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PETROBANK ANNOUNCES COLOMBIAN OPERATIONAL UPDATE

Calgary, Alberta – January 13, 2003 – Petrobank Energy and Resources Ltd. is pleased to announce the current status of continuing drilling and completion activity in Colombia.

Orito Field

Our first development well in the Orito field in Colombia, Orito 110 ("DEV-1"), was directionally drilled to a total depth of 6,640 feet (6,523 feet True Vertical Depth) and cased as a potential oilwell. The well penetrated pay zones in the Tertiary Pepino and Cretaceous Caballos formations. During the initial completion operation, a total of 104 feet of Caballos sand was perforated in six separate intervals covering a gross section of 161 feet of Caballos formation. In an attempt to accelerate the initial incremental production date for contractual purposes, all six intervals were placed on production simultaneously and the well was initially tested with temporary jet-pump equipment at rates in excess of 1,000 barrels of oil per day. The well exhibited immediate signs of cement failure resulting in a rapid increase in watercut during the test. Well log and pressure data analysis confirm the existence of a channel in the cement, which puts certain pay zones in direct communication with the underlying aquifer. Prior to implementing any form of remedial cement workover, the decision was made to selectively test each individual perforation interval to ascertain exact inflow performance and to determine the physical extent of the channel in the cement. These testing and completion operations have been hampered by a series of operational and mechanical difficulties, resulting in the replacement of most of the temporary downhole and surface equipment during the past 30 days. Recently, the supplier of most of the testing services and equipment was replaced and, since this change, operations have proceeded without major incident. The top two Caballos perforation intervals, totaling 18 feet and representing the least permeable part of the formation have now been tested at sustained un-stimulated rates of approximately 60 barrels of oil per day at very low water cuts indicating good quality cement bond to at least the base of the second Caballos perforation interval. We will continue to progressively test lower perforation intervals until such time as the exact extent of the cement bond failure is identified, at which time a decision on a remedial cement squeeze will be made. We are currently testing the third and fourth Caballos perforation intervals, totaling 52 feet, which include one of the primary targets of this completion operation. If these perforations have a good quality cement bond, and we achieve attractive production rates, we will likely install appropriate electrical submersible pumping (ESP) equipment and place the well on production from the top four Caballos intervals without performing a cement squeeze.

Orito 110 also has good hydrocarbon shows in three separate sands in the shallower Tertiary Pepino formation at depths ranging from 1,506 to 1,638 feet. Significant volumes of free oil from this zone were recovered during the drilling operations at pressures that were indicative of non-depleted reservoir conditions. The nearest Pepino production in the Orito field is approximately 1.8 kilometers to the southwest and typical Pepino wells in the Orito field have produced at initial rates of 500 to 800 BOPD with average cumulative production to date of 500 thousand barrels per well (four existing Pepino wells in Orito have each recovered more than 2 million barrels to date). We expect to drill an additional well at this location to separately evaluate the Pepino formation in the context of a broader Pepino drilling and workover program. We are also currently evaluating shut in and low productivity Caballos wells for bypassed pay in the Pepino zone as potential candidates for recompletion.

Our second development well, Orito 111 ("DEV-2"), was drilled vertically to a total depth of 6,678 feet. A total gross Caballos interval of 160 feet will be perforated in various intervals totaling 75 feet. The lower 55 feet of perforations are currently being tested with a jet pump system and plans are to test all the remaining Caballos intervals and place the well on production with an ESP. Orito 111 well also encountered indications of hydrocarbon pay in the Pepino formation, which will require drilling an additional shallow well on this wellsite to evaluate.

Our third development well, Orito 112 ("DEV-3"), was spudded January 4, 2003 and is being drilled directionally to a total depth of 7,100 feet (7,000 feet True Vertical Depth). The well is currently drilling at 3,500 feet and we expect to reach total depth by the end of January.

In addition to the first phase of drilling at Orito, we have completed our first workover on an existing Caballos producer, the Orito 90 well. This workover involved cleaning the wellbore of accumulated sand and debris, re-perforating 58 feet of Caballos reservoir, and replacing the existing inefficient gas lift technology with an ESP. The well was previously producing less than 35 barrels of oil per day at a 90% water cut and had cumulatively produced 1.75 million barrels over the past 20 years. The workover has increased production to more than 400 barrels of oil per day at a 65% water cut. We currently have plans for three additional workovers in our initial program, entailing removing any accumulated fill from the wellbores, re-perforating if necessary, and replacing gas lift equipment with ESPs. Additional opportunities of this type have been identified within the field and a follow-up program of ESP installations is anticipated.

After completion of drilling operations on Orito 112, we will be making a decision to either immediately drill further Caballos wells or to commence drilling Pepino targets in order to provide additional technical information for planning purposes. Surface leases at our first three Orito locations have been designed to accommodate the drilling of additional wells. Additional Caballos and Pepino drilling targets have also been identified which will require new surface lease construction.

Pursuant to our Orito Incremental Production Contract, we receive 79% of all incremental production and pay an initial 8 percent royalty. At Orito, Caballos oil averages approximately 33° API and the Pepino zone averages 26° API. Effective January 1, 2003, the Orito field base curve has been determined and incremental production is being recognized under the Orito contract.

Neiva Field

At Neiva, we have completed ten wells in our initial recompletion program. These recompletions involved shooting up to 250 feet of new Honda zone perforations in each existing producing wellbore. Total incremental production from these recompletions is currently 350 barrels of oil per day. Once production rates from these re-completed wells stabilize, pump speeds will be increased to reduce casing fluid levels and maximize productivity. These recompletions were performed significantly under initial budget, and as a result, an additional seven recompletions are planned at Neiva and should be completed by mid-February.

Our first of five development wells at Neiva has been cased at a total depth of 3,211 feet. The well encountered 1,400 feet of gross interval (approximately 650 feet of net sand). The completion program will commence this week and is designed to identify gas, oil, and water productivity of the various reservoir intervals.

The Company has spudded the second development well, and has plans to drill at least three further wells at Neiva and conduct further stimulations and recompletions as performance results warrant. Pursuant to our Neiva incremental production contract, we participate in 69% of incremental production and pay an initial 8 per cent royalty. Effective December 1, 2002, the Dina Terciarios field base curve has been determined and incremental production is being recognized under the Neiva contract for this field.

2003 Outlook

Petrobank plans to spend up to $70 million in 2003 in Colombia, primarily on Caballos and Pepino drilling at Orito. The Orito field currently is estimated to have 1.1 billion barrels of original oil in place, of which only 220 million barrels has been recovered to date. Despite early operational and mechanical difficulties at Orito 110, we are encouraged by the initial technical results from our activity on both of these Colombian blocks. To date, costs on our drilling and recompletion operations have been materially lower than budgeted. As a result, we expect to achieve improved investment efficiency as our program expands.

FOR FURTHER INFORMATION PLEASE CONTACT:

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or
Corey Ruttan
Director Corporate Finance

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Certain statements in this press release are "forward-looking statements" within the meaning of the United States Private Securities Litigation Reform Act of 1995. Specifically, this press release contains forward-looking statements relating to, production estimates and the expected amount and timing of capital projects. 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; fluctuation in foreign currency exchange rates; the uncertainty of reserve estimates; changes in environmental and other regulations; risks associated with oil and gas operations; and other factors, many of which are beyond the control of the Company. 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 forecast.

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THE MANITOBA
SECURITIES
COMMISSION

SEDAR Project # 449293
N° de projet du SEDAR 449293

RECEIPT FOR AN INITIAL ANNUAL INFORMATION FORM
VISA DE NOTICE ANNUELLE INITIALE

Receipt is hereby acknowledged of an Initial Annual Information Form dated May 17, 2002 of
Le présent visa est accordé à l'égard d'une notice annuelle initiale datée du 17 Mai, 2002
et émanant de

Petrobank Energy and Resources Ltd.

This final decision document evidences that a notice of acceptance of the regulator in **Manitoba** has been issued.
Le présent document de décision confirme qu'un avis d'acceptation a été délivré par les autorités en valeurs mobilières du **Manitoba**.

Dated at Winnipeg, Manitoba, February 10, 2003__.
Fait à Winnipeg, au Manitoba, le 10 Février, 2003.

"R. B. Bouchard"
Director, The Manitoba Securities Commission
Directeur, Commission des valeurs mobilières du Manitoba

The Manitoba Securities Commission
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PETROBANK ANNOUNCES YEAR END CANADIAN RESERVE ADDITIONS AND OPERATIONS UPDATE

CALGARY, Alberta – February 27, 2003

Canadian Reserve Update

Petrobank's reserve engineers, Gilbert Laustsen Jung Associates Ltd. ("GLJ"), have completed their Canadian reserve evaluation as at January 1, 2003. Petrobank's total proved reserves increased year over year by 13.1 percent to 9.97 million barrels of oil equivalent (boe) converting gas on a 6 mcf per barrel basis. The Company's total proved plus probable reserves increased by 36.6 percent to 17.41 million boe. The Company replaced 2002 production by 164 percent on a total proved basis. These reserves were added at a finding and development cost (including future capital) of approximately $11.40/boe total proved and $6.30/boe proved plus probable. Based on the GLJ price forecast effective January 1, 2003, the Company's established reserves have a Net Present Value before tax at a 10% discount rate of $113.2 million. Petrobank's reserves are summarized as follows:

	Reserve Volumes			
	Liquids (Mbbls)	Gas (Bcf)	Mboe (6:1)	NPV(10%) ($MM)
Proved Producing	4,820	16.4	7,552	75.8
Total Proved	6,487	20.9	9,973	89.5
Total Proved + Probable	11,476	35.6	17,414	136.8
Established (P + ½ P)	8,982	28.3	13,693	113.2

Petrobank was successful in replacing production and increasing our reserve base during 2002 according to the following continuity (Mboe):

	Total Proved	Proven + Probable
January 1, 2002 reserves	8,814	12,751
2002 Production	(1,825)	(1,825)
Revisions	(239)	(858)
Dispositions	(215)	(270)
Acquisitions	1,061	1,914

Additions	2,378	5,702
January 1, 2003 reserves	9,973	17,414

Canadian Operational Update

The Company's domestic operations during 2002 generated mixed results. Mr. John D. Wright, President of Petrobank commented, "While our overall finding and development costs for the year were higher than we would like due to our limited drilling success in the first three quarters, we have focused on a few key projects starting in the fourth quarter with positive results. These projects include: development drilling at our Eyehill and Epping discoveries, commencement of waterflood operations at Wapella and an acquisition and recompletion program in Shekilie. The Eyehill and Epping projects have continued into this year with further drilling activity this quarter, and we plan increased activity levels at both our Lashburn and Jumpbush properties. The Company is well positioned to generate further growth in these project areas."

To date in 2003, Petrobank has successfully drilled and cased three of the six wells in our second phase infill-drilling program at Eyehill. Further drilling may be warranted in the second half of the year and a full waterflood of the field will be initiated in the third quarter. At the Epping project a minimum of four additional wells are planned for this quarter with potential for future infill drilling in the summer. At Lashburn, a 3D seismic survey has identified up to 6 horizontal drilling locations which will commence after spring break-up. Finally at Jumpbush, on the Siksika First Nations Reserve, two glauconite oil wells (one horizontal) and eight shallow gas wells will be drilled this quarter, with a further 12 shallow gas wells and up to 5 glauconite oil wells planned for the summer.

Current production in Canada is approximately 5,000 BOEPD (6:1) comprised of 3,000 barrels per day of liquids and 12.0 Mmcf/d of natural gas. Petrobank's 2003 Canadian conventional capital budget has been set at $24 million.

Petrobank has scheduled its annual general meeting for May 22, 2003 and expects to release its year-end financial results by the first week of April 2003.

FOR FURTHER INFORMATION PLEASE CONTACT:

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or
David Rain
V.P. Finance and Chief Financial Officer

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PETROBANK ANNOUNCES COLOMBIAN RESERVES AND OPERATIONAL UPDATE

Calgary, Alberta – March 3, 2003 – Petrobank Energy and Resources Ltd. is pleased to provide the first reserve assessment for the Company's Colombian operations as at January 1, 2003, and an update of the current status of continuing drilling, completion, and workover activities on the Orito and Neiva Blocks.

Colombian Reserves

Petrobank commissioned Gilbert Laustsen Jung Associates ("GLJ") of Calgary to prepare an initial reserves report on its Colombian properties as at year-end 2002. Based on activity through mid-January, total proved oil reserves of 4.6 million barrels ("mmbbls") have been assigned to the Orito and Neiva Blocks. The Company's total proved and probable reserves are 8.3 mmbbls for these Blocks. Based on GLJ's price forecast effective January 1, 2003, these reserves have an estimated net present value before tax (discounted at 10%) of U.S.$31.6 million for the total proved reserves and U.S.$49.7 million for the proved plus probable reserves. These reserve assignments are based on the results of Petrobank's initial three months of field work in Colombia, and do not include the results of certain of the recent operations outlined below. It is the Company's intent to commission a further reserve update later in the year to further evaluate the reserve delineation on the two Blocks.

Operations Update - Orito Field

Orito 110, "DEV-1"

Following extensive testing of individual sands and interference testing between sands that confirmed the existence of a channel in the cement behind the production casing into the water leg, two separate cement squeezes were conducted targeting two separate intervals. Following the squeezes, the cement inside the wellbore was drilled out and the oil-bearing intervals were re-perforated and fracture stimulated. Final jet-pump evaluation of the well commenced on February 26th and subsequently, the Company has run an electrical submersible pump ("ESP") in the well and placed the well on production as of today. Based on jet pump results to date, the ESP was sized to handle approximately 1600 barrels of fluid per day. The well will be monitored with real time bottomhole pressure information and wellsite testing facilities. Watercuts will be monitored and are expected to stabilize after the recovery of the fracture stimulation fluids. Although the cement squeeze operations were technically successful, we do not believe that we have completely isolated the water production. Near wellbore permeability has also been reduced due to the remedial cement work, and overall productivity of the well has been negatively impacted. Due to expected continuing high watercuts, the Company does not anticipate that this well will be capable of more than 400 BOPD. Our technical opinion is that with significantly better cement integrity and comparable geological results, similar future wells in the Orito Caballos pool should be more productive. The Company is also preparing to drill a twin well from the DEV-1 surface lease targeting production from the shallow Pepino zone, based on the free oil shows and log results obtained during drilling of Orito 110.

Orito 111, "DEV-2"

ESP pumping operations have commenced on our second development well, Orito 111, following testing of all potentially productive intervals in the Caballos. In the final completion, the upper 80 feet of the Caballos reservoir were perforated in five separate sands totaling 36 feet of perforations. The sands encountered in Orito 111 were of lower apparent permeability than those in offsetting wells and therefore, all perforations were fracture stimulated. The ESP installed in this well is capable of handling 700 barrels of total fluid per day. As with DEV-1, the ESP provides continuous bottomhole pressure information and the well productivity and watercut performance will be monitored and is expected to stabilize over the week following recovery of the fracture stimulation fluids. The Company does not anticipate this well being capable of more than 300 BOPD. Again, we are planning to drill a twin well from the DEV-2 surface lease to test the Pepino formation based on an evaluation of the well logs in Orito 111 over that interval.

Orito 112, "DEV-3"

Our third development well, Orito 112 ("DEV-3") completed drilling on February 21, 2003. This well was targeting an extension of the Orito field to the west, and encountered a full Caballos section. After drilling approximately 100 feet into the upper Caballos, a bottomhole drill stem test ("DST") was performed which recovered 32 barrels of clean oil and confirmed that this new lobe of the field was in pressure communication with the main portion of the reservoir. Following the DST, the well was drilled to total depth of 7,170 feet and cased as a potential oilwell. 258 feet of gross Caballos section was encountered, with approximately 192 feet of gross oil column. The well is currently being completed and a series of cased hole DST's, together with the open hole DST, have confirmed commercially significant oil productivity from the entire indicated oil column. The tested sands produced at watercuts ranging from 0% to 50% and recovered oil of greater than 40° API. The well will be immediately fitted with an ESP sized to handle 1000 barrels of total fluid per day. Initial watercuts are expected to be in the 25% to 50% range. Based on results from this well, the Company is planning to immediately drill a second Caballos well from this same platform targeting Caballos reserves further west in this extension of the field.

Caballos ESP Installation Program

Petrobank has completed its second ESP pump change workover of an existing Orito producer. Orito 72 was taken off the gas-lift system and installed with an ESP on January 30, 2003. Production before the workover was approximately 285 barrels of oil per day at a watercut of 50 to 60%. The well is currently producing over 500 barrels of oil per day at similar watercuts and is not as yet fully optimized. The initial performance of this workover has exceeded expectations and the company is currently evaluating changing the existing ESP to a larger unit. Petrobank has identified up to 15 additional ESP well installation candidates of varying potential. Two additional wells have been approved for immediate ESP changes and Petrobank will be seeking approval for an additional six in the near future. Petrobank's first ESP installation, Orito 90, continues to produce at approximately 400 Bopd, generating approximately 365 Bopd of incremental production.

Orito Field -Future Development Plans

Although the initial completions and testing operations at Orito 110 and 111 have been operationally difficult, these two wells have confirmed the presence of oil in the lower part of the saddle area between the north and south domes of the field. Prior to the most recent 3D seismic, these areas were interpreted as not containing productive reservoir. These wells, together with the 3D seismic, have helped to confirm our structural interpretation, which indicates several Caballos locations in structural positions considerably higher than Orito 111. These structural positions will place the thicker and often more permeable lower Caballos sandstones higher in the oil window of the reservoir - potentially enhancing both the total fluid

production potential and reducing the watercut. Also, successful delineation of the western lobe of the field from the Orito 112 extension will significantly enhance the total reserve potential of the field. Revised drilling and completion practices first tested at Orito 112 will be implemented and further enhanced in all future drilling operations targeting the Caballos as we address the challenges presented by existing equipment and services available in the Putumayo region. Finally, both ESP workovers to date have dramatically exceeded expectations and provided the Company with a substantial inventory of locations to install new pumping equipment on existing wells. These results have also accelerated the Company's initiatives to commence large-scale waterflooding operations and to electrify the entire field.

Petrobank Elects to Proceed to Phase II of the Orito Contract

Based on our work to date, Petrobank has submitted our election to Ecopetrol to proceed with Phase II of the Orito contract. This election formalizes the Company's commitment to a minimum further U.S.$27 million investment program in the field. The initial work plan will include a fourth Caballos well to be drilled from the DEV-3 platform, the Pepino twin wells at DEV 1 and 2, and several more ESP pump changes. Petrobank is also in the process of obtaining environmental approvals to construct a fourth drilling pad in order to access up to six additional Caballos wells north and up-structure of DEV-2. These activities in turn will help to establish further development programs. The Company anticipates initiation of an extensive Pepino development program near mid-year. This program will initially consist of the drilling of twin wells at up to eight existing Caballos well locations that provide easy surface access and excellent geological control, which, if successful, will be followed by a larger scale Pepino development drilling program. Our planning is focused on conducting this shallow well program using a minimum disturbance drilling design to improve cost and time efficiencies, while minimizing the environmental impact of our operations.

January 1, 2003 saw the formal recognition of incremental production at Orito. Current incremental production in Orito is approximately 550 Bopd. Ecopetrol is currently active with a service rig in the field repairing several wells currently down with minor mechanical problems. With the new well ESP's coming onstream, production should rise significantly in the coming weeks. Pursuant to our Orito Incremental Production Contract, we receive 79% of all incremental production.

Operations Update - Neiva Field

At Neiva, four of the five wells in our initial drilling program have been drilled. The first new well, DT-70 was drilled and cased as a potential Honda well. The well was completed and placed on production with a progressing cavity pump ("PCP") and is currently producing approximately 80 barrels of oil per day. The second well, DT-72 was drilled to a total depth of 4,212 feet and in addition to the Honda, evaluated the slightly deeper Doima-Chicoral reservoir. Following significant oil shows during drilling, the Doima-Chicoral zone was completed with an uncemented liner and placed on production with a PCP system. The well was tested at rates of approximately 300 Bopd and is currently producing in excess of 180 Bopd to the battery. Fluid levels indicate additional potential and the pump speed is being increased to optimize production. A pressure survey was conducted on the zone during completion, which indicates that the reservoir still has very high pressure despite the fact that the nearby offset well (DT-56) has produced over 600,000 Bbls since commencing production in January 1988. The Honda zone in DT-72 also looks very prospective on logs and the company therefore plans to twin the well from the same surface lease for Honda production. A geological and seismic review of the field indicates an initial program of up to seven additional Doima-Chicoral locations and the Company is in the process of obtaining the necessary approvals to proceed with an expanded drilling program.

The third well (DT-69) was drilled for Honda production and is currently being completed and tested and should be on production using a PCP system in the next few days. Initial swab test results indicate that the

well will meet or exceed expectations, and should be capable of approximately 150 Bopd. Completion of the fourth well, also a Honda test, commenced March 1st, 2003. The fifth well (DT-71) at Neiva spudded on February 27th and is also targeting the Honda formation.

Petrobank continues to monitor and optimize production from our first 10 well workover program on existing producing Honda wells. In addition to those wells, an additional three wells have also been stimulated. The company designed and applied a mutual solvent stimulation to well DT-56 which is the Doima-Chicoral producer offsetting our new DT-72 well. Prior to the workover, the well was producing approximately 90 Bopd and subsequent to this stimulation is currently producing 176 Bopd with a very high fluid level.

Incremental production at Neiva was formally recognized as of December 1, 2002. Current incremental production is 650 Bopd and will continue to rise as the new wells start to produce into the battery. Petrobank is moving immediately to follow-up on these initial successes, especially in the Doima-Chicoral reservoir. Pursuant to our Neiva incremental production contract, we realize 69% of incremental production.

2003 Outlook -Colombia

Petrobank currently plans to spend $70 million (U.S.$45 million) in 2003 in Colombia, primarily on Caballos and Pepino drilling and ESP installations at Orito and the Doima-Chicoral drilling program at Neiva. Our initial programs in both fields have provided a wealth of operational and reservoir data and our operating and cost efficiencies are rapidly improving. In recent days, total incremental production in Colombia has reached 1,200 Bopd with Company interest production of approximately 900 Bopd. These volumes do not include any production from our three new Caballos wells in Orito or our last two Honda wells in Neiva. With the election to proceed to Phase II in Orito, our operations are set to advance to the next level.

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PETROBANK ESTABLISHES HEAVY OIL BUSINESS UNIT TO COMMERCIALIZE NEW TECHNOLOGY

Calgary, Alberta – February 24, 2003

Petrobank Energy & Resources Ltd. ("Petrobank") is pleased to announce the creation of a Heavy Oil Business Unit named Orion Oil Canada Ltd. ("Orion") and the appointment of Mr. Chris J. Bloomer as Vice President of that business unit. Mr. John D. Wright, President and CEO of Petrobank, described the creation of Orion as "an example of the Company's strategy to create a diverse portfolio of high impact opportunities. This is the culmination of over two years of evaluation and development by Petrobank of the potentially groundbreaking THAI heavy oil insitu recovery technology. We have consciously created a business unit structure that allows us to have a keen focus on our near term efforts, such as Latin America and Canada, while strategically positioning Petrobank to exploit high impact longer term initiatives such as oil sands and to pilot an exciting new technology. If we achieve commercial success with this innovative technology, Petrobank will have a tremendous strategic advantage in heavy oil asset development and will also be able to license the technology throughout the world."

Appointment of Chris Bloomer to Head Orion

Mr. Bloomer joins Petrobank as V.P. Heavy Oil and assumes the leadership of Orion, bringing over 20 years experience in the energy industry spanning both the upstream and downstream sectors. He began his career at Shell Canada and moved with increasing responsibility from exploration to economics, oil sands development, planning, and marketing, culminating in his role as Director, Liquids Business Centre. While at Shell he was involved with the ongoing development of its Peace River insitu oil sands project as well as upgrading initiatives. Subsequently, Mr. Bloomer was Senior Vice President of Castle Energy Corporation (NASDAQ), and Chief Operating Officer of its Canadian interests and natural gas production and pipeline operations in Texas. He then assumed the role of President and Chief Operating Officer of Canadian TALON Resources, Ltd. (TSX), operating primarily in Latin America. Most recently Mr. Bloomer was a Managing Director with the executive search firm Korn/Ferry International in their Calgary office focusing on the domestic and international energy industry. Mr. Bloomer holds a Bachelor of Science degree in geology from the University of Toronto and is a member of the Association of Engineers Geologists and Geophysicists of Alberta ("APEGGA").

THAI/CAPRI - Leading Edge Technologies

One of Orion's initial goals will be to pilot and, if the pilot is successful, commercially develop the patented Toe-to-Heel-Air-Injection ("THAI") insitu combustion and CAPRI insitu catalytic upgrading technologies (the "Technologies"). As discussed in further detail below, Petrobank has entered into an agreement to acquire direct ownership of the Technologies. THAI is a radical modification to other insitu combustion processes and combines a vertical air injection well with a horizontal production well. In modeling this process, a near vertical combustion front is created that sweeps the oil from the toe of the horizontal producing well to the heel, at temperatures sufficient to efficiently recover up to an estimated 80% of the oil in place and also upgrade the crude oil insitu. Other potential benefits of THAI relative to other recovery processes such as steam assisted gravity drainage ("SAGD") include reduced capital costs per produced barrel, elimination of the burning of natural gas and the use of fresh water to generate steam, reduction or elimination of diluent normally required for transportation, an upgraded crude oil product at the wellhead, and reduced greenhouse gas emissions. The CAPRI process is incremental to the THAI technology and adds a refinery catalyst around the horizontal well bore which, if successful, will further upgrade the crude oil as it is produced. The THAI process was discovered in 1993 and has been advanced through numerous physical model laboratory runs and successful field model simulations utilizing the Computer Modeling Group's ("CMG") STARS reservoir modeling program. The Alberta Research Council ("ARC") held the THAI and CAPRI patents until 2001 when they were acquired by Capri Petroleum Technologies Ltd. ("CPTL"). CPTL then entered into an agreement with Petrobank to further develop the Technologies in exchange for Petrobank earning the royalty free use of the Technologies.

Recently, an independent committee of the Board of Directors of Petrobank determined it was in the Company's best interests to directly own the Technologies. Therefore Petrobank has entered into a definitive memorandum of understanding ("MOU") to acquire the Technologies. The Technologies will be acquired from CPTL whose majority shareholders are John D. Wright, President, CEO and a director of Petrobank and M. Bruce Chernoff, a director of Petrobank. The remaining shareholder of the company is Dr. Conrad Ayasse. Messrs. Wright and Chernoff have invested approximately $430,000 cash in the company to date as part of the ongoing development and testing of the Technologies. Under the terms of the MOU, CPTL will receive approximately $430,000 in cash and a 17.5% net profits interest royalty in future third party revenues generated from the Technologies. Following completion of the technology purchase, Messrs. Ayasse and Wright will hold 57% and 43% of CPTL, respectively. Petrobank will have the royalty free use rights to the Technologies and will only pay a net profits interest to CPTL on future license fees charged to third parties.

As part of the deal to acquire the Technologies, Dr. Ayasse, one of the principal inventors of THAI and CAPRI, has also been retained by Orion to assist in ongoing developments. Dr. Ayasse holds a Ph.D. in chemistry from the University of Dalhousie and brings an outstanding 26-year record of business and research success and innovation. He was the

President of the Petroleum Recovery Institute ("PRI") for 13 years until ARC acquired it in 1999. Before PRI, he was a senior research manger with Dow Chemical.

Orion to Focus on Petrobank's Oil Sands Assets

In 2003, Orion intends to file an experimental pilot project application with the AEUB to conduct a field pilot test of the THAI process. We are currently evaluating the bitumen resource potential on Petrobank's 42 sections of 100% owned oil sands leases near Christina Lake, Alberta, as a potential THAI pilot project site. Petrobank's property is situated near existing and developing infrastructure in the area of other major oil sands projects such as EnCana's Christina Lake Project. A 21 square kilometer 3D seismic survey is currently under way on the lands to be followed by a 12 well delineation-drilling program. The Company plans to spend approximately $4,000,000 in 2003 on seismic, drilling, and pilot project engineering, design and planning.

For further information please contact

Chris J. Bloomer, or John D. Wright
V.P. Heavy Oil President and CEO
Petrobank Energy and Resources Ltd.
2200, 400-3rd Ave. S.W.
Calgary, Alberta T2P 4H2
Telephone (430) 750-4400
Facsimile (403) 266-5794

Certain statements in this press release are "forward-looking statements" within the meaning of the United States Private Securities Litigation Reform Act of 1995. Specifically, this press release contains forward-looking statements relating to, prospects for technologies which remain unproven and the expected amount and timing of capital projects. 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: the ability to economically test, develop and utilize the technologies described herein, the feasibility of the technologies, general economic, market and business conditions; fluctuations in oil and gas prices; the results of exploration and development of drilling and related activities; fluctuation in foreign currency exchange rates; the uncertainty of reserve estimates; changes in environmental and other regulations; risks associated with oil and gas operations; and other factors, many of which are beyond the control of the Company. 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 forecast.

Computershare
600, 530-8th Avenue S.W., Calgary, AB T2P 3S8 Tel.: (403) 267-6800 Fax: (403) 267-6529

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March 27, 2003

Alberta Securities Commission
British Columbia Securities Commission
The Manitoba Securities Commission
Office of the Administrator, New Brunswick
Securities Commission of Newfoundland
Nova Scotia Securities Commission
Ontario Securities Commission
Commission des valeurs mobilières du Québec
Saskatchewan Securities Commission
Registrar of Securities, Government of the Yukon Territory
TSX

Dear Sirs:

Subject: Petrobank Energy and Resources Ltd.

We advise the following with respect to the upcoming Meeting of Shareholders for the subject Corporation:

1.	Meeting Type	:Annual General and Special (Non-Routine) Meeting
2.	Security Description of Voting Issue	:Common
3.	CUSIP Number	:716 45P 106
4.	Record Date	:April 21, 2003
5.	Meeting Date	:May 22, 2003
6.	Meeting Location	:Calgary, Alberta

Yours truly,
COMPUTERSHARE TRUST COMPANY OF CANADA

"signed by"
Kari Begg
Meeting Specialist
Direct Dial No. (403) 267-6566
Fax No. (403) 267-6529
Email: kari.begg@computershare.com

cc: Petrobank Energy and Resources Ltd.
Attention: Corey Ruttan

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Petrobank Energy and Resources Ltd.

Suite 2200, 400 – 3rd Avenue S.W.
Calgary, Alberta T2P 4H2
Telephone: (403) 750-4400
FAX: (403) 266-5794
TSE: PBG, PBG.N

PETROBANK ANNOUNCES 2002 YEAR-END RESULTS

Calgary, Alberta – March 31, 2003 – Petrobank Energy and Resources Ltd. is pleased to announce operational and financial results for the year ended December 31, 2002.

2002 Highlights

- Net capital expenditures totaled $42.9 million in 2002 including $15.6 million on the Company's two incremental production blocks in Colombia.
- Canadian finding and development costs in 2002 of $11.37 per proved barrel of oil equivalent (boe, 6 mcf = 1 boe) and $6.32 per proved plus probable boe (includes additional future capital of $6.7 million proved and $13.7 million proved plus probable).
- Average production increased 17% from 4,321 boe per day in 2001 to 5,047 boe per day in 2002. Colombian crude oil sales commenced in January 2003.
- Oil and natural gas revenue increased to $50.5 million in 2002 from $46.1 million in 2001.
- Cash flow from operations before changes in working capital increased 23% from $18.5 million in 2001 to $22.8 million in 2002.
- Year-end proved plus probable reserves totaled 25.7 million boe, including 8.3 million barrels attributed to Petrobank's Colombian assets, a 102% increase from 2001.

Net Capital Expenditures

For the years ended December 31, (thousands of $)	2002			2001
	Canada	**Colombia**	**Total**	Canada
Drilling and completions	**$14,683**	**$14,206**	**$28,889**	$9,363
Facilities and equipment	**1,518**	**137**	**1,655**	3,699
Land	**5,842**	**-**	**5,842**	5,715
Seismic	**493**	**276**	**769**	2,234
Asset acquisitions	**6,127**	**-**	**6,127**	-
Other	**1,930**	**1,016**	**2,946**	848
Dispositions [1]	**(3,334)**	**-**	**(3,334)**	(161,575)
Corporate acquisition [2]	**-**	**-**	**-**	115,322
Net capital expenditures (dispositions)	**$27,259**	**$15,635**	**$42,894**	$(24,394)

[1] In 2001, includes $1.0 million of non-cash proceeds excluded from proceeds on disposition of resource properties on the consolidated statement of cash flows.

[2] In 2001, represents the acquisition of Barrington Petroleum Ltd.

Production

	Liquids - Bbls/d		Gas - Mcf/d		BOEPD (6:1)	
	2002 Average	Current[1]	2002 Average	Current[1]	2002 Average	Current[1]
Southeast Saskatchewan	1,552	1,530	-	-	1,552	1,530
Northwest Alberta	327	360	10,796	7,650	2,126	1,635
Western Saskatchewan	291	500	-	-	291	500
Jumpbush	64	50	1,124	1,050	252	225
Other	389	400	2,621	2,550	826	825
Total - Canada	2,623	2,840	14,541	11,250	5,047	4,715
Colombia - Orito	-	710	-	-	-	710
Colombia - Neiva	-	395	-	-	-	395
Total - Colombia	-	1,105	-	-	-	1,105
Total	2,623	3,945	14,541	11,250	5,047	5,820

[1] Average field production for the week ended March 15, 2003.

Outlook

Petrobank's long-term business plan is directed at maximizing return on shareholders' equity by enhancing our western Canadian asset base and executing on high impact international opportunities. The Company's 2003 capital budget includes $40 million in Canada and US$45 million in Colombia.

Petrobank's year-end financial statements including notes thereto are being posted to SEDAR as well as the Company's website at www.petrobank.com. Petrobank plans to mail its annual report to shareholders on April 25, 2003 and has set a record date of April 21, 2003 for its Annual and Special Meeting of Shareholders to be held on Thursday, May 22, 2003 at 3:00 p.m. in the Bonavista Room at the Westin Hotel, 320 4th Avenue S.W., Calgary, Alberta.

FOR FURTHER INFORMATION PLEASE CONTACT:

John D. Wright
President and Chief Executive Officer
or
David J. Rain
Vice-President Finance and Chief Financial Officer

Petrobank Energy and Resources Ltd.
Suite 2200, 400 - 3rd Avenue S.W.
Calgary, Alberta T2P 4H2
Telephone: (403) 750-4400 or Facsimile: (403) 266-5794

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HIGHLIGHTS

	2002	2001	% change
FINANCIAL			
(Thousands of $ except where noted)			
For the year ended December 31,			
Oil and natural gas revenue	50,458	46,117	9
Cash flow from operations [1]	22,806	18,549	23
Per share (basic) [2]	0.45	0.46	(2)
Per share (diluted)	0.40	0.39	3
Net income	6,191	5,283	17
Net income (loss) attributable to common shareholders	(430)	431	
Per share (basic)	(0.01)	0.01	
Per share (diluted)	(0.01)	0.01	
Capital expenditures	46,228	21,859	111
As at December 31,			
Working capital (deficiency)	(5,151)	25,410	
Total assets	150,618	146,337	3
Net debt [3]	62,495	31,266	100
Shareholders' equity excluding subordinated notes	55,668	57,791	(4)
Common shares outstanding (000's)			
Basic	45,314	33,557	35
Diluted	50,287	56,376	(11)
OPERATIONS [4]			
For the year ended December 31,			
Operating netback ($/BOE except where noted)			
Oil and NGL price ($/Bbl)	31.11	28.09	11
Natural gas price ($/Mcf)	3.89	5.13	(24)
Oil and natural gas revenue, net of hedging	27.39	29.24	(6)
Royalties	5.84	5.00	17
Production expenses	6.68	6.55	2
Operating netback	14.87	17.69	(16)
Average daily production - Canada			
Oil and NGL's (bbls)	2,623	2,480	6
Natural gas (mcf)	14,541	11,047	32
Barrels of oil equivalent (BOE)	5,047	4,321	17
RESERVES (proved and probable)			
As at December 31,			
Oil and NGL's - Canada (mbbls)	11,476	6,427	79
Natural gas - Canada (Bcf)	35.6	37.9	(6)
Oil – Colombia (mbbls)	8,330	-	
Barrels of oil equivalent (mboe) [4]	25,744	12,751	102

[1] Calculated based on cash flow from operations before changes in working capital.
[2] Calculated based on cash flow from operations before changes in working capital less preferred share dividends and interest paid on subordinated notes and adding back $1.5 million of non-recurring well control costs in 2001.
[3] Includes working capital and subordinated notes reflected as equity on the balance sheet
[4] 6 Mcf of natural gas is equivalent to 1 barrel of oil equivalent (BOE).



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Notice of Annual and Special Meeting of Shareholders
to be held on May 22, 2003

The annual and special meeting of the shareholders of Petrobank Energy and Resources Ltd. will be held in the Bonavista Room at the Westin Hotel, 320 – 4th Avenue S.W., Calgary, Alberta on Thursday, May 22, 2003 at 3:00 p.m. (Calgary time) to:

1. receive and consider our financial statements for the year ended December 31, 2002, together with the report of the auditors;
2. fix the number of directors to be elected at the meeting at 7 members;
3. elect 7 directors;
4. appoint the auditors and to authorize the directors to fix their remuneration as such;
5. consider, and if thought fit, pass an ordinary resolution to approve an increase in the maximum number of common shares issuable under the stock option plan;
6. consider, and if thought fit, pass an ordinary resolution to amend certain terms and conditions under the stock option plan;
7. consider, and, if thought fit, pass an ordinary resolution to approve future private placements by the Corporation; and
8. transact such other business as may properly be brought before the meeting or any adjournment thereof.

The specific details of the matters proposed to be put before the meeting are set forth in the information circular - proxy statement accompanying this notice.

If you are unable to attend the meeting in person we request that you date and sign the enclosed form of proxy and mail it to or deposit it with our Secretary, c/o Computershare Trust Company of Canada, Proxy Department, 9th Floor - 100 University Avenue, Toronto, Ontario, M5J 2Y1. In order to be valid and acted upon at the meeting, forms of proxy must be returned to the aforesaid address not less than 48 hours before the time for holding the meeting or any adjournment thereof.

Only shareholders of record at the close of business on April 21, 2003 will be entitled to vote at the meeting, unless that shareholder has transferred any shares subsequent to that date and the transferee shareholder, not later than 10 days before the meeting, establishes ownership of the shares and demands that the transferee's name be included on the list of shareholders.

DATED at Calgary, Alberta this April 21, 2003.

By order of the board of directors

John D. Wright
President and Chief Executive Officer



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DATED at Calgary, Alberta this April 21, 2003.

By order of the board of directors

John D. Wright
President and Chief Executive Officer

PETROBANK
ENERGY AND RESOURCES LTD.

Information Circular - Proxy Statement
for the Annual and Special Meeting to be held on May 22, 2003

PROXIES

Solicitation of Proxies

This information circular - proxy statement is furnished in connection with the solicitation of proxies for use at our annual and special meeting of the shareholders to be held in the Bonavista Room at the Westin Hotel, 320 – 4th Avenue S.W., Calgary, Alberta on Thursday, May 22, 2003 at 3:00 p.m. (Calgary time) and at any adjournment thereof. Forms of proxy must be addressed to and reach our Secretary, c/o Computershare Trust Company of Canada, Proxy Department, 9th Floor - 100 University Avenue, Toronto, Ontario, M5J 2Y1, not less than 48 hours before the time for holding the meeting or any adjournment thereof. Only shareholders of record at the close of business on April 21, 2003 will be entitled to vote at the meeting, unless that shareholder has transferred any shares subsequent to that date and the transferee shareholder, not later than 10 days before the meeting, establishes ownership of the shares and demands that the transferee's name be included on the list of shareholders.

The instrument appointing a proxy must be in writing and must be executed by you or your attorney authorized in writing or, if you are a corporation, under your corporate seal or by a duly authorized officer or attorney of the corporation.

The persons named in the enclosed form of proxy are our officers. As a shareholder you have the right to appoint a person, who need not be a shareholder, to represent you at the meeting. To exercise this right you should insert the name of the desired representative in the blank space provided on the form of proxy and strike out the other names or submit another appropriate proxy.

Advice to Beneficial Holders of Common Shares

The information set forth in this section is of significant importance to you if you do not hold your common shares in your own name. Only proxies deposited by shareholders whose names appear on our records as the registered holders of common shares can be recognized and acted upon at the meeting. If common shares are listed in your account statement provided by your broker, then in almost all cases those common shares will not be registered in your name on our records. Such common shares will likely be registered under the name of your broker or an agent of that broker. In Canada, the vast majority of such shares are registered under the name of CDS & Co., the registration name for The Canadian Depository for Securities Limited, which acts as nominees for many Canadian brokerage firms. Common shares held by your broker or their nominee can only be voted upon your instructions. Without specific instructions, your broker or their nominee is prohibited from voting your shares.

Applicable regulatory policy requires your broker to seek voting instructions from you in advance of the meeting. Every broker has its own mailing procedures and provides its own return instructions, which you should carefully follow in order to ensure that your shares are voted at the meeting. Often, the form of proxy supplied by your broker is identical to the form of proxy provided to registered shareholders. However, its purpose is limited to instructing the registered shareholder how to vote on your behalf. The majority of brokers now delegate responsibility for obtaining instructions from clients to the ADP Investor Communications. The ADP Investor Communications mails a scannable voting instruction form in lieu of the form of proxy. You are asked to complete and return the voting instruction form to them by mail or facsimile. Alternately, you can call their toll-free telephone number to vote your shares. They then tabulate the results of all instructions received

and provide appropriate instructions respecting the voting of shares to be represented at the meeting. If you receive a voting instruction form from ADP Investor Communications it cannot be used as a proxy to vote shares directly at the meeting as the proxy must be returned to ADP Investor Communications well in advance of the meeting in order to have the shares voted.

Revocability of Proxy

You may revoke your proxy at any time prior to the meeting. If you or the person you give your proxy to attends personally at the meeting you or such person may revoke the proxy and vote in person. In addition to revocation in any other manner permitted by law, a proxy may be revoked by an instrument in writing executed by you or your attorney authorized in writing or, if you are a corporation, under your corporate seal or by a duly authorized officer or attorney of the corporation. To be effective the instrument in writing must be deposited either at our head office at any time up to and including the last business day before the day of the meeting, or any adjournment thereof, at which the proxy is to be used, or with the chairman of the meeting on the day of the meeting, or any adjournment thereof.

Persons Making the Solicitation

This solicitation is made on behalf of our management. We will bear the costs incurred in the preparation and mailing of the form of proxy, notice of annual and special meeting and this information circular - proxy statement. In addition to mailing forms of proxy, proxies may be solicited by personal interviews, or by other means of communication, by our directors, officers and employees who will not be remunerated therefor.

