 15, 2009 Petrobank sold 9.9 million shares of our Petrominerales holdings for gross proceeds of \$101.5 million. The Company did not record a gain or loss on this transaction.

⁽²⁾ Petrominerales repurchased a total of 1,874,600 Petrominerales common shares during the first six 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 June 30, 2009, Petrominerales had repurchased 3,200,600 common shares under their NCIB.

⁽³⁾ Relates to exercise of Petrominerales stock options.

Note 7 – Interest Expense

Interest expense includes the following:

	Three months ended		Six months ended	
	June 30,		June 30,	
	2009	2008	2009	2008
Cash interest	\$ 5,411	\$ 5,365	\$ 12,142	\$ 10,720
Accretion on Petrobank convertible debentures	2,948	2,747	6,554	5,415
Accretion on Petrominerales convertible debentures	1,271	1,232	2,581	2,414
Amortization of deferred financing costs	248	296	506	507
Capitalized interest related to Whitesands project ⁽¹⁾	(2,642)	(3,316)	(5,378)	(6,447)
Interest expense	\$ 7,236	\$ 6,324	\$ 16,405	\$ 12,609

⁽¹⁾ Capitalized interest includes \$5.1 million of cash and \$0.3 million of non-cash accretion (2008 – \$4.1 million and \$2.3 million, respectively).

Note 8 – 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, principal 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	June 30, 2009	Dec. 31, 2008
Bank debt – Petrobank principal amount	\$ 335,000	\$ 315,162
Bank debt – Petrominerales principal amount	11,625	-
Total bank debt	\$ 346,625	\$ 315,162
Working capital deficiency excluding bank debt	\$ 37,053	\$ 40,503
Convertible debentures – Petrobank principal amount (US\$)	5,100	250,000
Convertible debentures – Petrominerales principal amount (US\$)	81,700	81,700
Total convertible debentures (US\$)	\$ 86,800	\$ 331,700
Common share capital	\$ 861,737	\$ 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 June 30, 2009, the ratio of debt to annualized Canadian earnings before interest, taxes and non-cash items was 1.1 times, 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. Under both tranches of debentures, 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 the option to force conversion of the debentures at the prevailing conversion price after a period of time has elapsed 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, 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.

The sale of a portion of Petrobank's ownership in Petrominerales, the early inducement of the majority of Petrobank's 3% convertible debentures, and the US\$400 million convertible bond issuance in July 2009 by Petrobank have been the most significant changes to the Company's capital management during 2009.

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, \$28.1 million of cash and cash equivalents and restricted cash, a Canadian credit facility with \$65 million of available capacity, US\$70 million of available capacity available to Petrominerales and, in July 2009, Petrobank completed a

US\$400 million convertible debenture issuance which has allowed us to repay all outstanding Canadian bank debt and significantly increase our financial flexibility. While the proceeds from the issuance will initially be used to eliminate Canadian bank debt, \$400 million will be used to fund the formation of PetroBakken Energy Ltd. (Note 12) upon successful completion of the transaction.

Note 9 – 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 June 30, 2009 the majority of the Company's Canadian oil production was being sold to two purchasers. To help mitigate the risk associated with the significant amount of Canadian oil production being sold to the larger purchaser, the Company arranged for early payments and / or letters of credit. 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	June 30, 2009	Dec. 31, 2008
Oil and natural gas customers	\$ 131,318	\$ 57,085
Tax receivable	5,937	10,088
Other	5,445	14,529
Total	\$ 142,700	\$ 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 June 30, 2009, and did not provide for any doubtful accounts nor was it required to write-off any receivables during the six months ended June 30, 2009.