Exercise of Discretion by Proxy

The common shares represented by proxy in favour of management nominees will be voted on any poll at the meeting. Where you specify a choice with respect to any matter to be acted upon the shares will be voted on any poll in accordance with the specification so made. If you do not provide instructions your shares will be voted in favour of the matters to be acted upon as set out herein. The persons appointed under the form of proxy which we have furnished are conferred with discretionary authority with respect to amendments or variations of those matters specified in the form of proxy and notice of annual and special meeting and with respect to any other matters which may properly be brought before the meeting or any adjournment thereof. At the time of printing this information circular - proxy statement, we know of no such amendment, variation or other matter.

VOTING SHARES AND PRINCIPAL HOLDERS THEREOF

We are authorized to issue an unlimited number of common shares without nominal or par value and an unlimited number of preferred shares issuable in series. As at April 21, 2003, there were 45,548,341 common shares and no preferred shares issued and outstanding. Holders of common shares are entitled to one vote for each share held.

To the knowledge of our directors and officers, as at April 21, 2003, no person or company beneficially owns, directly or indirectly, or exercises control or direction over, more than 10% of the voting shares.

As at April 21, 2003, our directors and officers, as a group, beneficially owned, directly or indirectly, or exercised control over 13,518,435 common shares or 29.7% of the issued and outstanding common shares.

MATTERS TO BE ACTED UPON AT THE MEETING

ANNUAL BUSINESS

Consolidated Financial Statements and Auditors' Report

The audited consolidated financial statements of the Corporation for the year ended December 31, 2002 and the Auditors' Report thereon, as included in the 2002 Annual Report, will be received at the Meeting.

Election of Directors

At the meeting, the shareholders will be asked to fix the number of directors to be elected at the meeting at 7 members and to elect 7 directors. The nominees will hold office until the next annual general meeting or until their successors are elected or appointed.

Management is soliciting proxies, in the accompanying form of proxy, for an ordinary resolution in favour of fixing the board of directors at 7 members, and in favour of the election as directors of the 7 nominees set forth below:

John A. Brussa
M. Bruce Chernoff
Louis L. Frank
Kenneth R. McKinnon
Jerald L. Oaks
James D. Tocher
John D. Wright

In the event that a vacancy among such nominees occurs because of death or for any reason prior to the meeting, the proxy shall not be voted with respect to such vacancy.

The names and municipalities of residence of all of the persons nominated for election as directors, the approximate number of common shares beneficially owned, directly or indirectly, or over which control or direction is exercised, by each of them, the dates on which they became directors, and their principal occupations, as of April 21, 2003, were as follows:

Name of Nominee, Municipality of Residence and Position	Number of Common Shares Beneficially Owned or Controlled	Director Since	Principal Occupation
John A. Brussa [1][3] Calgary, Alberta Director	226,333	March 14, 2000	Barrister and Solicitor; Partner of Burnet, Duckworth & Palmer LLP.
M. Bruce Chernoff [1][2][3] Calgary, Alberta Director	3,302,041	March 14, 2000	President and Director of Caribou Capital Corp. (a private investment management company).
Louis L. Frank North Woodstock, New Hampshire Director	805,068	September 27, 1993	Independent Consultant, Director and Founder of Loon Mountain Recreation Corp.; President of Recco Inc. (a private oil and gas development and real estate development company).
Kenneth R. McKinnon Calgary, Alberta Corporate Secretary and Director	248,399	March 14, 2000	Chief Corporate Affairs Officer and General Counsel of Critical Mass Inc. (a private marketing company).
Jerald L. Oaks [1][2] Englewood, Colorado Director	426,000	September 27, 1993	Professional Engineer, President of Oaks Resources Management Inc. (a private petroleum engineering and management company).
James D. Tocher [2][3] Calgary, Alberta Chairman of the Board	3,647,661	October 8, 1992	Chairman of the Board of the Corporation, and Chairman of the Board of VX Optronics Corp. (a private technology company).
John D. Wright Calgary, Alberta President, Chief Executive Officer and Director	3,737,386	March 14, 2000	President and Chief Executive Officer of the Corporation.

Notes:
(1) Member of the Audit Committee.
(2) Member of the Reserves Committee.
(3) Member of the Compensation Committee.
(4) The Corporation does not have an executive committee of its members.

The information as to voting securities beneficially owned, directly or indirectly, is based upon information furnished to the Corporation by the nominees.

Appointment of Auditors

Management is soliciting proxies, in the accompanying form of proxy, in favour of the appointment of the firm of Deloitte & Touche LLP, Chartered Accountants, as our auditors, to hold office until the next annual meeting of the shareholders and to authorize the directors to fix their remuneration as such.

SPECIAL BUSINESS

Approval to increase the maximum number of common shares reserved for issuance under the Corporation's Stock Option Plan

The Toronto Stock Exchange (the "TSX") policies relating to stock option plans requires that the Corporation fix the number of common shares to be reserved for issuance under its stock option plan (the "Stock Option Plan"). The Board of Directors is requesting shareholder approval to amend the Corporation's Stock Option Plan to increase the maximum number of reserved and actually available for issuance thereunder by 695,000.

Options granted under the Stock Option Plan generally have a term of five years to expiry and typically vest equally over a four-year period starting on the first anniversary of the date of the grant. The Stock Option Plan allows the Corporation to provide financial assistance to facilitate the exercise of stock options, but in practice Petrobank does not provide such assistance. As at April 21, 2003, 3,857,965 common shares remained available for issuance under the Stock Option Plan of which 3,331,198 were reserved for issuance under outstanding options and 526,767 remained available for new option grants. If the proposed amendment had been in effect April 21, 2003, an aggregate of 1,221,767 common shares would have been available for future issuance thereunder which, combined with the options to purchase 3,331,198 common shares already granted and unexercised under the Stock Option Plan, would have represented 10.0% of the common shares issued and outstanding at April 21, 2003. This information is summarized in the table below.

The Board of Directors believes that increasing the number of common shares available under its Stock Option Plan maintains a reasonable balance between the interests of the Corporation in attracting and retaining employees through a balanced compensation program and the concerns of shareholders on the potential dilution arising from stock option grants. The exercise price for each option is not less than the closing price of the Corporation's common shares on the day of the grant. The Corporation grants options to employees in order to recruit and retain staff and to align employee interests with the interests of shareholders. The following table specifies the number of common shares that may be subject to option grants under the Stock Option Plan, after the proposed amendment, as at April 21, 2003.

	Common Shares Currently Subject to Outstanding Options	**Common Shares Available for Future Option Grants**	**Maximum Common Shares Subject to Option Grants**
Currently Approved	3,331,198	526,767	3,857,965
Proposed Increase	-	695,000	695,000
Total	3,331,198	1,221,767	4,552,965
% of Common Shares	7.3%	2.7%	10.0%

Accordingly, at the meeting, you will be asked to consider and, if thought appropriate, approve an ordinary resolution in the following form:

> BE IT RESOLVED, AS AN ORDINARY RESOLUTION OF THE SHAREHOLDERS OF Petrobank Energy and Resources Ltd., that Petrobank Energy and Resources Ltd. be and is hereby authorized to amend the Corporation's Employee Stock Option Plan to increase the maximum number of common shares of the Corporation reserved for issuance thereunder by 695,000.

Unless otherwise directed, the persons named in the enclosed form of proxy intend to vote the proxies in favour of the resolution referred to above.

Approval of Amendment to the Terms of the Corporation's Stock Option Plan

The Board of Directors is also requesting shareholder approval to amend certain terms and conditions of the Stock Option Plan as described below.

The Corporation's existing Stock Option Plan provides that in the event of an optionee's death, then vested stock options are exercisable for a period of six months. The Board of Directors is seeking approval to amend this provision such that all vested and unvested options are exercisable for a six month term in the event of the death of an optionee and also in the event an optionee becomes permanently disabled.

The Corporation's existing Stock Option Plan provides that vested stock options are exercisable for three months following the date an optionee ceases to be employed by the Corporation. The Board of Directors is seeking approval to shorten the term available for exercise under this provision from three months to seven days in the event the employee voluntarily ceases employment with the Corporation.

Accordingly, at the meeting, you will be asked to consider and, if thought appropriate, approve an ordinary resolution in the following form:

> BE IT RESOLVED, AS AN ORDINARY RESOLUTION OF THE SHAREHOLDERS OF Petrobank Energy and Resources Ltd., that Petrobank Energy and Resources Ltd. be and is hereby authorized to amend the terms of the Corporation's Employee Stock Option Plan as described in Petrobank's Information Circular dated April 21, 2003.

Unless otherwise directed, the persons named in the enclosed form of proxy intend to vote the proxies in favour of the modifications to the Corporation's Stock Option Plan referred to above.

Future Private Placements

The policies of the TSX provide that the aggregate number of shares of a listed corporation which are issued or made subject to issuance by way of one or more private placement transactions during any particular six month period may not exceed 25% of the number of shares outstanding at the beginning of the aforesaid six month period without first receiving the approval of the shareholders of the listed corporation on such terms and conditions as the TSX may impose in respect of securing such approval. The effect of this policy is to prevent a listed corporation from closing private placements that may, on a cumulative basis, exceed the aforesaid 25% limit until such time as the shareholders of the listed corporation have passed an ordinary resolution approving the private placement that the listed corporation intends to enter into, or unless advance shareholder approval is obtained.

Equity financing is one of the primary sources of capital presently available and anticipated to be available to the Corporation over the next year. In order to raise funds necessary to carry on current activities and fund future acquisition and development opportunities, we may need to raise additional equity. Management considers that it is in the best interests of Petrobank to obtain advance approval from its shareholders due to the possibility of entering into private placements that may exceed the TSX's 25% policy described above provided that such placements are completed within 12 months of the date that the shareholders give such advance approval. Obtaining advance approval should obviate the necessity of securing further shareholder approval for each specific private placement and will thus reduce the time required to obtain regulatory approval therefor. This in turn should decrease Petrobank's administrative costs relating to such private placements and should allow greater flexibility to facilitate the raising of additional capital. Petrobank understands that it is the current practice of the TSX that such advance approval will be recognized as effective as long as the TSX is satisfied with the disclosure in the proxy materials sent to shareholders in connection with the meeting at which such resolution will be considered.

Any private placement(s) contemplated by Petrobank in reliance on advance approval sought at the Meeting will be subject to the following additional characteristics:

(a) each private placement must be substantially with parties who are at arm's length to Petrobank;

(b) each placement cannot materially affect control of Petrobank; and

(c) the policies of the TSX relative to private placement pricing will be followed subject to the TSX's discretion to impose more restrictive policies, the TSX's current pricing policy is briefly described as follows:

> the price at which a share of Petrobank may be issued by way of private placement must not be lower than the closing market price of Petrobank's Shares as traded on the TSX on the day prior to the date that notice of the private placement is given to the TSX less the applicable discounts as follows:

Proposed Issue Price	**Maximum Discount**
$0.50 or less	25%
$0.51 to $2.00	20%
over $2.00	15%

(for these purposes, a private placement of unlisted convertible securities is deemed to be a private placement of the underlying listed securities at an issue price equal to the lowest possible price at which the securities are convertible by holders thereof).

The TSX has the discretion to determine whether or not a particular private placement is substantially at arm's length or will result in a material change of control. For these and other reasons, the TSX may require specific shareholder approval for any particular private placement.

In anticipation that Petrobank may wish to enter into one or more private placements to be completed within 12 months of the date of the meeting and such placements may result in the issuance of a number of common shares or securities convertible into common shares equal to 100% of the number of common shares currently outstanding, Petrobank requests that shareholders approve the following ordinary resolution:

> "BE IT RESOLVED that subject to regulatory approval and in compliance with the rules and policies of the Toronto Stock Exchange, Petrobank be allowed and is hereby authorized to enter into one or more private placement transactions during the 12 month period commencing on the date of adoption of this resolution by the shareholders providing for the issuance of up to 45,548,341 common shares or other securities convertible into a maximum of 45,548,341 common shares of Petrobank."

The directors of Petrobank believe the passing of the foregoing resolution is in the best interests of Petrobank, since it will give Petrobank additional flexibility in accessing capital markets on a timely basis. In order for the foregoing resolution to be passed, it must be approved by a simple majority of the votes cast by shareholders who vote in person or by proxy at the meeting. The persons named in the enclosed form of proxy, if named as proxy, intend to vote for the approval of the foregoing resolution.

EXECUTIVE COMPENSATION

Summary Compensation Table

The following table sets forth all annual and long-term compensation paid in respect of the individuals who, as at the most recently completed financial year ended December 31, 2002, meet the requirements to be classified as "Named Executive Officers" of the Corporation pursuant to the *Securities Act* (Ontario).

Name and Principal Positions	Year	Annual Compensation			Long-Term Compensation	All Other Compensation ($)
		Salary ($)	Bonus ($)	Other Annual Compensation ($) [1]	Securities Under Options Granted (#)	
JOHN D. WRIGHT	2002	- [2]	-	15,238	350,000 [4]	-
President, Chief	2001	- [2]	-	12,966	-	-
Executive Officer and	2000	- [2][3]	-	2,250	-	-
Director						
KEVIN L. ADAIR	2002	150,000	20,000	-	250,000	-
Vice President Latin	2001	150,000	12,500	-	-	-
America	2000	150,000	-	-	-	75,000[5]
GARRY T. HIDES	2002	130,000	20,000		150,000	-
Vice President Land	2001	118,333	9,167	-	-	-
	2000	110,000	-	-	50,000	55,000[5]
RENE J. LAPRADE	2002	140,000	20,000	-	50,000	-
Vice President Operations	2001	149,333 [6]	3,000	-	200,000	-
DAVID J. RAIN	2002	115,000	20,000	-	250,000 [4]	-
Vice President Finance	2001	105,000	12,500	-	-	-
and Chief Financial	2000	- [3]	-	-	-	-
Officer						

Notes:

(1) The value of perquisites and other personal benefits received by these Named Executive Officers, other than Mr. Wright, was not greater than the lesser of $50,000 and 10% of the total annual salary paid to them in the year in question. Other Annual Compensation for Mr. Wright includes employee share ownership plan contributions and parking.

(2) Mr. Wright was appointed President and Chief Executive Officer in March 2000. Mr. Wright's employment contract provided for nil salary and a payment of $180,000 in the event his employment contract is terminated by Petrobank or in the event of a change of control of the Corporation. Effective March 1, 2003 Mr. Wright's salary was adjusted to $180,000 per annum.

(3) During 2000, Petrobank paid $225,000 pursuant to a management services agreement covering the services of John D. Wright, David J. Rain and four other individuals who performed full time management services for the Corporation. The agreement was terminated effective January 1, 2001.

(4) Neither Mr. Wright nor Mr. Rain had been granted any other stock options by the Corporation in the past. Messrs. Wright and Rain agreed to the cancellation of these stock options in April 2003. As a result, stock options cannot be granted to Mr. Wright or Mr. Rain within a two-year period without shareholder approval. An alternative compensation arrangement will be considered by the Compensation Committee in 2003.

(5) Payments were made in connection with the elimination of employment contracts that provided for payments equal to 12 months salary in the event of a change of control.

(6) Includes consulting fees paid to Mr. Laprade. Mr. Laprade was appointed Vice President Operations of Petrobank in October 2001.

No long-term compensation was paid to the "Named Executive Officers" in the form of restricted share awards or long-term incentive plan payouts during the year ended December 31, 2002.

Long-Term Incentive Plans – Option Grants During the Year Ended December 31, 2002

The following table sets forth, with respect to each of the Named Executive Officers, details regarding stock options granted during the year ended December 31, 2002.

Name	Securities Under Options Granted (#)	% of Total Options Granted to Employees in Financial Year	Exercise or Base Price ($/Security)	Market Value of Securities Underlying Options on the Date of Grant ($/Security)	Expiration Date
John D. Wright	350,000	10.4%	$2.25	$2.25	September 3, 2007
Kevin L. Adair	175,000	5.2%	$1.62	$1.62	March 1, 2007
	75,000	2.2%	$2.50	$2.50	October 30, 2007
Garry T. Hides	150,000	4.5%	$2.50	$2.50	October 30, 2007
Rene J. Laprade	50,000	1.5%	$1.62	$1.62	March 1, 2007
David J. Rain	250,000	7.4%	$2.25	$2.25	September 3, 2007

Aggregated Option Exercises During the Year Ended December 31, 2002 and Year-End Option Values

The following table sets forth, with respect to each of the Named Executive Officers, the number of stock options exercised and the aggregate value realized on exercise during 2002 and the number of unexercised stock options and the value of in-the-money stock options at December 31, 2002.

Name	Securities Acquired on Exercise (#)	Aggregated Value Realized ($)	Unexercised Stock Options at Year-End Exercisable/Unexercisable (#)	Value of Unexercised in-the-Money Stock Options at Year-End [1] Exercisable/Unexercisable ($)
John D. Wright	Nil	Nil	Nil/350,000	Nil/385,000
Kevin L. Adair	395,000	394,540	162,500/187,500	236,625/274,875
Garry T. Hides	150,000	75,000	100,000/150,000	172,500/127,500
Rene J. Laprade	Nil	Nil	62,500/187,500	104,125/312,375
David J. Rain	Nil	Nil	Nil/250,000	Nil/275,000

Notes:

(1) Based on the closing price of the Corporation's common shares on December 31, 2002 of $3.35 less exercise price.

COMPENSATION COMMITTEE REPORT ON EXECUTIVE COMPENSATION

Composition of the Compensation Committee

The members of the Compensation Committee are John A. Brussa, M. Bruce Chernoff and James D. Tocher. No member of the Compensation Committee is employed by the Corporation or its affiliates. Mr. Chernoff is the former Executive Vice President and Chief Financial Officer of the Corporation and Mr. Tocher is the former Chief Executive Officer of the Corporation.

Executive Compensation Policy

The Corporation's compensation philosophy is aimed at attracting and retaining quality and experienced people, which is critical to our success. All compensation is based upon the performance of both the Corporation and the individual employee and is comprised of three elements: base salary, short-term incentive compensation (being cash bonuses) and long-term incentive compensation (being stock based compensation). Each element of compensation is determined on an individual basis.

The Corporation may, based upon individual and corporate performance, award cash bonuses to its employees, and executive officers to supplement annual salaries. The award of bonuses is determined, in the case of non-executive employees, by the senior management of the Corporation and approved by the Compensation Committee. The Compensation Committee in consultation with the Chief Executive Officer establishes base salaries and cash bonuses for Vice Presidents and the Compensation Committee establishes the Chief Executive Officer's compensation.

Stock options are normally awarded by the Compensation Committee upon commencement of employment with the Corporation based on the level of responsibility within the Corporation and are intended to align executive and shareholder interests by attempting to create a direct link between compensation and shareholder return as measured through the price of the Corporation's shares. Additional grants are made periodically to recognize the exemplary performance of, or the special contribution by, eligible individuals. An annual grant may be made to eligible individuals based on individual performance and the performance of the Corporation during the most recently completed financial year in relation to performance achieved by industry peer corporations during the comparable period.

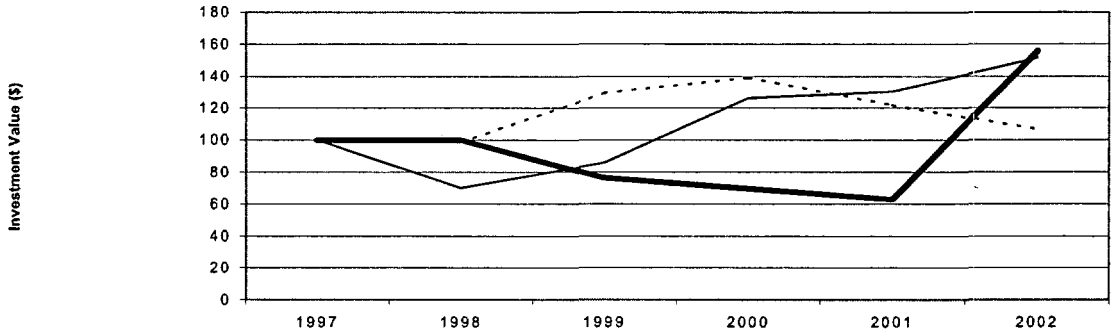
The Corporation's Chief Executive Officer did not receive an annual salary in 2002. Effective March 1, 2003 the Compensation Committee approved an annual salary for Mr. Wright of $180,000. Based on independent surveys, this salary level is considered low compared to the Corporation's peer group. Mr. Wright has significant exposure to the Corporation's share price through his investment in the Corporation's common shares. The Corporation believes it is important for the Chief Executive Officer's compensation to be aligned with the Shareholders' interests and it is intended that bonuses and stock based compensation account for a large component of Mr. Wright's total compensation package.

The Corporation's compensation policies have allowed us to attract and retain a team of motivated professionals and support staff working towards the common goal of enhancing shareholder value. The Compensation Committee reviews compensation policies to ensure that they are competitive within the oil and natural gas industry and consistent with the Corporation's performance.

Report Submitted by:
John A. Brussa
M. Bruce Chernoff
James D. Tocher

Performance Graph

The following graph illustrates the Corporation's five year cumulative shareholder return, as measured by the closing price of the common shares at the end of each financial year, assuming an initial investment of $100, compared to the TSX Composite Index and the TSX Oil & Gas Exploration & Production Index, assuming the reinvestment of dividends where applicable.



	31-Dec-97	31-Dec-98	31-Dec-99	31-Dec-00	31-Dec-01	31-Dec-02
PBG	100	100	76	70	63	156
TSX Composite Index	100	98	130	139	122	107
TSX O&G E&P Index	100	70	86	126	130	152

Remuneration of Directors

The Corporation does not currently pay its non-management directors any cash compensation except that directors are reimbursed for their out-of-pocket expenses incurred in carrying out their duties as directors. Non-management directors have historically been entitled to participate in our Stock Option Plan. The Directors, as a group, agreed to cancel their outstanding stock options in April 2003. An alternative compensation arrangement for non-management directors will be considered by the Compensation Committee in 2003. The Corporation pays Mr. McKinnon $12,000 per annum for corporate secretarial services.

Indebtedness of Directors and Senior Officers

No director or senior officer, or their associates or affiliates, has been indebted to the Corporation since the commencement of the financial year ended December 31, 2002.

CORPORATE GOVERNANCE

The board of directors and management believes in the importance of good corporate governance and its effectiveness in promoting enhanced shareholder value. The TSX has required that listed corporations disclose their approach to corporate governance, making particular reference to the guidelines set out in the December 1994 report of the TSX Committee on Corporate Governance. When a corporation's corporate governance system differs from these guidelines, it is required to give an explanation of the differences. The guidelines contained in the TSX report are not mandatory and the TSX report recognizes that the unique characteristics of individual corporations will result in varying degrees of compliance with such guidelines. The board of directors and management will continue to monitor the current initiatives of the securities regulatory authorities in Canada with respect to corporate governance in order to ensure that our corporate governance practice complies with all applicable legal requirements. The following summary also addresses each of the guidelines of the TSX with respect to corporate governance including an explanation of any divergence from the stated guidelines.

1. *The board of directors should explicitly assume responsibility for the stewardship of the corporation:*

The Board has full plenary powers and the statutory responsibility to oversee the conduct of the business of the Corporation and to supervise management who is responsible for the day-to-day conduct of the business of the Corporation. The Board's fundamental objectives are to enhance and preserve long-term shareholder value and to ensure the Corporation meets its obligations on an ongoing basis. While the Board has delegated the responsibility for day-to-day management of the Corporation to management, the Board has implicitly and explicitly acknowledged its responsibility for the stewardship of the Corporation, including the responsibility for:

(a) approving and monitoring the Corporation's strategic planning through a regular reporting and review process;
(b) the identification of the principal risks of the Corporation's business and ensuring the implementation of appropriate systems to manage these risks;
(c) the appointment of the senior executive officers and for succession planning;
(d) ensuring timely and accurate communications to Shareholders of financial and other matters in accordance with applicable law; and
(e) ensuring the implementation and integrity of the Corporation's internal control and management information systems.

2. *A majority of directors should be "unrelated" (independent):*

The Board is proposed to be comprised of seven members, a majority (five) of whom are considered "unrelated directors", with the President and Chief Executive Officer being considered a "related director" as those terms are defined by the TSX. Mr. Chernoff is also considered to be a "related director" on the basis that he is the Corporation's former Executive Vice President and Chief Financial Officer. All the unrelated directors have no business relationships with the Corporation other than the ownership of shares except that Mr. Brussa is a partner in a law firm that provides legal services to the Corporation. It is the Board's opinion that this relationship does not impair Mr. Brussa's ability to act in the best interests of the Shareholders and accordingly Mr. Brussa is considered to be independent.

3. *Analysis of independence determinations:*

Under the TSX guidelines, an "unrelated" director is a director who is independent of management and free from any business or other relationship that could, or could reasonably be perceived to, materially interfere with the director's ability to act with a view to the best interests of the Corporation. These determinations of independence are provided under item 2 above.

4. Appoint a committee responsible for appointment and assessment of directors composed exclusively of outside directors, a majority of whom are unrelated:

Historically, the full board of directors has performed the function of a nominating committee of the Corporation with the responsibility for the appointment and assessment of directors. This practice does not comply with the stated guidelines of the TSX. The Board believes that these procedures have proved to be a practical and effective approach to these governance issues in light of the Corporation's particular circumstances, including the size of the Board, and the size of the Corporation.

5. Implement a process for assessing the effectiveness of the Board as a whole, the committees of the Board and the contribution of individual directors:

The Board as a whole periodically reviews the effectiveness of the Board, its committees, and the contributions of individual board members. This assessment is often conducted through informal discussion and evaluation of members' contributions.

6. Provide orientation and education programs for new recruits and continuing education for all directors:

The Board has historically provided an orientation and education program for directors on an as requested basis and as a result, does not comply with the stated guidelines of the TSX, but the Board believes that these procedures have proved to be a practical and effective approach in light of the Corporation's particular circumstances, including the size of the Board, the size of the Corporation and the nature and scope of the Corporation's business and operations and the experience and expertise of board members.

7. Examine the size and composition of the Board and undertake, where appropriate, a program to establish a Board comprised of members who facilitate effective decision-making:

The Board considers that seven members is an appropriate number of directors having regard to the size of the Corporation, the nature of its business and operations and the experience and expertise required to carry out duties effectively while maintaining a diversity of views and experience.

8. Review the adequacy and form of compensation of the directors reflecting risks and responsibilities:

The Compensation Committee periodically reviews the compensation of the directors, which is discussed under the heading Remuneration of Directors.

9. Committees of the Board should generally be composed solely of non-management directors, a majority of whom are unrelated directors:

The Board has three committees: the Audit Committee, the Reserves Committee, and the Compensation Committee, all of which are comprised solely of non-management directors and a majority of unrelated directors. Mr. Chernoff is a member of each of these committees and is considered to be a "related director' solely on the basis that he is the Corporation's former Executive Vice President and Chief Financial Officer. From time to time ad hoc committees of the Board may also be appointed.

10. Every Board should expressly assume responsibility for, or assign to a committee of directors the general responsibility for, developing the corporation's approach to governance issues:

The entire Board has retained the responsibility for determining the Corporation's approach to corporate governance.

11. Define mandates for the Board and for the CEO, involving the definition of the limits to management's responsibilities. In addition, the Board should approve or develop the corporate objectives which the CEO is responsible for meeting and assess the CEO against these objectives:

The Board has the statutory responsibility to oversee the conduct of the business of the Corporation and has delegated the responsibility for the day-to-day conduct of the business to the CEO and other members of management, subject to compliance with plans and objectives approved from time to time by the Board. The CEO is assessed based on corporate objectives established by Petrobank's strategic plan which is regularly reviewed by the Board.

12. Establish structures and procedures to enable the Board to function independently of management:

The Chairman of the Board is independent of management and the committees of the Board meet independently of management as required. The Audit Committee regularly meets with the Corporation's external auditors without management present. The Reserves Committee meets with the Corporation's independent engineers without management present.

13. Establish an audit committee with a specifically defined mandate comprised entirely of unrelated directors:

The Audit Committee is responsible for reviewing the external audit function and the preparation of financial statements and reviewing and recommending for approval to the Board all public financial disclosure information such as financial statements and prospectuses. It also ensures that management has effective internal control systems and meets from time to time with external auditors without management present. The Corporation does not have internal auditors and given the size of the Corporation this is considered practical and appropriate.

The Audit Committee is comprised of Messrs. Brussa (Chairman), Chernoff and Oaks all of whom are considered financially literate. Messrs. Brussa and Oaks are unrelated directors and Mr. Chernoff is considered to be a "related" director solely on the basis that he is the Corporation's former Executive Vice President and Chief Financial Officer. The Board considers Mr. Chernoff's participation on this committee to be appropriate given his level of financial and audit committee experience.

14. Implement a system which enables an individual director to engage an external adviser at the expense of the corporation in appropriate circumstances:

Individual directors may engage outside advisors, at the Corporation's expense.

INTEREST OF INSIDERS IN MATERIAL TRANSACTIONS

In January 2002, upon acquisition of a private company, the Corporation assumed debt of $0.6 million, payable indirectly to Messrs. Chernoff and Wright. Subsequent to December 31, 2002, the Corporation repaid this balance.

In August 2002, the Company announced that an independent committee of the Board of Directors reached an agreement to repurchase certain outstanding securities held by management and directors including Messrs. Brussa, Chernoff, McCagherty, Rain and Wright. This agreement resulted in the repurchase of the Company's outstanding 8.6 million preferred shares and cancellation of an equivalent number of common share purchase warrants in exchange for 8.6 million common shares. The Company also made a $1.0 million cash payment to settle $1.9 million of future dividend entitlements on the preferred shares. In addition, the Company paid $5.5 million to repurchase 8,475,667 outstanding common share purchase warrants from the

holders of those warrants who agreed to exercise their remaining 2,133,333 common share purchase warrants for $3.2 million. The net effect of these transactions was to eliminate $0.9 million in future dividends, and decrease the amount of future share dilution by 8.5 million common shares.

In February 2003, the Company announced that an independent committee of the Board of Directors reached an agreement to acquire certain heavy oil technologies from a private company partially owned by Messrs. Chernoff and Wright for their original cost of $0.4 million. In addition, Mr. Wright and an unrelated party have retained a combined 17.5% net profits interest in future third party royalties generated from the technologies.

Except as disclosed herein, there were no material interests, direct or indirect, of the Corporation's insiders, proposed nominees for election as directors, or any associate or affiliate of such insiders or nominees since January 1, 2002, or in any proposed transaction, which has affected or would materially affect the Corporation or any of its subsidiaries.

INTEREST OF CERTAIN PERSONS AND COMPANIES IN MATTERS TO BE ACTED UPON

Our management is not aware of any material interest of any director or executive officer or anyone who has held office as such since the beginning of our last financial year or of any associate or affiliate of any of the foregoing in any matter to be acted on at the meeting, save as is disclosed herein.

OTHER MATTERS

Our management knows of no amendment, variation or other matter to come before the meeting other than the matters referred to in the notice of annual and special meeting. However, if any other matter properly comes before the meeting, the accompanying proxy will be voted on such matter in accordance with the best judgment of the person voting the proxy.

The contents and the sending of this information circular - proxy statement have been approved by our directors.

The foregoing contains no untrue statement of a material fact and does not omit to state a material fact that is required to be stated or that is necessary to make a statement not misleading in light of the circumstances in which it was made.

Dated: April 21, 2003

John D. Wright
President and
Chief Executive Officer

David J. Rain
Vice President Finance and
Chief Financial Officer

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CORPORATE FINANCE

PETROBANK ENERGY AND RESOURCES LTD.

FORM OF PROXY

For the Annual and Special Meeting to be held on May 22, 2003

I, _____ of _____, being a shareholder of Petrobank Energy and Resources Ltd. hereby appoint John D. Wright, President and Chief Executive Officer, or, failing him, Kenneth R. McKinnon, Corporate Secretary, both of the City of Calgary, in the Province of Alberta, or, instead of either of the foregoing, _____ of _____, as my proxy, with full power of substitution, to attend and act and vote for me and on my behalf at the annual and special meeting of the shareholders of Petrobank Energy and Resources Ltd. to be held on May 22, 2003 and at any adjournment thereof and at every poll that may take place in consequence thereof. Without limiting the general powers conferred, I hereby direct the said proxy to vote the shares represented by this proxy as follows, on the following matters, namely:

1. FOR _____ or AGAINST _____ the resolution fixing the number of directors to be elected at the meeting at 7 members;
2. FOR _____ or WITHHOLD FROM VOTING FOR _____ the election as directors for the ensuing year of the 7 nominees proposed by management in our information circular-proxy statement dated April 21, 2003;
3. FOR _____ or WITHHOLD FROM VOTING FOR _____ the appointment of Deloitte & Touche LLP, Chartered Accountants, as our auditors and to authorize the directors to fix their remuneration as such;
4. FOR _____ or AGAINST _____ the resolution authorizing future private placements by the Company;
5. FOR _____ or AGAINST _____ the resolution authorizing an increase in the maximum number of common shares issuable under the Company's stock option plan;
6. FOR _____ or AGAINST _____ the resolution authorizing the amendment of certain terms and conditions under the Company's stock option plan; and
7. At the discretion of the said proxy upon any amendment or variation of the above matters or any other matter that may properly be brought before the meeting or any adjournment thereof in such manner as such proxy in his sole judgment may determine.

I hereby revoke any proxies heretofore given.

Your shares will be voted as directed in the spaces provided above or, if no direction is given, be voted in favour of each of the above matters. You have the right to appoint a person, who need not be a shareholder, to attend and to act for you at the meeting, other than the persons designated above. To exercise such right, the names of the persons designated by management should be crossed out and the name of the shareholder's appointee should be legibly printed in the blank space provided.

This solicitation is made on behalf of our management.

DATED this _____ day of _____, 2003

_____
Signature of shareholder

_____
Name of shareholder (please print)

NOTES:

1. If you are a corporation, your corporate seal must be affixed or this form of proxy must be signed by a duly authorized officer or attorney of the corporation.

2. If you are an executor, administrator, trustee, etc. you should indicate their capacity.

3. This form of proxy must be dated and the signature of the proxy should be exactly the same as the name in which the shares are registered.

4. This proxy will not be valid and will not be acted upon or voted unless it is signed and dated and delivered to the attention of our Secretary, c/o Computershare Trust Company of Canada, Proxy Department, 9th Floor - 100 University Avenue, Toronto, Ontario, M5J 2Y1, not less than 48 hours before the time for holding the meeting or any adjournment thereof.

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CORPORATE FINANCE

Management's Report

Management is responsible for the integrity and objectivity of the information contained in this annual report and for the consistency between the consolidated financial statements and other financial and operating data contained elsewhere in this report. The accompanying consolidated financial statements have been prepared by management in accordance with accounting principles generally accepted in Canada using estimates and careful judgment, particularly in those circumstances where transactions affecting a current period are dependent upon future events. The accompanying consolidated financial statements have been prepared using policies and procedures established by management and fairly reflect the Company's financial position, results of operations and changes in financial position, within Canadian generally accepted accounting principles. Management has established and maintains a system of internal controls that is designed to provide reasonable assurance that assets are safeguarded from loss or unauthorized use and the financial information is reliable and accurate.

The consolidated financial statements have been examined by external auditors. During 2002, Petrobank changed its auditors from Arthur Andersen LLP to Deloitte & Touche LLP. Their examination provides an independent view as to management's discharge of its responsibilities insofar as they relate to the fairness of reported financial results and the financial condition of the Company.

The Audit Committee of the Board of Directors has reviewed in detail the consolidated financial statements with management and the external auditors. The consolidated financial statements have been approved by the Board of Directors on the recommendation of the Audit Committee.

"signed"

John D. Wright
President & Chief Executive Officer
Calgary, Canada
March 14, 2003

"signed"

David J. Rain
Vice-President Finance & Chief Financial Officer
Calgary, Canada

· Auditors' Report ·

To the Shareholders of Petrobank Energy and Resources Ltd.:

We have audited the consolidated balance sheet of PETROBANK ENERGY AND RESOURCES LTD. as at December 31, 2002 and the consolidated statements of income and retained earnings and cash flows for the year then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audit.

We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2002 and the results of its operations and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

The consolidated financial statements as at December 31, 2001 and for the year then ended were audited by other auditors who expressed an opinion without reservation on those financial statements in their report dated April 2, 2002.

"signed"

Deloitte & Touche LLP
Chartered Accountants
Calgary, Canada
March 14, 2003

· Consolidated Balance Sheets ·

As at December 31, (Thousands of Canadian dollars)	2002	2001
Assets		
Current assets		
Cash and cash equivalents	**$ 12,224**	$ 25,311
Temporary investment (note 4)	**–**	1,000
Accounts receivable and other current assets	**11,521**	20,795
	23,745	47,106
Capital assets (note 4)	**126,873**	99,231
	$ 150,618	$ 146,337
Liabilities and Shareholders' Equity		
Current liabilities		
Accounts payable and accrued liabilities (note 12)	**$ 28,896**	$ 21,696
Obligations under gas hedging contracts (note 6)	**8,097**	9,410
Future site restoration liability	**613**	764
	37,606	31,870
Shareholders' equity		
Subordinated notes (note 7)	**57,344**	56,676
Share capital (note 8)		
Preferred shares	**–**	12,888
Common shares	**48,054**	30,341
Retained earnings	**7,614**	14,562
	113,012	114,467
	$ 150,618	$ 146,337

Commitments and contingencies (note 15)
Subsequent events (note 16)

See accompanying notes to these consolidated financial statements.

Signed on behalf of the Board:

"signed"
James D. Tocher
Chairman

"signed"
John A. Brussa
Chairman of the Audit Committee

· Consolidated Statements of Income and Retained Earnings ·

Years Ended December 31, (Thousands of Canadian dollars, except per share amounts)	2002	2001
Revenues		
Oil and natural gas	**$ 50,458**	$ 46,117
Royalties	**(10,751)**	(7,886)
	39,707	38,231
Other (note 11)	**284**	1,582
	39,991	39,813
Expenses		
Production	**12,307**	10,330
General and administrative	**3,784**	6,292
Interest on long-term debt	**–**	2,338
Depletion, depreciation and site restoration	**17,269**	12,580
	33,360	31,540
Income before unusual items and taxes	**6,631**	8,273
Unusual items (note 10)	**654**	5,026
Income before taxes	**7,285**	13,299
Capital and future income taxes (note 9)	**1,094**	8,016
Net income	**6,191**	5,283
Interest on subordinated notes (note 7)	**(6,107)**	(3,333)
Preferred share dividends and related taxes (note 8)	**(514)**	(1,370)
Non-controlling interest (note 3)	**–**	(149)
Net income (loss) attributable to common shareholders	**(430)**	431
Retained earnings, beginning of year	**14,562**	14,800
Repurchase of securities (note 8)	**(6,518)**	(669)
Retained earnings, end of year	**$ 7,614**	$ 14,562
Earnings per share (note 8)		
Basic	**$ (0.01)**	$ 0.01
Diluted	**$ (0.01)**	$ 0.01

See accompanying notes to these consolidated financial statements.

· Consolidated Statements of Cash Flows ·

Years Ended December 31, (Thousands of Canadian dollars)	2002	2001
Operating Activities		
Net income	**$ 6,191**	$ 5,283
Depletion, depreciation and site restoration	**17,269**	12,580
Unusual items (note 10)	**(654)**	(6,526)
Future income taxes (note 9)	**–**	7,212
Cash flow from operations	**22,806**	18,549
Changes in other non-cash items (note 14)	**4,728**	(3,315)
	27,534	15,234
Financing Activities		
Issuance of common shares (note 8)	**4,450**	–
Repurchase of securities (note 8)	**(6,530)**	(1,425)
Preferred share dividends and related taxes (note 8)	**(514)**	(1,370)
Repayment of long-term debt	**–**	(57,199)
Issuance of subordinated notes and related share purchase warrants (notes 7 and 8)	**–**	11,446
Interest on subordinated notes (note 7)	**(5,439)**	(3,103)
Amortization of obligations under gas hedging contracts (note 6)	**(419)**	(7,222)
Settlement of obligations under gas hedging contracts (note 6)	**(894)**	(12,368)
Changes in other non-cash items (note 14)	**(878)**	(713)
	(10,224)	(71,954)
Investing Activities		
Expenditures on capital assets (note 4)	**(46,228)**	(21,859)
Proceeds on disposition of capital assets (note 4)	**3,334**	160,575
Corporate acquisitions (note 3)	**(42)**	(50,332)
Site restoration expenditures	**(1,129)**	(349)
Proceeds on disposition of temporary investment	**1,654**	–
Changes in other non-cash items (note 14)	**12,014**	(6,004)
	(30,397)	82,031
Net change in cash position	**(13,087)**	25,311
Cash and cash equivalents, beginning of year	**25,311**	–
Cash and cash equivalents, end of year	**$ 12,224**	$ 25,311

See accompanying notes to these consolidated financial statements.

· Notes to the Consolidated Financial Statements ·

As at and for the years ended December 31, 2002 and 2001
(All tabular amounts expressed in thousands of Canadian dollars, except share amounts)

1. Description of Business

Petrobank Energy and Resources Ltd. (the "Company" or "Petrobank"), is a public company listed on the Toronto Stock Exchange and incorporated under the Business Corporations Act (Alberta). Petrobank is engaged in the production, development and exploration of oil and natural gas in Colombia and the Western Canadian Sedimentary Basin.

2. Summary of Significant Accounting Policies

These consolidated financial statements are prepared in accordance with Canadian generally accepted accounting principles and include the accounts of the Company and its subsidiaries.

Measurement Uncertainty

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities as at the date of the consolidated balance sheets and the reported amounts of revenues, expenses, and cash flows during the periods presented. Actual results could materially differ from those estimates.

Capital Assets

The Company accounts for its oil and natural gas operations in accordance with the Canadian Institute of Chartered Accountants' guideline on full cost accounting in the oil and natural gas industry whereby all costs related to the acquisition of oil and natural gas properties are capitalized. Such costs include land and lease acquisition costs, annual charges on non-producing properties, geological and geophysical costs, and costs of drilling and equipping productive and non-productive wells.

Gains and losses are not recognized upon disposition of oil and natural gas properties unless crediting the proceeds against accumulated costs would result in a change in the rate of depletion of more than 20%.

Capitalized costs are accumulated on a country-by-country basis and are depreciated and depleted using the unit of production method based upon estimated proved reserves as determined by independent engineers. Included in costs subject to depletion are estimated costs to develop proved reserves. Reserve and production volumes are converted to common units on the basis of their approximate relative energy content. Costs relating to undeveloped properties may be excluded from the depletion base until it is determined whether or not proved reserves exist or if impairment of such costs has occurred. Depreciation of office equipment is provided at 30% using the declining balance method.

The Company applies a country-by-country ceiling test to ensure that the net carrying value of oil and natural gas properties net of future income tax and future site restoration liabilities do not exceed the estimated future net cash flows ultimately recoverable from these properties. In estimating this future recoverable amount, the Company includes future net revenues from production of proved reserves at year-end market prices, including the effects of hedging, less future estimated administrative, financing, future site restoration, and income tax costs. The Company excludes its unproved oil and natural gas properties, at cost less impairment, from its ceiling test. The ceiling test is a cost recovery test and is not intended to be an estimate of fair value.

The Company does not capitalize general and administrative or interest costs.

Future Site Restoration

Estimated future site restoration and abandonment costs are provided for in the current period using the unit-of-production method based on estimated proved reserves. The annual charge is accounted for as an expense and the accumulated provision is reflected as a long-term liability. Actual site restoration expenditures are deducted from the accumulated provision in the year incurred. Future costs are estimated based upon current legislation, technology and industry standards.

Temporary Investments

Temporary investments are accounted for using the cost method whereby the investment is initially recorded at cost and earnings from such investments are recognized only to the extent received or receivable. Temporary investments are adjusted to the lower of carrying value and market value at subsequent balance sheet dates.

Derivative Financial Instruments

The Company may utilize derivative financial instruments in its management of exposures to fluctuations in crude oil and natural gas prices, foreign currency exchange rates and interest rates. The Company does not enter into derivative financial instruments for trading or speculative purposes. The Company formally documents all relationships between hedging instruments and hedged items, as well as its risk management objective and strategy for undertaking various hedge transactions. This process includes linking all derivatives to specific assets and liabilities on the balance sheet or to specific firm commitments or forecasted transactions. The Company also formally assesses, both at the hedge's inception and on an ongoing basis, whether the derivatives that are used in hedging transactions are highly effective in offsetting changes in fair values or cash flows of hedged items. Gains and losses on contracts that constitute effective hedges are deferred and recognized in income when the related transactions occur.

Joint Operations
The majority of the Company's oil and natural gas operations are conducted jointly with others and accordingly these consolidated financial statements reflect only the Company's proportionate interest in such activities.

Revenue Recognition
Revenues from the sale of crude oil, natural gas and natural gas liquids are recognized when title passes to the customer.

Foreign Currency Translation
The Company translates foreign currency denominated monetary assets and liabilities of its integrated foreign subsidiaries at the exchange rate in effect at the balance sheet date and non-monetary assets and liabilities are translated at historical exchange rates. Revenues and expenses are translated at estimated transaction date exchange rates except depletion and depreciation expense, which is translated at the same historical exchanges rates as the related assets. Exchange gains or losses are included in the determination of net income.

Earnings per Share
The Company computes earnings per share using the treasury stock method to determine the dilutive effect of "in-the-money" stock options and share purchase warrants. This method assumes that the proceeds on exercise of in-the-money stock options and share purchase warrants are used to repurchase the Company's common shares at the average market price during the relevant period.

Stock Based Compensation
The Company provides stock-based compensation in the form of stock options to directors, officers and employees. The Company accounts for its stock based compensation plan using the intrinsic value based method whereby no costs are recognized in the statement of operations for stock options granted at market prices to employees and directors. Consideration received on exercise of stock options is credited to share capital.

Income Taxes

The Company accounts for income taxes using the liability method. Under this method, the Company records future income taxes to reflect any difference between the accounting and tax bases of assets and liabilities. Future income tax assets are recognized to the extent it is more likely than not sufficient future taxable income will be available to allow the future income tax asset to be realized.

Subordinated Notes

The subordinated notes are reflected as equity on the balance sheet and the interest thereon is excluded from the determination of net income as the Company has the option to issue common shares to settle both interest and principal payments.

Cash and Cash Equivalents

Cash and cash equivalents include securities with a maturity of three months or less when purchased.

3. Business Combinations

On January 15, 2002, the Company acquired a private company for a cash payment of $42,000, issuance of 250,000 Petrobank common shares and the assumption of a working capital deficiency of $0.6 million. A maximum of 700,000 additional Petrobank common shares are issuable to the former shareholders of the acquiree upon achievement of certain performance criteria before January 16, 2004. The acquired working capital deficiency is made up primarily of a balance indirectly payable to two directors of the Company that was settled subsequent to December 31, 2002. The acquisition has been accounted for using the purchase method as follows:

Purchase price	
Cash	$ 42
Common shares issued	387
	$ 429
Allocation of purchase price:	
Working capital deficiency	$ (610)
Capital assets	1,039
	$ 429

On April 12, 2001, the Company purchased 97.2% of the outstanding common shares of Barrington Petroleum Ltd. ("Barrington"), a publicly traded oil and gas company, for cash of $52.3 million. Through a Plan of Arrangement made effective July 18, 2001, Petrobank acquired the remaining 2.8% non-controlling interest in Barrington through the payment of $0.6 million in cash and the issuance of 454,808 Petrobank common shares valued at $0.7 million. Effective January 1, 2002, Petrobank and Barrington were amalgamated. The business combination was accounted for using the purchase method of accounting as follows:

Net purchase price:	
Cash	$ 52,884
Common shares issued	682
Transaction costs	3,258
Cash acquired	(5,810)
	$ 51,014
Allocation of purchase price:	
Capital assets	$ 144,322
Future income tax assets	24,150
Non-controlling interest	149
Working capital deficiency	(6,753)
Obligations under gas hedging contracts	(29,000)
Long-term debt	(36,854)
Subordinated notes	(45,000)
	$ 51,014

4. Capital Assets

December 31, 2002	Cost	Accumulated Depletion and Depreciation	Net Book Value
Oil and natural gas properties			
Canada	**$ 135,340**	**$ 27,814**	**$ 107,526**
Colombia	**15,635**	**–**	**15,635**
Corporate and other	**4,860**	**1,148**	**3,712**
	$ 155,835	**$ 28,962**	**$ 126,873**

December 31, 2001	Cost	Accumulated Depletion and Depreciation	Net Book Value
Oil and natural gas properties			
Canada	$ 108,579	$ 12,005	$ 96,574
Corporate and other	3,323	666	2,657
	$ 111,902	$ 12,671	$ 99,231

At December 31, 2002, oil and natural gas properties included $30.5 million (2001 – $32.0 million) relating to unproved properties in Canada, and $2.5 million (2001 – $0.5 million) of costs incurred internationally that have been excluded from the depletion calculation. Costs incurred in Colombia totaling $15.6 million (2001 – nil) have also been excluded from the depletion calculation as oil sales did not commence until 2003.

Dispositions

In 2002, Petrobank completed minor property dispositions for total proceeds of $3.3 million dollars. In the first quarter of 2001, Petrobank disposed of substantially all its producing resource properties for cash proceeds of $101.0 million resulting in a pre-tax gain of $12.9 million. Following the acquisition of Barrington, the Company completed a series of non-core property dispositions in 2001 for total proceeds of $60.6 million, comprised of $59.6 million in cash and $1.0 million in share purchase warrants of a publicly traded oil and natural gas company reflected on the balance sheet as a temporary investment. This temporary investment was disposed of in May 2002 resulting in a $0.7 million gain.

Net Expenditures

The Company's net expenditures on capital assets for the year ended December 31, 2002 are broken down geographically as follows:

Canada	$ 27,259
Colombia	15,635
	$ 42,894

All capital expenditures in 2001 related to Canada.

5. Credit Facility

The Company has a $45.0 million credit facility with a $40.0 million borrowing base limit. The facility is a revolving operating demand loan under which the Company can borrow at bank prime plus 0.125% or Bankers Acceptance fee rates plus 1.625%. Advances under the facility are collateralized by a $100 million demand debenture on all present and future Canadian assets of the Company as well as a general assignment of the Company's book debts, a negative pledge to provide fixed charges on major producing petroleum properties and an assignment of material contracts.

At December 31, 2002 and 2001 the Company had not drawn under its credit facility. The effective interest rate under the credit facility was 4.625% at December 31, 2002.

Interest paid approximated interest expense for the years ended December 31, 2002 and 2001.

6. Obligations under Gas Hedging Contracts

The Company assumed certain natural gas physical delivery obligations upon the acquisition of Barrington. These obligations were recorded at their fair value of $29.0 million at the time of acquisition. A portion of this amount was amortized to oil and natural gas revenue for the year ended December 31, 2002 ($0.4 million; 2001 – $7.2 million). The liability was also reduced by $0.9 million in 2002 (2001 – $12.4 million) for cash payments made to settle portions of the outstanding obligations. The remaining obligations under these contracts at December 31, 2002 had a carrying value of $8.1 million. These obligations are amortized to oil and natural gas revenues over the term of the related contracts.

7. Subordinated Notes

Pursuant to a Plan of Arrangement completed on July 18, 2001, each holder of Barrington gas linked subordinated notes, paying 12% interest, agreed to exchange each of their $1,000 notes for a $950 Petrobank 9% subordinated note due July 31, 2006 and one unit purchase warrant. Noteholders exercised 12,962 unit purchase warrants prior to their expiry, resulting in the issuance of an additional $13.0 million of subordinated notes and 777,720 share purchase warrants for net cash proceeds of $11.5 million. The outstanding subordinated notes were recorded at their fair value of $56.4 million at the date of issue and the discount to the $60.4 million face value is being amortized to interest on subordinated notes over the term of the notes using an effective interest rate of 10.7%. Amortization for the year ended December 31, 2002 totaled $0.7 million (2001 – $0.2 million). In certain circumstances, the notes may be repaid at their face value prior to their maturity date and the Company has the option of issuing common shares, at prevailing market prices, to settle quarterly interest payments as well as the principal amount. The notes are unsecured and subordinate to the Company's existing credit facility and any other senior debt that may be outstanding from time to time.

8. Share Capital

Authorized

Unlimited number of common shares
Unlimited number of preferred shares issuable in series

Share Capital Restructuring

In August 2002, the Company announced that an independent committee of the Board of Directors reached an agreement to repurchase certain outstanding securities held by management and directors. This agreement resulted in the repurchase of the Company's outstanding 8.6 million preferred shares and cancellation of an equivalent number of common share purchase warrants in exchange for 8.6 million common shares. The Company also made a $1.0 million cash payment to settle $1.9 million of future dividend entitlements on the preferred shares. In addition, the Company paid $5.5 million to repurchase 8,475,667

outstanding common share purchase warrants to the holders of those warrants who agreed to exercise their remaining 2,133,333 common share purchase warrants for $3.2 million. The net effect of these transactions was to eliminate $0.9 million in future dividends, and decrease the number of diluted common shares by 8.5 million. Payments relating to the repurchase of common share purchase warrants and settlement of future dividend rights totaling $6.5 million have been reflected as a reduction of retained earnings.

Preferred Shares

The preferred shares repurchased pursuant to the Company's August 2002 share capital restructuring paid dividends at 6% per annum and had a face value of $12.9 million. Dividends and related taxes totaled $0.5 million in 2002 (2001 – $1.4 million).

Common Shares

	Number	Amount
Balance, December 31, 2000	33,957,332	$ 30,415
Issued in connection with corporate acquisition	454,808	682
Repurchased pursuant to issuer bid	(855,000)	(770)
Proceeds on issuance of share purchase warrants	–	14
Balance, December 31, 2001	33,557,140	$ 30,341
Issued pursuant to corporate acquisition	**250,000**	**387**
Exercise of stock options	**775,249**	**1,250**
Repurchased pursuant to issuer bid	**(10,927)**	**(12)**
Exercise of warrants	**2,133,333**	**3,200**
Issued pursuant to repurchase of securities	**8,609,000**	**12,888**
Balance, December 31, 2002	**45,313,795**	**$ 48,054**

The amount associated with share repurchases reflects the average issuance price of these shares. The excess of the amounts paid for these shares over the average issuance price is reflected as a reduction of retained earnings (2002 – $9,000; 2001 – $468,000).

Share Purchase Warrants

As at December 31, 2002, the Company had 777,720 share purchase warrants outstanding that allow the holders to purchase an equivalent number of common shares at $2.50 per share on or before July 18, 2003 (note 7).

Share Appreciation Rights

During 2002, the 200,000 share appreciation rights outstanding at December 31, 2001 were cancelled with 50,000 of these rights being replaced with an equal number of stock options. At December 31, 2002 there were no share appreciation rights outstanding.

Stock Options

The Company has established a stock option plan whereby the Company may grant options to its directors, officers, employees, consultants and underwriters. The Company's shareholders have approved the issuance of up to 4.9 million stock options under this plan. The number of stock options available for grant under the plan has been reduced to 4.1 million due to the exercise of stock options during 2002. At the next meeting of shareholders, the Company intends to request approval to increase the number of stock options available for grant under the plan to 10% of the number of common shares outstanding. The exercise price of each option is no less than the market price of the Company's stock on the date of the grant. Stock option terms are determined by the Company's Board of Directors but typically, options vest evenly over a period of four years from the date of grant and expire five years after the date of grant. The following is a continuity of stock options outstanding:

	2002		2001	
	Stock Options	Weighted-Average Exercise Price	Stock Options	Weighted-Average Exercise Price
Opening	**2,823,334**	**$ 1.73**	2,320,000	$ 1.71
Granted	**3,359,500**	**2.21**	1,218,334	1.72
Exercised	**(775,249)**	**(1.61)**	–	–
Cancelled	**(1,212,101)**	**(1.94)**	(715,000)	(1.63)
Closing	**4,195,484**	**$ 2.08**	2,823,334	$ 1.73

The following summarizes information about stock options outstanding as at December 31, 2002:

Range of Exercise Prices $	Number Outstanding At Dec. 31, 2002	Weighted-Average Remaining Contractual Life (Years)	Weighted-Average Exercise Price	Number Exercisable At Dec. 31, 2002	Weighted-Average Exercise Price
1.35 – 1.99	1,927,650	3.2	$ 1.69	726,200	$ 1.77
2.00 – 2.99	2,017,834	4.6	2.32	32,084	2.04
3.00 – 3.40	250,000	4.9	3.09	–	–
	4,195,484	4.0	$ 2.08	758,284	$ 1.78

Earnings Per Share

Earnings per share have been calculated based on the weighted average number of shares outstanding for the year of 37,441,521 (2001 – 33,677,460). Earnings per share are based on net income attributable to common shareholders. Diluted calculations include nil additional shares in 2002 (2001 – 1,414,009) for the potential impact of share purchase warrants and stock options.

Stock Based Compensation

The Company accounts for its stock based compensation plan using the intrinsic value based method whereby no costs are recognized in the statements of operations for stock options granted at market prices to employees and directors. The Company's net income (loss) per common share on a diluted basis reflects the impact of the potential dilution arising from the future exercise of outstanding stock options. Had compensation expense associated with the Company's stock option plan been recognized using the fair value method for option grants after January 1, 2002, the Company's pro forma net income attributable to common shareholders for the year ended December 31, 2002 would have been reduced by $0.2 million and earnings per share would have been reduced to a loss of $0.02 per share.

The fair value of stock options granted is estimated on the grant date using the Black Scholes option-pricing model using the following assumptions:

Risk free interest rate	4%
Dividend rate	0%
Expected life (years)	4.0
Expected volatility	45%

9. Income Taxes

The provision for income taxes differs from the amount that would have been expected by applying statutory corporate income tax rates to income before taxes. The principal reasons for this difference are as follows:

	2002	2001
Income before taxes	**$ 7,285**	$ 13,299
Statutory income tax rate	**43.20%**	42.62%
Expected tax expense	**$ 3,147**	$ 5,668
Increase (decrease) in income tax resulting from:		
Non-deductible crown charges, net of royalty credits	**2,797**	1,724
Resource allowance	**(2,538)**	(683)
Deductible payments charged to retained earnings	**(2,350)**	–
Future tax asset not recognized (recognized)	**(834)**	503
Non-taxable portion of capital gain	**(141)**	–
Other	**(81)**	–
Future income tax provision	**–**	7,212
Capital taxes	**1,094**	804
Capital and future income tax provision	**$ 1,094**	$ 8,016

The components of the Company's future income tax assets and liabilities arising from temporary differences are as follows:

As at December 31,	2002		2001	
	Future Income Tax Assets	Future Income Tax Liabilities	Future Income Tax Assets	Future Income Tax Liabilities
Non-capital losses	**$ 15,680**	**$ –**	$ 15,384	$ –
Obligations under gas hedging contracts	**2,623**	**–**	4,010	–
Future site restoration	**199**	**–**	326	–
Capital assets	**6,847**	**7,112**	–	7,569
Subordinated notes	**–**	**1,772**	–	2,033
Other	**38**	**–**	372	–
	25,387	**8,884**	20,092	9,602
Valuation allowance	**(16,503)**	**–**	(10,490)	–
	$ 8,884	**$ 8,884**	$ 9,602	$ 9,602

Income taxes paid approximate capital tax expense for the years ended December 31, 2002 and 2001.

10. Unusual Items

	2002	2001
Gain on sale of securities	**$ 654**	$ –
Impairment of unproved properties	**–**	(6,400)
Gain on sale of resource properties	**–**	12,926
Control of well costs	**–**	(1,500)
	$ 654	$ 5,026

The Company's historical costs of $6.4 million associated with its exploration prospect in Guinea Bissau, Northwest Africa were written off in 2001. In the first quarter of 2002, this prospect was drilled by a third party at their expense and did not encounter commercial quantities of hydrocarbons. Subsequent to December 31, 2002, the Company disposed of its interests in this prospect for nil proceeds. In the event the project achieves commerciality before September 2009, Petrobank is entitled to a U.S.$1.0 million payment.

The Company incurred $1.5 million of control of well costs relating to a well acquired from Barrington in Northwest Alberta that experienced a blowout in June of 2001.

The events that gave rise to these gains and costs are not anticipated to recur.

11. Other Revenue

Other revenue of $0.3 million in 2002 (2001 – $1.6 million) consists of interest income.

12. Related Party Transactions

See "Share Capital Restructuring" in note 8 which describes a series of transactions between the Company and certain managers and directors with respect to shares and warrants held by those persons.

Included in accounts payable at December 31, 2002 is a $0.6 million balance payable indirectly to two of the Company's directors. This balance payable was assumed as part of the corporate acquisition in 2002 (see note 3) and was repaid subsequent to December 31, 2002.

In February 2003, the Company announced that an independent committee of the Board of Directors reached an agreement to acquire certain heavy oil technologies indirectly from two directors of the Company for their original cost of $0.4 million. In addition, a director and an unrelated party have retained a combined 17.5% net profits interest in future third party royalties generated from the technologies.

13. Financial Instruments and Financial Risk Management

The nature of oil and natural gas operations and the issuance of debt expose the Company to fluctuations in commodity prices, foreign currency exchange rates and interest rates. The Company manages these risks by operating in a manner that minimizes its exposure to the extent practical, and through the periodic use of derivative instruments. The Board of Directors periodically reviews the results of all derivative activities and all outstanding positions.

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. The majority of the Company's oil production in Canada is sold on a month-to-month basis to two marketing companies, which have credit ratings of BB+ and BBB, respectively. The Company's maximum credit exposure to these marketing companies is revenues from two month's oil sales. While counter-parties to derivative instruments expose the Company to losses in the event of non-performance, the Company currently only deals with one major institution, rated AA, and does not anticipate non-performance by this counter-party.

Commodity Price Risk Management

Financial Derivative Contracts

At December 31, 2002, the following financial swaps were outstanding:

Daily Volume	Term	Benchmark	Price
1,000 Bbls	Calendar 2003	WTI	US$22.70
500 Bbls	Calendar 2003	WTI	US$25.90
1,000 Bbls	Calendar 2004	WTI	US$24.00

Physical Gas Hedging Contracts

The Company is committed to deliver 2,225 GJ per day of natural gas under an escalating price contract that expires October 31, 2012. The wellhead price under this contract, at December 31, 2002, was set at $3.14 per GJ. The contract provides for an annual price escalation between 4% and 10%, based on hydroelectric and natural gas price inflation. Broader price redeterminations are to be made in 2007 and 2012, resulting in a new price that can vary from 65% to 135% of the previous year's price based on prevailing natural gas prices.

The Company is also committed to natural gas deliveries of 5,275 GJ per day at the Malin, Oregon delivery point until October 31, 2005. In connection with this commitment, the Company holds an equivalent amount of firm transportation service on the ANG and PGT pipeline systems at a cost of $0.52 per GJ. The Company receives the market price at the delivery point, less the relevant transportation charges.

Fair Value of Financial Instruments

The estimated fair values of the following financial instruments at December 31, 2002 are:

	Carrying Value	Fair Value
Liabilities		
Financial derivative contracts	$ –	$ 2,326
Physical gas hedging contracts	8,097	7,292
Subordinated notes	57,344	54,400

The fair value liability of the financial derivative contracts is supported by U.S.$1.0 million of credit and cash deposited with the counter-party. This collateral is adjusted as the fair value of the related liability changes.

The fair values of the Company's remaining financial instruments at December 31, 2002 approximate their carrying values. Fair values of financial derivative contracts and physical gas hedging contracts are determined based on the estimated cash payment or receipt necessary to settle the contract at December 31, 2002. Cash payments are calculated based on discounted cash flow analysis using prevailing market prices at the time. The estimated fair value of the subordinated notes is based on public trading values at December 31, 2002.

14. Changes in other Non-Cash Items

	2002	2001
Accounts receivable and other current assets	**$ 9,274**	$ (8,332)
Accounts payable and accrued liabilities	**7,200**	6,710
Deferred revenue	**–**	(1,657)
Non-cash working capital deficiency acquired	**(610)**	(6,753)
	$ 15,864	$ (10,032)
Attributable to operating activities	**$ 4,728**	$ (3,315)
Attributable to financing activities	**(878)**	(713)
Attributable to investing activities	**12,014**	(6,004)

15. Commitments and Contingencies

In May 2002, the Company assumed the remaining work commitments on two incremental production (IP) blocks and three exploration blocks in Colombia. At December 31, 2002, the Company's remaining work commitments on these blocks are as follows:

(US$000's)	Orito IP	Neiva IP	Exploration	Total
2003	$ 1,000	$ –	$ 8,500	$ 9,500
2004	27,000	9,500	–	36,500
	$ 28,000	$ 9,500	$ 8,500	$ 46,000

Petrobank has secured these work commitments through the issuance of letters of credit totaling $3.8 million. The exploration commitments represent the estimated cost of completing work obligations under the respective contracts. Subsequent to December 31, 2002 the Company satisfied its remaining phase one commitments at Orito ($1.0 million) and elected to commit to a second phase of development ($27.0 million). Petrobank's 2003 capital spending plans anticipate satisfying all Colombian work commitments in 2003. The Company plans to fund these commitments with its credit facility and cash flow from operations.

Pursuant to the acquisition of petroleum properties in Canada in 2002, the Company is committed to spend $1.6 million on development drilling at the acquired properties in 2003.

The Company is committed to payments under operating leases for office space, net of sub-lease arrangements, as follows:

2003	$ 748
2004	620
2005	601
2006	200
	$ 2,169

The Company is party to certain legal actions relating to disputes with industry participants, the outcome of which cannot be reasonably determined. In the opinion of management, the resolution of these matters will not have a material effect on the Company's financial position or results of operations.

16. Subsequent Events

The Company completed certain transactions subsequent to December 31, 2002 as described in notes 10 and 12.

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·Management's Discussion and Analysis·

The following management's discussion and analysis (MD&A) should be read in conjunction with the consolidated financial statements for the year ended December 31, 2002 and the accompanying notes to those financial statements that begin on page 43 of this annual report.

This MD&A contains forward-looking statements that reflect management's objectives and expectations as at the date of this report. These objectives and expectations involve risks and uncertainties. There is no guarantee that these objectives will be met, nor that the expected operating and commodity price conditions will occur. The Company's actual results may differ materially from those anticipated in these forward-looking statements.

Financial sums in the text and tables below are stated in Canadians dollars unless otherwise indicated. Metrics concerning Colombian operations are frequently stated in U.S. dollars, as indicated.

Important Corporate Background Information

In the first quarter of 2001, the Company disposed of virtually all of its producing assets. In the second quarter of 2001, Petrobank acquired Barrington Petroleum Ltd. (Barrington) and subsequently completed a comprehensive rationalization process including a series of non-core property dispositions, field optimization, and a significant reduction of overhead. The timing of these transactions and the differences in the asset bases acquired versus those disposed of impact the comparability of results against the prior year.

In 2002, Petrobank assumed work commitments on two incremental production blocks and three exploration blocks in Colombia. The Company spent $15.6 million in Colombia before year-end, primarily during the fourth quarter. Incremental production began in December 2002 with oil sales commencing in January 2003.

Canadian Netback Analysis ($/boe, except where noted)

Years ended December 31,	2002	2001
Oil and natural gas liquids price ($/bbl)	**$ 31.11**	$ 28.09
Natural gas price ($/mcf)	**3.89**	5.13
Oil and natural gas revenue	**27.39**	29.24
Royalties	**(5.84)**	(5.00)
Operating costs	**(6.68)**	(6.55)
Operating netback	**14.87**	17.69
General and administrative expenses	**(2.05)**	(3.99)
Cash netback	**$ 12.82**	$ 13.70
Average daily production		
Oil and natural gas liquids (bbls)	**2,623**	2,480
Natural gas (mcf)	**14,541**	11,047
Total (boe)	**5,047**	4,321

Anticipated Colombian Netbacks

Petrobank currently expects to receive netbacks on its blocks in Colombia in 2003 as follows:

	Orito		Neiva	
	(US$/bbl)	API	(US$/bbl)	API
Assumed WTI	US$25.00	40°	US$25.00	40°
Stream differential	(3.40)		(4.35)	
Price at Colombia port	21.60	29°	20.65	26°
Colombia pipeline tariff	(1.40)		(2.85)	
Wellhead quality adjustment	0.32		(1.15)	
Wellhead price	20.52	31°	16.65	20°
Royalty (8 percent)	(1.64)		(1.33)	
Operating costs[1]	(4.00)		(2.30)	
Operating netback	US$14.88		US$13.02	

[1] Includes fixed Ecopetrol per barrel operating fee.

Revenue

Oil and natural gas revenue before royalties was $50.5 million for the year ended December 31, 2002, an increase of 9 percent from $46.1 million in 2001. This result is attributable to an increase of 17 percent in average production to 5,047 boe per day in 2002, offset by a decrease of 6 percent in average product prices to $27.39 per boe. By commodity, the average selling price for crude oil and natural gas liquids increased to $31.11 per barrel in 2002 from $28.09 per barrel in 2001, while the average selling price for natural gas decreased to $3.89 per mcf in 2002 from $5.13 per mcf in 2001.

Production

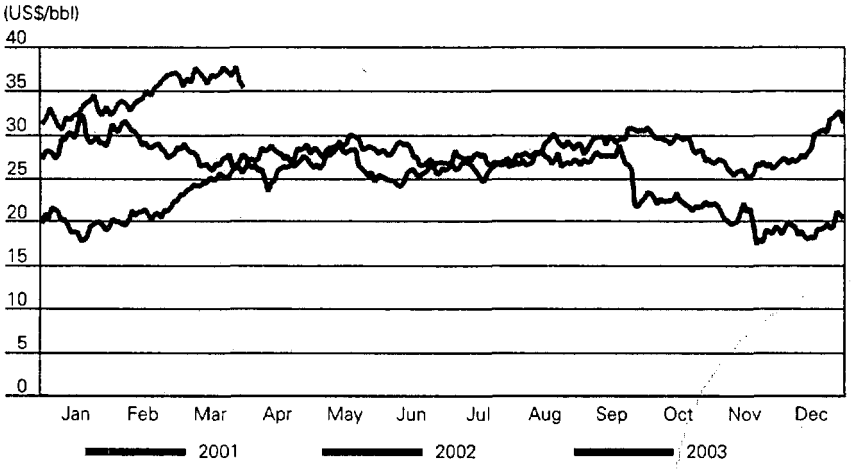
Oil and NGLs production increased by 6 percent while natural gas production increased by 32 percent. Oil and NGLs production increased as a result of the inclusion of a full year of production from the properties acquired from Barrington in April 2001, offset by production sold in connection with property rationalization later in 2001. When compared to oil and NGLs production of 2,380 barrels per day in April 2001 following the acquisition of Barrington, and excluding production from properties sold in 2001, average production increased by 10 percent to 2,623 barrels per day in 2002. This increase is attributable to drilling activity in southeastern and western Saskatchewan. Petrobank's planned Canadian oil development activity in 2003 is focused on drilling in western Saskatchewan and at Jumpbush in southern Alberta.

Natural gas production increased by 32 percent to 14,541 mcf per day in 2002 from 11,047 mcf per day in 2001. This increase resulted mainly from the Company's natural gas discovery at Hamburg in the fourth quarter of 2001, combined with the facility operator's May-November 2001 shut-in of natural gas production at Zama. Natural gas development expenditures in 2003 will be focused on the Company's Jumpbush property and to a lesser extent on northwestern Alberta.

Realized Sales Prices

The increase in Petrobank's realized crude oil and NGLs sales prices in 2002 was a result of increasing world oil prices and narrowing of crude oil differentials for Canadian medium and heavy-gravity crude oils. The Company's average selling price for crude oil and NGLs in 2002 was $32.32 per barrel, before financial hedging losses of $1.21 per barrel, representing a US$5.49 per barrel differential to WTI. This compares to a US$7.64 per barrel differential to WTI in the fourth quarter of 2001.

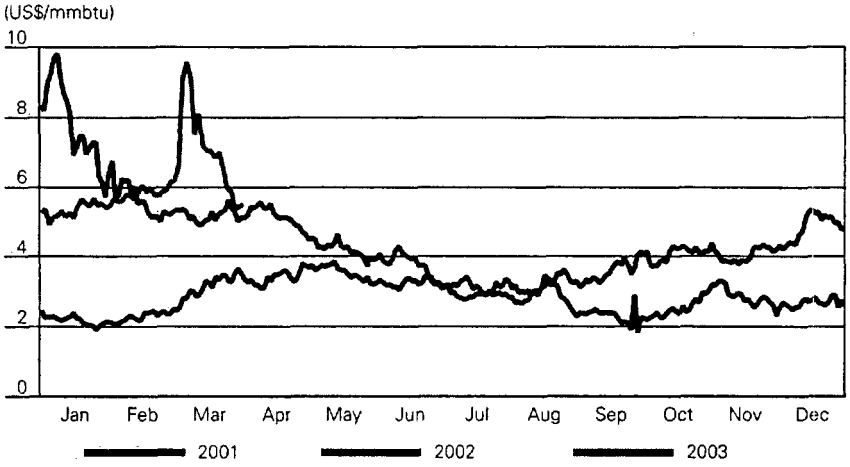
WTI Oil Prices



Included in natural gas revenues in 2002 is $0.4 million ($0.08 per mcf) for amortization of obligations under gas hedging contracts compared to $7.2 million ($1.79 per mcf) in 2001. Upon acquisition of Barrington in early 2001, Petrobank recognized a $29 million liability related to the negative impact that existing physical gas hedging contracts were expected to have on future gas revenues. The amount of the liability is being amortized to natural gas revenues over time to reflect revenues as though production were unencumbered by these contracts. Petrobank paid $12.4 million during 2001 and $0.9 million during 2002 to settle certain of these contracts. The remaining obligations under these contracts are described in note 13 to the consolidated financial statements.

Assuming an average NYMEX natural gas price of US$5.00 per mmbtu, the Company would expect to receive an average wellhead natural gas price in 2003 of approximately Cdn$5.50 per mcf. Amortization of obligations under natural gas hedging contracts is estimated to increase revenue by approximately $0.8 million ($0.18 per mcf) in 2003, an amount not included in the above estimated wellhead price.

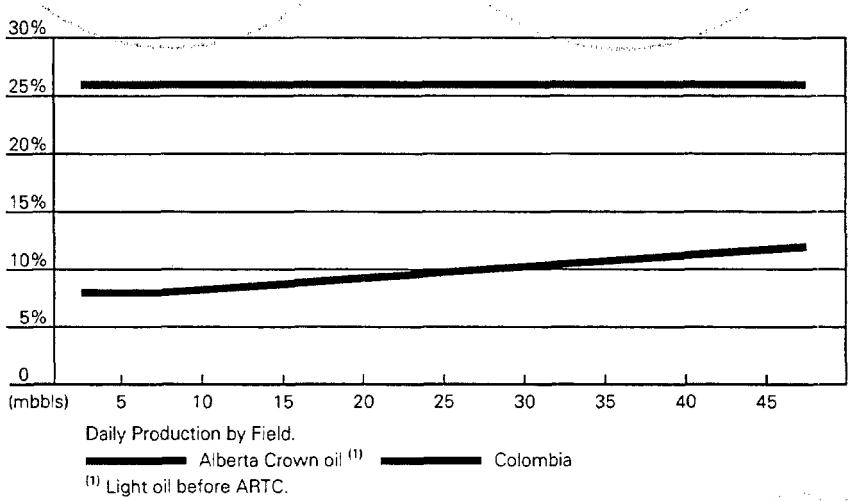
NYMEX Natural Gas Prices



Royalties

Net royalty expense increased to $10.8 million in 2002 from $7.9 million in 2001. As a percentage of revenue before the impact of hedging and amortization of obligations under gas hedging contracts, royalties increased slightly to 21 percent in 2002 from 20 percent in 2001. The Company expects 2003 royalties in Canada to be approximately 22 percent of revenues before hedging. On a consolidated basis, the Company expects royalty rates to decline, as oil sales from Colombia, which incur initial royalties at eight percent, form a larger component of total production. Colombian royalty rates are to increase when incremental production on a field basis exceeds 5,000 barrels of oil per day, but will remain significantly lower than comparable rates in Canada, as depicted in the graph below.

Comparison of Royalty Rates



Operating Costs

Operating costs increased to $12.3 million in 2002 from $10.3 million in 2001. On a unit of production basis, operating costs increased slightly to $6.68 per boe in 2002 from $6.55 per boe in 2001. The Company expects 2003 production expenses in Canada to remain at this level on a per unit basis. In Colombia, the state oil company (Ecopetrol) operates the Company's incremental production blocks at a fixed fee of US$3.48 per barrel of oil produced at Orito and US$1.90 per barrel at Neiva. These fees make up approximately 90 percent of our estimated total operating costs in Colombia.

General and Administrative Expenses

General and administrative expenses were $3.8 million ($2.05 per boe) in 2002, compared to $6.3 million ($3.99 per boe) in 2001. These decreases resulted from office and staff consolidation following the acquisition of Barrington in 2001. The Company does not capitalize general and administrative expenses. With the addition of Colombian production, Petrobank expects general and administrative expenses to be approximately $1.90 per boe in 2003.

Depletion, Depreciation and Site Restoration

Depletion, depreciation and site restoration expenses increased to $17.3 million ($9.37 per boe) in 2002 from $12.6 million ($7.98 per boe) in 2001. Costs per unit of production increased as a result of only moderate success from the Company's exploratory drilling program in southeast Saskatchewan. Based on the December 31, 2002 Colombian reserve report, initial depletion expense on production in Colombia is expected to be approximately $10.00 per barrel. The Colombian depletion rate will be adjusted throughout 2003 for expected reserve additions associated with Petrobank's 2003 capital plan.

Unusual Items

In 2002, Petrobank recorded a gain of $0.7 million on the sale of securities received as partial compensation for an asset disposition. This compares to income of $5.0 million from unusual non-recurring items in 2001, including a pre-tax gain of $12.9 million on the sale of assets offset by a charge of $6.4 million due to the impairment of the Company's Guinea Bissau exploration project and a charge of $1.5 million related to well control costs.

Capital and Income Tax Expenses

Income tax expense decreased to $1.1 million in 2002 from $8.0 million in 2001. Taxes in 2002 consisted of federal Large Corporations Tax and Saskatchewan capital taxes which are calculated at 3.6 percent of revenues earned in Saskatchewan. The majority of the income tax expense in 2001 related to future income taxes associated with asset dispositions that occurred in the first quarter of 2001. These dispositions exposed the Company to a potential cash income tax liability of approximately $20 million that was entirely deferred as a result of the acquisition of Barrington.

At December 31, 2002, the Company had Canadian tax pools of $130 million and accordingly does not expect to pay Canadian income taxes for several years. In Colombia, the corporate income tax rate is 38.5 percent and capital expenditures are deductible on a straight-line basis over a five-year period. The Company anticipates paying cash taxes in Colombia in 2003.

Tax Pools

As at December 31, 2002 ($ millions)	Amount
Canadian oil and gas property expense (10%)	$ 15.0
Canadian development expense (30%)	30.0
Canadian exploration expense (100%)	12.0
Undepreciated capital costs (25%)	35.0
Non-capital losses carried forward (100%)	36.0
Other	2.0
Total Canada	**130.0**
Colombia	30.0
Total tax pools	**$ 160.0**

Interest on Subordinated Notes

Upon acquisition in 2001, Barrington had $50.0 million face value of natural gas price-linked subordinated notes outstanding paying 12 percent interest per annum, which Petrobank replaced with $47.5 million face value of subordinated notes paying 9 percent interest per annum. In the third quarter of 2001, Petrobank issued an additional $12.9 million of these new notes for cash proceeds of $11.5 million. The Petrobank notes allow the Company to settle both interest and principal obligations through the issuance of common shares, and thus the entire balance is reflected as equity on the balance sheet. The effective interest rate on the subordinated notes is 10.7 percent. Interest expense for the year ended December 31, 2002 totaled $6.1 million, including $0.7 million associated with amortization of the discount from the face value to the carrying value of $57.3 million. Interest on the notes totaled $3.3 million in 2001, a year-over-year difference attributable to the fact that the notes were only outstanding for a portion of the year in 2001.

Net Income Attributable to Common Shareholders

Net income attributable to common shareholders decreased from $0.4 million ($0.01 per share) in 2001 to a loss of $0.4 million ($0.01 per share) in 2002. The year-over-year decrease is attributable to increased depletion expense, decreased revenues associated with amortization of obligations under gas hedging contracts in 2001 and non-recurring income from unusual items in 2001, partially offset by higher production volumes in 2002.

Cash Flow from Operations

Cash flow from operations before changes in working capital increased to $22.8 million in 2002 from $18.5 million in 2001, a result attributable to reduced general and administrative expenses and higher production volumes offset partially by lower combined sales prices.

Net Asset Value (NAV)

As at December 31, 2002

($000s except per share amounts and shares outstanding)

Established reserves, discounted at 10 percent[1]		
Canada	$	113,156
Colombia		66,089
Canadian undeveloped land and seismic – western Canada ($40/acre)		26,000
Working capital deficit		(5,151)
Fair value of financial commodity hedging contracts (based on GLJ price case)[2]		(429)
Carrying value of subordinated debt[3]		(57,344)
Basic NAV		142,321
Proceeds on exercise of in-the-money stock options and warrants[4]		10,467
Diluted NAV	$	152,788
Basic common shares outstanding		45,314
Net asset value per basic common share	$	3.14
Diluted common shares outstanding		50,232
Net asset value per diluted common share	$	3.04

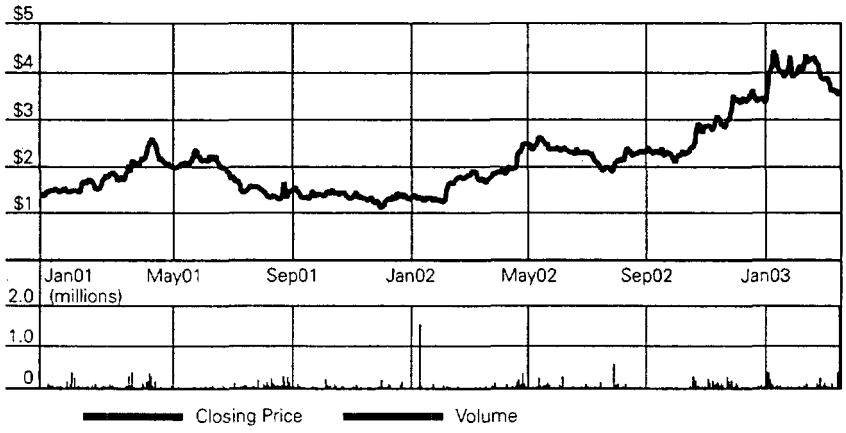
(1) Based on GLJ's January 1, 2003 price forecast.

(2) Petrobank's physical natural gas hedge contracts are reflected in GLJ's reserve economics.

(3) Carrying value reflects an 11 percent yield to maturity. At December 31, 2002 face value and trading value were $60.4 million and $54.4 million, respectively.

(4) Assumes that 777,720 warrants are exercised for proceeds of $1.9 million and 4,140,000 in-the-money employee stock options are exercised for proceeds of $8.5 million.

Common Share Trading History



Liquidity and Capital Resources

During 2002, Petrobank financed net capital expenditures of $42.9 million largely through positive cash flow of $22.8 million and use of cash and working capital in existence at the beginning of the year. Petrobank entered 2003 with cash of $12.2 million, a working capital deficit of $5.2 million and no bank debt.

Petrobank's plans for 2003 include capital spending of approximately $40 million in Canada and US$45 million in Colombia, for a base total of Cdn$110 million. The Company has a sufficient inventory of opportunities to increase capital investment in Colombia to as much as US$80 million in 2003 if the Company's initial plans meet with success and sufficient additional capital is available.

Assuming a reasonable degree of technical success and an average WTI price of US$25 per barrel and a NYMEX natural gas price of US$5.20 per mmbtu, Petrobank's base budget should generate cash flow of approximately $60 million in 2003. The Company will therefore require additional capital resources of $50-$60 million to complete its currently planned program in 2003. Entering 2003, Petrobank had a $45 million credit facility with an unutilized borrowing base of $40 million, leaving borrowing capacity along with opening cash balances to fund a significant proportion of the additional required capital.

Petrobank's borrowing base is currently being reviewed by our bank based on the January 1, 2003 reserve report. Possible sources of additional capital include the following:

- The existing bank facility is supported only by the Company's Canadian assets as Canadian banks are reluctant to lend against international assets. It may be possible to obtain a new credit facility with one or more international banks that would include lending value for the Colombian assets. As at December 31, 2002, the present value (10 percent discount rate) of the Colombian proved reserves was US$31.5 million, of which the majority was undeveloped. The Company believes its planned capital program in Colombia will succeed in reclassifying these reserves to the proved-producing category, which would facilitate a Colombian borrowing base with international lenders. Petrobank's ability to close a bank facility providing lending value for Colombian assets will depend in part on our ability to provide an appropriate risk mitigation structure. Bank debt supported in part by Colombian assets will require interest rates which are 200-300 basis points higher than debt supported exclusively by Canadian assets.

- The Company has the ability to issue incremental debt that is unsecured and subordinate to any bank facility. This could be in the form of an incremental issuance of the subordinated notes currently outstanding or other debt that is unsecured. Petrobank's ability to complete such an offering will depend on how much demand exists in the capital markets for this type of security. The Company believes Petrobank's cash flows will be sufficient to service a fully drawn credit facility, our outstanding subordinated notes plus an incremental debt offering. The cost associated with unsecured debt is significantly higher than that of secured debt, depending on the degree of overall

leverage in the Company. The attractiveness of these forms of debt to Petrobank include a longer-term to maturity (existing subordinated notes do not mature until July 2006) and increased flexibility versus a bank facility.

- Pre-export financing entails selling future oil production for cash and committing to deliver that production in later years to satisfy interest and principal repayment obligations. This form of debt has particular relevance to companies with international operations, such as Petrobank. Pre-export financing is typically combined with an oil price risk mitigation strategy that fixes the value of future oil deliveries required to service and repay the debt.

- Petrobank has the ability to issue additional common shares, with or without flow-through tax attributes. Flow-through shares would allow Petrobank to pass through oil and natural gas exploration tax pools (100 percent deductible) to the investor. This form of financing is particularly attractive to Petrobank given our strong tax position in Canada. Typically, these shares attract a premium to existing market prices, but the value of the issue is limited to planned exploration expenditures in Canada within 12-24 months of the issue. Petrobank may also be able to issue ordinary common shares. Proceeds and dilution to existing shareholders will depend on Petrobank's share price at the time.