The Company's accounts receivable are aged as follows:

As at	June 30, 2009	Dec. 31, 2008
Not past due	\$ 136,401	\$ 78,697
Past due	6,299	3,005
Total	\$ 142,700	\$ 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 June 30, 2009:

Financial Liability	< 1 Year	1-3 Years	3-5 Years	Total
Accounts payable and accrued liabilities	\$ 223,103	\$ -	\$ -	\$ 223,103
Canadian bank debt – principal	-	335,000	-	335,000
Petrominerales bank debt – principal (US\$)	10,000	-	-	10,000
Petrobank convertible debentures – principal (US\$)	-	-	5,100 ⁽¹⁾	5,100
Petrominerales convertible debentures – principal (US\$)	-	81,700 ⁽²⁾	-	81,700
Total ⁽³⁾	\$234,728	\$ 429,976	\$ 5,929	\$ 670,633

⁽¹⁾ The debentures are convertible to common shares of Petrobank at a conversion price of US\$28.4902 per share. Upon conversion, a total of 179,022 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. In July 2009, Petrobank issued US\$400 million of 5.125% convertible debentures maturing in July 2015, with a conversion price of US\$38.08 per share. Upon conversion, a total of 10,504,202 additional common shares may be issued.

⁽²⁾ 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.

⁽³⁾ US\$ amounts have been converted using a period end exchange rate of 1.1625.

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 June 30, 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 \$0.1 million higher for the three months ended June 30, 2009 (2008 – \$9.8 million lower). Other comprehensive income would have been \$23.4 million higher (2008 – \$6.5 million higher) primarily due to the foreign currency balances of Petrominerales that are translated into Petrobank's consolidated financial statements.

The Company had no forward exchange rate contracts in place as at or during the six months ended June 30, 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 June 30, 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 June 30,		Six months ended June 30,	
	2009	2008	2009	2008
Risk management contracts				
Realized gain (loss)	\$ 6,172	\$ (8,738)	\$ 16,727	\$ (12,178)
Unrealized loss	(16,392)	(35,191)	(24,720)	(36,091)
Loss on risk management contracts	\$ (10,220)	\$ (43,929)	\$ (7,993)	\$ (48,269)

The unrealized loss represents the change in fair value of the crude oil price risk management contracts related to expected future settlements. The fair value of the remaining risk management assets at June 30, 2009 was \$8.7 million (December 31, 2008 – \$32.9 million), of which \$8.2 million related to the crude oil price risk management contracts. If crude oil prices had been 10% lower on June 30, 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 \$2.1 million higher for the three and six 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 June 30, 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 June 30, 2009 was \$0.5 million. Had interest rates been 1% higher for the three months ended June 30, 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 June 30, 2009, net income would be unchanged and other comprehensive income would have increased by \$2.0 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 June 30, 2009 is disclosed below by financial instrument category, as well as any related gain, loss, expense or revenue for the six months ended June 30, 2009:

Financial Instrument	Carrying Value	Fair Value	Gain / (Loss)	Expense	Revenue
<i>Assets Held For Trading</i>					
Cash and cash equivalents ⁽¹⁾	24,049	24,049	-	-	-
Restricted cash	4,036	4,036	-	-	-
Risk management contracts	8,697	8,697	(7,993) ⁽²⁾	-	-
<i>Loans and Receivables</i>					
Accounts receivable and other current assets	149,268	149,268	-	-	-
<i>Other Liabilities</i>					
Accounts payable and accrued liabilities	223,103	223,103	-	-	-
Bank debt	344,815	346,625	-	1,957 ⁽³⁾	-
Convertible debentures	91,619	89,672 ⁽⁴⁾	22,038 ⁽⁵⁾	14,380 ⁽⁶⁾	-
Obligations under gas sale contract and deferred credit	4,462	2,406	-	(44)	410

⁽¹⁾ The effective yield on cash equivalents at June 30, 2009 was 0.2% (December 31, 2008 – 0.6%).

⁽²⁾ Included in loss on risk management contracts on the statement of operations and retained earnings, and statement of comprehensive income. In addition, an unrealized gain of \$0.5 million is included in the statement of comprehensive income related to the Company's interest rate hedges. The unrealized loss of \$24.7 million representing the change in fair value of the contracts is added back on the statement of cash flow.

⁽³⁾ 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 June 30, 2009 was 2.6% (December 31, 2008 – 3.5%).

- (4) The Company estimated the fair value of the convertible debentures based on market transactions close to June 30, 2009. The principal amounts of the Petrobank and Petrominerales convertible debentures at June 30, 2009 are US\$5.1 million and US\$81.7 million, respectively.
- (5) Included in foreign exchange gain on the statement of operations and retained earnings, statement of comprehensive income and statement of cash flow.
- (6) 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.