- As a key component of our business plan, Petrobank regularly assesses the future growth potential of all assets in our portfolio. We have harvested and will continue to harvest assets that we believe to be fully valued. Proceeds from these sales are available for immediate reinvestment in our existing capital projects or may be retained for deployment on future opportunities.

Success in Colombia will increase the need for Petrobank to seek debt financing outside of the Canadian bank lending market, as the ratio of the Company's non-Canadian asset value to Canadian asset value increases. Petrobank may need to rely increasingly on financing considered to be non-traditional in the Canadian E&P industry. We believe the key will be to implement our capital program in tranches, a managed approach that would match incremental spending to sourcing new capital and generating additional cash flow from recent drilling and workover activities.

In addition, we will continue to make cash flow projections using a conservative commodity price outlook to ensure sufficient funds can be generated even during a price downturn. We believe that under virtually all scenarios, we will be able to complete our remaining Colombian work commitments, which totaled US$46 million at December 31, 2002.

Included in the 2003 capital budget are projects that can be deferred, if necessary, without significant impact on short-term cash flow. For example, the Company has planned $6.0 million of expenditures related to its coal bed methane and Orion heavy oil projects in Canada. If these programs were deferred until late 2003 or 2004, there would be no impact on cash flow. In addition, the Colombian capital program could be modified to reduce expenditures at Orito by including a larger number of low-cost Pepino wells or Caballos workovers and fewer of the more expensive Caballos wells. The Company does not anticipate the need to make a significant investment in inventory or other forms of working capital in 2003.

Petrobank faces no legal restrictions on repatriating funds from Colombia to Canada. Colombia does not require revenue retention in local currency or within its banking system. This allows Petrobank to allocate its capital program geographically without corresponding cash flows on a country-by-country basis.

Net Capital Expenditures

	2002			2001
($000s)	Canada	Colombia	Total	Canada
Drilling and completions	**$ 14,683**	**$ 14,206**	**$ 28,889**	$ 9,363
Facilities and equipment	**1,518**	**137**	**1,655**	3,699
Land	**5,842**	**–**	**5,842**	5,715
Seismic	**493**	**276**	**769**	2,234
Asset acquisitions	**6,127**	**–**	**6,127**	–
Other	**1,930**	**1,016**	**2,946**	848
Dispositions[1]	**(3,334)**	**–**	**(3,334)**	(161,575)
Corporate acquisition[2]	**–**	**–**	**–**	115,322
Net capital expenditures (dispositions)	**$ 27,259**	**$ 15,635**	**$ 42,894**	$ (24,394)

(1) In 2001, includes $1.0 million of non-cash proceeds excluded from proceeds on disposition of resource properties on the consolidated statement of cash flows.

(2) In 2001, represents the acquisition of Barrington Petroleum Ltd.

Risks and Uncertainties

Petrobank is exposed to a variety of risks, including but not limited to competitive, operational, political, regulatory, environmental and financial risks.

The oil and natural gas industry is highly competitive, particularly in regard to exploration for and development of new sources of oil and natural gas reserves. Our competitors often include companies much larger than Petrobank, with greater access to financial resources. Our future success is driven in large part by our ability to find and exploit new oil and natural gas reserves at reasonable costs and reinvestment ratios. The process of evaluating prospects and estimating oil and natural gas reserves is complex and subject to uncertainty. Actual operating results, including production performance, will vary from those estimated, possibly materially. The Company manages these risks by maintaining a focused asset base with high working interests and by hiring qualified professionals, including independent reserve engineers, with appropriate industry experience.

Petrobank is exposed to a number of operational risks inherent in the industry, including accidents, well blowouts, uncontrolled flows and environmental risks. Operational risks are managed using prudent field operating procedures. The Company has a detailed emergency response plan to deal with potential incidents and maintains a comprehensive insurance program to reduce the risk of significant economic loss, but not all risks can be practically covered. Losses resulting from adverse events associated with these risks could have a material adverse impact on the Company's operations.

Petrobank currently has operations in Canada and Colombia and is evaluating other international projects. The Company seeks to operate in regions where the petroleum industry is a key component of the economy to help mitigate the risks associated with operating in foreign jurisdictions. Petrobank believes that management's experience operating internationally helps reduce these risks. Some countries in which the Company operates in the future could be considered politically and economically unstable. In Colombia, the government has a long record of democracy and an established legal framework that, in our opinion, minimizes political risks.

Colombia has a publicized history of security problems associated with certain insurgent groups. The Company and its personnel are subject to these risks but through effective security and social programs, the Company believes these risks can be effectively managed. For a broader discussion of these risks and programs please see the discussion under the heading The Environment, Community Relations and Security in Colombia on page 16 of this annual report. It has become impractical worldwide to obtain insurance coverage to protect against terrorist incidents and as a result the Company's insurance program excludes this coverage. Consequently, an incident of this sort could have a material adverse impact on the Company's operations and financial results.

The Company is subject to extensive governmental and environmental regulations in its operating jurisdictions. Changes to these regulations, including Canada's recent ratification of the Kyoto Protocol on greenhouse gas emissions, could increase the costs of conducting business (Colombia is not currently bound by the Protocol's CO_2 reduction requirements.) Environmental risks inherent in the oil and natural gas industry are subject to increasingly stringent laws and regulations. The Company operates in accordance with all environmental legislation and strives to minimize the environmental impact of its operations by including safety programs and environmental protection/mitigation in its business plans.

Petrobank is exposed to normal financial risks inherent within the oil and natural gas industry, including commodity price risk, exchange rate risk, interest rate risk, and credit risk. The Company conducts its operations in a manner intended to minimize exposure to these risks, as described in note 13 to the consolidated financial statements.

The Company's most significant financial market risk is the price of crude oil, which is influenced by global supply and demand, OPEC policy, and worldwide political events. In addition, the price received for our heavier crudes is subject to a widening in the differential to light oil prices. Natural gas prices in Canada are influenced primarily by North American supply and demand and to a lesser extent by local market conditions. Management believes it is neither appropriate nor possible to eliminate 100 percent of the Company's exposure to fluctuations in commodity prices. The Company continuously monitors market conditions and selectively utilizes derivative instruments to reduce exposure to commodity prices.

To the extent revenues generated and costs incurred in U.S. dollars are not equivalent, they expose the Company to exchange-rate risk. Capital expenditures in Colombia are expected to exceed cash flow in 2003, which acts as a partial natural hedge to our exposure on the sale of our oil and natural gas in U.S. markets. The Company is not currently using derivative instruments to manage any exchange-rate risk.

Petrobank is exposed to fluctuations in short-term interest rates in connection with the use of its floating-rate bank facility. At December 31, 2002, this facility was unutilized. The Company's subordinated notes pay interest at a fixed nine percent interest rate and as such minimize Petrobank's exposure to interest-rate risk.

Sensitivities

The Company's earnings and cash flow are sensitive to changes in crude oil and natural gas prices, currency exchange rates and interest rates. Volatility in commodity prices and exchange rates may also have an impact on the budgeted capital expenditure program and resulting cash flows in 2003.

Sensitivities are calculated using the following base assumptions for 2003:

Average daily production	
Oil and NGLs (bbls)	
Canada	3,500
Colombia	4,500
Natural gas (mmcf)	12.0
Total (boe)	10,000
Average commodity prices	
WTI (US$/bbl)	$ 25.00
NYMEX (US$/mmbtu)	$ 5.00
Canadian/US dollar exchange rate	Cdn$1.50/US$1.00

The expected impacts on 2003 cash flow resulting from changes to the following factors, averaged over a full year, are as follows:

($ millions)	
Change of:	
Crude oil	
US$1.00/bbl WTI	$ 2.7
100 bbls per day production – Canada	$ 0.6
100 bbls per day production – Colombia	$ 0.5
Natural gas	
US$0.50/mmbtu NYMEX	$ 2.4
1.0 mmcf per day production	$ 1.5
Financial	
$0.01 Canadian/US dollar exchange rate	$ 0.6
1 percent Bank of Canada interest rate	$ 0.2

Outlook

For a discussion of the Company's future business prospects, please see the President's Message to Shareholders and the Review of Operations.



DAVID RAIN
VICE PRESIDENT FINANCE AND CHIEF FINANCIAL OFFICER

PETROBANK
ENERGY AND RESOURCES LTD.

NEWS RELEASE

PETROBANK ANNOUNCES SUBORDINATED NOTE FINANCING

Calgary, Alberta - April 29, 2003 - Petrobank Energy and Resources Ltd. ("Petrobank") is pleased to announce that it has entered into an agreement to issue $40.0 million face value of subordinated notes and approximately 1.4 million common share purchase warrants for proceeds of approximately $36.4 million, before accrued interest and agents' commissions. This financing will be completed on a "best efforts" private placement basis. The subordinated notes will be issued pursuant to Petrobank's existing subordinated note indenture (TSX: PBG.N), which stipulates a 9% coupon and a July 31, 2006 maturity date. The common share purchase warrants will be exercisable into common shares at $4.00 and will expire 36 months after closing. The most recent 5-day average trading price of the subordinated notes and common shares of Petrobank were $88.50 and $3.27, respectively.

The syndicate will be led by Merrill Lynch Canada Inc., and includes Jennings Capital Inc., and Tristone Capital Inc. Closing of the offering is expected to occur on May 5, 2003, and is subject to regulatory approval. On completion of this financing, the Company will have $100.4 million of face value of subordinated notes outstanding; approximately $15 million in cash and an undrawn $40 million bank facility.

Total production for the first quarter of 2003 averaged 5,273 boe per day including 2,757 barrels of oil and natural gas liquids and 10.9 mmcf per day of natural gas in Canada, and 695 barrels of oil per day in Colombia. Current daily production in Canada is approximately 3,200 barrels of oil and natural gas liquids and 12 mmcf of natural gas and in Colombia oil production is approximately 1,100 barrels per day. A complete operational update will be included with Petrobank's first quarter results, which are expected to be released on or about May 21, 2003.

Completion of this financing will facilitate the completion of Petrobank's 2003 capital spending program of $40 million in Canada and U.S. $45 million in Colombia.

The Company's annual report has been mailed to shareholders and can be viewed at www.petrobank.com. The Annual and Special Meeting of the Shareholders will be held on Thursday, May 22, 2003 at 3:00 p.m. at the Westin Hotel, 320 – 4th Avenue S.W., Calgary, Alberta. Petrobank's common shares and subordinated notes are listed on the Toronto Stock Exchange under the symbols PBG and PBG.N, respectively.

FOR FURTHER INFORMATION PLEASE CONTACT:

John D. Wright, President and Chief Executive Officer
Telephone: (403) 750-4400

David Rain, VP Finance and Chief Financial Officer
Telephone: (403) 750-4400

www.petrobank.com

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Computershare

600, 530 – 8th Ave SW., Calgary, AB T2P 3S8 Tel.: (403) 267-6800 Fax.: (403) 267-6529

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April 28, 2003

Alberta Securities Commission
British Columbia Securities Commission
The Manitoba Securities Commission
Nova Scotia Securities Commission
Ontario Securities Commission
Commission des valeurs mobilières du Québec
Saskatchewan Securities Commission
TSX

Dear Sirs:

Subject: Petrobank Energy and Resources Ltd.

We confirm that the following material was sent by pre-paid mail on April 25, 2003, to the registered shareholders of the common shares of the subject Corporation:

1. 2002 Annual Report
2. Notice of Meeting / Information Circular
3. Proxy
4. Proxy Return Envelope
5. Supplemental Mail List Card

We further confirm that copies of the above mentioned material were sent by courier, on April 25, 2003, to each intermediary holding shares of the Corporation who responded to the search procedures pursuant to Canadian Securities Administrators' National Instrument 54-101 regarding shareholder communications.

In compliance with security regulations, we are providing this material to you in our capacity as agent for the subject Corporation.

Yours truly,

"signed by"

Tracy McAdam
Mailing Specialist
Client Services Stock Transfer
Email: Tracy.McAdam@Computershare.com

cc: Petrobank Energy and Resources Ltd.
Attention: Corey Ruttan

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MATERIAL CHANGE REPORT

1. Reporting Issuer:

Petrobank Energy and Resources Ltd.

2. Date of Material Change:

April 29, 2003

3. News Release

A press release disclosing the details outlined in this Material Change Report was issued by CCN Matthews from Calgary, Alberta on April 29, 2003 and disseminated through the facilities of CCN Matthews and would have been received by the securities commissions where Petrobank Energy and Resources Ltd. is a "reporting issuer" and the stock exchanges on which the securities of Petrobank Energy and Resources Ltd. are listed and posted for trading in the normal course of its dissemination.

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5. Full Description of Material Change:

See attached Schedule "A".

6. Reliance on Confidentiality Provisions:

Not Applicable

7. Omitted Information:

Not Applicable

8. Senior Officers:

For further information, please contact:

Mr. John D. Wright, President and Chief Executive Officer,
Petrobank Energy and Resources Ltd., Calgary, Alberta,
Telephone (403) 750-4400

David Rain, VP Finance and Chief Financial Officer,
Petrobank Energy and Resources Ltd., Calgary, Alberta,
Telephone (403) 750-4400

9. Statement of Senior Officer:

The foregoing accurately discloses the material change referred to in this report.

DATED as of April 29, 2003, at the City of Calgary, in the Province of Alberta.

Petrobank Energy and Resources Ltd.

Per: (signed) "*David J. Rain*"
David J. Rain
Vice President, Finance and Chief Financial Officer

cc: Toronto Stock Exchange

Schedule "A"

PETROBANK
ENERGY AND RESOURCES LTD.

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David J. Rain
Vice President, Finance and Chief Financial Officer

cc: Toronto Stock Exchange

Schedule "A"

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www.petrobank.com

PETROBANK
ENERGY AND RESOURCES LTD.

NEWS RELEASE

PETROBANK ANNOUNCES COMPLETION OF SUBORDINATED NOTE FINANCING

Calgary, Alberta – May 6, 2003 - Petrobank Energy and Resources Ltd. ("Petrobank") is pleased to announce that it has closed its previously announced financing, resulting in the issuance of $40.0 million face value of subordinated notes and 1,420,300 common share purchase warrants for proceeds, net of costs and agents' commissions, of approximately $35.0 million. The subordinated notes have been issued pursuant to Petrobank's existing subordinated note indenture (TSX: PBG.N), which stipulates a 9% interest rate and a maturity date of July 31, 2006. Interest on these notes will accrue from the date of issuance. The common share purchase warrants are exercisable into common shares at $4.00 and expire after 36 months.

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www.petrobank.com

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FORM 45-102F2

Certificate under Subsection 2.7(2) or (3) of Multilateral Instrument 45-102 Resale of Securities

Petrobank Energy and Resources Ltd. has distributed securities under a provision listed in Appendix D or E to Multilateral Instrument 45-102 or a provision of securities legislation that specifies that the first trade of the securities is subject to section 2.5 or 2.6 of Multilateral Instrument 45-102 and hereby certifies that in respect of a distribution on May 6, 2003 of $40,000,000 (Canadian) principal amount of 9% subordinated notes and 1,420,300 common share purchase warrants of Petrobank Energy and Resources Ltd., Petrobank Energy and Resources Ltd. was a qualifying issuer within the meaning of Multilateral Instrument 45-102 Resale of Securities at the distribution date.

DATED at Calgary, Alberta this 14th day of May, 2003.

PETROBANK ENERGY AND RESOURCES LTD.

By: (signed) "*David J. Rain*"
David J. Rain
Vice President Finance and Chief Financial Officer

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MATERIAL CHANGE REPORT

1. Reporting Issuer:

Petrobank Energy and Resources Ltd.

2. Date of Material Change:

May 6, 2003

3. News Release

A press release disclosing the details outlined in this Material Change Report was issued by CCN Matthews from Calgary, Alberta on May 6, 2003 and disseminated through the facilities of CCN Matthews and would have been received by the securities commissions where Petrobank Energy and Resources Ltd. is a "reporting issuer" and the stock exchanges on which the securities of Petrobank Energy and Resources Ltd. are listed and posted for trading in the normal course of its dissemination.

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6. Reliance on Confidentiality Provisions:

Not Applicable

7. Omitted Information:

Not Applicable

8. Senior Officers:

For further information, please contact:

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Petrobank Energy and Resources Ltd., Calgary, Alberta,
Telephone (403) 750-4400

David Rain, VP Finance and Chief Financial Officer,
Petrobank Energy and Resources Ltd., Calgary, Alberta,
Telephone (403) 750-4400

9. Statement of Senior Officer:

The foregoing accurately discloses the material change referred to in this report.

DATED as of May 6, 2003, at the City of Calgary, in the Province of Alberta.

Petrobank Energy and Resources Ltd.

Per: (signed) "*David J. Rain*"
David J. Rain
Vice President, Finance and Chief Financial Officer

cc: Toronto Stock Exchange

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PETROBANK ENERGY AND RESOURCES LTD.

ANNUAL INFORMATION FORM

FOR THE YEAR ENDED DECEMBER 31, 2002

MAY 16, 2003

TABLE OF CONTENTS

ABBREVIATIONS AND DEFINITIONS 1

SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENT 1

THE COMPANY 2
- Incorporation and Organization 2
- General Development of the Company 2
- Trends 3

BUSINESS OF THE COMPANY 3
- Production 4
- Principal Properties 4
  - Western Canadian Focus Areas 4
  - Colombia 6

LAND HOLDINGS 7

OIL AND GAS WELLS 8

OIL AND GAS RESERVES 8
- Canada 9
- Colombia 10

RECONCILIATION OF RESERVES 12

DRILLING ACTIVITY 14

HISTORY 14

FUTURE COMMITMENTS 16

EXPLORATION AND DEVELOPMENT 16

DIRECTORS AND OFFICERS OF PETROBANK 17

PERSONNEL 19

DIVIDEND RECORD 19

MARKET FOR SECURITIES 20

MANAGEMENT'S DISCUSSION AND ANALYSIS 20

SELECTED FINANCIAL INFORMATION 20

INDUSTRY CONDITIONS 20
- Regulation 20
- Environmental 22
- Colombia 22

RISK FACTORS 23

ADDITIONAL INFORMATION 26

ABBREVIATIONS AND DEFINITIONS

In this Annual Information Form, the abbreviations set forth below have the following meanings:

"M$"	thousands of Canadian dollars	**"mmcf"**	1,000,000 cubic feet
"MM$"	millions of Canadian dollars	**"bcf"**	1,000,000,000 cubic feet
"bbl"	Barrel	**"mcf/d"**	one thousand cubic feet per day
"mbbl"	1,000 barrels	**"mcfe"**	1,000 cubic feet of gas equivalent
"mmbbl"	1,000,000 barrels	**"mmcf/d"**	one million cubic feet per day
"bbl/d"	barrel per day	**"boe"**	barrel of oil equivalent
"stb"	stock tank barrel	**"mboe"**	1,000 barrels of oil equivalent
"mstb"	1,000 stock tank barrels		
"NGL"	natural gas liquids	**"boe/d"**	barrel of oil equivalent per day
"mcf"	1,000 cubic feet	**"m3"**	cubic metre
		"US $"	United States Dollars

Note: for the purposes of this document, 6 mcf of natural gas and 1 bbl of NGL each equal 1 bbl of oil or 1 boe, such conversion not being based on either price or energy content.

In this Annual Information Form, the capitalized terms set forth below have the following meanings:

"ABCA" means the *Business Corporations Act*, R.S.A. 2000, c. B-9, as amended, together with any amendments thereto and all regulations promulgated thereunder;

"ARTC" means the Alberta royalty tax credit;

"Common Shares" means common shares in the share capital of the Company;

"GAAP" means Canadian generally accepted accounting principles;

"GLJ Report" means the independent engineering evaluation of Petrobank's crude oil and natural gas reserves prepared by Gilbert Laustsen Jung Associates Ltd. (**"GLJ"**), independent oil and gas reservoir engineers of Calgary, Alberta, dated February 25, 2003 and effective January 1, 2003;

"Petrobank" or the **"Company"** means Petrobank Energy and Resources Ltd.; and

"TSX" means the Toronto Stock Exchange.

In this Annual Information Form, references to "dollars" and "$" are to the currency of Canada, unless otherwise indicated.

SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENT

Petrobank is hereby providing cautionary statements identifying important factors that could cause the Company's actual results to differ materially from those projected in forward-looking statements made in this Annual Information Form. Any statements that express, or involve discussions as to, expectations, beliefs, plans, objectives, assumptions or future events or performance (often, but not always, through the use of words or phrases such as "will likely result," "are expected to," "will continue," "is anticipated," "estimated," "intends," "plans," "projection" and "outlook") 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 the forward looking statements. Accordingly, any such statements are qualified in their entirety by reference to, and are accompanied by, the factors discussed throughout this Annual Information Form. Among the key factors that have a direct bearing on the Company's results of operations are the nature of the Company's involvement in the business of exploration for, and development and production of oil and natural gas reserves, fluctuations in prices received for oil and natural gas, fluctuations in interest rates and the fluctuation of the

exchange rate between the Canadian dollar and the United States dollar. These and other factors are discussed herein under "Management's Discussion and Analysis", incorporated by reference from the Company's 2002 Annual Report, and elsewhere in this Annual Information Form.

Because actual results or outcomes could differ materially from those expressed in any forward-looking statements of the Company made by or on behalf of the Company, investors should not place undue reliance on any such forward-looking statements. Further, any forward-looking statement is made only as of a certain date, and the Company undertakes no obligation to update any forward-looking statement or statements to reflect events or circumstances after the date on which such statement is made or to reflect the occurrence of unanticipated events, except as required by applicable securities laws. New factors emerge from time to time, and it is not possible for management to predict all of these factors and to assess in advance the impact of each such factor on the Company's business or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statement.

THE COMPANY

Incorporation and Organization

The Company was incorporated under the ABCA on December 1, 1983 as "Petrobank Energy Resources Ltd.". On September 8, 1986, Articles of Amendment were filed to change the Company's name to "Petrobank Energy and Resources Ltd.". On September 8, 1993, the Company filed Articles of Amendment to delete the private company restrictions thereunder. On March 7, 2000, the Company filed Articles of Amendment to create the first series of Preferred Shares designated as Preferred Shares, Series A and on August 22, 2000 to create the second and third series of Preferred Shares designated as Preferred Shares, Series B and Series C. On January 1, 2002, the Company filed Articles of Amalgamation to amalgamate with its wholly owned subsidiary, Barrington Petroleum Ltd. ("Barrington").

The Company's principal office and registered office is located at Suite 2600, 240 - 4th Avenue S.W., Calgary, Alberta, T2P 4H4.

General Development of the Company

Three-Year History

Effective March 15, 2000, Caribou Capital Corp. invested an aggregate sum of $12,913,500 in the Company in exchange for 8,609,000 Preferred Shares and 19,218,000 share purchase warrants and its personnel assumed senior management positions within the Company.

On January 16, 2001, the Company disposed of its properties in the Alder Flats area of Alberta for net proceeds of $85.1 million.

On April 12, 2001, the Company acquired 97.2% of the outstanding common shares of Barrington for consideration of $0.68 per Barrington common share. The total cash purchase price totalled $52 million.

On April 23, 2001, the Company disposed of its properties in the Blood Magrath area of Alberta for net proceeds of $15.9 million. On July 18, 2001, Petrobank's plan of arrangement with Barrington was made effective whereby Petrobank acquired the remaining 2.8% interest in Barrington for consideration of $0.70 per Barrington common share or $1.3 million. In addition, the former holders of $50 million of Barrington gas linked notes paying interest at 12%, agreed to exchange their notes into $47.5 million of new Petrobank subordinated notes paying 9% interest. Barrington noteholders also subscribed for an additional $13 million of Petrobank subordinated notes.

Through the remainder of 2001, the Company completed a series of non-core area dispositions resulting in proceeds of $60.6 million.

In May 2002, the Company assumed the remaining work commitments on two incremental production (IP) blocks and three exploration blocks in Colombia. At December 31, 2002, the Company's remaining work commitments on these blocks totalled U.S. $46 million. The company commenced commercial production in Colombia in January 2003.

In November 2002, the Company reorganized its management into three business units; Canada, Latin America and Heavy Oil. The Heavy Oil business unit is operating through Petrobank's wholly owned subsidiary, Orion Oil Canada Ltd., which was created to undertake the world's first field pilot of the revolutionary THAI *in situ* heavy oil recovery and upgrading technology.

Trends

There are a number of trends that have been developing in the oil and gas industry that appear to be shaping the near future of the business. The first trend is the consolidation phase that the industry has been going through. This trend has affected companies of all sizes and the trend appears to be continuing.

The second trend that has been developing in the oil and gas industry is the reduced access to equity financing that the industry is currently experiencing. This trend can be partly attributed to the higher relative returns that have been experienced in other sectors of the market, as well as the general negative investor sentiment in the broader market. Many institutional investors who have traditionally invested in junior oil and gas securities have little cash for investment in new issues as a result of heavy unit redemptions in the past six to nine months. During the last two quarters this trend has been correcting somewhat and institutional investors appear to be beginning to refocus on traditional sectors for investment opportunities. Time is required to see if this trend results in additional investment in the junior oil and gas sector.

The third trend that has been developing in the oil and gas industry is the current influence of royalty trusts on the Canadian portion of the oil and gas industry. While American companies dominated the acquisition market in the first three quarters of 2001, royalty trusts recently have been acquiring companies and assets in Canada in order to grow their cash flows and distributions. Some oil and gas production companies have also reorganized themselves into royalty trusts to capture the attractive valuations presently awarded to such trusts by the equity markets. Should the energy royalty trusts continue to be able to access the capital markets on a more favourable basis, this could continue to change the structure of the Canadian oil and gas industry.

The Canadian/U.S. exchange rate also influences commodity prices for Canadian producers as there is a high correlation between Canadian and U.S. oil and natural gas prices. The recent strengthening of the Canadian dollar against the U.S. dollar has resulted in reduced netbacks for Canadian oil and gas producers.

BUSINESS OF THE COMPANY

Petrobank's business strategy is focused on return on shareholders' equity through the continued growth of the Western Canadian asset base combined with the pursuit and execution of higher impact international projects. In Western Canada, the Corporation operates primarily in four focus areas, Southeast Saskatchewan, Western Saskatchewan, Jumpbush Alberta and Northwest Alberta. Internationally, the Corporation has two IP blocks and three exploration blocks in Colombia.

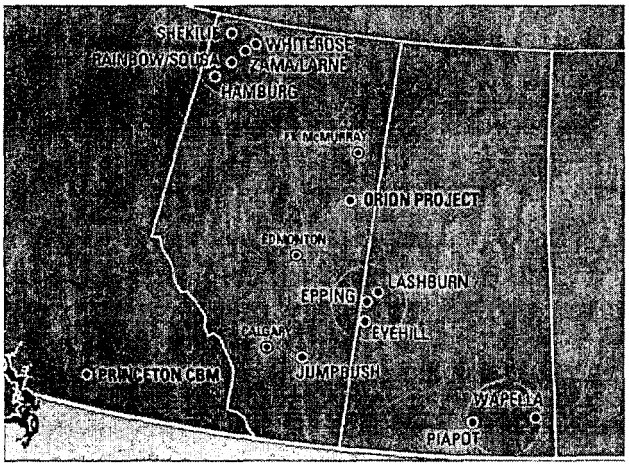
Production

Average daily production by major producing region is summarized as follows:

	Liquids - Bbls		Gas - Mcf		BOE (6:1)	
	2002 Average	Q1 2003	2002 Average	Q1 2003	2002 Average	Q1 2003
Southeast Saskatchewan	1,552	1,498	-	-	1,552	1,498
Northwest Alberta	327	423	10,796	7,309	2,126	1,641
Western Saskatchewan	291	452	-	13	291	454
Jumpbush	64	49	1,124	1,304	252	267
Other	389	335	2,621	2,294	826	717
Total - Canada	2,623	2,757	14,541	10,920	5,047	4,577
Colombia - Orito	-	378	-	-	-	378
Colombia - Neiva	-	317	-	-	-	317
Total - Colombia	-	695	-	-	-	695
Total	2,623	3,452	14,541	10,920	5,047	5,272

Principal Properties

Western Canadian Focus Areas



Southeast Saskatchewan

The 100 percent-owned Wapella property in southeastern Saskatchewan provides Petrobank with a stable base of low operating cost, medium-gravity oil from the Shaunavon and other Jurassic Age formations. Production averaged 1,552 barrels per day in 2002, with operating costs of approximately $5.50 per barrel. Our primary opportunity to add incremental value lies in implementing a waterflood to boost production and add reserves by increasing the overall recovery ratio of the original oil in place.

The waterflood project will require drilling of eight new infill wells plus conversion of five older producers into water injectors. With regulatory approvals pending, Petrobank anticipates the waterflood will may be initiated by the fourth quarter of 2003.

Western Saskatchewan

Petrobank's conventional heavy to medium-gravity crude oil properties in the Alberta-Saskatchewan border region represent classic exploitation and optimization scenarios for adding value at relatively low cost and low risk.

At its Lashburn property, Petrobank increased its working interest from 41 percent to 60 percent in the fourth quarter of 2002 to create a dominant position. Production was 300 barrels per day of 14° API oil net to Petrobank at year-end. Development of Lashburn will be aimed at increasing the recovery factor from the Waseca pool using horizontal wells. A new 3D seismic survey has identified up to six horizontal well locations. This $1.8 million drilling program is to commence as soon as possible after spring break-up. Each successful well is anticipated to deliver incremental production of approximately 100 barrels per day and reserves of approximately 90,000 barrels.

Petrobank's new, 100 percent-owned Sparky play at Eyehill saw nine wells drilled in 2002, of which eight were successful, resulting in combined production of 200 barrels per day of 19° API oil by year-end. An additional six wells have been drilled and cased for Sparky oil in the first quarter for 2003. Results from the latest wells will determine the economic viability of an infill drilling program on 20-acre spacing, followed by installation of an oil battery and initiation of a waterflood scheme in the third quarter of 2003. This project is aimed at increasing production to 800 barrels per day with reserve additions of approximately 800,000 barrels.

Petrobank also has a 100 percent interest in our Epping property where four wells were drilled and cased by mid-April, targeting 18°API Sparky oil. The Company expects to complete these wells and drill an additional three locations by June 2003.

Jumpbush Alberta

Petrobank's Jumpbush play on the Siksika First Nation Reserve in southern Alberta represents an opportunity to add production and reserves of natural gas and oil from an existing under-exploited asset. Jumpbush is being developed in partnership with the Siksika Energy and Resources Company, which owns a 30% working interest. The joint venture owns an under-utilized strategic gas plant in the area, with excess capacity of 11 mmcf/d, creating a decisive competitive advantage. Petrobank's production from Jumpbush at year-end 2002 was 1.2 mmcf/d of natural gas and 60 bbl/d of oil.

Petrobank is planning a $7.5 million, 32-well program at Jumpbush for 2003. The first phase will consist of two Glauconite oil wells (one vertical and one horizontal) and eight shallow (600 metre) Belly River and Medicine Hat natural gas wells. The second phase will have 17 Belly River and Medicine Hat natural gas wells plus, depending on first phase results, up to five additional vertical and horizontal Glauconite oil wells.

The shallow horizons at Jumpbush create a low-deliverability natural gas play, which offers strong economics for a producer that can control costs and achieve a high success rate. Target production rates are approximately 100 mcf/d per successful natural gas well. With 30 additional sections of undeveloped lands, Petrobank has a two-year inventory of development opportunities at Jumpbush, which the Company hopes to augment through further land acquisitions.

Northwest Alberta

Although Petrobank's northern Alberta properties will not experience significant development in 2003, they still offer opportunities to add value at low cost. Production from this area averaged 2,126 boe/d in 2002. At Zama, Petrobank purchased a minority partner's interests and conducted several recompletions and exited 2002 with natural gas production of 5.3 mmcf/d. No new drilling is planned in this area in 2003. At Larne, three shallow natural gas wells were drilled in 2002 to prove reserves on one block. Follow-up development of this shallow play awaits infrastructure development closer to the area. Petrobank plans recompletions in the Slave Point, Sulphur Point and other uphole horizons in 2003 to partially offset natural production declines in the area.

At Shekilie, Petrobank purchased its partner's majority interest, followed by one well recompletion and other surface facility optimizations. This program doubled the Keg River oil volume to 450 bbls/d and added one million barrels of proved reserves at an average finding and development cost of only $5.50 per barrel.

Colombia

Colombia is an oil-rich country with major potential for value-creation through the application of current technologies and exploitation strategies to under-capitalized producing fields. Petrobank has Incremental Production Contracts ("IPCs") in two such fields in southwestern Colombia. Petrobank's strategy is to realize near-term cash flow from these exploitation opportunities by applying North American technical and business models, followed by opportunity-driven exploration as the area's additional geological potential comes into focus. The Colombian government has encouraged foreign participation by making contracts available at very attractive fiscal terms. Each IPC provides that Petrobank will share in a portion (initially 79 percent in the case of the Orito IP block and 69 percent in the case of Neiva) of the incremental production from the field generated by its development activities. Each IPC has an established baseline of production which corresponds to the decline curve predicted by production from the past twenty years. Petrobank's net share is subject to an 8 percent royalty paid to the government.



Orito

Like many reservoirs in the region, the Orito Field in the Putumayo Basin of southwestern Colombia is a world-class reservoir in the latter stages of primary development. With an estimated 1.1 billion barrels of original oil in place, approximately 20 percent of which has been produced to date, Orito offers numerous opportunities to create value through in-fill drilling, field extension, facilities upgrades, secondary recovery and other techniques proven in Canada and elsewhere in the world.

Orito produced an average of 3,600 bbl/d from 41 wells in 2002. The area has extensive field infrastructure, good seismic control and connection to an underutilized export pipeline, enabling immediate fiscalization of any incremental oil production. Historically, Ecopetrol has managed the field without the capital resources needed for a comprehensive program of late-primary exploitation and secondary recovery. Our IPC creates a win-win opportunity, as Petrobank gains access to all existing infrastructure and data, while Ecopetrol participates in any incremental upside Petrobank generates over the life of the contract.

Orito contains three main oil-producing or prospective zones (Pepino, Villeta and Caballos). To significantly enhance current production, we will initially employ a combination of late-stage primary recovery techniques, such as drilling in-fill wells, changing from gas lift to electrical submersible pumps, and re-completing wells to enhance oil inflow. Reperforation and alteration of the lift methodology at one well recently increased

production from 40 barrels per day to over 400 barrels per day. Additionally, Petrobank will drill new wells in under-developed areas of the field. Over the medium term, Petrobank anticipates launching a secondary recovery program involving injecting large volumes of water to increase recovery.

Neiva

The Neiva Field in the upper Magdalena Basin lies approximately 300 kilometres northeast of Orito. Neiva has shallow multi-zone reservoirs facilitating low-risk exploitation drilling. Production in 2002 averaged 3,900 barrels per day from 59 wells, with cumulative production at approximately 25 percent of the estimated 220 million barrels of original oil-in-place. This low-pressure system requires fundamental exploitation techniques to realize additional value. Success will be determined by Petrobank's ability to control capital costs.

Neiva's reservoir consists of sand-shale sequences totaling up to 1,500 feet of gross pay containing natural gas, oil and water. These sands may not be amenable to waterflood because of the multitude of individual sand shale sequences over a massive vertical column. Petrobank's program will include infill drilling, pump and gathering system optimization, and workovers focusing on re-perforation and scale treatment operations. Initial efforts have been focused on the shallower Honda and Doima/Chicoral zones. The deeper Tenay/Caballos zone offers potential for higher-risk, higher-productivity wells. Successful Tenay wells have averaged 1,500 barrels per day of initial production. Three existing Tenay wells have collectively produced more than 8 million barrels of oil to date. The Company has reprocessed and reinterpreted the existing 3D seismic over the field and is evaluating a range of go-forward development options in this zone.

LAND HOLDINGS

The undeveloped land holdings of the Company as at December 31, 2002, are set forth in the following table:

	Undeveloped Acres	
	Gross[1]	Net[2]
Alberta	255,000	211,000
Saskatchewan	270,000	258,000
Other	78,000	59,000
Total Canada	603,000	528,000
Colombia	478,000	328,000

Notes:

(1) "Gross" acres means the total number of acres in which the Company has an interest.

(2) "Net" acres refers to the Company's net working interest in the gross acres.

OIL AND GAS WELLS

The following table summarizes Petrobank's interests as at December 31, 2002 in oil and natural gas wells which are producing or which are considered capable of production. All significant non-producing oil and natural gas wells are within economic distance of transportation facilities.

	Producing Wells				Non-Producing Wells			
	Oil		Natural Gas		Oil		Natural Gas	
	Gross[(1)]	Net[(2)]	Gross[(1)]	Net[(2)]	Gross[(1)]	Net[(2)]	Gross[(1)]	Net[(2)]
Alberta	99	46.5	197	58.5	2	2.0	8	4.8
Saskatchewan	152	88.6	-	-	36	29.6	-	-
Other	12	0.8	-	-	-	-	-	-
Canada	263	135.9	197	58.5	38	31.6	8	4.8
Orito	42	33.2	-	-	60	47.4	-	-
Neiva	59	40.7	-	-	13	9.0	-	-
Colombia	101	73.9	-	-	73	56.4	-	-
Total	364	209.8	197	58.5	111	88.0	8	4.8

Notes:

(1) "Gross" wells refers to all wells in which Petrobank owns a working interest.

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

OIL AND GAS RESERVES

GLJ has prepared the GLJ Report evaluating the proved and probable additional crude oil, NGL and natural gas reserves of Petrobank's properties, both in Canada and Colombia, as of January 1, 2003. In preparing its report, GLJ obtained basic information from Petrobank, which included land data, well information, geological information, reservoir studies, estimates of on-stream dates, contract information, current hydrocarbon product prices, operating cost data, capital budget forecasts, financial data and future operating plans. Other engineering, geological or economic data required by GLJ was obtained from public records, other operators and from GLJ's non-confidential files. GLJ did not independently verify the factual information that Petrobank provided to it or that it obtained from other sources. GLJ did not conduct a field inspection.

The following tables, based on the GLJ Report, show the estimated share as at the dates indicated of Petrobank's crude oil, natural gas and NGL reserves and the present value of estimated future cash flow for these reserves using escalated and constant prices and costs as indicated. **The present worth of estimated future cash flow is stated after provisions for estimated future capital expenditures and before provisions for future abandonment costs and provision for income taxes. The present worth of estimated future cash flow for Petrobank's Colombia properties is presented in US $.**

CRUDE OIL AND NATURAL GAS RESERVES AND PRESENT WORTH OF ESTIMATED FUTURE CASH FLOW

Canada

Escalated Dollar Economics

Reserve Category	Remaining Reserves						Present Value of Future Cash Flow Before Income Taxes Discounted at Rates of			
	Crude Oil		Natural Gas		NGLs					
	Gross	Net	Gross	Net	Gross	Net	0%	10%	15%	20%
	mstb	mstb	Mmcf	mmcf	mstb	mstb	M$	M$	M$	M$
Proved Developed										
Producing	4,653	3,977	16,390	12,775	167	119	106,767	75,758	67,419	61,147
Non-Producing	4	4	3,562	2,673	32	21	8,483	5,666	4,811	4,166
Proved Undeveloped	1,628	1,466	962	832	2	2	14,825	8,050	5,995	4,449
Total Proved	6,285	5,448	20,914	16,280	202	142	130,075	89,475	78,225	69,763
Probable Additional	4,906	4,308	14,713	11,573	83	58	94,144	47,363	36,640	29,347
Total Before Risk	11,191	9,756	35,627	27,853	285	200	224,219	136,837	114,865	99,110
Reduction Due to Risk	(2,453)	(2,154)	(7,357)	(5,786)	(41)	(29)	(47,072)	(23,681)	(18,320)	(14,674)
Total After Risk	8,738	7,602	28,270	22,067	244	171	177,147	113,156	96,545	84,436

Constant Dollar Economics

Reserve Category	Remaining Reserves						Present Value of Future Cash Flow Before Income Taxes Discounted at Rates of			
	Crude Oil		Natural Gas		NGLs					
	Gross	Net	Gross	Net	Gross	Net	0%	10%	15%	20%
	mstb	mstb	Mmcf	mmcf	mstb	mstb	M$	M$	M$	M$
Proved Developed										
Producing	4,898	4,136	16,727	13,056	171	121	170,556	117,880	103,539	92,856
Non-Producing	4	4	3,490	2,634	32	20	11,949	7,914	6,695	5,780
Proved Undeveloped	1,664	1,480	980	841	2	2	35,643	21,693	17,490	14,328
Total Proved	6,566	5,620	21,197	16,531	205	143	218,148	147,487	127,724	112,964
Probable Additional	5,064	4,349	15,115	11,866	84	58	164,530	82,286	63,909	51,550
Total Before Risk	11,630	9,969	36,312	28,397	289	201	382,678	229,773	191,633	164,514
Reduction Due to Risk	(2,532)	(2,174)	(7,557)	(5,933)	(42)	(29)	(82,265)	(41,143)	(31,954)	(25,775)
Total After Risk	9,098	7,795	28,755	22,464	247	172	300,413	188,630	159,679	138,739

Colombia

Escalated Dollar Economics

Reserve Category	Remaining Reserves Crude Oil Gross	Remaining Reserves Crude Oil Net	Present Value of Future Cash Flow Before Income Taxes Discounted at Rates of 0%	10%	15%	20%
	mstb	mstb	M$	M$	M$	M$
Proved Developed Producing	119	113	1,746	1,619	1,564	1,513
Non-Producing	-	-	-	-	-	-
Proved Undeveloped	4,501	4,272	40,333	29,911	26,182	23,124
Total Proved	4,620	4,385	42,079	31,530	27,746	24,637
Probable Additional	3,710	3,521	36,453	20,725	16,337	13,182
Total Before Risk	8,330	7,906	78,532	52,255	44,083	37,819
Reduction Due to Risk	(1,855)	(1,761)	(18,227)	(10,363)	(8,168)	(6,591)
Total After Risk	6,475	6,146	60,306	41,892	35,914	31,228

Constant Dollar Economics

Reserve Category	Remaining Reserves Crude Oil Gross	Remaining Reserves Crude Oil Net	Present Value of Future Cash Flow Before Income Taxes Discounted at Rates of 0%	10%	15%	20%
	stb	stb	M$	M$	M$	M$
Proved Developed Producing	119	113	2,550	2,346	2,258	2,178
Non-Producing	-	-	-	-	-	-
Proved Undeveloped	3,921	3,722	65,825	50,987	45,587	41,110
Total Proved	4,040	3,835	68,376	53,333	47,845	43,288
Probable Additional	3,837	3,641	73,567	42,083	33,343	27,089
Total Before Risk	7,877	7,476	141,942	95,416	81,188	70,377
Reduction Due to Risk	(1,919)	(1,821)	(36,784)	(21,042)	(16,672)	(13,544)
Total After Risk	5,959	5,656	105,159	74,374	64,516	56,833

Notes:

(1) **"Gross"** reserves are defined as those accruing to the Company before deduction of all royalties and interests owned by others.

"Net" reserves are defined as those accruing to the Company after deduction of all royalties and interests owned by others.

(2) Probable additional cash flows presented in the GLJ Report are prepared at full value assuming that the quantities and values of the forecast production are unrisked. For the purpose of these tables, a risk factor of 50% has been applied to the probable additional reserves and cash flows to determine the "Total After Risk" estimates.

(3) **"Proved Reserves"** are those reserves estimated as recoverable under current technology and anticipated economic conditions for the escalated dollar economics and existing economic conditions for the constant dollar economics, from that portion of a reservoir which can be reasonably evaluated as economically productive on the basis of analysis of drilling, geological, geophysical and engineering data, including the reserves to be obtained by enhanced recovery processes demonstrated to be economical and technically successful in the subject reservoir.

(a) **"Proved Developed Producing Reserves"** are those developed reserves that are actually on production or, if not producing, that could be recovered from existing wells or facilities and where the reason for the current non-producing status is the choice of the owner rather than the lack of markets or some other reason. An illustration of such a situation is where a well or zone is capable or production but is shut in because its deliverability is not required to meet contract commitments.

(b) **"Proved Developed Non-Producing Reserves"** are those developed reserves that are not currently producing due to lack of facilities and/or markets.

(c) **"Proved Undeveloped Reserves"** are proved reserves which are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreages are limited to those drilling units offsetting productive units, which are reasonably certain of production when drilled.

(4) **"Probable Additional Reserves"** are those reserves where the analysis of drilling, geological, geophysical and engineering data does not demonstrate to be proved under current technology and anticipated economic conditions for the escalated dollar economics and existing economic conditions for the constant dollar economics, but where such analysis suggests the likelihood of their existence and future recovery. Probable additional reserves to be obtained by the application of enhanced recovery processes will be the increased recovery over and above that estimated in the proved category which can be realistically estimated for the pool on the basis of enhanced recovery processes which can be reasonably expected to be instituted in the future.

(5) Price Forecast

GILBERT LAUSTSEN JUNG ASSOCIATES LTD. PRICE FORECAST
EFFECTIVE DATE JANUARY 1, 2003

Natural Gas Prices

YEAR	AECO-C Spot (Cdn$/mmbtu)
2003	5.65
2004	5.00
2005	4.70
2006	4.85
2007	4.85
2008	4.85
2009	4.85
2010	4.90
2011	4.95
2012	5.05
2013	5.10

After 2013 prices were increased 1.5 percent per year.

Oil Prices

YEAR	WTI @ Cushing	Edmonton – 40 API	Cromer – 29 API	Bow River at Hardisty
2003	25.50	38.50	33.00	29.50
2004	22.00	32.50	29.00	25.50
2005	21.00	30.50	27.00	24.50
2006	21.00	30.50	27.50	25.00
2007	21.25	30.50	27.50	25.00
2008	21.75	31.00	28.00	25.50
2009	22.00	31.50	28.50	26.00
2010	22.25	32.00	29.00	26.50
2011	22.50	32.50	29.50	27.00
2012	23.00	33.00	30.00	27.50
2013	23.25	33.50	30.50	28.00

After 2013, prices were increased 1.5 percent per year.

(6) Product prices in the constant price evaluations are based on actual prices received for oil, natural gas liquids and natural gas at December 31, 2002.

The constant price assumptions assume the continuance of current laws, regulations and operating costs in effect on the effective date of the GLJ Report. In addition, operating and capital costs have not been increased on an inflationary basis.

(7) ARTC varies from a maximum of 75% of $2.0 million when the oil price is below US $15 per barrel to a minimum of 25% of $2.0 million when the oil price is above US$30 per barrel. For the cash flow projection, the ARTC program was assumed to stay in place for a period of 10 years.

(8) GLJ estimates the total capital costs net to Petrobank to achieve the estimated future net proved and probable production revenues set out in the GLJ Report, based on escalating cost assumptions, to be $22.6 million (discounted at 10%) for Canada and US $27.3 million (discounted at 10%) for Colombia.

GLJ estimates the total capital costs net to Petrobank to achieve the estimated future net proved and probable production revenues set out in the GLJ Report, based on constant cost assumptions, to be $22.5 million (discounted at 10%) for Canada and US $27.0 million (discounted at 10%) for Colombia.

(9) Cash flow is income derived from the sale of net reserves, less all capital costs, production taxes, and operating costs and before provision for future abandonment costs, income taxes and administrative overhead costs.

RECONCILIATION OF RESERVES

A reconciliation of the Company's Canadian oil and natural gas reserves for the two-year period ended December 31, 2002 is set out below. All Colombian reserves as at December 31, 2002 were added during 2002.

CANADA

	Gross				
Crude Oil (Mbbls)	Proved Producing	Proved Non-Producing	Total Proved	Risked Probable	Total Established
January 1, 2001	-	-	-	-	-
Discoveries	344	-	344	63	407
Acquisitions	4,658	795	5,453	1,116	6,569
Dispositions	1,397	(434)	963	(177)	786
Revisions of prior estimates	(1,527)	(54)	(1,581)	(150)	(1,731)
Production	(833)	-	(833)	-	(833)
January 1, 2002	4,039	307	4,346	852	5,198
Discoveries	440	1,368	1,808	1,322	3,130
Acquisitions	777	115	892	356	1,248
Dispositions	(23)	-	(23)	(18)	(41)
Revisions of prior estimates	273	(157)	115	(59)	56
Production	(853)	-	(853)	-	(853)
January 1, 2003	4,653	1,632	6,285	2,453	8,738

Natural Gas (Bcf)	Gross				
	Proved Producing	Proved Non-Producing	Total Proved	Risked Probable	Total Established
January 1, 2001	0.3	1.4	1.7	0.6	2.2
Discoveries	2.3	0.3	2.7	0.1	2.8
Acquisitions	27.8	28.5	56.2	11.9	68.2
Dispositions	6.1	(4.5)	1.6	(4.1)	(2.5)
Revisions of prior estimates	(12.0)	(21.1)	(33.1)	(2.0)	(35.1)
Production	(4.0)	-	(4.0)	-	(4.0)
January 1, 2002	20.4	4.6	25.0	6.5	31.5
Discoveries	1.6	1.7	3.3	2.2	5.5
Acquisitions	0.7	0.2	0.9	0.4	1.3
Dispositions	(0.6)	(0.6)	(1.2)	(0.2)	(1.4)
Revisions of prior estimates	(0.4)	(1.4)	(1.8)	(1.5)	(3.3)
Production	(5.3)	-	(5.3)	-	(5.3)
January 1, 2003	16.4	4.5	20.9	7.4	28.3

NGL's (Mbbls)	Gross				
	Proved Producing	Proved Non-Producing	Total Proved	Risked Probable	Total Established
January 1, 2001	-	1	1	-	1
Discoveries	165	2	167	1	168
Acquisitions	477	611	1,088	144	1,232
Dispositions	29	(91)	(62)	(41)	(103)
Revisions of prior estimates	(355)	(466)	(821)	(66)	(887)
Production	(72)	-	(72)	-	(72)
January 1, 2002	244	57	301	38	339
Discoveries	18	(2)	16	3	19
Acquisitions	8	14	22	8	30
Dispositions	-	-	-	-	-
Revisions of prior estimates	1	(34)	(33)	(7)	(40)
Production	(104)	-	(104)	-	(104)
January 1, 2003	167	35	202	42	244

DRILLING ACTIVITY

The following table summarizes the Company's drilling results for the years ended December 31, 2002 and 2001.

	Year ended December 31,			
	2002		2001	
	Gross[1]	Net[2]	Gross[1]	Net[2]
Oil				
Canada	18	14.6	16	12.4
Colombia	2	1.6	-	-
Natural Gas	7	6.0	10	6.5
Dry & Abandoned	13	13.0	3	3.0
Total	40	35.2	29	21.9

Notes:

(1) "Gross" wells refers to all wells in which the Company has either a working interest or a royalty interest.

(2) "Net" wells refers to the aggregate of the percentage working interests of the Company in the gross wells, and, in some cases, subject to adjustment after payout.

HISTORY

The following table shows the Company's average working interest production volumes before deduction of royalties payable to others, average netbacks received and oil and gas capital expenditures incurred for each of the last eight fiscal quarters and the years then ended:

	Three Months Ended				
	Mar 31, 2002	June 30, 2002	Sept 30, 2002	Dec 31, 2002	2002
Production					
Oil and Natural Gas Liquids (bbl/d)	2,704	2,541	2,596	2,652	2,623
Gas (mcf/d)	17,323	16,546	13,134	11,244	14,541
Total (boe/d)	5,591	5,299	4,785	4,526	5,047

	Three Months Ended				
	Mar 31, 2001	June 30, 2001	Sept 30, 2001	Dec 31, 2001	2001
Production					
Oil and Natural Gas Liquids (bbl/d)	271	3,297	2,978	3,322	2,480
Gas (mcf/d)	5,583	16,198	9,143	12,730	11,047
Total (boe/d)	1,202	5,997	4,502	5,444	4,321

Crude Oil and NGL Netback ($ per bbl)

	Three Months Ended				
	Mar 31, 2002	June 30, 2002	Sept 30, 2002	Dec 31, 2002	2002
Sales revenue [1]	29.48	30.98	32.74	31.27	31.11
Royalties [2]	5.34	6.82	7.39	7.20	6.68
Operating costs [3]	5.73	5.51	6.24	7.32	6.21
Netback	18.41	18.65	19.11	16.75	18.22

	Three Months Ended				
	Mar 31, 2001	June 30, 2001	Sept 30, 2001	Dec 31, 2001	2001
Sales revenue [1]	36.66	32.05	32.18	19.96	28.09
Royalties [2]	5.62	5.66	5.85	2.94	4.79
Operating costs [3]	5.11	8.22	6.81	5.58	6.81
Netback	25.93	18.17	19.52	11.44	16.49

Natural Gas Netbacks ($ per mcf)

	Three Months Ended				
	Mar 31, 2002	June 30, 2002	Sept 30, 2002	Dec 31, 2002	2002
Sales revenue [1]	3.21	3.99	3.63	5.09	3.89
Royalties [2]	0.70	0.88	0.71	1.03	0.82
Operating costs [3]	1.14	1.15	1.15	1.40	1.20
Netback	1.37	1.96	1.77	2.66	1.87

	Three Months Ended				
	Mar 31, 2001	June 30, 2001	Sept 30, 2001	Dec 31, 2001	2001
Sales revenue [1]	8.95	6.11	4.63	2.81	5.13
Royalties [2]	1.91	0.79	0.90	0.56	0.88
Operating costs [3]	0.51	1.18	0.92	1.19	1.03
Netback	6.53	4.14	2.81	1.06	3.22

Notes:

(1) After reduction for hedging costs.

(2) After inclusion of ARTC.

(3) Operating costs are expenses incurred in the operation of producing properties and include items such as field staff salaries, power, fuel, chemicals, repairs and maintenance, property taxes, processing and treating fees, overhead fees and other costs.

Oil and Gas Capital Expenditures ($000's)

	Three Months Ended				
	Mar 31, 2002	June 30, 2002	Sept 30, 2002	Dec 31, 2002	2002
Land	214	2,345	379	2,904	5,842
Seismic	(269)	(27)	549	516	769
Drill and complete	5,507	1,845	2,419	19,118	28,889
Facilities and equipment	585	391	314	365	1,655
Property acquisitions	-	-	1,336	4,791	6,127
Other	876	328	816	926	2,946
	6,913	4,882	5,813	28,620	46,228

Capital expenditures in 2002 include $15.6 million of expenditures in Colombia, which are detailed on page 37 of the Annual Report which information is incorporated herein by reference.

	Three Months Ended				
	Mar 31, 2001	June 30, 2001	Sept 30, 2001	Dec 31, 2001	2001
Land	640	2,191	1,049	1,835	5,715
Seismic	39	29	49	2,117	2,234
Drill and complete	186	4,962	1,886	2,329	9,363
Facilities and equipment	364	1,848	1,175	312	3,699
Other	138	188	260	262	848
	1,367	9,218	4,419	6,855	21,859

FUTURE COMMITMENTS

At December 31, 2002, the Company had in place contracts for the following:

Product	Period	Volume	Fixed Price	Index
Crude Oil	Calendar 2003	1,000 bbl/day	US $22.70	WTI
	Calendar 2003	500 bbl/day	US $25.90	WTI
	Calendar 2004	1,000 bbl/day	US $24.00	WTI

The Company is committed to deliver 2,225 GJ per day of natural gas under an escalating price contract that expires October 31, 2012. The wellhead price under this contract, at December 31, 2002, was set at $3.14 per GJ. The contract provides for an annual price escalation between 4 percent and 10 percent, based on hydroelectric and natural gas price inflation. Broader price redeterminations are to be made in 2007 and 2012, resulting in a new price that can vary from 65 percent to 135 percent of the previous year's price based on prevailing natural gas prices.

The Company is also committed to natural gas deliveries of 5,275 GJ per day at the Malin, Oregon delivery point until October 31, 2005. In connection with this commitment, the Company holds an equivalent amount of firm transportation service on the ANG and PGT pipeline systems at a cost of $0.52 per GJ. The Company receives the market price at the delivery point, less the relevant transportation charges.

See Note 15 to Financial Statements on pages 59 and 60 of the Annual Report which information is incorporated herein by reference.

EXPLORATION AND DEVELOPMENT

Exploration and development plans are discussed under the headings "Principal Properties" on pages 4 through 7 and "Management Discussion and Analysis" on pages 28 through 40 of the Annual Report which information is incorporated herein by reference. Petrobank's current capital budget contemplates spending $40 million in Canada and US $45 million in Colombia in 2003.

DIRECTORS AND OFFICERS OF PETROBANK

The name, municipality of residence, position and principal occupation of each of the directors and senior officers of Petrobank are as follows:

Name and Municipality of Residence	Positions Held	Principal Occupation During Last Five Years
Kevin L. Adair Calgary, Alberta, Canada	Vice President Latin America	Vice President of Latin America since November 2002. Vice President Business Development and Marketing of the Company from March 2000 to October 2002; President and Chief Operating Officer of the Company from April 1998 to March 2000; Executive Vice-President and Chief Operating Officer of the Company from December 1997 to March 1998.
Chris J. Bloomer Calgary, Alberta, Canada	Vice President Heavy Oil	Vice President Heavy Oil since January 2003, Managing Director of Korn/Ferry International (Calgary) from May 1999 to December 2002, President and Chief Operating Officer of Canadian TALON Resources, Ltd. from August 1997 to May 1999.
John A. Brussa [(1)/(3)] Calgary, Alberta, Canada	Director	Director of the Company since March 2000; Barrister and Solicitor; Partner of Burnet, Duckworth & Palmer LLP since 1987. Director of several public companies.
M. Bruce Chernoff [(1)/(2)/(3)] Calgary, Alberta, Canada	Director	Director of the Company since March 2000; President and Director of Caribou Capital Corp. ("Caribou"), a private investment company, since June 1999; Chairman of Harvest Energy Corp. since July 2002; Executive Vice-President and Chief Financial Officer of the Company from March 2000 to October 2001; Executive Vice-President and Chief Financial Officer of Pacalta Resources Ltd. from February 1999 to May 1999; Executive Vice-President of Pacalta from March 1997 to January 1999. Director of several public companies.
Louis L. Frank North Woodstock, New Hampshire, U.S.A.	Director	Director of the Company since September 1993; Independent Consultant; Director and founder of Loon Mountain Recreation Corp.; President of Recco Inc., a private oil and gas development and real estate development company.

Name and Municipality of Residence	Positions Held	Principal Occupation During Last Five Years
Garry Hides Calgary, Alberta, Canada	Vice President Land	Vice President Land of Petrobank since October 2001; Manager Land of the Company from November 1997 to September 2001.
Rene Laprade Calgary, Alberta, Canada	Vice President Operations	Vice President Operations of the Company since October 2001; Manager Operations of Barrington from May 2001 to September 2001; Independent Consultant from May 2000 to May 2001, Vice President Operations of Petrorep Resources from June 1995 to May 2000.
Ken C. McCagherty Calgary, Alberta, Canada	Director	President of West Energy Limited Ltd. (a private oil and gas company) since January 2003. Director of the Company since October 2001. Senior Vice President and Chief Operating Officer of the Company from October 2001 to November 2002; Vice-President and Chief Operating Officer of the Company from March 2000 to October 2001. Vice-President and Director of Caribou from June 1999 to December 2001; Director, Special Projects of Pacalta Resources Ltd. from October 1998 to May 1999; Engineering Consultant from October 1997 to September 1998.
Kenneth R. McKinnon Calgary, Alberta, Canada	Corporate Secretary and Director	Director of the Company since March 2000 and Corporate Secretary of the Company since November 1997; Chief Corporate Affairs Officer and General Counsel of Critical Mass Inc. since September 2000; Vice President, Finance and Chief Financial Officer of the Company from November 1997 to March 2000.
Jerald L. Oaks [(1)/(2)] Englewood, Colorado, U.S.A.	Director	Director of the Company since September 1993; Professional Engineer, President of Oaks Resources Management Inc. since June 1986.
David J. Rain Calgary, Alberta, Canada	Vice President Finance and Chief Financial Officer	Vice President Finance and CFO of the Company since October 2001; Director, Corporate Finance of the Company from March 2000 to October 2001. Vice President, Finance and CFO of Caribou since June 1999; Treasurer and Corporate Controller of Pacalta Resources Ltd. from May 1997 to May 1999.
Doreen Scheidt Calgary, Alberta, Canada	Corporate Controller	Corporate Controller of the Company since December 2001; Manager, Operations Accounting of Northstar Energy Company, formerly Morrison Petroleums Ltd., from November 1994 to November 2001.

Name and Municipality of Residence	Positions Held	Principal Occupation During Last Five Years
R. Gregg Smith Calgary, Alberta, Canada	Vice President Canada	Vice President Canada since March 2003, various positions at Hunt Oil Company of Canada Ltd. including Exploration Manager, Senior Geophysicist and Exploration Team Leader from July 2000 to August 2002, Senior Geophysicist of Newport Petroleum Ltd. from July 1998 to July 2000, Senior Geophysicist of Pinnacle Resources Ltd. from August 1997 to July 1998.
James D. Tocher [(2)/(3)] Calgary, Alberta, Canada	Chairman of the Board	Chairman of the Board of the Company since September 1993; Chief Executive Officer from September 1993 to March 2000; Chairman of the Board of VX Optronics Corp., (a private technology company), since March 1989.
John D. Wright Calgary, Alberta, Canada	President, Chief Executive Officer and Director	President, Chief Executive Officer and Director of the Company since March 2000; General Manager of Ecuadorian Operations of Alberta Energy Company from May 1999 to December 1999; President and CEO of Pacalta Resources Ltd. from May 1996 to May 1999. Director of two other public companies.

Notes:

(1) Member of the Audit Committee

(2) Member of the Reserves Committee

(3) Member of the Compensation Committee

The term of office of each director expires at the next annual meeting of shareholders.

As at April 21, 2003, the directors and senior officers of Petrobank, as a group, beneficially owned, directly or indirectly, 13,518,435 Common Shares constituting approximately 29.7% of the issued and outstanding Common Shares.

PERSONNEL

As at December 31, 2002, Petrobank had 37 employees in Canada and 19 in Colombia.

DIVIDEND RECORD

Petrobank has not declared or paid any dividends on its Common Shares since its incorporation, and does not foresee the declaration or payment of any dividends on the Common Shares in the near future. Any decision to pay dividends on the Common Shares will be made by the board of directors on the basis of Petrobank's earnings, financial requirements and other conditions existing at such future time. Pursuant to the terms of the loan agreement with its current banker, the Company cannot declare or pay dividends on its Common Shares without obtaining the bank's consent.

MARKET FOR SECURITIES

The Company's outstanding Common Shares and Subordinated Notes are listed and posted for trading on the TSX under the trading symbols "PBG" and "PBG.N", respectively.

MANAGEMENT'S DISCUSSION AND ANALYSIS

Reference is made to the information under the headings "Management's Discussion and Analysis" contained on pages 28 through 40 and "Quarterly Summary" contained on pages 62 and 63 of Petrobank's Annual Report for the year ended December 31, 2002, which information is incorporated herein by reference.

SELECTED FINANCIAL INFORMATION

The following table sets forth selected financial information of the Company for the three years ended December 31, 2002. Amounts are expressed in thousands of dollars, except for share amounts.

	Year Ended December 31		
	2002	2001	2000
Oil and natural gas revenue	50,458	46,117	46,392
Cash flow from operations [1]	22,806	18,549	25,281
Per share – basic $ [2]	0.45	0.46	0.74
Per share – diluted $	0.40	0.39	0.62
Net income	6,191	5,283	9,826
Net income (loss) attributable to common shareholders	(430)	431	9,218
Per share – basic $	(0.01)	0.01	0.27
Per share – diluted $	(0.01)	0.01	0.23
Capital expenditures	46,228	21,859	34,921
Working capital (deficiency)	(5,151)	25,410	(2,523)
Net debt [3]	62,495	31,266	22,868
Total assets	150,618	146,337	112,410

Notes:

(1) Calculated based on cash flow from operations before changes in other non-cash items.

(2) Calculated based on cash flow from operations before changes in other non-cash items less preferred share dividends and interest paid on subordinated notes and adding back $1.5 million of non-recurring well control costs in 2001.

(3) Includes working capital, long-term debt, and subordinated notes that are reflected as equity on the balance sheet.

INDUSTRY CONDITIONS

Regulation

The oil and natural gas industry in Canada is subject to extensive controls and regulations imposed by various levels of government. Petrobank does not expect that any of these controls or regulations will affect its operations in a manner materially different than they would affect other oil and gas companies of similar size.

Crude oil and natural gas located in Alberta, Saskatchewan and British Columbia are owned predominantly by the respective provincial governments. Provincial governments grant rights to explore for and produce oil and natural gas under leases, licenses and permits with terms generally varying from two years to five years and on conditions contained in provincial legislation. Leases, licenses and permits may be continued indefinitely by producing under the lease, license or permit. Some of the oil and natural gas located in these provinces is privately owned and rights to explore for and produce oil and natural gas are granted by the mineral owners on negotiated terms and conditions.

In Canada, producers of oil negotiate sales contracts directly with oil purchasers, with the result that the market determines the price of oil. The price depends in part on oil quality, prices of competing fuels, distance to market and the value of refined products. Oil exports may be made under export contracts having terms not exceeding one year in the case of oil other than heavy oil, and not exceeding two years in the case of heavy oil, so long as an order approving any such export has been obtained from the National Energy Board. Any oil export to be made pursuant to a contract of longer duration requires an exporter to obtain an export license from the National Energy Board and the issue of a license requires the approval of the Canadian federal government. The term of the license may not exceed 25 years.

In Canada, the price of natural gas sold in interprovincial and international trade is determined by negotiation between buyers and sellers. Natural gas exported from Canada is subject to regulation by the Government of Canada through the National Energy Board. Producers and exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts must continue to meet criteria prescribed by the National Energy Board. Natural gas exports for a term of two years or less, or for 2 to 20 years in quantities not more than 1.1 million cubic feet per day may be made under a National Energy Board order, or, in the case of exports for a longer duration or larger volumes, under a National Energy Board license and Canadian federal government approval.

The provincial governments of Alberta, British Columbia and Saskatchewan also regulate the removal of natural gas from those provinces for consumption elsewhere. They do so based on such factors as reserve availability, transportation arrangements and market considerations.

In addition to federal regulations, each province has legislation and regulations which govern land tenure, royalties, production rates, environmental protection and other matters. The royalty regime is a significant factor in the profitability of oil and natural gas production. Royalties payable on production from lands other than government lands are determined by negotiations between the mineral owner and the lessee. Royalties on government land are determined by government regulation and are generally calculated as a percentage of the value of gross production, and the rate of royalties payable generally depends upon prescribed reference prices, well productivity, geographical location, field discovery date and the type or quality of the petroleum product produced.

From time to time the governments of Canada, Alberta, British Columbia and Saskatchewan have established incentive programs which have included royalty rate deduction and tax credits for the purpose of encouraging oil and natural gas exploration or enhanced recovery projects.

In Alberta, a producer of oil or natural gas is entitled to a credit against the royalties payable to the government by virtue of the ARTC program. The ARTC program is based on a price sensitive formula, and ranges between 75%, for prices for oil at or below $100 per cubic meter ($15.90 per barrel), to 25%, for prices above $210 per cubic meter ($33.39 per barrel). In general, the ARTC rate is applied to a maximum of $2,000,000 of government royalties payable for each producer or associated group of producers. Government royalties on production from producing properties acquired from companies claiming maximum entitlement to ARTC will generally not be eligible for ARTC. The rate is established quarterly based on the average "par price", as determined by the Alberta Department of Energy for the previous quarterly period.

The North American Free Trade Agreement among the governments of Canada, the United States and Mexico became effective on January 1, 1994. NAFTA carries forward most of the material energy terms that are contained in the Canada-US Free Trade Agreement. Subject to the General Agreement on Tariffs and Trade, Canada continues to remain free to determine whether exports of energy resources to the United States or Mexico will be allowed, so long as any export restrictions do not:

- reduce the proportion of energy resources exported relative to total supply (based upon the proportion prevailing in the most recent 36 month period or another representative period agreed upon by the parties);
- impose an export price higher than the domestic price (subject to an exception that applies to some measures that only restrict the value of exports); or
- disrupt normal channels of supply.

All three countries are prohibited from imposing minimum or maximum export or import price requirements, with some limited exceptions.

Environmental

The oil and natural gas industry is governed by environmental regulation under Canadian federal and provincial laws, rules and regulations, which restrict and prohibit the release or emission and regulate the storage and transportation of various substances produced or utilized in association with oil and gas industry operations. In addition, applicable environmental laws require that well and facility sites be abandoned and reclaimed, to the satisfaction of provincial authorities, in order to prevent pollution from former operations. Also, environmental laws may impose upon "responsible persons" remediation obligations on property designated as a contaminated site. Responsible persons include persons responsible for the substance causing the contamination, persons who caused the release of the substance and any present or past owner, tenant or other person in possession of the site. A breach of environmental laws may result in the imposition of fines and penalties, in addition to the costs of abandonment and reclamation.

All applicable environmental laws are consolidated in the *Environmental Protection and Enhancement Act.* Under this Act, environmental standards and requirements that apply to compliance, cleanup and reporting are stricter. Also, the range of enforcement actions available and the severity of penalties have been significantly increased. These changes will have an incremental increase in the cost of conducting oil and natural gas operations in Alberta.

Petrobank is committed to meeting its responsibilities to protect the environment wherever it operates and anticipates making increased, although not material, expenditures of both a capital and expense nature as a result of the increasingly stringent laws relating to the protection of the environment. Petrobank believes that it is in material compliance with environmental laws and regulations applicable as at the date hereof.

In December 2002 the Government of Canada ratified the Kyoto Protocol. This protocol calls for Canada to reduce its greenhouse gas emissions to 6 percent below 1990 levels during the period between 2008 and 2012. The protocol will only become legally binding when it is ratified by at least 55 countries, covering at least 55 percent of the emissions addressed by the protocol. If the protocol becomes legally binding, it is expected to affect the operation of all industries in Canada, including the oil and gas industry. As details of the implementation of this protocol have yet to be announced, the effect on Petrobank cannot be determined at this time.

Colombia

The Company is the owner of interests in, and is engaged in the exploration for, and development and production of oil from two incremental production contracts (Orito and Neiva) and three exploration contracts granted by Empresa Colombiana de Petroleos ("Ecopetrol"), the Colombian national oil company. Each concession is governed by a separate contract with Ecopetrol. Generally, the contracts cover a specific period and require

certain expenditures in the early years of the contract in order to advance to subsequent development phases. The Company's current activities are currently focused on its incremental production contracts which provide that the Company is permitted to carry out development activities on the blocks and share in incremental production generated above a predefined baseline. The Company's initial participation levels at Orito and Neiva are 79% and 69%, respectively. These participation levels decline on a contract by contract basis once the ratio of cumulative total revenues to total costs (R factor) exceeds 1.5 times. At R factors above 2.5 times the participation levels at Orito and Neiva are fixed at 39.5% and 34.5%, respectively.

Royalties are calculated on a field-by-field basis using a sliding scale that ranges from 8% (for production up to 5,000 barrels per day) up to a maximum of 25% (for production above 600,000 barrels per day).

The Company's oil production is currently being sold pursuant to a sales contract with Ecopetrol whereby the price paid, adjusted for quality differences, for each barrel of oil sold is determined based on the monthly average of WTI less a variable differential as follows:

Average WTI (US$/bbl)	Differential (US$/bbl)	
	Orito	Neiva
$15 or less	$3.60	$6.30
$15.01 to $20.00	$4.10	$7.30
$20.01 to $25.00	$4.60	$8.30
$25.01 to $30.00	$5.60	$8.80
Over $30	$6.60	$9.30

The Company or Ecopetrol may cancel this sales contract on one month's notice after which, the Company may elect to export its oil production directly.

Development plans are submitted to Ecopetrol for approval for all exploration and development activities conducted on the Company's Colombian properties. In addition, the Company files an environmental management plan (PMA) covering the contemplated activities with the Ministry of the Environment. PMA's are submitted to demonstrate compliance with applicable Colombian law but advance approval is not required to commence activities within existing development areas (Orito and Neiva). In exploration areas an approved PMA is required before work commences.

The Company's pretax income from Colombian sources, as defined under Colombian law, is subject to Colombian income taxes at a statutory rate of 38.5%, although a "presumptive" minimum income tax based on net assets, may apply in years of little or no net income which may be recovered against future cash taxes otherwise payable. The Company's income after Colombian income taxes is subject to a Colombian remittance tax that accrues at a rate of 7%, which may be eliminated under certain circumstances if the Company reinvests such income in Colombia.

RISK FACTORS

An investment in Petrobank may be considered speculative due to the nature of the Company's involvement in the exploration for, and the acquisition, development, production and marketing of, oil and natural gas and its current stage of development. Oil and gas operations involve many risks which even a combination of experience and knowledge and careful evaluation may not be able to overcome. There is no assurance that further commercial quantities of oil and natural gas will be discovered or acquired by the Company.

The oil and natural gas industry is intensely competitive. Competition is particularly intense in the acquisition of prospective oil and natural gas properties and oil and gas reserves. Petrobank's competitive position depends on its geological, geophysical and engineering expertise, its financial resources, its ability to develop its properties and its ability to select, acquire and develop proved reserves. Petrobank competes with a substantial number of other companies having larger technical staffs and greater financial and operational resources. Many such companies not only engage in the acquisition, exploration, development and production of oil and natural gas reserves, but also carry on refining operations and market refined products. Petrobank also competes with major and independent oil and natural gas companies and other industries supplying energy and fuel in the marketing and sale

of oil and natural gas to transporters, distributors and end users, including industrial, commercial and individual consumers. Petrobank also competes with other oil and natural gas companies in attempting to secure drilling rigs and other equipment necessary for drilling and completion of wells. Such equipment may be in short supply from time to time. Finally, companies not previously investing in oil and natural gas may choose to acquire reserves to establish a firm supply or simply as an investment. Such companies will also provide competition for Petrobank.

The marketability of oil and natural gas acquired or discovered is affected by numerous factors beyond the control of Petrobank. These factors include reservoir characteristics, market fluctuations, the proximity and capacity of oil and natural gas pipelines and processing equipment and government regulation. Oil and natural gas operations (exploration, production, pricing, marketing and transportation) are subject to extensive controls and regulations imposed by various levels of government which may be amended from time to time. See "Industry Conditions". Petrobank's oil and natural gas operations may also be subject to compliance with federal, provincial and local laws and regulations controlling the discharge of materials into the environment or otherwise relating to the protection of the environment. Although the Company believes that it is in material compliance with current applicable environmental regulations, changes to such regulations may have a material adverse effect on the Company. See "Industry Conditions - Environmental Regulation".

Both oil and natural gas prices are unstable and are subject to fluctuation. Any material decline in prices could result in a reduction of Petrobank's net production revenue and overall value and could result in ceiling test writedowns. The economics of producing from some wells may change as a result of lower prices, which could result in a reduction in the volumes of Petrobank's reserves. Petrobank might also elect not to produce from certain wells at lower prices. All of these factors could result in a material decrease in Petrobank's net production revenue causing a reduction in its oil and gas acquisition and development activities. In addition, bank borrowings available to the Company are in part determined by the borrowing base of the Company. A substantial material decline in prices from historical average prices could further reduce the Company's borrowing base, therefore reducing the bank credit available to the Company and possibly require that a portion of the Company's bank debt be repaid.

The Company uses the full cost method of accounting for oil and natural gas properties. Under this accounting method, capitalized costs are reviewed for impairment to ensure that the carrying amount of these costs is recoverable based on expected future cash flows. To the extent that such capitalized costs (net of accumulated depreciation and depletion) less future taxes exceed the present value of estimated future net cash flows from the Company's proved oil and natural gas reserves, those excess costs would be required to be charged to operations.

From time to time the Company may enter into agreements to receive fixed prices on its oil and natural gas production to offset the risk of revenue losses if commodity prices decline; however, if commodity prices increase beyond the levels set in such agreements, the Company will not benefit from such increases.

From time to time the Company may enter into agreements to fix the exchange rate of Canadian to United States dollars in order to offset the risk of revenue losses if the Canadian dollar increases in value compared to the United States dollar; however, if the Canadian dollar declines in value compared to the United States dollar, the Company will not benefit from the fluctuating exchange rate.

Oil and natural gas exploration operations are subject to all the risks and hazards typically associated with such operations, including hazards such as fire, explosion, blowouts, cratering and oil spills, each of which could result in substantial damage to oil and natural gas wells, production facilities, other property and the environment or in personal injury. In accordance with industry practice, the Company is not fully insured against all of these risks, nor are all such risks insurable. Although Petrobank maintains liability insurance in an amount that it considers adequate and consistent with industry practice, the nature of these risks is such that liabilities could exceed policy limits, in which event Petrobank could incur significant costs that could have a materially adverse effect upon its financial condition. Oil and natural gas production operations are also subject to all the risks typically associated with such operations, including premature decline of reservoirs and the invasion of water into producing formations.

Oil and natural gas exploration and development activities are dependent on the availability of drilling and related equipment in the particular areas where such activities will be conducted. Demand for such limited equipment or access restrictions may affect the availability of such equipment to the Company and may delay exploration and development activities. To the extent Petrobank is not the operator of its oil and gas properties, Petrobank will be dependent on such operators for the timing of activities related to such properties and will be largely unable to direct or control the activities of the operators.

Although title reviews will be done according to industry standards prior to the purchase of most oil and natural gas producing properties or the commencement of drilling wells, such reviews do not guarantee or certify that an unforeseen defect in the chain of title will not arise to defeat the claim of Petrobank which could result in a reduction of the revenue received by Petrobank.

There are numerous uncertainties inherent in estimating quantities of reserve and cash flows to be derived therefrom, including many factors that are beyond the control of the Company. The reserve and cash flow information set forth in this Annual Information Form represent estimates only. The reserves and estimated future net cash flow from the Company's properties have been independently evaluated effective January 1, 2003 by GLJ. These evaluations include a number of assumptions relating to factors such as initial production rates, production decline rates, ultimate recovery of reserves, timing and amount of capital expenditures, marketability of production, future prices of oil and natural gas, operating costs and royalties and other government levies that may be imposed over the producing life of the reserves. These assumptions were based on price forecasts in use at the date the relevant evaluations were prepared and many of these assumptions are subject to change and are beyond the control of the Company. Actual production and cash flows derived therefrom will vary from these evaluations, and such variations could be material. The foregoing evaluations are based in part on the assumed success of exploitation activities intended to be undertaken in future years. The reserves and estimated cash flows to be derived therefrom contained in such evaluations will be reduced to the extent that such exploitation activities do not achieve the level of success assumed in the evaluations.

From time to time the Company may enter into transactions to acquire assets or the shares of other companies. These transactions may be financed partially or wholly with debt, which may increase the Company's debt levels above industry standards. Depending on future exploration and development plans, the Company may require additional financing which may not be available or, if available, may not be available on favourable terms.

In addition to the risks faced by Canadian oil and gas companies, the Company is subject to risks related to its foreign operations in Colombia as a portion of the Company's business regulated by the laws and regulations of Colombia, including those related to the development, production, marketing, transportation of crude oil and natural gas, taxation and environmental and safety matters. The Company may be adversely affected by changes in governmental policies or social instability or other political or economic developments in Colombia that are outside the Company's control including among other things, expropriation, risks of war and terrorism, foreign exchange and repatriation restrictions, changing political conditions and monetary fluctuations and changing governmental policies including taxation policies.

Certain directors of Petrobank are also directors of other oil and gas companies and as such may, in certain circumstances, have a conflict of interest requiring them to abstain from certain decisions. Conflicts, if any, will be subject to the procedures and remedies of the ABCA.

Please also see the information under the heading "Risks and Uncertainties" in the Annual Report on pages 38 and 39 which information is incorporated herein by reference.

ADDITIONAL INFORMATION

Additional information, including information as to directors' and officers' remuneration and indebtedness, principal holders of the Company's securities, options to purchase securities and interests of insiders in material transactions, is contained in the Management Proxy Circular of the Company dated April 21, 2003 provided for the annual and special meeting of the shareholders of the Company to be held on May 22, 2003. Additional financial information is also provided in the Company's consolidated financial statements for the year ended December 31, 2002 which are contained in the Annual Report of the Corporation for the year ended December 31, 2002.

Upon request the Company will provide to any person:

1. One copy of this Annual Information Form together with one copy of any document, or the pertinent pages of any document incorporated by reference in the Annual Information Form;

2. One copy of the Company's consolidated financial statements contained in the Annual Report for the year ended December 31, 2002, together with the report of the auditors thereon, and one copy of any of the Company's interim financial statements subsequent to such audited consolidated financial statements;

3. One copy of the Company's Management Proxy Circular provided for the annual and special meeting of the shareholders of the Company to be held on May 22, 2003; and

4. When the Company's securities are in the course of a distribution pursuant to a short form prospectus or when a preliminary short form prospectus has been filed in respect of a distribution of the Company's securities, also upon request to the Company, one copy of any other document that is incorporated by reference in the preliminary or final short form prospectus, as the case may be.

Copies of these documents may be obtained in some cases upon payment of a reasonable charge upon request to:

Petrobank Energy and Resources Ltd.
Suite 2600, 240 - 4th Avenue S.W.
Calgary, Alberta
T2P 4H4
Phone: (403) 750-4400
Fax: (403) 266-5794

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PETROBANK
ENERGY AND RESOURCES LTD.

NEWS RELEASE

PETROBANK ANNOUNCES FIRST QUARTER RESULTS & OPERATIONAL UPDATE

Calgary, Alberta – May 22, 2003 – Petrobank is pleased to provide the following operational update for each of our three business units, as well as the financial results of the Company for the first quarter of 2003. We are continuing to execute on our overall strategy to create value through our three business units.

In Canada, we have had positive results from two of our new project areas and we expect to have a very active drilling program for the remainder of the year. The entire oil and gas industry has been affected by recent weather conditions which created a prolonged "break-up" season. This has delayed a few of our initiatives by a number of weeks, but we are on target to drill more than 70 wells planned for this year, Petrobank's most active program to date. We are also in the final stages of selling one of our more fully developed properties, creating liquidity on our balance sheet and allowing us to focus our efforts on more value-added opportunities. In Colombia, our initial Orito drilling program has confirmed our geological and seismic interpretations. We have been challenged this year by certain operational and timing difficulties, but overall, our program is proceeding as planned, and we are mapping out a clear path to fully realize the value of our two Incremental Production Contracts. Finally, in Orion, our heavy oil business unit, we are progressing with our plans to submit a pilot project application in the third quarter of this year with a view to commencing a pilot of our revolutionary heavy oil technology (THAI) in early 2004.

Petrobank achieved cash flows of $8.5 million in the first quarter on revenues of $17.9 million. In May 2003, the Company issued an additional $40 million of subordinated notes along with 1.4 million common share purchase warrants for net proceeds of $35 million, increasing our financial flexibility.

OPERATIONAL UPDATE

Canadian Business Unit

In the first quarter, Petrobank drilled a total of 21 wells resulting in 13 oil wells and 8 dry holes. We were successful at our Eyehill and Epping plays where we continued to delineate our successful discoveries from the fourth quarter of 2002. Although we have been delayed by recent weather conditions, we expect to have all of these new wells onstream by the end of the second quarter. The Company also evaluated a new shallow gas prospect in Saskatchewan by leasing a number of "drilling islands" and drilling exploratory test wells into a major Saskatchewan land sale. Unfortunately, the play concept did not develop into a commercial project; however, we did not expose any further capital at the land sale. Although the overall results were below expectations, we were able to evaluate and assess a potentially large opportunity for the Company with a limited investment of capital.

Petrobank is moving forward with our assessment of the coal bed methane (CBM) potential of our Princeton project with a 100 km seismic program planned for the summer to be followed by a five well pilot test. Petrobank recently acquired a successful test seismic line across the Princeton basin that provided an excellent subsurface image of the basin and the necessary parameters for future seismic acquisition.

Currently, the Company is in the final stages of closing the sale of our Zama/Larne and Whiterose properties for $16.5 million, which consist primarily of sour, Slave Point gas in northwest Alberta. We have consistently found it difficult to profitably expand our operations in this area due to the limited drilling season and our reliance on third-party gas processing. Proceeds of this sale will provide the Company with future flexibility and liquidity.

Latin American Business Unit

Orito Block Operations

In the Orito area, three test wells have been drilled to date and initially completed in the Caballos formation to test three distinct geological concepts. A fourth well to further delineate a new extension to the Orito Caballos pool is currently being drilled. The results of these wells are outlined below.

The first well, Dev 1, encountered oil pay in the Caballos and Pepino zones. Initial completion operations in the Caballos were complicated by the fact that the well had a serious channel in the cement behind the production casing. After an extended series of remedial cement squeeze operations and a number of recompletions, the Company has concluded that the water influx through the cement channel cannot be eliminated and that the well will be incapable of producing at sustained rates of greater than 150 BOPD. A decision was made to suspend the Caballos zone and re-complete the well in the Pepino zone. The well is currently on test following a fracture stimulation, and flow results from this, the Company's first Pepino oil well, are expected in the next two weeks. We still consider the potential of the Caballos zone at Dev 1 to be excellent and future plans may include a re-drill and additional tests of the Caballos formation from the Dev 1 drilling platform.

Petrobank's second Caballos well, Dev 2, tested the productive capability of the "saddle" zone which separates the two main producing portions of the Orito field. This well encountered a series of Caballos sands, which, after extensive testing and stimulation, appear to be anomalously tight. Total fluid inflow in this well does not appear to be sustainable in excess of 150 barrels per day, and therefore a decision was made to suspend the Caballos perforations and re-complete the well in the Pepino zone. If successful, this will be the Company's second new Pepino well in the Orito field. Petrobank does not currently have any plans to drill additional wells into the saddle area of the field, and will instead focus future drilling in this area to the west and north of Dev 2.