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. Canadian 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 10 – Changes in Non-Cash Working Capital

	Three months ended June 30, 2009		Six months ended June 30, 2009	
Change in:				
Accounts receivable and other current assets	\$ (29,009)	\$ (19,501)	\$ (67,566)	\$ (97,316)
Accounts payable and accrued liabilities	(69,905)	(5,775)	(39,674)	57,346
Income taxes payable	-	1,660	-	1,660
Depletion related to other current assets	39	-	911	(363)
Deferred credit	1,702	-	1,702	-
	(97,173)	(23,616)	(104,627)	(38,673)
Working capital deficiencies acquired	-	-	-	(14,358)
	\$ (97,173)	\$ (23,616)	\$ (104,627)	\$ (53,031)
Changes relating to:				
Attributable to operating activities	\$ (29,216)	\$ (22,615)	\$ (43,108)	\$ (76,406)
Attributable to financing activities	\$ -	\$ -	\$ -	\$ -
Attributable to investing activities	\$ (67,957)	\$ (1,001)	\$ (61,519)	\$ 23,375

Note 11 – Commitments and Contingencies

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

At June 30, 2009, the Company has flow-through share expenditures of \$3.6 million (December 31, 2008 – \$15.3 million) remaining to be spent in 2009.

Pursuant to exploration contracts, Petrominerales has work commitments totalling US\$61.8 million (December 31, 2008 – US\$48.6 million) to be completed during the next three years. The work commitments are normal course of business exploration activities that include property costs, acquisition and processing of seismic data and drilling exploration wells. Petrominerales has issued letters of credit totalling US\$10.2 million and pledged US\$3.5 million in restricted cash to guarantee the obligations under these exploration contracts.

At June 30, 2009 Petrominerales has remaining costs of US\$3.8 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 12 – Formation of PetroBakken Energy Ltd.

On August 4, 2009, Petrobank and TriStar Oil and Gas Ltd. ("TriStar") entered into an arrangement that will create a new publicly listed company, PetroBakken Energy Ltd. ("PetroBakken"), which will be a Bakken-focused, light oil exploration and production company. PetroBakken is expected to trade on the TSX upon completion of the transaction under the symbol PBN.

Petrobank will capitalize PetroBakken with its Canadian Business Unit assets and \$400 million of cash. PetroBakken will then acquire all the outstanding shares of TriStar. In return, Petrobank will receive 109.8 million common shares of PetroBakken which will represent approximately 64% of PetroBakken's anticipated shares outstanding. Consideration to TriStar shareholders will consist of a combination of PetroBakken common shares and cash. In aggregate, TriStar shareholders will receive approximately \$580 million in cash and 61,762,500 shares of PetroBakken, representing 36% of PetroBakken's anticipated shares outstanding.

PetroBakken will use the purchase method to account for the acquisition of TriStar. At inception Petrobank will own 64% of PetroBakken, the remaining 36% of which will be reflected on Petrobank's consolidated balance sheet within non-controlling interests. PetroBakken's earnings or losses will be included in Petrobank's net income and adjusted to reflect the portion attributable to the non-controlling interests.