Petrobank's third Caballos well, Dev 3 was drilled to test a potential westward extension of the main Orito field. This extension was interpreted from the new 3D seismic data and lies outside the previously defined pool limit. The well encountered the Caballos reservoir in a new structural high, was successfully completed, and has been producing at an average rate of 400 BOPD of very high quality (43° API) crude oil. Recently we decided to suspend the lowest set of perforations (which were producing at high water cuts) and fracture stimulate the upper two sand intervals. Test results are expected from this well in the next two weeks. With this successful demonstration of the existence of a new extension to the Orito field, the Company plans to drill at least three additional wells to delineate the extent of this accumulation.

Petrobank's fourth Caballos well, Dev 4, was spudded as a delineation well to the Dev 3 pool extension. The well penetrated the Caballos formation at a similar structural depth to Dev 3 and encountered highly permeable upper Caballos sands. During drilling of the Caballos section, the high permeability resulted in lost circulation and a Caballos sidetrack had to be constructed around a short portion of the stuck drillstring. As a result of these prolonged drilling operations, this well encountered additional drilling complications in the upper section of the hole. At present, we are preparing to run intermediate casing to the top of the Caballos zone. The permeable Caballos section will then be drilled and cased with a liner. Initial geological analysis of this portion of the Dev 4 wellbore indicates that the sand sequences are very similar to those found in Dev 3.

Other Opportunities in Orito

The Company has also completed a series of workover operations and engineering studies in the Orito Field. We conducted a pilot project of three Electrical Submersible Pump (ESP) conversions to demonstrate the merits of lift modernization. This pilot project has greatly exceeded our expectations. It is clear from our work to date that further Caballos reserves optimization is possible with ESP conversions. In addition to pressure and petrophysical data from the new wellbores, we have also gathered current static and dynamic pressure data from many wells in the pool. This data indicates that the entire reservoir is in general pressure communication and that the current average reservoir pressure is higher than previously estimated. A new 3D reservoir simulation has been completed and updated with the new structural, pressure, and production information. The model is being used to plan the optimal depletion strategy for the Caballos reservoir, through drilling, recompletions and waterflooding. Finally, our geological interpretation of the shallow Pepino zone indicates a significant upside in this horizon. We are currently evaluating surface locations (which limit to a certain extent where we can drill) in order to commence a program to delineate further Pepino potential in the contract area.

Using the data from our initial work plan, we have prepared a comprehensive field redevelopment plan for Orito that includes extensive modernization of the artificial lift through the installation of ESPs and involves a full program of well stimulations, re-perforations, recompletions, additional Caballos wells, and water injection. The plan also includes workovers, recompletions, and additional drilling in the Pepino, and contemplates a secondary recovery pilot in the main Pepino reservoir. This "omnibus" redevelopment plan has been formally submitted to Ecopetrol, Colombia's state oil company, and is in advanced stages of the approval process. At present, Petrobank is proceeding with some of the initial activities of the plan, including Pepino workovers and completions and additional ESP installations in Caballos wells. We currently have three service rigs and one drilling rig active in the Orito area.

Neiva Block Operations

At Neiva, we executed our initial plan to assess the potential to infill drill the Dina zone and to test the productive potential of the Doima Chicoral zone. In addition to the drilling program, we also reprocessed and reinterpreted a large 3D seismic survey obtained by Ecopetrol. This reinterpretation resulted in a completely new understanding of the Doima-Chicoral reservoir, indicating significantly more oil-in-place than previously assumed. Based on our results to date, we have put in place a large inventory of further low-risk drilling opportunities, which we will schedule into our future drilling plans. We plan to drill an additional two wells to further delineate the Doima Chicoral zone in the latter half of this year. Operations at Neiva proceeded efficiently and within cost expectations. An excellent working relationship with the Ecopetrol operations team at Neiva allowed for the seamless addition of one well to the drilling program and several wells to the workover program during project execution.

Orion Heavy Oil Business Unit

Orion's plan to complete an experimental pilot project application to test the THAI technology is proceeding according to plan. During the first quarter, Orion conducted a 20 square kilometre 3D seismic survey over our Christina Lake property to further delineate the potential bitumen resource. Our present assessment is that there may be approximately 500 million barrels of bitumen contained within the area evaluated by the seismic. Technical design of the pilot, as well as environmental assessments and field-scale reservoir simulations of the process are proceeding according to schedule. The Company is also finalizing all business arrangements to purchase the intellectual property rights surrounding the THAI/CAPRI technologies. Current plans are to have the experimental pilot project application finalized and ready for submission by the third quarter of 2003.

FINANCIAL OVERVIEW

(Gas volumes have been converted to barrels of oil equivalent ("boe") on a 6 mcf equals 1 boe basis.)

Petrobank generated cash flow from operations in the first quarter of 2003 of $8.5 million, a 55% improvement over the same period last year. Similarly, net income increased to $3.5 million from $1.0

million. The increase in earnings is attributable to a higher average realized price of $37.64/boe (2002 - $24.21/boe) slightly offset by lower volumes of 5,272 boepd (2002 – 5,591 boepd). Results in the first quarter reflect average production from Colombia of 695 bopd at a netback of $29.39/bbl. Capital expenditures in the quarter totaled $36.0 million, including $8.9 million in Canada, $1.5 million in our Heavy Oil business unit and $25.6 million in Colombia. Net debt at the end of March, including subordinated notes reflected as equity on the balance sheet, was $91.6 million.

Production

Oil and NGL production during the first quarter averaged 2,757 barrels per day (bpd) in Canada, a slight increase from the 2,704 bpd produced in the first quarter of 2002 and 4% higher than the fourth quarter of 2002. First quarter natural gas production of 10.9 million cubic feet per day (mmcfpd) decreased 37% from the 17.3 mmcfpd produced in the first quarter of 2002 and 3% from the 11.2 mmcfpd produced in the fourth quarter of 2002. Natural gas production has declined significantly over the past year primarily due to the anticipated declines associated with the Company's Northwest Alberta properties, in particular at Hamburg and Zama/Larne. The Company's large slave point discovery at Hamburg has declined from 3.7 mmcfpd in the first quarter of 2002 to 1.1 mmcfpd in the first quarter of 2003.

In addition, the Company commenced oil production from its Colombian operations in January 2003 and averaged 695 bpd, net to Petrobank before royalties, in the first quarter. Colombian production in the first quarter is made up of incremental production generated from our first three wells in Orito, five new wells in Neiva and a number of workovers carried out on both blocks.

On a barrel of oil equivalent basis, production averaged 5,272 boe per day (boepd) in the first quarter of the year, a 16% increase over the fourth quarter of 2002 and a 6% decrease from the 5,591 boepd produced in the first quarter of 2002.

Realized Sales Prices

The average Canadian oil and NGL price received in the first quarter was $33.30 per barrel, an increase of 13% compared to the $29.48 per barrel received in the first quarter of 2002. Canadian oil and NGL prices averaged $41.42 per barrel, before hedging losses of $8.12 per barrel, representing a U.S.$6.43 discount to average WTI prices in the quarter. The average natural gas price received in the first quarter was $7.37 per mcf a 130% increase from $3.21 per mcf in the first quarter of 2002. The natural gas price reflects the impact of the Company's long-term physical gas sales contracts that generated lower realized prices during the quarter. Oil sales prices in Colombia averaged $38.58 per barrel in the first quarter, representing a U.S.$8.32 discount to WTI. We anticipate a reduction in net sales prices in the second quarter due to a lower average WTI price, and a stronger Canadian dollar.

Royalties

Royalties increased from $2.4 million in the first quarter of 2002 to $4.2 million in the current period reflecting higher revenues. Colombian royalties are included in this quarter at a rate of 8%. Canadian royalties as a percentage of revenue increased from 20% in the first quarter of 2002 to 26% in the current period. The increase resulted partly from the impact of the Company's forward gas sale contracts, as crown royalties are paid based on posted prices as opposed to actual prices received. In addition, increased commodity prices during the current quarter resulted in higher crown royalty rates.

Production Expenses

Production expenses in Canada increased 15% from $6.31 per boe in the first quarter of 2002 to $7.24 per boe in the current period. This increase is largely a result of the fixed nature of certain operating costs combined with lower Canadian production volumes. Production expenses in Colombia averaged $6.09 per barrel in the first quarter.

General and Administrative Expenses

General and administrative expenses increased to $1.4 million in the first quarter of 2003 from $1.0 million in the comparable 2002 period. The increase relates to incremental overhead associated with the Company's Colombian operations.

Depletion, Depreciation and Site Restoration Expense

Depletion, depreciation and site restoration expense for the first quarter increased to $5.0 million ($10.52 per boe) from $4.5 million ($8.91 per boe) for the same period in 2002. This increase is due partly to significant excess costs incurred on our first two Caballos wells in Orito, which were difficult to complete. As we continue our development work in Orito, which includes a large component of investments in well workovers and pump installations,, the Company anticipates booking additional reserves at lower costs which will serve to reduce depletion expense. In addition, finding and development costs in Canada increased slightly over the same period.

Interest on Subordinated Notes

Interest on subordinated notes totaled $1.5 million for the first quarter of 2003, consistent with the comparative period. Interest on these notes will increase in future periods as a result of the issuance of an additional $40 million of notes in May 2003.

Capital Expenditures

Capital expenditures in the first quarter totaled $36.0 million, of which $10.4 million was spent in Canada and $25.6 million in Colombia. Colombian expenditures were focused on drilling, completions and workovers in Neiva and Orito. Technical difficulties associated with initial drilling and completion operations at Orito have increased the costs of drilling our first phase of wells on this block.

Liquidity and Capital Resources

At March 31, 2003 net debt totaled $91.6 million, including the outstanding subordinated notes and $8.2 million of bank debt drawn on our $40 million secured Canadian credit facility. In May 2003, the Company issued an additional $40 million face value of subordinated notes and 1.4 million share purchase warrants for net proceeds of approximately $35 million. On a proforma basis, this leaves the Company with approximately $67 million of available cash and undrawn credit at March 31, 2003, to carry out the remainder of its 2003 capital program.

OUTLOOK

In the first quarter of 2003, Petrobank initiated the most aggressive plan in the Company's history. Our current 2003 capital plan contemplates investing $40 million in Canada (including $4 million in Orion) and U.S. $45 million in Colombia. With the recent subordinated note financing, our balance sheet provides the flexibility to efficiently execute the following opportunities. In Canada, we are focused on growing our business with a plan to drill more than 70 wells and develop two new areas. We will continue to be opportunistic with respect to Canadian assets through focused acquisitions and dispositions of properties where we have maximized value. Our Princeton Project has the potential to create a niche in the evolving Canadian CBM business. To date our Colombian operations confirm the potential to add new reserves through the redevelopment of existing fields, and as we fortify our Latin American operating platform, we will look for similar opportunities in the region. With the Orion business unit we have captured and are advancing the development of technologies with the potential to transform oil sands and heavy oil production globally. I look forward to continuing to update our shareholders on these activities in the future.

FOR FURTHER INFORMATION PLEASE CONTACT:

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David Rain, Vice President, Finance and Chief Financial Officer
Telephone: (403) 750-4400

· Highlights ·

As at and for the three months ended March 31,	2003	2002	% change
Financial			
($000s, except where noted)			
Oil and natural gas revenue	17,917	12,185	47
Cash flow from operations [1]	8,530	5,501	55
Per share – basic $ [2]	0.16	0.12	33
Per share – diluted $ [2]	0.15	0.10	50
Net income	3,537	1,019	247
Net income (loss) attributable to common shareholders	2,020	(715)	
Per share – basic $	0.04	(0.02)	
Per share – diluted $	0.04	(0.02)	
Capital expenditures	35,961	6,913	420
Net debt [3]	91,599	33,309	175
Shareholders' equity excluding subordinated notes	57,759	57,463	1
Common shares outstanding (000s)			
Basic	45,354	33,807	34
Diluted	50,544	57,057	(11)
Operations [4]			
Canadian operating netback ($/boe except where noted)			
Oil and NGLs revenue ($/bbl)	33.30	29.48	13
Natural gas revenue ($/mcf)	7.37	3.21	130
Oil and natural gas revenue	37.64	24.21	55
Royalties	9.77	4.76	105
Production expenses	7.24	6.31	15
Operating netback	20.63	13.14	57
Colombian operating netback ($/bbl)			
Oil revenue	38.58		
Royalties	3.09		
Production expenses	6.09		
Operating netback	29.40		
Average daily production			
Canada - oil and NGLs (bbls)	2,757	2,704	2
Canada - natural gas (mcf)	10,920	17,323	(37)
Total Canada (boe)	4,577	5,591	(18)
Colombia - oil (bbls)	695	-	100
Total Company (boe)	5,272	5,591	(6)

(1) Cash flow from operations before changes in other non-cash items.
(2) Calculated based on cash flow from operations before changes in other non-cash items less preferred share dividends and interest paid on subordinated notes.
(3) Includes working capital (deficiency) and subordinated notes reflected as equity on the balance sheet.
(4) 6 Mcf of natural gas is equivalent to 1 barrel of oil equivalent (BOE).

· Consolidated Balance Sheets ·

As at (Thousands of Canadian dollars)	**March 31, 2003** (Unaudited)	December 31, 2002
Assets		
Current assets		
Cash and cash equivalents	**$ -**	$ 12,224
Accounts receivable and other current assets	**13,701**	11,521
	13,701	23,745
Capital assets	**158,196**	126,873
	$ 171,897	$ 150,618
Liabilities and Shareholders' Equity		
Current liabilities		
Accounts payable and accrued liabilities	**$ 39,576**	$ 28,896
Bank debt	**8,204**	-
	47,780	28,896
Obligations under gas hedging contracts	**7,897**	8,097
Future site restoration liability	**941**	613
	56,618	37,606
Shareholders' equity		
Subordinated notes (note 4)	**57,520**	57,344
Common shares (note 2)	**48,125**	48,054
Retained earnings	**9,634**	7,614
	115,279	113,012
	$ 171,897	$ 150,618

Subsequent event (note 4)

See accompanying notes to these consolidated financial statements

· Consolidated Statements of Income and Retained Earnings ·

Three months ended March 31,	2003	2002
(Unaudited, thousands of Canadian dollars, except per share amounts)		
Revenues		
Oil and natural gas	$ 17,917	$ 12,185
Royalties	(4,219)	(2,396)
	13,698	9,789
Expenses		
Production	3,365	3,176
General and administrative	1,369	966
Interest on bank debt	41	-
Depletion, depreciation and site restoration	4,993	4,482
	9,768	8,624
Income before other items and taxes	3,930	1,165
Other expense (income)	119	(105)
Capital tax expense	274	251
Net income	3,537	1,019
Interest on subordinated notes	1,517	1,499
Preferred share dividends and related taxes	-	235
Net income (loss) attributable to common shareholders	2,020	(715)
Retained earnings, beginning of period	7,614	14,562
Retained earnings, end of period	$ 9,634	$ 13,847
Earnings (loss) per share (note 2)		
Basic	$ 0.04	$ (0.02)
Diluted	$ 0.04	$ (0.02)

See accompanying notes to these consolidated financial statements

· Consolidated Statements of Cash Flow ·

Three months ended March 31,	2003	2002
(Unaudited, thousands of Canadian dollars)		
Operating Activities		
Net income	$ 3,537	$ 1,019
Depletion, depreciation and site restoration	4,993	4,482
Cash flow from operations	8,530	5,501
Changes in other non-cash items	(1,738)	3,555
	6,792	9,056
Financing Activities		
Issuance of bank debt	8,204	-
Issuance of common shares (note 2)	71	-
Preferred share dividends and related taxes	-	(235)
Interest on subordinated notes	(1,341)	(1,341)
Amortization of obligations under gas hedging contracts	(200)	(217)
Changes in other non-cash items	-	813
	6,734	(980)
Investing Activities		
Expenditures on capital assets	(35,961)	(6,913)
Proceeds on disposition of capital assets	-	1,972
Corporate acquisition	-	(42)
Site restoration expenditures	(27)	-
Changes in other non-cash items	10,238	1,705
	(25,750)	(3,278)
Net change in cash position	(12,224)	4,798
Cash and cash equivalents, beginning of period	12,224	25,311
Cash and cash equivalents, end of period	$ -	$ 30,109

See accompanying notes to these consolidated financial statements

As at and for the three months ended March 31, 2003
(All tabular amounts are expressed in thousands of Canadian dollars, except share amounts)

Note 1 – Significant Accounting Policies

The interim consolidated financial statements as at and for the three months ended March 31, 2003 should be read in conjunction with the audited consolidated financial statements as at and for the year ended December 31, 2002. The notes to these interim consolidated financial statements do not conform in all respects to the note disclosure requirements of generally accepted accounting policies for annual financial statements. These interim consolidated financial statements are prepared using the same accounting policies and methods of computation as disclosed in the audited consolidated financial statements as at and for the year ended December 31, 2002. These interim consolidated financial statements include disclosure of segmented information in Note 6, which was not provided in the December 31, 2002 consolidated financial statements, as the Company did not have results from operations in Colombia during the year ended December 31, 2002.

Note 2 – Share Capital

As at March 31, 2003 the Company had outstanding 45,353,871 common shares, 774,960 share purchase warrants, and 4,415,668 stock options.

Common Share Continuity	Number	Amount
Balance at December 31, 2002	45,313,795	$ 48,054
Exercise of stock options	37,316	64
Exercise of share purchase warrants	2,760	7
Balance at March 31, 2003	45,353,871	$ 48,125

Stock Option Continuity	Number	Weighted - Average Exercise Price
Balance at December 31, 2002	4,195,484	$ 2.08
Granted	262,500	3.67
Exercised	(37,316)	(1.71)
Cancelled	(5,000)	(3.40)
Balance at March 31, 2003	4,415,668	$ 2.17

Earnings Per Share

Earnings (loss) per share have been calculated based on the weighted average number of common shares outstanding for the three month period ended March 31, 2003 of 45,339,439 (2002 – 33,665,473). Earnings (loss) per share are based on net income (loss) attributable to common shareholders. The diluted calculation for the three month period ended March 31, 2003 includes 2,223,148 (2002 – nil) additional shares for the potential impact of share purchase warrants and stock options.

Stock Based Compensation

The Company accounts for its stock based compensation plans using the intrinsic value based method whereby no costs are recognized in the statements of operations for stock options granted at market price to employees and directors. Had compensation expense associated with the Company's stock option plan been recognized using the fair value method for stock option grants after January 1, 2002, the Company's net income attributable to common shareholders for the three months ended March 31, 2003 would have been reduced by $119,000 (2002 – net loss increased by $12,000) and net earnings (loss) per share would have approximated reported amounts.

The fair value of stock options granted during the reported periods are estimated using the Black Scholes option pricing model using the following assumptions:

Three months ended March 31,	2003	2002
Risk free interest rate	4%	4%
Dividend rate	0%	0%
Expected life (years)	4	4
Expected volatility	30%	20%

Note 3 – Related Party Transactions

In January 2002, the Company acquired a private company and assumed a $0.6 million balance payable indirectly to two of the Company's directors that was settled in February 2003.

In February 2003, the Company announced that an independent committee of the Board of Directors reached an agreement to acquire certain heavy oil technologies indirectly from two directors of the Company for their original cost of $0.4 million. In addition, a director and an unrelated party have retained a combined 17.5% net profits interest in future third party royalties generated from the technologies.

Note 4 – Subsequent Event

In May 2003, the Company closed a subordinated note financing, resulting in the issuance of $40.0 million face value of subordinated notes and 1,420,300 common share purchase warrants for proceeds, net of costs and agents' commissions, of approximately $35.0 million. The subordinated notes were issued pursuant to Petrobank's existing subordinated note indenture, which stipulates a 9% interest rate and a maturity date of July 31, 2006. Interest on the notes is payable quarterly and accrues from the date of issuance. The subordinated notes and related interest associated with these new subordinated notes will be accounted for in the same manner as the outstanding subordinated notes. The common share purchase warrants are exercisable for common shares at $4.00 each and expire on May 6, 2006.

Note 5 – Commitments and Contingencies

As at March 31, 2003, the Company's remaining work commitments in Colombia totaled U.S.$31 million.

Note 6 – Segmented Information

The Company commenced commercial production from its Colombian operations in January 2003 and accordingly segmented results are presented below only for the three months ended March 31, 2003.

	Canada	Colombia	Total
Revenues			
Oil and natural gas	$ 15,504	2,413	$ 17,917
Royalties	(4,026)	(193)	(4,219)
	11,478	2,220	13,698
Expenses			
Production	2,984	381	3,365
General and administrative	932	437	1,369
Depletion, depreciation and site restoration	4,137	856	4,993
Segmented income	$ 3,425	546	$ 3,971
Non-segmented expenses			
Interest on bank debt			(41)
Other			(119)
Capital tax			(274)
Net income			3,537
Interest on subordinated notes			1,517
Net income attributable to common shareholders			$ 2,020
Identifiable assets	$125,712	46,185	$171,897
Capital expenditures	$ 10,383	25,578	$ 35,961

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CORPORATE FINANCE

Petrobank is pleased to provide the following operational update for each of our three business units, as well as the financial results of the Company for the first quarter of 2003. We are continuing to execute on our overall strategy to create value through our three business units.

In Canada, we have had positive results from two of our new project areas and we expect to have a very active drilling program for the remainder of the year. The entire oil and gas industry has been affected by recent weather conditions which created a prolonged "break-up" season. This has delayed a few of our initiatives by a number of weeks, but we are on target to drill more than 70 wells planned for this year, Petrobank's most active program to date. We are also in the final stages of selling one of our more fully developed properties, creating liquidity on our balance sheet and allowing us to focus our efforts on more value-added opportunities. In Colombia, our initial Orito drilling program has confirmed our geological and seismic interpretations. We have been challenged this year by certain operational and timing difficulties, but overall, our program is proceeding as planned, and we are mapping out a clear path to fully realize the value of our two Incremental Production Contracts. Finally, in Orion, our heavy oil business unit, we are progressing with our plans to submit a pilot project application in the third quarter of this year with a view to commencing a pilot of our revolutionary heavy oil technology (THAI) in early 2004.

Petrobank achieved cash flows of $8.5 million in the first quarter on revenues of $17.9 million. In May 2003, the Company issued an additional $40 million of subordinated notes along with 1.4 million common share purchase warrants for net proceeds of $35 million, increasing our financial flexibility.

OPERATIONAL UPDATE

Canadian Business Unit

In the first quarter, Petrobank drilled a total of 21 wells resulting in 13 oil wells and 8 dry holes. We were successful at our Eyehill and Epping plays where we continued to delineate our successful discoveries from the fourth quarter of 2002. Although we have been delayed by recent weather conditions, we expect to have all of these new wells onstream by the end of the second quarter. The Company also evaluated a new shallow gas prospect in Saskatchewan by leasing a number of "drilling islands" and drilling exploratory test wells into a major Saskatchewan land sale. Unfortunately, the play concept did not develop into a commercial project; however, we did not expose any further capital at the land sale. Although the overall results were below expectations, we were able to evaluate and assess a potentially large opportunity for the Company with a limited investment of capital.

Petrobank is moving forward with our assessment of the coal bed methane (CBM) potential of our Princeton project with a 100 km seismic program planned for the summer to be followed by a five well pilot test. Petrobank recently acquired a successful test seismic line across the Princeton basin that provided an excellent subsurface image of the basin and the necessary parameters for future seismic acquisition.

Currently, the Company is in the final stages of closing the sale of our Zama/Larne and Whiterose properties for $16.5 million, which consist primarily of sour, Slave Point gas in northwest Alberta. We have consistently found it difficult to profitably expand our operations in this area due to the limited drilling season and our reliance on third-party gas processing. Proceeds of this sale will provide the Company with future flexibility and liquidity.

Latin American Business Unit

Orito Block Operations

In the Orito area, three test wells have been drilled to date and initially completed in the Caballos formation to test three distinct geological concepts. A fourth well to further delineate a new extension to the Orito Caballos pool is currently being drilled. The results of these wells are outlined below.

The first well, Dev 1, encountered oil pay in the Caballos and Pepino zones. Initial completion operations in the Caballos were complicated by the fact that the well had a serious channel in the cement behind the production casing. After an extended series of remedial cement squeeze operations and a number of recompletions, the Company has concluded that the water influx through the cement channel cannot be eliminated and that the well will be incapable of producing at sustained rates of greater than 150 BOPD. A decision was made to suspend the Caballos zone and re-complete the well in the Pepino zone. The well is currently on test following a fracture stimulation, and flow results from this, the Company's first Pepino oil well, are expected in the next two weeks. We still consider the potential of the Caballos zone at Dev 1 to be excellent and future plans may include a re-drill and additional tests of the Caballos formation from the Dev 1 drilling platform.

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Petrobank's fourth Caballos well, Dev 4, was spudded as a delineation well to the Dev 3 pool extension. The well penetrated the Caballos formation at a similar structural depth to Dev 3 and encountered highly permeable upper Caballos sands. During drilling of the Caballos section, the high permeability resulted in lost circulation and a Caballos sidetrack had to be constructed around a short portion of the stuck drillstring. As a result of these prolonged drilling operations, this well encountered additional drilling complications in the upper section of the hole. At present, we are preparing to run intermediate casing to the top of the Caballos zone. The permeable Caballos section will then be drilled and cased with a liner. Initial geological analysis of this portion of the Dev 4 wellbore indicates that the sand sequences are very similar to those found in Dev 3.

Other Opportunities in Orito

The Company has also completed a series of workover operations and engineering studies in the Orito Field. We conducted a pilot project of three Electrical Submersible Pump (ESP) conversions to demonstrate the merits of lift modernization. This pilot project has greatly exceeded our expectations. It is clear from our work to date that further Caballos reserves optimization is possible with ESP conversions. In addition to pressure and petrophysical data from the new wellbores, we have also gathered current static and dynamic pressure data from many wells in the pool. This data indicates that the entire reservoir is in general pressure communication and that the current average reservoir pressure is higher than previously estimated. A new 3D reservoir simulation has been completed and updated with the new

structural, pressure, and production information. The model is being used to plan the optimal depletion strategy for the Caballos reservoir, through drilling, recompletions and waterflooding. Finally, our geological interpretation of the shallow Pepino zone indicates a significant upside in this horizon. We are currently evaluating surface locations (which limit to a certain extent where we can drill) in order to commence a program to delineate further Pepino potential in the contract area.

Using the data from our initial work plan, we have prepared a comprehensive field redevelopment plan for Orito that includes extensive modernization of the artificial lift through the installation of ESPs and involves a full program of well stimulations, re-perforations, recompletions, additional Caballos wells, and water injection. The plan also includes workovers, recompletions, and additional drilling in the Pepino, and contemplates a secondary recovery pilot in the main Pepino reservoir. This "omnibus" redevelopment plan has been formally submitted to Ecopetrol, Colombia's state oil company, and is in advanced stages of the approval process. At present, Petrobank is proceeding with some of the initial activities of the plan, including Pepino workovers and completions and additional ESP installations in Caballos wells. We currently have three service rigs and one drilling rig active in the Orito area.

Neiva Block Operations

At Neiva, we executed our initial plan to assess the potential to infill drill the Dina zone and to test the productive potential of the Doima Chicoral zone. In addition to the drilling program, we also reprocessed and reinterpreted a large 3D seismic survey obtained by Ecopetrol. This reinterpretation resulted in a completely new understanding of the Doima-Chicoral reservoir, indicating significantly more oil-in-place than previously assumed. Based on our results to date, we have put in place a large inventory of further low-risk drilling opportunities, which we will schedule into our future drilling plans. We plan to drill an additional two wells to further delineate the Doima Chicoral zone in the latter half of this year. Operations at Neiva proceeded efficiently and within cost expectations. An excellent working relationship with the Ecopetrol operations team at Neiva allowed for the seamless addition of one well to the drilling program and several wells to the workover program during project execution.

Orion Heavy Oil Business Unit

Orion's plan to complete an experimental pilot project application to test the THAI technology is proceeding according to plan. During the first quarter, Orion conducted a 20 square kilometre 3D seismic survey over our Christina Lake property to further delineate the potential bitumen resource. Our present assessment is that there may be approximately 500 million barrels of bitumen contained within the area evaluated by the seismic. Technical design of the pilot, as well as environmental assessments and field-scale reservoir simulations of the process are proceeding according to schedule. The Company is also finalizing all business arrangements to purchase the intellectual property rights surrounding the THAI/CAPRI technologies. Current plans are to have the experimental pilot project application finalized and ready for submission by the third quarter of 2003.

FINANCIAL OVERVIEW

(Gas volumes have been converted to barrels of oil equivalent ("boe") on a 6 mcf equals 1 boe basis.)

Petrobank generated cash flow from operations in the first quarter of 2003 of $8.5 million, a 55% improvement over the same period last year. Similarly, net income increased to $3.5 million from $1.0 million. The increase in earnings is attributable to a higher average realized price of $37.64/boe (2002 - $24.21/boe) slightly offset by lower volumes of 5,272 boepd (2002 – 5,591 boepd). Results in the first quarter reflect average production from Colombia of 695 bopd at a netback of $29.39/bbl. Capital expenditures in the quarter totaled $36.0 million, including $8.9 million in Canada, $1.5 million in our Heavy Oil business unit and $25.6 million in Colombia. Net debt at the end of March, including subordinated notes reflected as equity on the balance sheet, was $91.6 million.

Production

Oil and NGL production during the first quarter averaged 2,757 barrels per day (bpd) in Canada, a slight increase from the 2,704 bpd produced in the first quarter of 2002 and 4% higher than the fourth quarter of 2002. First quarter natural gas production of 10.9 million cubic feet per day (mmcfpd) decreased 37% from the 17.3 mmcfpd produced in the first quarter of 2002 and 3% from the 11.2 mmcfpd produced in the fourth quarter of 2002. Natural gas production has declined significantly over the past year primarily due to the anticipated declines associated with the Company's Northwest Alberta properties, in particular at Hamburg and Zama/Larne. The Company's large slave point discovery at Hamburg has declined from 3.7 mmcfpd in the first quarter of 2002 to 1.1 mmcfpd in the first quarter of 2003.

In addition, the Company commenced oil production from its Colombian operations in January 2003 and averaged 695 bpd, net to Petrobank before royalties, in the first quarter. Colombian production in the first quarter is made up of incremental production generated from our first three wells in Orito, five new wells in Neiva and a number of workovers carried out on both blocks.

On a barrel of oil equivalent basis, production averaged 5,272 boe per day (boepd) in the first quarter of the year, a 16% increase over the fourth quarter of 2002 and a 6% decrease from the 5,591 boepd produced in the first quarter of 2002.

Realized Sales Prices

The average Canadian oil and NGL price received in the first quarter was $33.30 per barrel, an increase of 13% compared to the $29.48 per barrel received in the first quarter of 2002. Canadian oil and NGL prices averaged $41.42 per barrel, before hedging losses of $8.12 per barrel, representing a U.S.$6.43 discount to average WTI prices in the quarter. The average natural gas price received in the first quarter was $7.37 per mcf a 130% increase from $3.21 per mcf in the first quarter of 2002. The natural gas price reflects the impact of the Company's long-term physical gas sales contracts that generated lower realized prices during the quarter. Oil sales prices in Colombia averaged $38.58 per barrel in the first quarter, representing a U.S.$8.32 discount to WTI. We anticipate a reduction in net sales prices in the second quarter due to a lower average WTI price, and a stronger Canadian dollar.

Royalties

Royalties increased from $2.4 million in the first quarter of 2002 to $4.2 million in the current period reflecting higher revenues. Colombian royalties are included in this quarter at a rate of 8%. Canadian royalties as a percentage of revenue increased from 20% in the first quarter of 2002 to 26% in the current period. The increase resulted partly from the impact of the Company's forward gas sale contracts, as crown royalties are paid based on posted prices as opposed to actual prices received. In addition, increased commodity prices during the current quarter resulted in higher crown royalty rates.

Production Expenses

Production expenses in Canada increased 15% from $6.31 per boe in the first quarter of 2002 to $7.24 per boe in the current period. This increase is largely a result of the fixed nature of certain operating costs combined with lower Canadian production volumes. Production expenses in Colombia averaged $6.09 per barrel in the first quarter.

General and Administrative Expenses

General and administrative expenses increased to $1.4 million in the first quarter of 2003 from $1.0 million in the comparable 2002 period. The increase relates to incremental overhead associated with the Company's Colombian operations.

Depletion, Depreciation and Site Restoration Expense

Depletion, depreciation and site restoration expense for the first quarter increased to $5.0 million ($10.52 per boe) from $4.5 million ($8.91 per boe) for the same period in 2002. This increase is due partly to significant excess costs incurred on our first two Caballos wells in Orito, which were difficult to complete. As we continue our development work in Orito, which includes a large component of investments in well workovers and pump installations,, the Company anticipates booking additional reserves at lower costs

which will serve to reduce depletion expense. In addition, finding and development costs in Canada increased slightly over the same period.

Interest on Subordinated Notes

Interest on subordinated notes totaled $1.5 million for the first quarter of 2003, consistent with the comparative period. Interest on these notes will increase in future periods as a result of the issuance of an additional $40 million of notes in May 2003.

Capital Expenditures

Capital expenditures in the first quarter totaled $36.0 million, of which $10.4 million was spent in Canada and $25.6 million in Colombia. Colombian expenditures were focused on drilling, completions and workovers in Neiva and Orito. Technical difficulties associated with initial drilling and completion operations at Orito have increased the costs of drilling our first phase of wells on this block.

Liquidity and Capital Resources

At March 31, 2003 net debt totaled $91.6 million, including the outstanding subordinated notes and $8.2 million of bank debt drawn on our $40 million secured Canadian credit facility. In May 2003, the Company issued an additional $40 million face value of subordinated notes and 1.4 million share purchase warrants for net proceeds of approximately $35 million. On a proforma basis, this leaves the Company with approximately $67 million of available cash and undrawn credit at March 31, 2003, to carry out the remainder of its 2003 capital program.

OUTLOOK

In the first quarter of 2003, Petrobank initiated the most aggressive plan in the Company's history. Our current 2003 capital plan contemplates investing $40 million in Canada (including $4 million in Orion) and U.S. $45 million in Colombia. With the recent subordinated note financing, our balance sheet provides the flexibility to efficiently execute the following opportunities. In Canada, we are focused on growing our business with a plan to drill more than 70 wells and develop two new areas. We will continue to be opportunistic with respect to Canadian assets through focused acquisitions and dispositions of properties where we have maximized value. Our Princeton Project has the potential to create a niche in the evolving Canadian CBM business. To date our Colombian operations confirm the potential to add new reserves through the redevelopment of existing fields, and as we fortify our Latin American operating platform, we will look for similar opportunities in the region. With the Orion business unit we have captured and are advancing the development of technologies with the potential to transform oil sands and heavy oil production globally. I look forward to continuing to update our shareholders on these activities in the future.



· Highlights ·

As at and for the three months ended March 31,	2003	2002	% change
Financial			
($000s, except where noted)			
Oil and natural gas revenue	17,917	12,185	47
Cash flow from operations [1]	8,530	5,501	55
Per share – basic $ [2]	0.16	0.12	33
Per share – diluted $ [2]	0.15	0.10	50
Net income	3,537	1,019	247
Net income (loss) attributable to common shareholders	2,020	(715)	
Per share – basic $	0.04	(0.02)	
Per share – diluted $	0.04	(0.02)	
Capital expenditures	35,961	6,913	420
Net debt [3]	91,599	33,309	175
Shareholders' equity excluding subordinated notes	57,759	57,463	1
Common shares outstanding (000s)			
Basic	45,354	33,807	34
Diluted	50,544	57,057	(11)
Operations [4]			
Canadian operating netback ($/boe except where noted)			
Oil and NGLs revenue ($/bbl)	33.30	29.48	13
Natural gas revenue ($/mcf)	7.37	3.21	130
Oil and natural gas revenue	37.64	24.21	55
Royalties	9.77	4.76	105
Production expenses	7.24	6.31	15
Operating netback	20.63	13.14	57
Colombian operating netback ($/bbl)			
Oil revenue	38.58		
Royalties	3.09		
Production expenses	6.09		
Operating netback	29.40		
Average daily production			
Canada - oil and NGLs (bbls)	2,757	2,704	2
Canada - natural gas (mcf)	10,920	17,323	(37)
Total Canada (boe)	4,577	5,591	(18)
Colombia - oil (bbls)	695	-	100
Total Company (boe)	5,272	5,591	(6)

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(1) Cash flow from operations before changes in other non-cash items.
(2) Calculated based on cash flow from operations before changes in other non-cash items less preferred share dividends and interest paid on subordinated notes.
(3) Includes working capital (deficiency) and subordinated notes reflected as equity on the balance sheet.
(4) 6 Mcf of natural gas is equivalent to 1 barrel of oil equivalent (BOE).

Petrobank is pleased to provide the following operational update for each of our three business units, as well as the financial results of the Company for the first quarter of 2003. We are continuing to execute on our overall strategy to create value through our three business units.

In Canada, we have had positive results from two of our new project areas and we expect to have a very active drilling program for the remainder of the year. The entire oil and gas industry has been affected by recent weather conditions which created a prolonged "break-up" season. This has delayed a few of our initiatives by a number of weeks, but we are on target to drill more than 70 wells planned for this year, Petrobank's most active program to date. We are also in the final stages of selling one of our more fully developed properties, creating liquidity on our balance sheet and allowing us to focus our efforts on more value-added opportunities. In Colombia, our initial Orito drilling program has confirmed our geological and seismic interpretations. We have been challenged this year by certain operational and timing difficulties, but overall, our program is proceeding as planned, and we are mapping out a clear path to fully realize the value of our two Incremental Production Contracts. Finally, in Orion, our heavy oil business unit, we are progressing with our plans to submit a pilot project application in the third quarter of this year with a view to commencing a pilot of our revolutionary heavy oil technology (THAI) in early 2004.

Petrobank achieved cash flows of $8.5 million in the first quarter on revenues of $17.9 million. In May 2003, the Company issued an additional $40 million of subordinated notes along with 1.4 million common share purchase warrants for net proceeds of $35 million, increasing our financial flexibility.

OPERATIONAL UPDATE

Canadian Business Unit

In the first quarter, Petrobank drilled a total of 21 wells resulting in 13 oil wells and 8 dry holes. We were successful at our Eyehill and Epping plays where we continued to delineate our successful discoveries from the fourth quarter of 2002. Although we have been delayed by recent weather conditions, we expect to have all of these new wells onstream by the end of the second quarter. The Company also evaluated a new shallow gas prospect in Saskatchewan by leasing a number of "drilling islands" and drilling exploratory test wells into a major Saskatchewan land sale. Unfortunately, the play concept did not develop into a commercial project; however, we did not expose any further capital at the land sale. Although the overall results were below expectations, we were able to evaluate and assess a potentially large opportunity for the Company with a limited investment of capital.

Petrobank is moving forward with our assessment of the coal bed methane (CBM) potential of our Princeton project with a 100 km seismic program planned for the summer to be followed by a five well pilot test. Petrobank recently acquired a successful test seismic line across the Princeton basin that provided an excellent subsurface image of the basin and the necessary parameters for future seismic acquisition.

Currently, the Company is in the final stages of closing the sale of our Zama/Larne and Whiterose properties for $16.5 million, which consist primarily of sour, Slave Point gas in northwest Alberta. We have consistently found it difficult to profitably expand our operations in this area due to the limited drilling season and our reliance on third-party gas processing. Proceeds of this sale will provide the Company with future flexibility and liquidity.

Latin American Business Unit

Orito Block Operations

In the Orito area, three test wells have been drilled to date and initially completed in the Caballos formation to test three distinct geological concepts. A fourth well to further delineate a new extension to the Orito Caballos pool is currently being drilled. The results of these wells are outlined below.

The first well, Dev 1, encountered oil pay in the Caballos and Pepino zones. Initial completion operations in the Caballos were complicated by the fact that the well had a serious channel in the cement behind the production casing. After an extended series of remedial cement squeeze operations and a number of recompletions, the Company has concluded that the water influx through the cement channel cannot be eliminated and that the well will be incapable of producing at sustained rates of greater than 150 BOPD. A decision was made to suspend the Caballos zone and re-complete the well in the Pepino zone. The well is currently on test following a fracture stimulation, and flow results from this, the Company's first Pepino oil well, are expected in the next two weeks. We still consider the potential of the Caballos zone at Dev 1 to be excellent and future plans may include a re-drill and additional tests of the Caballos formation from the Dev 1 drilling platform.

Petrobank's second Caballos well, Dev 2, tested the productive capability of the "saddle" zone which separates the two main producing portions of the Orito field. This well encountered a series of Caballos sands, which, after extensive testing and stimulation, appear to be anomalously tight. Total fluid inflow in this well does not appear to be sustainable in excess of 150 barrels per day, and therefore a decision was made to suspend the Caballos perforations and re-complete the well in the Pepino zone. If successful, this will be the Company's second new Pepino well in the Orito field. Petrobank does not currently have any plans to drill additional wells into the saddle area of the field, and will instead focus future drilling in this area to the west and north of Dev 2.

Petrobank's third Caballos well, Dev 3 was drilled to test a potential westward extension of the main Orito field. This extension was interpreted from the new 3D seismic data and lies outside the previously defined pool limit. The well encountered the Caballos reservoir in a new structural high, was successfully completed, and has been producing at an average rate of 400 BOPD of very high quality (43° API) crude oil. Recently we decided to suspend the lowest set of perforations (which were producing at high water cuts) and fracture stimulate the upper two sand intervals. Test results are expected from this well in the next two weeks. With this successful demonstration of the existence of a new extension to the Orito field, the Company plans to drill at least three additional wells to delineate the extent of this accumulation.

Petrobank's fourth Caballos well, Dev 4, was spudded as a delineation well to the Dev 3 pool extension. The well penetrated the Caballos formation at a similar structural depth to Dev 3 and encountered highly permeable upper Caballos sands. During drilling of the Caballos section, the high permeability resulted in lost circulation and a Caballos sidetrack had to be constructed around a short portion of the stuck drillstring. As a result of these prolonged drilling operations, this well encountered additional drilling complications in the upper section of the hole. At present, we are preparing to run intermediate casing to the top of the Caballos zone. The permeable Caballos section will then be drilled and cased with a liner. Initial geological analysis of this portion of the Dev 4 wellbore indicates that the sand sequences are very similar to those found in Dev 3.

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The Company has also completed a series of workover operations and engineering studies in the Orito Field. We conducted a pilot project of three Electrical Submersible Pump (ESP) conversions to demonstrate the merits of lift modernization. This pilot project has greatly exceeded our expectations. It is clear from our work to date that further Caballos reserves optimization is possible with ESP conversions. In addition to pressure and petrophysical data from the new wellbores, we have also gathered current static and dynamic pressure data from many wells in the pool. This data indicates that the entire reservoir is in general pressure communication and that the current average reservoir pressure is higher than previously estimated. A new 3D reservoir simulation has been completed and updated with the new

structural, pressure, and production information. The model is being used to plan the optimal depletion strategy for the Caballos reservoir, through drilling, recompletions and waterflooding. Finally, our geological interpretation of the shallow Pepino zone indicates a significant upside in this horizon. We are currently evaluating surface locations (which limit to a certain extent where we can drill) in order to commence a program to delineate further Pepino potential in the contract area.

Using the data from our initial work plan, we have prepared a comprehensive field redevelopment plan for Orito that includes extensive modernization of the artificial lift through the installation of ESPs and involves a full program of well stimulations, re-perforations, recompletions, additional Caballos wells, and water injection. The plan also includes workovers, recompletions, and additional drilling in the Pepino, and contemplates a secondary recovery pilot in the main Pepino reservoir. This "omnibus" redevelopment plan has been formally submitted to Ecopetrol, Colombia's state oil company, and is in advanced stages of the approval process. At present, Petrobank is proceeding with some of the initial activities of the plan, including Pepino workovers and completions and additional ESP installations in Caballos wells. We currently have three service rigs and one drilling rig active in the Orito area.

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Orion Heavy Oil Business Unit

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(Gas volumes have been converted to barrels of oil equivalent ("boe") on a 6 mcf equals 1 boe basis.)

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Production

Oil and NGL production during the first quarter averaged 2,757 barrels per day (bpd) in Canada, a slight increase from the 2,704 bpd produced in the first quarter of 2002 and 4% higher than the fourth quarter of 2002. First quarter natural gas production of 10.9 million cubic feet per day (mmcfpd) decreased 37% from the 17.3 mmcfpd produced in the first quarter of 2002 and 3% from the 11.2 mmcfpd produced in the fourth quarter of 2002. Natural gas production has declined significantly over the past year primarily due to the anticipated declines associated with the Company's Northwest Alberta properties, in particular at Hamburg and Zama/Larne. The Company's large slave point discovery at Hamburg has declined from 3.7 mmcfpd in the first quarter of 2002 to 1.1 mmcfpd in the first quarter of 2003.

In addition, the Company commenced oil production from its Colombian operations in January 2003 and averaged 695 bpd, net to Petrobank before royalties, in the first quarter. Colombian production in the first quarter is made up of incremental production generated from our first three wells in Orito, five new wells in Neiva and a number of workovers carried out on both blocks.

On a barrel of oil equivalent basis, production averaged 5,272 boe per day (boepd) in the first quarter of the year, a 16% increase over the fourth quarter of 2002 and a 6% decrease from the 5,591 boepd produced in the first quarter of 2002.

Realized Sales Prices

The average Canadian oil and NGL price received in the first quarter was $33.30 per barrel, an increase of 13% compared to the $29.48 per barrel received in the first quarter of 2002. Canadian oil and NGL prices averaged $41.42 per barrel, before hedging losses of $8.12 per barrel, representing a U.S.$6.43 discount to average WTI prices in the quarter. The average natural gas price received in the first quarter was $7.37 per mcf a 130% increase from $3.21 per mcf in the first quarter of 2002. The natural gas price reflects the impact of the Company's long-term physical gas sales contracts that generated lower realized prices during the quarter. Oil sales prices in Colombia averaged $38.58 per barrel in the first quarter, representing a U.S.$8.32 discount to WTI. We anticipate a reduction in net sales prices in the second quarter due to a lower average WTI price, and a stronger Canadian dollar.

Royalties

Royalties increased from $2.4 million in the first quarter of 2002 to $4.2 million in the current period reflecting higher revenues. Colombian royalties are included in this quarter at a rate of 8%. Canadian royalties as a percentage of revenue increased from 20% in the first quarter of 2002 to 26% in the current period. The increase resulted partly from the impact of the Company's forward gas sale contracts, as crown royalties are paid based on posted prices as opposed to actual prices received. In addition, increased commodity prices during the current quarter resulted in higher crown royalty rates.

Production Expenses

Production expenses in Canada increased 15% from $6.31 per boe in the first quarter of 2002 to $7.24 per boe in the current period. This increase is largely a result of the fixed nature of certain operating costs combined with lower Canadian production volumes. Production expenses in Colombia averaged $6.09 per barrel in the first quarter.

General and Administrative Expenses

General and administrative expenses increased to $1.4 million in the first quarter of 2003 from $1.0 million in the comparable 2002 period. The increase relates to incremental overhead associated with the Company's Colombian operations.

Depletion, Depreciation and Site Restoration Expense

Depletion, depreciation and site restoration expense for the first quarter increased to $5.0 million ($10.52 per boe) from $4.5 million ($8.91 per boe) for the same period in 2002. This increase is due partly to significant excess costs incurred on our first two Caballos wells in Orito, which were difficult to complete. As we continue our development work in Orito, which includes a large component of investments in well workovers and pump installations,, the Company anticipates booking additional reserves at lower costs

which will serve to reduce depletion expense. In addition, finding and development costs in Canada increased slightly over the same period.

Interest on Subordinated Notes

Interest on subordinated notes totaled $1.5 million for the first quarter of 2003, consistent with the comparative period. Interest on these notes will increase in future periods as a result of the issuance of an additional $40 million of notes in May 2003.

Capital Expenditures

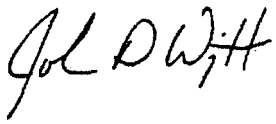
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Liquidity and Capital Resources

At March 31, 2003 net debt totaled $91.6 million, including the outstanding subordinated notes and $8.2 million of bank debt drawn on our $40 million secured Canadian credit facility. In May 2003, the Company issued an additional $40 million face value of subordinated notes and 1.4 million share purchase warrants for net proceeds of approximately $35 million. On a proforma basis, this leaves the Company with approximately $67 million of available cash and undrawn credit at March 31, 2003, to carry out the remainder of its 2003 capital program.

OUTLOOK

In the first quarter of 2003, Petrobank initiated the most aggressive plan in the Company's history. Our current 2003 capital plan contemplates investing $40 million in Canada (including $4 million in Orion) and U.S. $45 million in Colombia. With the recent subordinated note financing, our balance sheet provides the flexibility to efficiently execute the following opportunities. In Canada, we are focused on growing our business with a plan to drill more than 70 wells and develop two new areas. We will continue to be opportunistic with respect to Canadian assets through focused acquisitions and dispositions of properties where we have maximized value. Our Princeton Project has the potential to create a niche in the evolving Canadian CBM business. To date our Colombian operations confirm the potential to add new reserves through the redevelopment of existing fields, and as we fortify our Latin American operating platform, we will look for similar opportunities in the region. With the Orion business unit we have captured and are advancing the development of technologies with the potential to transform oil sands and heavy oil production globally. I look forward to continuing to update our shareholders on these activities in the future.



John D. Wright
President and Chief Executive Officer
May 22, 2003

· Consolidated Balance Sheets ·

As at (Thousands of Canadian dollars)	March 31, 2003 (Unaudited)	December 31, 2002
Assets		
Current assets		
Cash and cash equivalents	**$ -**	$ 12,224
Accounts receivable and other current assets	**13,701**	11,521
	13,701	23,745
Capital assets	**158,196**	126,873
	$ 171,897	$ 150,618
Liabilities and Shareholders' Equity		
Current liabilities		
Accounts payable and accrued liabilities	**$ 39,576**	$ 28,896
Bank debt	**8,204**	-
	47,780	28,896
Obligations under gas hedging contracts	**7,897**	8,097
Future site restoration liability	**941**	613
	56,618	37,606
Shareholders' equity		
Subordinated notes (note 4)	**57,520**	57,344
Common shares (note 2)	**48,125**	48,054
Retained earnings	**9,634**	7,614
	115,279	113,012
	$ 171,897	$ 150,618

Subsequent event (note 4)

See accompanying notes to these consolidated financial statements

· Consolidated Statements of Income and Retained Earnings ·

Three months ended March 31,	2003	2002
(Unaudited, thousands of Canadian dollars, except per share amounts)		
Revenues		
Oil and natural gas	$ 17,917	$ 12,185
Royalties	(4,219)	(2,396)
	13,698	9,789
Expenses		
Production	3,365	3,176
General and administrative	1,369	966
Interest on bank debt	41	-
Depletion, depreciation and site restoration	4,993	4,482
	9,768	8,624
Income before other items and taxes	3,930	1,165
Other expense (income)	119	(105)
Capital tax expense	274	251
Net income	3,537	1,019
Interest on subordinated notes	1,517	1,499
Preferred share dividends and related taxes	-	235
Net income (loss) attributable to common shareholders	2,020	(715)
Retained earnings, beginning of period	7,614	14,562
Retained earnings, end of period	$ 9,634	$ 13,847
Earnings (loss) per share (note 2)		
Basic	$ 0.04	$ (0.02)
Diluted	$ 0.04	$ (0.02)

See accompanying notes to these consolidated financial statements

· Consolidated Statements of Cash Flow ·

Three months ended March 31, (Unaudited, thousands of Canadian dollars)	2003	2002
Operating Activities		
Net income	$ 3,537	$ 1,019
Depletion, depreciation and site restoration	4,993	4,482
Cash flow from operations	8,530	5,501
Changes in other non-cash items	(1,738)	3,555
	6,792	9,056
Financing Activities		
Issuance of bank debt	8,204	-
Issuance of common shares (note 2)	71	-
Preferred share dividends and related taxes	-	(235)
Interest on subordinated notes	(1,341)	(1,341)
Amortization of obligations under gas hedging contracts	(200)	(217)
Changes in other non-cash items	-	813
	6,734	(980)
Investing Activities		
Expenditures on capital assets	(35,961)	(6,913)
Proceeds on disposition of capital assets	-	1,972
Corporate acquisition	-	(42)
Site restoration expenditures	(27)	-
Changes in other non-cash items	10,238	1,705
	(25,750)	(3,278)
Net change in cash position	(12,224)	4,798
Cash and cash equivalents, beginning of period	12,224	25,311
Cash and cash equivalents, end of period	$ -	$ 30,109

See accompanying notes to these consolidated financial statements

As at and for the three months ended March 31, 2003
(All tabular amounts are expressed in thousands of Canadian dollars, except share amounts)

Note 1 – Significant Accounting Policies

The interim consolidated financial statements as at and for the three months ended March 31, 2003 should be read in conjunction with the audited consolidated financial statements as at and for the year ended December 31, 2002. The notes to these interim consolidated financial statements do not conform in all respects to the note disclosure requirements of generally accepted accounting policies for annual financial statements. These interim consolidated financial statements are prepared using the same accounting policies and methods of computation as disclosed in the audited consolidated financial statements as at and for the year ended December 31, 2002. These interim consolidated financial statements include disclosure of segmented information in Note 6, which was not provided in the December 31, 2002 consolidated financial statements, as the Company did not have results from operations in Colombia during the year ended December 31, 2002.

Note 2 – Share Capital

As at March 31, 2003 the Company had outstanding 45,353,871 common shares, 774,960 share purchase warrants, and 4,415,668 stock options.

Common Share Continuity	Number	Amount
Balance at December 31, 2002	45,313,795	$ 48,054
Exercise of stock options	37,316	64
Exercise of share purchase warrants	2,760	7
Balance at March 31, 2003	45,353,871	$ 48,125

Stock Option Continuity	Number	Weighted - Average Exercise Price
Balance at December 31, 2002	4,195,484	$ 2.08
Granted	262,500	3.67
Exercised	(37,316)	(1.71)
Cancelled	(5,000)	(3.40)
Balance at March 31, 2003	4,415,668	$ 2.17

Earnings Per Share

Earnings (loss) per share have been calculated based on the weighted average number of common shares outstanding for the three month period ended March 31, 2003 of 45,339,439 (2002 – 33,665,473). Earnings (loss) per share are based on net income (loss) attributable to common shareholders. The diluted calculation for the three month period ended March 31, 2003 includes 2,223,148 (2002 – nil) additional shares for the potential impact of share purchase warrants and stock options.

Stock Based Compensation

The Company accounts for its stock based compensation plans using the intrinsic value based method whereby no costs are recognized in the statements of operations for stock options granted at market price to employees and directors. Had compensation expense associated with the Company's stock option plan been recognized using the fair value method for stock option grants after January 1, 2002, the Company's net income attributable to common shareholders for the three months ended March 31, 2003 would have been reduced by $119,000 (2002 – net loss increased by $12,000) and net earnings (loss) per share would have approximated reported amounts.

The fair value of stock options granted during the reported periods are estimated using the Black Scholes option pricing model using the following assumptions:

Three months ended March 31,	2003	2002
Risk free interest rate	4%	4%
Dividend rate	0%	0%
Expected life (years)	4	4
Expected volatility	30%	20%

Note 3 – Related Party Transactions

In January 2002, the Company acquired a private company and assumed a $0.6 million balance payable indirectly to two of the Company's directors that was settled in February 2003.

In February 2003, the Company announced that an independent committee of the Board of Directors reached an agreement to acquire certain heavy oil technologies indirectly from two directors of the Company for their original cost of $0.4 million. In addition, a director and an unrelated party have retained a combined 17.5% net profits interest in future third party royalties generated from the technologies.

Note 4 – Subsequent Event

In May 2003, the Company closed a subordinated note financing, resulting in the issuance of $40.0 million face value of subordinated notes and 1,420,300 common share purchase warrants for proceeds, net of costs and agents' commissions, of approximately $35.0 million. The subordinated notes were issued pursuant to Petrobank's existing subordinated note indenture, which stipulates a 9% interest rate and a maturity date of July 31, 2006. Interest on the notes is payable quarterly and accrues from the date of issuance. The subordinated notes and related interest associated with these new subordinated notes will be accounted for in the same manner as the outstanding subordinated notes. The common share purchase warrants are exercisable for common shares at $4.00 each and expire on May 6, 2006.

Note 5 – Commitments and Contingencies

As at March 31, 2003, the Company's remaining work commitments in Colombia totaled U.S.$31 million.

Note 6 – Segmented Information

The Company commenced commercial production from its Colombian operations in January 2003 and accordingly segmented results are presented below only for the three months ended March 31, 2003.

	Canada	Colombia	Total
Revenues			
Oil and natural gas	$ 15,504	2,413	$ 17,917
Royalties	(4,026)	(193)	(4,219)
	11,478	2,220	13,698
Expenses			
Production	2,984	381	3,365
General and administrative	932	437	1,369
Depletion, depreciation and site restoration	4,137	856	4,993
Segmented income	$ 3,425	546	$ 3,971
Non-segmented expenses			
Interest on bank debt			(41)
Other			(119)
Capital tax			(274)
Net income			3,537
Interest on subordinated notes			1,517
Net income attributable to common shareholders			$ 2,020
Identifiable assets	$125,712	46,185	$171,897
Capital expenditures	$ 10,383	25,578	$ 35,961

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FEE RULE

FORM 13-502F1
ANNUAL PARTICIPATION FEE FOR REPORTING ISSUERS

Reporting Issuer Name: **PETROBANK ENERGY AND RESOURCES LTD.**

Participation Fee for the Financial Year Ending: **DECEMBER 31, 2003**

Complete Only One of 1, 2 or 3:

1. Class 1 Reporting Issuers (Canadian Issuers – Listed in Canada and/or the U.S.)

Market value of equity securities:			
Total number of equity securities of a class or series outstanding at the end of the issuer's most recent financial year		45,314	
Simple average of the closing price of that class or series as of the last trading day of each of the months of the financial year (under paragraph 2.5(a)(ii)(A) or (B) of the Rule)	X	$2.27	
Market value of class or series	=		$102,863(A)
(Repeat the above calculation for each class or series of equity securities of the reporting issuer that are listed and posted for trading, or quoted on a marketplace in Canada or the United States of America at the end of the financial year)			(A)
Market value of corporate debt or preferred shares of Reporting Issuer or Subsidiary Entity referred to in Paragraph 2.5(b)(ii): **[Based on December 31, 2002 closing price of TSX: PBG.N]**			$54,400(B)
(Repeat for each class or series of corporate debt or preferred shares)			(B)
Total Capitalization (add market value of all classes and series of equity securities and market value of debt and preferred shares) (A) + (B) =			$157,263
Total fee payable in accordance with Appendix A of the Rule			$15,000
Reduction for transitional fee owing			**$11,250**
Total Fee Payable x Number of entire months remaining in current financial year after the date that the Rule comes into force / 12			
Late Fee, if applicable (please include the calculation pursuant to section 2.9 of the Rule)			

2. Class 2 Reporting Issuers (Other Canadian Issuers)

Financial Statement Values (use stated values from the audited financial statements of the reporting issuer as at its most recent audited year end):

Retained earnings or deficit

Contributed surplus

Share capital or owners' equity, options, warrants and preferred shares (whether such shares are classified

as debt or equity for financial reporting purposes)
Long term debt (including the current portion) _____

Capital leases (including the current portion) _____

Minority or non-controlling interest _____

Items classified on the balance sheet between current liabilities and shareholders' equity (and not otherwise listed above)

Any other item forming part of shareholders' equity and not set out specifically above

Total Capitalization

Total Fee payable pursuant to Appendix A of the Rule

Reduced fee for new Reporting Issuers (see section 2.8 of the Rule)

Total Fee Payable x $\frac{\text{Number of months remaining in financial year or elapsed since most recent financial year}}{12}$

Late Fee, if applicable (please include the calculation pursuant to section 2.9 of the Rule) _____

3. Class 3 Reporting Issuers (Foreign Issuers)

Market value of securities:
If the issuer has debt or equity securities listed or traded on a marketplace located anywhere in the world (see paragraph 2.7(a) of the Rule):
Total number of the equity or debt securities outstanding at the end of the reporting issuer's most recent financial year _____

Simple average of the published closing market price of that class or series of equity or debt securities as of the last trading day of each of the months of the financial year on the marketplace on which the highest volume of the class or series of securities were traded in that financial year. X _____

Percentage of the class registered in the name of, or held beneficially by, an Ontario person X _____

(Repeat the above calculation for each class or series of equity or debt securities of the reporting issuer) = _____

Capitalization (add market value of all classes and series of securities) _____

Or, if the issuer has no debt or equity securities listed or traded on a marketplace located anywhere in the world (see paragraph 2.7(b) of the Rule):

Financial Statement Values (use stated values from the audited financial statements of the reporting issuer as at its most recent audited year end):

Retained earnings or deficit _____

Contributed surplus _____

Share capital or owners' equity, options, warrants and preferred shares (whether such shares are classified as debt or equity for financial reporting purposes) _____

Long term debt (including the current portion) _____

Capital leases (including the current portion) _____

Minority or non-controlling interest _____

Items classified on the balance sheet between current liabilities and shareholders' equity (and not otherwise listed above) _____

Any other item forming part of shareholders' equity and not set out specifically above _____

Percentage of the outstanding equity securities registered in the name of, or held beneficially by, an Ontario person X _____

Capitalization _____

Total Fee payable pursuant to Appendix A of the Rule _____

Reduced fee for new Reporting Issuers (see section 2.8 of the Rule)

Total Fee Payable x $\frac{\text{Number of months remaining in financial year or elapsed since most recent financial year}}{12}$ _____

Late Fee, if applicable
(please include the calculation pursuant to section 2.9 of the Rule) _____

Notes and Instructions

1. This participation fee is payable by reporting issuers other than investment funds that do not have an unregistered investment fund manager.

2. The capitalization of income trusts or investment funds that have no investment fund manager, which are listed or posting for trading, or quoted on, a marketplace in either or both of Canada or the U.S. should be determined with reference to the formula for Class 1 Reporting Issuers. The capitalization of any other investment fund that has no investment fund manager should be determined with reference to the formula for Class 2 Reporting Issuers.

3. All monetary figures should be expressed in Canadian dollars and rounded to the nearest thousand. Closing market prices for securities of Class 1 and Class 3 Reporting Issuers should be converted to Canadian dollars at the [daily noon] in effect at the end of the issuer's last financial year, if applicable.

4. A reporting issuer shall pay the appropriate participation fee no later than the date on which it is required to file its annual financial statements.

5. The number of listed securities and published market closing prices of such listed securities of a reporting issuer may be based upon the information made available by a marketplace upon which securities of the reporting issuer trade, unless the issuer has knowledge that such information is inaccurate and the issuer has knowledge of the correct information.

6. Where the securities of a class or series of a Class 1 Reporting Issuer have traded on more than one marketplace in Canada, the published closing market prices shall be those on the marketplace upon which the highest volume of the class or series of securities were traded in that financial year. If none of the class or series of securities were traded on a marketplace in Canada, reference should be made to the marketplace in the United States on which the highest volume of that class or series were traded.

7. Where the securities of a class or series of securities of a Class 3 Reporting Issuer are listed on more than one exchange, the published closing market prices shall be those on the marketplace on which the highest volume of the class or series of securities were traded in the relevant financial year.

Gas volumes have been converted to barrels of oil equivalent ("boe") so that 6 mcf of gas equals 1 boe. This report contains certain disclosures that are considered non-GAAP terms such as cash flow from operations, cash flow per share, net debt, and operating netback. These measures are commonly utilized in the oil and gas industry and are considered informative for our shareholders. Specifically, cash flow from operations and cash flow per share represent cash generated from operating activities before changes in non-cash working capital. We consider these measures important as they demonstrate our ability to generate sufficient cash to fund future growth opportunities and repay debt.

Petrobank generated cash flow from operations in the second quarter of 2003 of $6.2 million, a 5% increase over the same period last year. The increase in cash flow from operations is attributable to higher average netbacks slightly offset by lower production volumes of 5,129 boepd (2002 – 5,299 boepd). The second quarter of 2003 includes 1,028 barrels of oil per day ('bopd") of Colombian production, which the Company did not have last year. Capital expenditures net of dispositions in the quarter totaled $8.1 million, including $8.7 million of expenditures in Canada and $16.0 million in Colombia, offset by proceeds of $16.6 million on the sale of the Company's Zama/Larne and Whiterose properties. Net debt at the end of June, including subordinated notes reflected as equity on the balance sheet, was $94.8 million.

Subsequent to the second quarter, Petrobank entered into an agreement to acquire all the outstanding shares of Monolith Oil Corp, a private company (the "Acquired Assets"), for $42 million net of estimated working capital to be acquired. The transaction is scheduled to close on September 17, 2003 and is expected to add approximately 2,700 boepd of primarily natural gas production.

Production

Oil and NGL production during the second quarter averaged 2,758 barrels per day (bpd) in Canada, a 9% increase from the 2,541 bpd produced in the second quarter of 2002 and consistent with the first quarter of 2003. Second quarter natural gas production of 8.1 million cubic feet per day (mmcfpd) decreased 51% from the 16.5 mmcfpd produced in the second quarter of 2002 and 26% from the 10.9 mmcfpd produced in the first quarter of 2003. The decrease in natural gas production is a result of anticipated declines associated with the Company's Northwest Alberta properties and the sale of the Company's Zama/Larne and Whiterose properties in May 2003 that at the time, were producing 4 mmcfpd. The Company's recent acquisition and drilling activity at Jumpbush targeting natural gas is expected to add estimated gross productive capacity of approximately 12 mmcfpd. Initially production at Jumpbush will be limited to Petrobank's share of plant capacity or 8.4 mmcfpd. In addition, the Acquired Assets are currently producing 2,700 boepd comprised of 14.5 mmcfpd and 280 barrels per day of oil and NGLs.

Colombian oil production increased from 695 bopd in the first quarter of 2003 to 1,028 bopd in the second quarter. The Company is currently producing 1,800 bopd from Colombia and expects to exit 2003 at approximately 3,000 bopd.

Realized Sales Prices

The average Canadian oil and NGL price received in the second quarter was $28.00 per barrel, a 10% decrease from the $30.98 per barrel received in the second quarter of 2002. Canadian oil and NGL prices averaged $31.81 per barrel, before hedging losses of $3.81 per barrel, representing a U.S.$6.18 discount to average WTI prices in the quarter. The average natural gas price received in the second quarter was $6.34 per mcf a 59% increase from $3.99 per mcf in the second quarter of 2002. The natural gas price reflects the impact of the Company's long-term physical gas sales contracts that generated lower realized prices during the quarter. Oil sales prices in Colombia averaged $29.74 per barrel in the second quarter, representing a U.S.$7.64 discount to WTI. Incremental volumes associated with the Company's drilling program at Jumpbush and the Acquired Assets are expected to increase Petrobank's average realized prices as all production is unhedged.

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Royalties

Royalties decreased from $2.9 million in the second quarter of 2002 to $2.6 million in the current period. Colombian royalties are included in this quarter at a rate of 8%. Canadian royalties as a percentage of revenue decreased slightly from 22% in the second quarter of 2002 to 20% in the current period. The Company's average Canadian royalty rate is expected to increase with the addition of gas production from the Acquired Assets, which attract higher royalty rates.

Production Expenses

Production expenses in Canada increased 29% from $6.24 per boe in the second quarter of 2002 to $8.06 per boe in the current period. This increase is largely a result of the fixed nature of certain operating costs combined with lower Canadian production volumes. Production expenses in Colombia averaged $7.93 per barrel in the second quarter and are expected to decline on a per unit basis as production levels increase. Production expenses per unit are expected to decline as production expenses on the Acquired Assets are forecast to be less than $5.00 per boe and incremental volumes from Jumpbush are to be processed at the Company's gas plant where the majority of costs are fixed.

General and Administrative Expenses

General and administrative expenses increased to $1.7 million in the second quarter of 2003 from $1.0 million in the comparable 2002 period. The increase relates to incremental overhead associated with the Company's Colombian operations and annual bonuses paid in the current period. General and administrative costs are expected to remain relatively unchanged with the addition of the Acquired Assets and as such per-unit costs are expected to decline.

Depletion, Depreciation and Site Restoration Expense

Depletion, depreciation and site restoration expense for the second quarter increased to $5.3 million ($11.25 per boe) from $4.3 million ($8.98 per boe) for the same period in 2002. This increase is due largely to higher than anticipated costs of executing our initial investment program in Colombia.

Interest on Subordinated Notes

Interest on subordinated notes totaled $2.3 million for the second quarter of 2003, an increase from the $1.5 million in the comparative period. This increase is due to the issuance of an additional $40 million of these notes in May 2003.

Capital Expenditures

Capital expenditures in Canada during the quarter were concentrated on drilling in Western Saskatchewan and Jumpbush. Colombian expenditures were focused on drilling, completions and workovers in Neiva and Orito. Technical difficulties associated with initial drilling and completion operations at Orito have increased the costs of our first phase of wells on this block.

Liquidity and Capital Resources

At June 30, 2003 net debt totaled $94.8 million, including subordinated notes reflected as equity on the balance sheet. On a proforma basis, assuming the acquisition of the Acquired Assets had occurred on June 30, 2003 net debt would increase to $121.8 million. As part of the consideration, Petrobank is issuing a $14.5 million debenture that matures on January 31, 2004. The repayment of the debenture is expected to be funded in large part from cash flows associated with the Acquired Assets along with increases in Petrobank's Canadian borrowing base associated with recent reserve additions.

This Report contains forward-looking statements that reflect management's objectives and expectations as at the date of this report. These objectives and expectations involve risks and uncertainties that are common to the oil and natural gas industry. There is no guarantee that these objectives will be met, nor that the expected operating and commodity price conditions will occur. The Company's actual results may differ materially from those anticipated in these forward-looking statements.



· Highlights ·

	Three months ended June 30, 2003	2002	% change	Six months ended June 30, 2003	2002	% change
Financial						
($000s, except where noted)						
Oil and natural gas revenue	**14,459**	13,173	**10**	**32,376**	25,358	**28**
Cash flow from operations [1]	**6,185**	5,899	**5**	**14,715**	11,400	**29**
Per share – basic $ [2]	**0.09**	0.13	**(31)**	**0.25**	0.24	**4**
Per share – diluted $ [2]	**0.09**	0.10	**(10)**	**0.24**	0.20	**20**
Net income	**935**	2,223	**(58)**	**4,472**	3,242	**38**
Net income (loss) attributable to common shareholders	**(1,363)**	465		**657**	(250)	
Per share – basic $	**(0.03)**	0.01		**0.01**	(0.01)	
Per share – diluted $	**(0.03)**	0.01		**0.01**	(0.01)	
Capital expenditures	**24,696**	4,882	**406**	**60,657**	11,795	**414**
Net debt [3]	**94,801**	31,602	**199**	**94,801**	31,602	**199**
Common shares outstanding (000s)						
Basic	**45,594**	34,207	**33**	**45,594**	34,207	**33**
Diluted	**51,587**	57,330	**(10)**	**51,587**	57,330	**(10)**
Operations [4]						
Canadian operating netback ($/boe except where noted)						
Oil and NGLs revenue ($/bbl)	**28.00**	30.98	**(10)**	**30.64**	30.21	**1**
Natural gas revenue ($/mcf)	**6.34**	3.99	**59**	**6.93**	3.60	**93**
Oil and natural gas revenue	**31.29**	27.32	**15**	**34.62**	25.73	**35**
Royalties	**6.29**	6.02	**4**	**8.12**	5.38	**51**
Production expenses	**8.06**	6.24	**29**	**7.63**	6.28	**21**
Operating netback	**16.94**	15.06	**12**	**18.87**	14.07	**34**
Colombian operating netback ($/bbl)						
Oil revenue	**29.74**			**33.27**		
Royalties	**2.40**			**2.67**		
Production expenses	**7.93**			**7.18**		
Operating netback	**19.41**			**23.42**		
Average daily production						
Canada - oil and NGLs (bbls)	**2,758**	2,541	**9**	**2,758**	2,622	**5**
Canada - natural gas (mcf)	**8,057**	16,546	**(51)**	**9,480**	16,932	**(44)**
Total Canada (boe)	**4,101**	5,299	**(23)**	**4,338**	5,444	**(20)**
Colombia - oil (bbls)	**1,028**	-	**100**	**862**	-	**100**
Total Company (boe)	**5,129**	5,299	**(3)**	**5,200**	5,444	**(5)**

(1) Cash flow from operations before changes in other non-cash items.
(2) Calculated based on cash flow from operations before changes in other non-cash items less preferred share dividends and interest paid on subordinated notes.
(3) *Includes working capital (deficiency) and subordinated notes reflected as equity on the balance sheet.*
(4) 6 Mcf of natural gas is equivalent to 1 barrel of oil equivalent (BOE).

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· Report to Shareholders ·

Petrobank Energy and Resources Ltd. ("Petrobank") is pleased to provide this operational update of our Canadian and international activities, our second quarter financial results, and the announcement of a corporate acquisition.

Although initial activities in Colombia have been hampered by technical difficulties and operational delays at the field level, recent well results have been very encouraging and total current production from our Colombian operation has now exceeded 1,800 bopd. The Company remains highly confident in the resource potential of our Colombian assets. We have undertaken a third party reservoir simulation study that indicates that our planned development program for the main productive interval in the Orito field, the Caballos zone, should yield gross incremental production of 50 million barrels over the primary term of the contract. Petrobank's share of incremental production at Orito is currently 79%. As field development continues over the next two to four years it is anticipated that these volumes will be incorporated into our independent reserve evaluation.

In Canada, an aggressive drilling program has yielded impressive results, particularly in the Jumpbush area where we have drilled a series of gas wells, which have significantly exceeded our preliminary expectations. These new gas wells will be tied-in to our existing underutilized facilities in the area through the third quarter, yielding initial incremental production of approximately 4 mmcfpd in the fourth quarter. A follow-up drilling program will continue to delineate the ultimate reserve potential of our extensive contiguous land base.

As a strategic complement to our recent Canadian operational success, the Company today announces that it has entered into an agreement to acquire all the outstanding shares of Monolith Oil Corp. ("Monolith"), a privately owned oil and natural gas company for $42 million (net of acquired working capital). Monolith's properties are focused in the Nevis and Red Willow areas of east central Alberta and bring a significant inventory of gas-weighted, high impact opportunities, which add to, and geologically and operationally complement, our recent successes at Jumpbush.

Monolith Acquisition Summary

- Current daily production of 2,700 boepd (92% gas)
- Acquisition cost of $15,600/boepd and $12.60/boe including future development costs based on Petrobank's internal estimate of established reserves (3.5 mmboe)
- 111% accretive to proforma cash flow per share for the second quarter of 2003
- Significant prospect inventory, with more than 50 drillable locations currently identified
- Land base of 51,000 net acres (27,000 undeveloped)
- High working interest, operated properties

OPERATIONAL UPDATE

Canadian Business Unit

An extended spring break-up resulted in a delay in commencing our second quarter drilling program, but since the end of the first quarter Petrobank has drilled a total of 34 wells resulting in 10 oil wells, 20 gas wells and 4 dry holes.

The majority of these wells have been drilled at our Jumpbush property east of Calgary where we are very encouraged by initial testing results. The target for these wells is predominantly the Belly River and Medicine Hat zones with the deeper and more prolific Glauconite and Ellerslie zones targeted in certain locations. To date, a total of 21 wells at a 70% working interest have been drilled at Jumpbush with 20 cased for gas and one dry hole. Completion of these wells is ongoing and we expect incremental net gas production of approximately 4 mmcfpd in the fourth quarter. We plan to drill an additional 12 gas wells at

Jumpbush during the remainder of 2003 that are forecast to add an incremental 4 mmcfpd of net initial deliverability. During the second quarter we were successful in acquiring an additional 95 gross sections of land in the area accompanied by a shut in gas well that was recently tied in and put on production at a gross rate in excess of 1 mmcfpd. All Jumpbush gas production is being tied into our largely underutilized gas plant that is capable of processing 12 mmcfpd. Capacity increases at this plant are being considered given our current level of success and future drilling plans. Petrobank's technical interpretation indicates our land base could have up to 200 additional drilling locations.

In Western Saskatchewan, a further 12 wells were drilled since the end of the first quarter, five at Epping, six at Eyehill and a horizontal oil well at Lashburn. In 2003, a total of 20 wells have been drilled to date, resulting in 18 oil wells. At Eyehill, we have identified at least 23 follow-up locations and intend to implement a waterflood to enhance oil recoveries. In addition, Petrobank has acquired an additional 5,000 acres of undeveloped land for future growth in the area. Current net production from these properties is approximately 1,000 bopd.

On May 31, 2003, the Company closed the sale of its Zama/Larne and Whiterose properties in northwest Alberta for proceeds of $16.6 million. Production from these properties was approximately 700 boepd at closing which consisted primarily of sour, Slave Point gas. The short drilling season and reliance on third-party gas processing limited our ability to add value at these properties. Sale proceeds from this disposition have allowed us to pursue other opportunities, including the Monolith acquisition.

Canadian production is currently 4,100 boepd, which is consistent with average second quarter production despite the sale of our Zama/Larne and Whiterose properties. Following the completion and tie in of the recent drilling activity in Jumpbush, Petrobank anticipates Canadian production to be approximately 4,600 boepd and following the completion of the Monolith transaction approximately 7,300 boepd.

Monolith Acquisition

Monolith is a private oil and gas company with a focused group of assets in east central Alberta that are natural gas weighted and have significant upside potential. Geologically, these properties are very similar to our existing play types at our Jumpbush property with the primary target being the Glauconite and Ellerslie zones with secondary potential in the Viking, Belly River, and Stettler zones. At current production of 2,700 boepd, the transaction is highly accretive to cash flow per share. Additionally, these properties generate higher operating netbacks than Petrobank's existing Canadian reserve base, and we do not anticipate a need for any material increase in technical or administrative staff as a result of this transaction.

The total purchase price consideration of $42.0 million (net of acquired working capital) is made up of $15.0 million of Petrobank common shares to be priced based on the average trading price for the 10 trading days prior to closing, a $14.5 million debenture and $12.5 million in cash. The debenture will be secured but subordinate to Petrobank's secured credit facility, bear interest at 9% per annum payable monthly, and will mature on January 31, 2004. Subject to certain conditions, including regulatory approval, we anticipate closing this transaction on or about September 17, 2003.

Selected Proforma Information

	Petrobank Second Quarter	Proforma[1]	% Change
Average daily production			
Canada			
Oil and NGLs (bbls)	2,758	2,978	8
Natural gas (mcf)	8,057	22,937	185
Total Canada (boe)	4,101	6,801	66
Colombia			
Oil (bbls)	1,028	1,028	-
Total Company (boe)	5,129	7,829	53
Daily production per thousand common shares	0.112	0.153	37
Cash flow from operations (000's)	$6,185	$12,185	97
Cash flow per share	$0.09	$0.19	111
Canadian operating netback ($/boe)	$16.94	$20.83	23
Net debt (000's)	$94,801	$121,801	28
Net debt/cash flow	3.8	2.5	(34)
Shareholders equity (000's)	$57,579	$72,579	26
Common shares outstanding (000's)	45,594,258	51,029,041[2]	12

Proforma production of 7,829 boepd consists of 5,129 boepd as reported by Petrobank in the second quarter of 2003 plus current Monolith production of 2,700 boepd. For comparison purposes, proforma current production is as follows:

Petrobank's existing Canadian properties (boepd)	4,100
Jumpbush estimated production awaiting tie-in (boepd)	500
Monolith properties (boepd)	2,700
Total Canada (boepd)	7,300
Colombia (bopd)	1,800
Total Company (boepd)	9,100

[1] Proforma results reflect actual Petrobank results for the three months ended June 30, 2003 and include results of operations from the Monolith assets based on current daily production of 14.9 mmcfpd and 220 barrels of oil and natural gas liquids per day and estimated average operating netbacks for the second quarter of 2003 of $26.75/boe.

[2] For purposes of this proforma analysis only, it is assumed that 5,434,783 Petrobank shares are issued to the Monolith shareholders based on the average trading price for the 10 trading days ending August 28, 2003 of $2.76 per Petrobank share.

Latin American Business Unit

As discussed in our first quarter report, our initial efforts in Colombia, particularly in the Orito IPC, have been technically challenging and, as a result, the Company has incurred significant cost overruns and incremental production has lagged expectations. Despite these setbacks, we remain highly confident in the resource potential of our Colombian blocks. This has been confirmed by a recently completed third party simulation study which indicates approximately 50 million barrels of incremental production potential during the primary term of the contract from Orito's Caballos zone. The other productive intervals at Orito as well as all horizons in the Neiva field also continue to exhibit further upside potential. The results of recent drilling and completion operations in Colombia are summarized below.

Our first well at Orito, Dev 1, encountered oil pay in the Caballos and Pepino zones. Initial completion operations in the Caballos were complicated by the fact that the well had a serious water channel in the cement behind the production casing. Remedial cement squeeze operations and recompletions were

unsuccessful and the Caballos zone was suspended. The well was recompleted in the Pepino zone and is currently producing approximately 40 barrels of oil per day.

Petrobank's second Orito well, Dev 2, tested the "saddle" zone that separates the two main producing portions of the Orito field. This well encountered the anticipated Caballos sands, but unfortunately these sands were anomalously tight resulting in a decision to re-complete the well in the Pepino zone. These recompletion operations did not result in commercial quantities of hydrocarbons and the well is currently suspended.

Petrobank's third Orito well, Dev 3 encountered the Caballos reservoir in a new structural high, proving a new western extension of the Orito pool. The well was originally produced at rates averaging 400 bopd of very high quality crude oil. We decided to suspend the lowest set of perforations and fracture stimulate the upper two sand intervals to decrease total water production. Following a prolonged recompletion operation, the well is currently producing approximately 350 bopd at a watercut of approximately 8%. This well is equipped with an electrical submersible pump ("ESP") and we continue to monitor pump efficiency to optimize well performance.

Petrobank's fourth Caballos well, Dev 4, was drilled as an extension to the Dev 3 discovery. The well penetrated the Caballos formation at a similar structural depth to Dev 3 and encountered highly permeable upper Caballos sands. The well commenced production under natural flow on June 11, 2003, has produced approximately 31,000 barrels to date and is currently still flowing naturally at rates of approximately 430 bopd with no water. Dev 4 is equipped with an ESP that will be activated once the well is no longer capable of natural flow. Both of these latest two wells produce high quality 43° API crude oil and confirm the productivity of this new western extension of the Orito pool.

We are continually reassessing our drilling and completion programs, well-site supervision, and field service providers in order to improve operational execution. To this end, the Company has contracted a better-equipped drilling rig to drill our fifth Caballos well. This equipment, together with modifications to our well design and completion program, should result in significantly improved operational and cost performance. This new Caballos well will be drilled into the Orito north dome from our fourth drilling pad where up to six infill locations are planned. The equipment is currently on site and beginning to rig-up with well spud expected by mid-September.

Along with this well, our near term activity will be focused on adding production by installing high volume ESPs in existing producing wells. Installing these ESPs is the first step toward implementing a broad waterflood that is integral to our development plan as envisioned in the recent reservoir simulation conducted by the Computer Modeling Group.

Petrobank is also pleased to announce the appointment of Mark Holliday to the position of Manager, Colombian Operations. Mark is a graduate of Louisiana State University with a Bachelor of Science degree in Petroleum Engineering. Mark has over 22 years of extensive international experience in drilling and completion operations including six years service in the Latin American countries of Argentina, Venezuela, and Ecuador. Mark's experience in these operating environments will provide a valuable addition to our Colombian team.

Exploration Blocks

Petrobank has completed a thorough review of our three Colombian exploration blocks. These blocks were acquired as part of the original acquisition from Encana in 2002. Our technical review indicated these blocks have poor exploration potential based on low hydrocarbon prospectivity, remote location, difficult surface access, and poor social infrastructure. As a result, the Company negotiated with Ecopetrol to relinquish these blocks along with their related work commitments (estimated to cost over $8.5 million). Petrobank has agreed to pay $0.75 million to Ecopetrol to complete the relinquishment agreement. Petrobank continues to evaluate other Colombian development and exploration opportunities and together with two industry partners is currently applying for an association (exploration) contract on a large exploratory block in the country's Middle Magdalena Valley basin.

Orion Heavy Oil Business Unit

The Company recently completed the acquisition of the intellectual property rights and all patents in Canada , the United Sates, Venezuela and the United Kingdom for the THAI and CAPRI heavy oil in situ recovery technologies. Engineering, process design and environmental work is in the final stages to support an application to the AEUB for an experimental pilot project application to test the THAI technology on the Company's oil sands leases near Christina Lake, Alberta.

· Management's Discussion and Analysis ·

Gas volumes have been converted to barrels of oil equivalent ("boe") so that 6 mcf of gas equals 1 boe. This report contains certain disclosures that are considered non-GAAP terms such as cash flow from operations, cash flow per share, net debt, and operating netback. These measures are commonly utilized in the oil and gas industry and are considered informative for our shareholders. Specifically, cash flow from operations and cash flow per share represent cash generated from operating activities before changes in non-cash working capital. We consider these measures important as they demonstrate our ability to generate sufficient cash to fund future growth opportunities and repay debt.

Petrobank generated cash flow from operations in the second quarter of 2003 of $6.2 million, a 5% increase over the same period last year. The increase in cash flow from operations is attributable to higher average netbacks slightly offset by lower production volumes of 5,129 boepd (2002 – 5,299 boepd). The second quarter of 2003 includes 1,028 barrels of oil per day ('bopd") of Colombian production, which the Company did not have last year. Capital expenditures net of dispositions in the quarter totaled $8.1 million, including $8.7 million of expenditures in Canada and $16.0 million in Colombia, offset by proceeds of $16.6 million on the sale of the Company's Zama/Larne and Whiterose properties. Net debt at the end of June, including subordinated notes reflected as equity on the balance sheet, was $94.8 million.