Note 13 – Segmented Information

Three months ended June 30,	2009			2008		
	Canada and Other ⁽¹⁾	Colombia	Total	Canada and Other ⁽¹⁾	Colombia	Total
Revenues						
Oil and natural gas	\$ 102,452	\$ 121,944	\$ 224,396	\$ 168,757	\$ 78,722	\$ 247,479
Royalties	(13,195)	(9,771)	(22,966)	(17,581)	(7,421)	(25,002)
Loss on risk management contracts	(10,220)	-	(10,220)	(34,140)	(9,789)	(43,929)
Interest income	51	210	261	119	391	510
	79,088	112,383	191,471	117,155	61,903	179,058
Expenses						
Production	11,610	15,299	26,909	13,343	7,251	20,594
Transportation	1,541	13,404	14,945	4,283	1,405	5,688
General and administrative	4,440	3,173	7,613	3,435	2,710	6,145
Stock-based compensation	5,554	1,434	6,988	3,348	675	4,023
Interest	4,649	2,587	7,236	3,551	2,773	6,324
Foreign exchange loss (gain)	(29,797)	7,290	(22,507)	(1,894)	(931)	(2,825)
Depletion, depreciation and accretion	53,394	44,860	98,254	43,079	14,125	57,204
	51,391	88,047	139,438	69,145	28,008	97,153
Income before taxes	27,697	24,336	52,033	48,010	33,895	81,905
Current taxes	-	1,391	1,391	-	1,784	1,784
Future income taxes	5,769	4,740	10,509	14,326	734	15,060
Net income	21,928	18,205	40,133	33,684	31,377	65,061
Less: Net income attributable to non-controlling interest	-	5,466	5,466	-	7,425	7,425
Net income attributable to Petrobank	\$ 21,928	\$ 12,739	\$ 34,667	\$ 33,684	\$ 23,952	\$ 57,636
Identifiable assets	\$ 1,695,568	\$ 725,603	\$ 2,421,171	\$ 1,325,570	\$ 500,894	\$ 1,826,464
Goodwill	\$ 63,171	\$ -	\$ 63,171	\$ 54,860	\$ -	\$ 54,860
Expenditures on capital and other assets	\$ 51,219	\$ 103,955	\$ 155,174	\$ 91,719	\$ 80,637	\$ 172,356

⁽¹⁾ Canada includes Heavy Oil Business Unit capital expenditures of \$12.3 million in 2009 (2008 – \$22.0 million), identifiable assets at June 30, 2009 of \$396.0 million (2008 – \$323.2 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.

Six months ended June 30,	2009			2008		
	Canada and Other ⁽¹⁾	Colombia	Total	Canada and Other ⁽¹⁾	Colombia	Total
Revenues						
Oil and natural gas	\$ 197,938	\$ 217,244	\$ 415,182	\$ 278,180	\$ 148,590	\$ 426,770
Royalties	(23,766)	(18,641)	(42,407)	(26,104)	(13,906)	(40,010)
Loss on risk management contracts	(7,993)	-	(7,993)	(36,338)	(11,931)	(48,269)
Interest income	81	309	390	253	1,701	1,954
	166,260	198,912	365,172	215,991	124,454	340,445
Expenses						
Production	25,146	29,559	54,705	25,161	15,787	40,948
Transportation	3,992	27,422	31,414	8,100	3,275	11,375
General and administrative	8,380	6,592	14,972	6,468	5,152	11,620
Stock-based compensation	11,808	2,856	14,664	5,582	1,087	6,669
Interest	10,858	5,547	16,405	7,164	5,445	12,609
Foreign exchange loss (gain)	(22,803)	3,780	(19,023)	5,819	1,398	7,217
Depletion, depreciation and accretion	112,288	94,711	206,999	80,606	29,869	110,475
	149,669	170,467	320,136	138,900	62,013	200,913
Income before taxes	16,591	28,445	45,036	77,091	62,441	139,532
Current taxes	-	2,868	2,868	-	2,722	2,722
Future income taxes (recovery)	4,087	(2,931)	1,156	25,245	5,629	30,874
Net income	12,504	28,508	41,012	51,846	54,090	105,936
Less: Net income attributable to non-controlling interest	-	7,887	7,887	-	12,763	12,763
Net income attributable to Petrobank	\$ 12,504	\$ 20,621	\$ 33,125	\$ 51,846	\$ 41,327	\$ 93,173
Identifiable assets	\$ 1,695,568	\$ 725,603	\$ 2,421,171	\$ 1,325,570	\$ 500,894	\$ 1,826,464
Goodwill	\$ 63,171	\$ -	\$ 63,171	\$ 54,860	\$ -	\$ 54,860
Expenditures on capital and other assets	\$ 142,653	\$ 189,662	\$ 332,315	\$ 223,243	\$ 149,383	\$ 371,626

⁽¹⁾ Canada includes Heavy Oil Business Unit capital expenditures of \$33.7 million in 2009 (2008 – \$43.0 million), identifiable assets at June 30, 2009 of \$396.0 million (2008 – \$323.2 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.



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Suite 1900, 111 – 5th Avenue S.W. - Calgary, Alberta T2P 3Y6 - 403.750.4400 - 403.266.5794

E-mail: ir@petrobank.com - Website: www.petrobank.com

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