Subsequent to the second quarter, Petrobank entered into an agreement to acquire all the outstanding shares of Monolith Oil Corp, a private company (the "Acquired Assets"), for $42 million net of estimated working capital to be acquired. The transaction is scheduled to close on September 17, 2003 and is expected to add approximately 2,700 boepd of primarily natural gas production.

Production

Oil and NGL production during the second quarter averaged 2,758 barrels per day (bpd) in Canada, a 9% increase from the 2,541 bpd produced in the second quarter of 2002 and consistent with the first quarter of 2003. Second quarter natural gas production of 8.1 million cubic feet per day (mmcfpd) decreased 51% from the 16.5 mmcfpd produced in the second quarter of 2002 and 26% from the 10.9 mmcfpd produced in the first quarter of 2003. The decrease in natural gas production is a result of anticipated declines associated with the Company's Northwest Alberta properties and the sale of the Company's Zama/Larne and Whiterose properties in May 2003 that at the time, were producing 4 mmcfpd. The Company's recent acquisition and drilling activity at Jumpbush targeting natural gas is expected to add estimated gross productive capacity of approximately 12 mmcfpd. Initially production at Jumpbush will be limited to Petrobank's share of plant capacity or 8.4 mmcfpd. In addition, the Acquired Assets are currently producing 2,700 boepd comprised of 14.5 mmcfpd and 280 barrels per day of oil and NGLs.

Colombian oil production increased from 695 bopd in the first quarter of 2003 to 1,028 bopd in the second quarter. The Company is currently producing 1,800 bopd from Colombia and expects to exit 2003 at approximately 3,000 bopd.

Realized Sales Prices

The average Canadian oil and NGL price received in the second quarter was $28.00 per barrel, a 10% decrease from the $30.98 per barrel received in the second quarter of 2002. Canadian oil and NGL prices averaged $31.81 per barrel, before hedging losses of $3.81 per barrel, representing a U.S.$6.18 discount to average WTI prices in the quarter. The average natural gas price received in the second quarter was $6.34 per mcf a 59% increase from $3.99 per mcf in the second quarter of 2002. The natural gas price reflects the impact of the Company's long-term physical gas sales contracts that generated lower realized prices during the quarter. Oil sales prices in Colombia averaged $29.74 per barrel in the second quarter, representing a U.S.$7.64 discount to WTI. Incremental volumes associated with the Company's drilling program at Jumpbush and the Acquired Assets are expected to increase Petrobank's average realized prices as all production is unhedged.

Royalties

Royalties decreased from $2.9 million in the second quarter of 2002 to $2.6 million in the current period. Colombian royalties are included in this quarter at a rate of 8%. Canadian royalties as a percentage of revenue decreased slightly from 22% in the second quarter of 2002 to 20% in the current period. The Company's average Canadian royalty rate is expected to increase with the addition of gas production from the Acquired Assets, which attract higher royalty rates.

Production Expenses

Production expenses in Canada increased 29% from $6.24 per boe in the second quarter of 2002 to $8.06 per boe in the current period. This increase is largely a result of the fixed nature of certain operating costs combined with lower Canadian production volumes. Production expenses in Colombia averaged $7.93 per barrel in the second quarter and are expected to decline on a per unit basis as production levels increase. Production expenses per unit are expected to decline as production expenses on the Acquired Assets are forecast to be less than $5.00 per boe and incremental volumes from Jumpbush are to be processed at the Company's gas plant where the majority of costs are fixed.

General and Administrative Expenses

General and administrative expenses increased to $1.7 million in the second quarter of 2003 from $1.0 million in the comparable 2002 period. The increase relates to incremental overhead associated with the Company's Colombian operations and annual bonuses paid in the current period. General and administrative costs are expected to remain relatively unchanged with the addition of the Acquired Assets and as such per-unit costs are expected to decline.

Depletion, Depreciation and Site Restoration Expense

Depletion, depreciation and site restoration expense for the second quarter increased to $5.3 million ($11.25 per boe) from $4.3 million ($8.98 per boe) for the same period in 2002. This increase is due largely to higher than anticipated costs of executing our initial investment program in Colombia.

Interest on Subordinated Notes

Interest on subordinated notes totaled $2.3 million for the second quarter of 2003, an increase from the $1.5 million in the comparative period. This increase is due to the issuance of an additional $40 million of these notes in May 2003.

Capital Expenditures

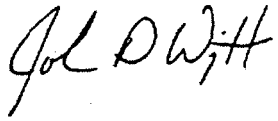
Capital expenditures in Canada during the quarter were concentrated on drilling in Western Saskatchewan and Jumpbush. Colombian expenditures were focused on drilling, completions and workovers in Neiva and Orito. Technical difficulties associated with initial drilling and completion operations at Orito have increased the costs of our first phase of wells on this block.

Liquidity and Capital Resources

At June 30, 2003 net debt totaled $94.8 million, including subordinated notes reflected as equity on the balance sheet. On a proforma basis, assuming the acquisition of the Acquired Assets had occurred on June 30, 2003 net debt would increase to $121.8 million. As part of the consideration, Petrobank is issuing a $14.5 million debenture that matures on January 31, 2004. The repayment of the debenture is expected to be funded in large part from cash flows associated with the Acquired Assets along with increases in Petrobank's Canadian borrowing base associated with recent reserve additions.

Outlook

Although initial operations in Colombia have been operationally challenging we remain enthusiastic about the world-class resource potential of our fields. Our near term drilling plans at Orito will be focused on infill Caballos drilling in the North dome of the field where productivity is proven and on the west extension that has been identified from our Dev 3 and 4 wells. We will also be focusing on low cost ESP installations that have the ability to quickly increase productivity and which are essential to our future waterflood plans. In Canada, we have achieved very strong results from our initial drilling program at Jumpbush. This has established a significant amount of incremental production and further infill and delineation drilling opportunities. The addition of the Monolith assets further strengthens our Canadian operating platform and our long-term financial flexibility. Our greatly expanded prospect inventory will enable us to fuel our longer-term growth from our conventional Canadian properties. Lastly, Petrobank has completed the acquisition of the THAI and CAPRI heavy oil technologies and we are in the process of submitting our experimental pilot project application to test the THAI technology. Interest in this project is growing rapidly, both domestically and internationally. We are excited about the range of opportunities available to Petrobank and look forward to updating shareholders on our progress.



John D. Wright
President and Chief Executive Officer
August 29, 2003

This Report contains forward-looking statements that reflect management's objectives and expectations as at the date of this report. These objectives and expectations involve risks and uncertainties that are common to the oil and natural gas industry. There is no guarantee that these objectives will be met, nor that the expected operating and commodity price conditions will occur. The Company's actual results may differ materially from those anticipated in these forward-looking statements.

· Consolidated Balance Sheets ·

(Unaudited, Thousands of Canadian dollars)

As at	June 30, 2003	December 31, 2002
Assets		
Current assets		
Cash and cash equivalents	**$ 9,115**	$ 12,224
Accounts receivable and other current assets	**13,346**	11,521
Inventory	**3,423**	-
	25,884	23,745
Capital assets	**161,306**	126,873
	$ 187,190	$ 150,618
Liabilities and Shareholders' Equity		
Current liabilities		
Accounts payable and accrued liabilities	**$ 28,365**	$ 28,896
Obligations under gas hedging contracts	**7,695**	8,097
Future site restoration liability	**1,231**	613
	37,291	37,606
Shareholders' equity		
Subordinated notes (note 3)	**92,320**	57,344
Common shares (note 2)	**49,308**	48,054
Retained earnings	**8,271**	7,614
	149,899	113,012
	$ 187,190	$ 150,618

See accompanying notes to these consolidated financial statements

· Consolidated Statements of Income and Retained Earnings ·

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

	Three months ended June 30,		Six months ended June 30,	
	2003	2002	2003	2002
Revenues				
Oil and natural gas	**$ 14,459**	$ 13,173	**$ 32,376**	$ 25,358
Royalties	**(2,571)**	(2,903)	**(6,790)**	(5,299)
	11,888	10,270	**25,586**	20,059
Expenses				
Production	**3,748**	3,008	**7,113**	6,184
General and administrative	**1,718**	980	**3,087**	1,946
Interest on bank debt	**98**	-	**139**	-
Depletion, depreciation and site restoration	**5,250**	4,330	**10,243**	8,812
	10,814	8,318	**20,582**	16,942
Income before other items and taxes	**1,074**	1,952	**5,004**	3,117
Other income (expense)	**149**	(58)	**30**	47
Capital tax expense	**(288)**	(325)	**(562)**	(576)
Unusual gain	**-**	654	**-**	654
Net income	**935**	2,223	**4,472**	3,242
Interest on subordinated notes	**2,298**	1,520	**3,815**	3,019
Preferred share dividends and related taxes	**-**	238	**-**	473
Net income (loss) attributable to common shareholders	**(1,363)**	465	**657**	(250)
Retained earnings, beginning of period	**9,634**	13,847	**7,614**	14,562
Retained earnings, end of period	**$ 8,271**	$ 14,312	**$ 8,271**	$ 14,312
Earnings (loss) per share (note 2)				
Basic	**$ (0.03)**	$ 0.01	**$ 0.01**	$ (0.01)
Diluted	**$ (0.03)**	$ 0.01	**$ 0.01**	$ (0.01)

See accompanying notes to these consolidated financial statements

· Consolidated Statements of Cash Flow ·

(Unaudited, Thousands of Canadian dollars)

	Three months ended June 30,		Six months ended June 30,	
	2003	2002	**2003**	2002
Operating Activities				
Net income	**$ 935**	$ 2,223	**$ 4,472**	$ 3,242
Depletion, depreciation and site restoration	**5,250**	4,330	**10,243**	8,812
Unusual gain	**-**	(654)	**-**	(654)
Cash flow from operations	**6,185**	5,899	**14,715**	11,400
Changes in other non-cash items	**(5,440)**	6,190	**(7,178)**	9,745
	745	12,089	**7,537**	21,145
Financing Activities				
Repayment of bank debt	**(8,204)**	-	**-**	-
Issuance of subordinated notes (note 3)	**34,410**	-	**34,410**	-
Issuance of common shares and share purchase warrants (notes 2 and 3)	**1,183**	622	**1,254**	622
Preferred share dividends and related taxes	**-**	(238)	**-**	(473)
Interest on subordinated notes	**(1,908)**	(1,356)	**(3,249)**	(2,697)
Amortization of obligations under gas hedging contracts	**(202)**	-	**(402)**	(217)
Changes in other non-cash items	**-**	(1,147)	**-**	(334)
	25,279	(2,119)	**32,013**	(3,099)
Investing Activities				
Expenditures on capital assets	**(24,696)**	(4,882)	**(60,657)**	(11,795)
Proceeds on disposition of capital assets	**16,626**	1,471	**16,626**	3,443
Corporate acquisition	**-**	-	**-**	(42)
Proceeds on disposition of temporary investment	**-**	1,654	**-**	1,654
Site restoration expenditures	**-**	(299)	**(27)**	(299)
Changes in other non-cash items	**(8,839)**	557	**1,399**	2,262
	(16,909)	(1,499)	**(42,659)**	(4,777)
Net change in cash position	**9,115**	8,471	**(3,109)**	13,269
Cash and cash equivalents, beginning of period	**-**	30,109	**12,224**	25,311
Cash and cash equivalents, end of period	**$ 9,115**	$ 38,580	**$ 9,115**	$ 38,580

See accompanying notes to these consolidated financial statements

As at and for the three and six month periods ended June 30, 2003
(All tabular amounts are expressed in thousands of Canadian dollars, except share amounts)

Note 1 – Significant Accounting Policies

These interim consolidated financial statements as at and for the three and six month periods ended June 30, 2003 should be read in conjunction with the audited consolidated financial statements as at and for the year ended December 31, 2002. The notes to these interim consolidated financial statements do not conform in all respects to the note disclosure requirements of generally accepted accounting policies for annual financial statements. These interim consolidated financial statements are prepared using the same accounting policies and methods of computation as disclosed in the audited consolidated financial statements as at and for the year ended December 31, 2002. These interim consolidated financial statements include disclosure of segmented information in Note 5, which was not provided in the December 31, 2002 consolidated financial statements, as the Company did not have results from operations in Colombia during the year ended December 31, 2002.

Note 2 – Share Capital

As at June 30, 2003 the Company had outstanding, 45,594,258 common shares, 2,195,260 share purchase warrants, and 3,797,831 stock options.

Common Share Continuity	Number	Amount
Balance at December 31, 2002	45,313,795	$ 48,054
Exercise of stock options	37,316	64
Exercise of share purchase warrants	2,760	7
Balance at March 31, 2003	45,353,871	48,125
Exercise of stock options	240,387	415
Proceeds on issuance of share purchase warrants (note 3)	-	768
Balance at June 30, 2003	45,594,258	$ 49,308

Stock Option Continuity	Number	Weighted-Average Exercise Price
Balance at December 31, 2002	4,195,484	$ 2.08
Granted	262,500	3.67
Exercised	(37,316)	(1.71)
Cancelled	(5,000)	(3.40)
Balance at March 31, 2003	4,415,668	2.17
Granted	543,050	3.24
Exercised	(240,387)	(1.72)
Cancelled	(920,500)	(2.30)
Balance at June 30, 2003	3,797,831	$ 2.32

Share Purchase Warrant Continuity	Number	Weighted-Average Exercise Price
Balance at December 31, 2002	777,720	$ 2.50
Exercised	(2,760)	(2.50)
Balance at March 31, 2003 [1]	774,960	2.50
Issued (note 3)	1,420,300	4.00
Balance at June 30, 2003	2,195,260	$ 3.47

[1] On July 18, 2003, 120,560 of these share purchase warrants expired and the remaining 654,400 were exercised for total proceeds of $1.6 million.

Earnings Per Share

Earnings (loss) per share have been calculated based on the weighted average number of common shares outstanding for the three month period ended June 30, 2003 of 45,534,147 (2002 – 34,021,215) and for the six month period of 45,437,331 (2002 – 33,844,327). Earnings (loss) per share are based on net income (loss) attributable to common shareholders. The diluted calculation for the three month period ended June 30, 2003 includes nil (2002 – 1,257,800) additional shares and for the six month period ended June 30, 2003 includes 1,105,433 (2002 – 632,375) additional shares for the potential impact of in-the-money share purchase warrants and stock options.

Stock Based Compensation

The Company accounts for its stock based compensation plans using the intrinsic value based method whereby no costs are recognized in the statements of operations for stock options granted at market price to employees and directors. Had compensation expense associated with the Company's stock option plan been recognized using the fair value method for stock option grants after January 1, 2002, the Company's loss attributable to common shareholders for the three months ended June 30, 2003 would have been increased by $153,000 (2002 – net income reduced by $33,000) and for the six months ended June 30, 2003 net income attributable to common shareholders would have been reduced by $272,000 (2002 – loss increased by $45,000) and net earnings (loss) per share would have approximated reported amounts.

The fair value of stock options granted during the reported periods are estimated using the Black Scholes option pricing model using the following assumptions:

Three months ended June 30,	2003	2002
Risk free interest rate	4.5%	4%
Dividend rate on common shares	0%	0%
Expected life (years) of stock options	4	4
Expected volatility of common share price	30%	20%

Note 3 – Subordinated Notes

On May 5, 2003, the Company closed a subordinated note financing, resulting in the issuance of $40.0 million face value of subordinated notes and 1,420,300 common share purchase warrants for proceeds, net of discount, issuance costs and agents' commissions, of $35.2 million. The net proceeds were allocated between the subordinated notes ($34.4 million) and the common share purchase warrants ($0.8 million). The subordinated notes are unsecured and were issued pursuant to Petrobank's existing subordinated note indenture, which provides for a 9% interest rate and a maturity date of July 31, 2006. Interest on the notes is payable quarterly and accrues from the date of issuance. These subordinated notes are accounted for in the same manner as the outstanding subordinated notes. The common share purchase warrants are exercisable for common shares at $4.00 each and expire on May 6, 2006.

Note 4 – Commitments and Contingencies

Subsequent to June 30, 2003, the Company agreed to settle its $8.5 million of work commitments under its three Colombian exploration blocks for $0.75 million. As at June 30, 2003, the Company's remaining work commitments on its incremental production blocks at Orito and Neiva in Colombia totaled U.S.$16 million and are required to be completed by June 2004.

Note 5 – Segmented Information

The Company commenced commercial production from its Colombian operations in January 2003 and accordingly segmented results are presented below for the three and six month periods ending June 30, 2003.

Three months ended June 30, 2003	Canada	Colombia	Total
Revenues			
Oil and natural gas	$ 11,677	2,782	$ 14,459
Royalties	(2,347)	(224)	(2,571)
	9,330	2,558	11,888
Expenses			
Production	3,007	741	3,748
General and administrative	1,229	489	1,718
Depletion, depreciation and site restoration	3,641	1,609	5,250
Segmented income	$ 1,453	(281)	$ 1,172
Non-segmented items			
Interest on bank debt			(98)
Other income			149
Capital tax expense			(288)
Net income			935
Interest on subordinated notes			2,298
Net loss attributable to common shareholders			$ (1,363)
Identifiable assets	$126,998	60,192	$187,190
Capital expenditures	$ 8,735	15,961	$ 24,696

Six months ended June 30, 2003	Canada	Colombia	Total
Revenues			
Oil and natural gas	$ 27,181	5,195	$ 32,376
Royalties	(6,373)	(417)	(6,790)
	20,808	4,778	25,586
Expenses			
Production	5,991	1,122	7,113
General and administrative	2,161	926	3,087
Depletion, depreciation and site restoration	7,778	2,465	10,243
Segmented income	$ 4,878	265	$ 5,143
Non-segmented items			
Interest on bank debt			(139)
Other income			30
Capital tax expense			(562)
Net income			4,472
Interest on subordinated notes			3,815
Net income attributable to common shareholders			$ 657
Identifiable assets	$126,998	60,192	$187,190
Capital expenditures	$ 19,118	41,539	$ 60,657

Note 6 – Subsequent Events

In July 2003, the Company closed its previously announced acquisition of certain heavy oil technologies indirectly from two directors of the Company for their original cost of $0.45 million. One of these directors and an unrelated party have retained a combined 17.5% net profits interest in any future third party royalties generated from the technologies.

On August 28, 2003 Petrobank entered into an agreement to acquire all the outstanding shares of a private oil and gas company, with closing expected to occur on or around September 17, 2003. The total purchase price consideration of $42.0 million (net of acquired working capital) is comprised of $15.0 million of Petrobank common shares, to be priced based on the average trading price for the 10 trading days preceding closing, a $14.5 million debenture and $12.5 million in cash. The debenture will be secured but subordinate to Petrobank's secured credit facility, bear interest at 9% per annum payable monthly, and mature on January 31, 2004. The transaction will be accounted for using the purchase method of accounting whereby the purchase price is allocated to the acquired assets, primarily consisting of petroleum and natural gas assets and working capital items, based on their respective fair values.

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Nova Scotia Securities Commission
Ontario Securities Commission
Commission des valeurs mobilières du Québec
Saskatchewan Securities Commission
TSX

Dear Sirs:

Subject: Petrobank Energy and Resources Ltd.

We confirm that the following material was sent by pre-paid mail on August 29, 2003 to the registered shareholders of the common shares of the subject Corporation:

1. Second Quarter Report 2003

In compliance with regulations made under the Securities Act, we are providing this material to you in our capacity as agent for the subject Corporation.

We also confirm that a copy of the above was mailed to all non-registered shareholders of the subject Corporation whose names appear on the Corporation's Supplemental Mailing List as defined in the Canadian Securities Administrators' National Instrument 54-102.

Yours truly,

"signed by"

Tracy Williams
Mailing Professional
ClientServicesMailings@Computershare.com

cc: Petrobank Energy and Resources Ltd.
Attention: Corey Ruttan

TW\43776

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MATERIAL CHANGE REPORT

Item 1. Reporting Issuer:

Petrobank Energy and Resources Ltd.
2600, 240 - 4th Avenue SW
Calgary, AB T2P 4H4

Item 2. Date of Material Change:

August 29, 2003

Item 3. News Release:

A Press Release reporting the material change was issued by the Issuer on August 29, 2003, through CCN Matthews.

Item 4. Summary of Material Change:

Petrobank Energy and Resources Ltd. ("Petrobank") announced that it entered into an agreement (the "Purchase and Sale Agreement") to acquire all of the outstanding shares of Monolith Oil Corp. ("Monolith"), a privately owned oil and natural gas company for $42 million (net of acquired working capital).

Monolith Acquisition Summary

- Current daily production of 2,700 boepd (92% gas) (6:1)
- Acquisition cost of $15,600/boepd and $12.60/boe including future development costs based on Petrobank's internal estimate of established reserves (3.5 mmboe)
- 111% accretive to proforma cash flow per share for the second quarter of 2003
- Significant prospect inventory, with more than 50 drillable locations currently identified
- Land base of 51,000 net acres (27,000 undeveloped)
- High working interest, operated properties
- Monolith's properties are focused in the Nevis and Red Willow areas of east central Alberta and bring a significant inventory of gas-weighted, opportunities, which add to, and geologically and operationally complement, Petrobank's recent successes at Jumpbush.

Item 5. Full Description of Material Change:

Petrobank announced that it entered into the Purchase and Sale Agreement to acquire all of the outstanding shares of Monolith, a privately owned oil and natural gas company for $42 million (net of acquired working capital).

The purchase price is payable as follows:

(a) $12,500,000 in cash, assuming anticipated working capital acquired;

(b) $14,500,000 principal amount of a Debenture, which will be secured but subordinate to Petrobank's secured credit facility, bear interest at 9% per annum, payable monthly and will mature on January 31, 2004; and

(c) $15 million payable in common shares of Petrobank ("Petrobank Shares"). The number of Petrobank Shares issued will be equal to $15 million divided by the weighted average trading price for all trades of Petrobank Shares on the Toronto Stock Exchange during the ten consecutive trading day period ending on the last business day prior to the closing of the transaction, subject to a maximum of eight million Petrobank Shares being issued.

Monolith is a private oil and gas company with a focused group of assets in east central Alberta that are natural gas weighted and have upside potential. Geologically, these properties are very similar to Petrobank's existing play types at Petrobank's Jumpbush property with the primary target being the Glauconite and Ellerslie zones with secondary potential in the Viking, Belly River, and Stettler zones. At current production of 2,700 boepd, the transaction is accretive to cash flow per share. Additionally, these properties generate higher operating netbacks than Petrobank's existing Canadian reserve base, and Petrobank does not anticipate a need for any material increase in technical or administrative staff as a result of this transaction.

Selected Combined Information

	Petrobank Second Quarter	Combined[1]	% Change
Average daily production			
Canada			
Oil and NGLs (bbls)	2,758	2,978	8
Natural gas (mcf)	8,057	22,937	185
Total Canada (boe)	4,101	6,801	66
Colombia			
Oil (bbls)	1,028	1,028	-
Total Company (boe)	5,129	7,829	53
Daily production per thousand common shares	0.112	0.153	37
Net debt (000's)	$ 94,801	121,801	28
Shareholders equity (000's)	$57,579	$ 72,529	26
Common shares outstanding (000's)	45,594,258	51,029,041[2]	12

Combined production of 7,829 boepd consists of 5,129 boepd as reported by Petrobank in the second quarter of 2003 plus current Monolith production of 2,700 boepd. For comparison purposes, combined current production, including Jumpbush estimated production, is as follows:

Petrobank's existing Canadian properties (boepd)	4,100
Jumpbush estimated production awaiting tie-in (boepd)	500
Monolith properties (boepd)	2,700
Total Canada (boepd)	7,300
Colombia (bopd)	1,800
Total Company (boepd)	9,100

(1) Combined results are based on current daily production of Monolith of 14.9 mmcfpd and 220 barrels of oil and natural gas liquids per day.
(2) For purposes of this combined analysis only, it is assumed that 5,434,783 Petrobank Shares are issued to the Monolith shareholders based on the average trading price for the 10 trading days ending August 28, 2003 of $2.76 per Petrobank Share.

The Sale and Purchase Agreement provides for the payment of a termination payment of $1,680,000 by Petrobank or the vendors if the agreement is terminated and the party terminating was not in default of any of their obligations under the agreement and the other party or parties do not concurrently have a right to terminate the agreement as a result of non-satisfaction of conditions.

Subject to satisfaction of certain conditions, including receipt of all required regulatory approvals, closing is scheduled for September 17, 2003.

Item 6. Reliance on Section 146(2) of the Securities Act (Alberta):

Not applicable

Item 7. Omitted Information:

Not applicable

Item 8. Senior Officer:

David Rain, VP Finance and Chief Financial Officer
Telephone: (403) 750-4400

Item 9. Statement of Senior Officer

The foregoing accurately discloses the material change referred to herein.

Dated as of August 29, 2003 at Calgary, Alberta.

Petrobank Energy and Resources Ltd.

By: Signed "*David Rain*"

Copy: Toronto Stock Exchange

PETROBANK
ENERGY AND RESOURCES LTD.

NEWS RELEASE

PETROBANK ANNOUNCES $10 MILLION FLOW THROUGH SHARE FINANCING

Calgary, Alberta – September 11, 2003 - Petrobank Energy and Resources Ltd. ("Petrobank") is pleased to announce that it has entered into an agreement to issue, on a "bought deal" private placement basis, 2,777,778 flow-through common shares at a price of $3.60 per share, for gross proceeds of $10.0 million. The net proceeds from the sale of the flow-through shares will be used to facilitate Petrobank's exploration and development activities, including our expanded inventory of opportunities associated with the recently announced acquisition of Monolith Oil Corp.

The shares will be issued through a syndicate of underwriters composed of Tristone Capital Inc., FirstEnergy Capital Corp. and Haywood Securities Inc. Closing of this financing is expected to occur on or about September 24, 2003 and is subject to normal regulatory approvals.

This news release shall not constitute an offer to sell or the solicitation of any offer to buy the securities in any jurisdiction. The common shares offered will not be and have not been registered under the United States Securities Act of 1933 and may not be offered or sold in the United States absent registration or an applicable exemption from the registration requirement.

NOT FOR DISTRIBUTION TO U.S. NEWSWIRE SERVICES OR FOR DISSEMINATION IN THE UNITED STATES.

FOR FURTHER INFORMATION PLEASE CONTACT:

John D. Wright, President and Chief Executive Officer
Telephone: (403) 750-4400

Corey Ruttan, Director Corporate Finance and Investor Relations
Telephone: (403) 750-4400

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MATERIAL CHANGE REPORT

Item 1. Reporting Issuer:

Petrobank Energy and Resources Ltd.
2600, 240 - 4th Avenue SW
Calgary, AB T2P 4H4

Item 2. Date of Material Change:

September 11, 2003

Item 3. News Release:

A Press Release reporting the material change was issued by the Issuer on September 11, 2003, through CCN Matthews.

Item 4. Summary of Material Change:

Petrobank Energy and Resources Ltd. ("Petrobank") announced that it has entered into a bought deal financing agreement with an underlying syndicate composed of Tristone Capital Inc., FirstEnergy Capital Corp. and Haywood Securities Inc., to issue 2,777,778 flow-through common shares at $3.60 per share, for gross proceeds of $10.0 million.

Item 5. Full Description of Material Change:

Petrobank announced that it has entered into a bought deal financing agreement with an underlying syndicate composed of Tristone Capital Inc., FirstEnergy Capital Corp. and Haywood Securities Inc., to issue 2,777,778 flow-through common shares at $3.60 per share, for gross proceeds of $10.0 million.

The issue is subject to normal regulatory approvals and closing is expected to occur on or about September 24, 2003. The proceeds from the issuance will be used to facilitate Petrobank's exploration and development activities, including its expanded inventory of opportunities associated with the recently announced acquisition of Monolith Oil Corp.

Item 6. Reliance on Section 146(2) of the Securities Act (Alberta):

Not applicable

Item 7. Omitted Information:

Not applicable

Item 8. Senior Officer:

John D. Wright, President and Chief Executive Officer
Telephone: (403) 750-4400

Item 9. Statement of Senior Officer

The foregoing accurately discloses the material change referred to herein.

Dated as of September 12, 2003 at Calgary, Alberta.

Petrobank Energy and Resources Ltd.

By: Signed "*John D. Wright*"

Copy: Toronto Stock Exchange

PETROBANK
ENERGY AND RESOURCES LTD.

NEWS RELEASE

PETROBANK CLOSES MONOLITH ACQUISITION

Calgary, Alberta – September 19, 2003 - Petrobank Energy and Resources Ltd. ("Petrobank") is pleased to announce that it has closed the previously announced acquisition of all the outstanding shares of Monolith Oil Corp. ("Monolith"), a privately owned oil and natural gas company. The total purchase price consideration of $42.0 million (net of estimated acquired working capital) is made up of 5,209,551 ($15.0 million) Petrobank common shares, a $14.5 million debenture and $12.5 million in cash. The debenture is secured but subordinate to Petrobank's secured credit facility, bears interest at 9% per annum payable monthly, and will mature on January 31, 2004.

The Monolith properties are focused in the Nevis and Red Willow areas of east central Alberta and bring a significant inventory of gas-weighted, high impact opportunities. Geologically, these properties are very similar to our existing play types at our Jumpbush property with the primary target being the Glauconite and Ellerslie zones with secondary potential in the Viking, Belly River, and Stettler zones. At current production of 2,700 boepd, the transaction is highly accretive to cash flow per share.

Monolith Acquisition Summary

- Current daily production of 2,700 boepd (92% gas)
- Acquisition cost of $15,600/boepd and $12.60/boe (including future development costs) based on Petrobank's internal estimate of established reserves of 3.5 mmboe
- 111% accretive to proforma cash flow per share for the second quarter of 2003
- Significant prospect inventory, with more than 50 drillable locations currently identified
- Land base of 51,000 net acres (27,000 undeveloped)
- High working interest, operated properties

This acquisition, along with our recent success at Jumpbush, have expanded Petrobank's inventory of high quality prospects. The previously announced $10 million flow-through financing facilitates the enhancement of our Canadian asset base.

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FOR FURTHER INFORMATION PLEASE CONTACT:

John D. Wright, President and Chief Executive Officer
Telephone: (403) 750-4400

Corey Ruttan, Director Corporate Finance and Investor Relations
Telephone: (403) 750-4400

www.petrobank.com

PETROBANK
ENERGY AND RESOURCES LTD.

NEWS RELEASE

PETROBANK CLOSES $10 MILLION FLOW THROUGH SHARE FINANCING

Calgary, Alberta – September 24, 2003 - Petrobank Energy and Resources Ltd. ("Petrobank") is pleased to announce that it has completed its offering of 2,777,778 flow-through common shares at a price of $3.60 per share, for gross proceeds of $10.0 million. The shares were sold on a "bought deal" private placement basis through a syndicate of underwriters composed of Tristone Capital Inc., FirstEnergy Capital Corp. and Haywood Securities Inc. The net proceeds from the sale of the flow-through shares will be used to facilitate Petrobank's exploration and development activities, including our expanded inventory of opportunities associated with the recently completed acquisition of Monolith Oil Corp.

FOR FURTHER INFORMATION PLEASE CONTACT:

John D. Wright, President and Chief Executive Officer
Telephone: (403) 750-4400

Corey Ruttan, Director Corporate Finance and Investor Relations
Telephone: (403) 750-4400

www.petrobank.com

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FORM 45-102F2

Certificate under Subsection 2.7(2) or (3) of Multilateral Instrument 45-102 Resale of Securities

Petrobank Energy and Resources Ltd., has distributed securities under a provision listed in Appendix D or E to Multilateral Instrument 45-102 or a provision of securities legislation that specifies that the first trade of the securities is subject to section 2.5 or 2.6 of Multilateral Instrument 45-102 and hereby certifies that in respect of a distribution on September 24, 2003 of 2,777,778 Common Shares of Petrobank Energy and Resources Ltd., Petrobank Energy and Resources Ltd. was a qualifying issuer within the meaning of Multilateral Instrument 45-102 Resale of Securities at the distribution date.

DATED this 24th day of September, 2003.

PETROBANK ENERGY AND RESOURCES LTD.

By: (signed) *"David J. Rain"*
David J. Rain
Vice-President, Finance & Chief Financial Officer

INSTRUCTIONS:

1. If the distribution date is on or after the effective date of Multilateral Instrument 45-102 and the issuer or selling security holder has completed 1. above, file this form on or before the tenth day after the distribution date with the securities regulatory authority in each jurisdiction in which a purchaser of the securities is located and section 2.7 of Multilateral Instrument 45-102 has been implemented. Section 2.7 has been implemented in Alberta, British Columbia, Newfoundland, Northwest Territories, Nova Scotia, Nunavut, Ontario and Saskatchewan.

2. If the issuer has completed 2 above, file this form with the securities regulatory authority in each jurisdiction in which a purchaser of the securities is located and section 2.7 of Multilateral Instrument 45-102 has been implemented.

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MATERIAL CHANGE REPORT

Item 1. Reporting Issuer:

Petrobank Energy and Resources Ltd.
2600, 240 - 4th Avenue SW
Calgary, AB T2P 4H4

Item 2. Date of Material Change:

September 19, 2003
September 24, 2003

Item 3. News Release:

Press Releases reporting the material changes were issued by the Issuer on September 19 and 24, 2003, respectively, through CCN Matthews.

Item 4. Summary of Material Change:

Petrobank Energy and Resources Ltd. ("Petrobank") announced that on September 19, 2003 it closed the previously announced acquisition of all the outstanding shares of Monolith Oil Corp. ("Monolith"), a privately owned oil and natural gas company. The total purchase price consideration of $42.0 million (net of estimated acquired working capital) is made up of 5,209,551 ($15.0 million) common shares of Petrobank, a $14.5 million debenture and $12.5 million cash. The debenture is secured but subordinate to Petrobank's secured credit facility, bears interest at 9.0% per annum payable monthly, and will mature on January 31, 2004.

Petrobank also announced that it completed on September 24, 2003 its offering of 2,777,778 flow-through common shares at a price of $3.60 per share, for gross proceeds of $10.0 million. The shares were sold on a "bought deal" private placement basis through a syndicate of underwriters composed of Tristone Capital Inc., FirstEnergy Capital Corp. and Haywood Securities Inc.

Item 5. Full Description of Material Change:

Petrobank announced that on September 19, 2003 it closed the previously announced acquisition of all the outstanding shares of Monolith, a privately owned oil and natural gas company. The total purchase price consideration of $42.0 million (net of estimated acquired working capital) is made up of 5,209,551 ($15.0 million) common shares of Petrobank, a $14.5 million debenture and $12.5 million cash. The debenture is secured but subordinate to Petrobank's secured credit facility, bears interest at 9.0% per annum payable monthly, and will mature on January 31, 2004.

Petrobank also announced that it completed on September 24, 2003 its offering of 2,777,778 flow-through common shares at a price of $3.60 per share, for gross proceeds of $10.0 million. The shares were sold on a "bought deal" private placement basis through a syndicate of underwriters composed of Tristone Capital Inc., FirstEnergy Capital Corp. and Haywood Securities Inc.

The net proceeds from the sale of the flow-through shares will be used to facilitate Petrobank's exploration and development activities, including its expanded inventory of opportunities associated with the acquisition of Monolith.

Item 6. **Reliance on Section 146(2) of the Securities Act (Alberta):**

Not applicable

Item 7. **Omitted Information:**

Not applicable

Item 8. **Senior Officer:**

David Rain, VP Finance and Chief Financial Officer
Telephone: (403) 750-4400

Item 9. **Statement of Senior Officer**

The foregoing accurately discloses the material change referred to herein.

Dated as of September 25, 2003 at Calgary, Alberta.

Petrobank Energy and Resources Ltd.

By: (signed) *"David Rain"*
David Rain

Copy: Toronto Stock Exchange

FORM 45-102F2

Certificate under Subsection 2.7(2) or (3) of
Multilateral Instrument 45-102 Resale of Securities

Petrobank Energy and Resources Ltd., has distributed securities under a provision listed in Appendix D or E to Multilateral Instrument 45-102 or a provision of securities legislation that specifies that the first trade of the securities is subject to section 2.5 or 2.6 of Multilateral Instrument 45-102 and hereby certifies that in respect of a distribution on September 19, 2003 of 5,209,551 Common Shares of Petrobank Energy and Resources Ltd. and a Debenture in the aggregate principal amount of $14.5 million, Petrobank Energy and Resources Ltd. was a qualifying issuer within the meaning of Multilateral Instrument 45-102 Resale of Securities at the distribution date.

DATED this 29th day of September, 2003.

PETROBANK ENERGY AND RESOURCES LTD.

By: (signed) *"Doreen Scheidt"*
Doreen Scheidt
Corporate Controller

INSTRUCTIONS:

1. If the distribution date is on or after the effective date of Multilateral Instrument 45-102 and the issuer or selling security holder has completed 1. above, file this form on or before the tenth day after the distribution date with the securities regulatory authority in each jurisdiction in which a purchaser of the securities is located and section 2.7 of Multilateral Instrument 45-102 has been implemented. Section 2.7 has been implemented in Alberta, British Columbia, Newfoundland, Northwest Territories, Nova Scotia, Nunavut, Ontario and Saskatchewan.

2. If the issuer has completed 2 above, file this form with the securities regulatory authority in each jurisdiction in which a purchaser of the securities is located and section 2.7 of Multilateral Instrument 45-102 has been implemented.

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PETROBANK
ENERGY AND RESOURCES LTD.

NEWS RELEASE

PETROBANK FILES WHITESANDS PILOT PROJECT APPLICATION TO TEST REVOLUTIONARY HEAVY OIL TECHNOLOGY

Calgary, Alberta – October 17, 2003 - Petrobank Energy and Resources Ltd. ("Petrobank") is pleased to announce that it has filed an application for approval of the WHITESANDS Experimental Pilot Project with the Alberta Energy and Utilities Board and Alberta Environment. The WHITESANDS project will be the first field scale test of the patented THAI™ (Toe-to-Heel-Air-Injection) *in-situ* heavy oil recovery technology. In making the announcement, John D. Wright, President and CEO of Petrobank said, "the THAI process has the potential to revolutionize the heavy oil extraction business worldwide, with substantially better economics and less environmental impact than other technologies currently in use."

THAI™ is a new *in-situ* combustion technology for the recovery of bitumen and heavy oil that combines a vertical air injection well with a horizontal production well. THAI™ has many potential benefits over other *in-situ* recovery methods, such as SAGD (Steam Assisted Gravity Drainage). Potential benefits include higher resource recovery, lower production and capital costs, minimal usage of natural gas and fresh water, a partially upgraded crude oil product, reduced diluent requirements for transportation, and lower greenhouse gas emissions. The THAI™ process also has the potential to operate in lower pressure, lower quality, thinner and deeper reservoirs than current steam–based processes. Petrobank owns the intellectual property rights associated with this patented technology.

Following receipt of regulatory approval, Petrobank, through its wholly-owned subsidiary Orion Oil Canada Ltd. ("Orion"), plans to initiate the WHITESANDS project on its 42 sections of 100 percent-owned oil sands leases near Conklin, Alberta. Early in 2003, a 20 square kilometer seismic survey was conducted over the project area, which, along with existing well control, identified an in-place bitumen resource of up to 500 million barrels.

Chris J. Bloomer, President and CEO of Orion, stated, "We have extensively tested the THAI process in the lab and confirmed its potential at a field-scale through numerical reservoir simulations. This analysis, along with engineering design, environmental assessment, and community consultation has culminated in the submission of our experimental pilot project application. Delineation drilling and site preparation for the pilot could begin early in 2004 with start up commencing later in 2004."

For more information on the THAI™ process and to view Orion's experimental pilot project application please visit Petrobank's website at www.petrobank.com or call:

John D. Wright, President and CEO – Petrobank Energy and Resources Ltd., or
Chris J. Bloomer, President and CEO - Orion Oil Canada Ltd.
Telephone: (403) 750-4400

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PETROBANK
ENERGY AND RESOURCES LTD.

NEWS RELEASE

PETROBANK ADVISES OF COLOMBIAN GUERILLA ACTIVITY

Calgary, Alberta – November 19, 2003 - At 9:30 p.m. Eastern Standard Time on November 18th, guerrillas initiated hostilities in the vicinity of four Ecopetrol operated fields in southern Colombia, including the Orito block. Colombian army personnel stationed on the Orito block took defensive action. None of Petrobank's personnel were affected. Certain Ecopetrol facilities incurred minor damage and as a precautionary measure, some wells in the field have been shut in. We have been informed that repairs will be completed within 24 hours.

FOR FURTHER INFORMATION PLEASE CONTACT:

John D. Wright, President and Chief Executive Officer
Telephone: (403) 750-4400

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PETROBANK
ENERGY AND RESOURCES LTD.

NEWS RELEASE

PETROBANK ANNOUNCES OPERATIONAL UPDATE AND THIRD QUARTER RESULTS

Calgary, Alberta – November 28, 2003 - Petrobank Energy and Resources Ltd. ("Petrobank") is pleased to provide this operational update of our Canadian and Colombian activities as well as our third quarter financial results.

OPERATIONAL UPDATE

Latin American Business Unit

During the quarter in Colombia, we drilled our fifth Caballos well ("DEV-5") on the Orito block with our re-engineered drilling and completion program. This was Petrobank's first Caballos well drilled into the Northern producing region of the field, and we are encouraged by its results. The well was drilled on budget, at a total cost of US$3.0 million, and is producing at a gross rate of 700 barrels of oil per day, exceeding initial expectations. Based on the results of this new well, we are currently drilling our sixth Caballos well ("DEV-6"), 500 meters from the DEV-5 location.

The guerilla activities in the Putumayo region, referred to in our press release dated November 19, 2003, have impacted production from the Orito Block. Including production from our DEV-5 well, we were producing approximately 2,200 net barrels of oil per day ("bopd") from our Colombian properties as of November 18, 2003. We are currently producing 1,750 bopd net. Ecopetrol and Petrobank are working together to re-establish our pre-existing production level. Assuming continued success at our DEV-6 location, and completion of several planned workovers, we expect to exit 2003 at approximately 3,000 net bopd.

To date, production in Colombia has been negatively impacted by both Petrobank operational difficulties and shortfalls or interruptions in Ecopetrol's baseline production levels in the Orito Block. We are working with Ecopetrol to increase their maintenance program associated with the baseline production. We believe these issues will be addressed and resolved in the near future, generating an increase in net production.

We continue to be confident in the significant resource potential of our Colombian assets as indicated by our recent drilling success at DEV-5. We are continuing to refine our internal reservoir simulation model to design an optimal field-wide secondary recovery plan. In addition, there are a number of exciting delineation opportunities that we would like to explore in 2004, which may increase our initial assessment of original oil in place and recoverable reserves.

To complement our incremental production contracts at Orito and Neiva, Petrobank continues to evaluate other Colombian development and exploration opportunities. Petrobank, along with two industry partners, signed an association (exploration) contract on a large exploratory block (Bloque Colombia). This block is in the country's Upper Magdalena Valley basin, northeast of our Neiva block. At a low initial cost (US$0.3 million net), this contract gives Petrobank the opportunity to evaluate and participate in a high impact exploration play with significant follow up opportunities.

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Canadian Business Unit

In Canada, we completed our first phase of drilling at Jumpbush with 20 of 21 wells being cased for natural gas. Production from 17 of these wells has just been tied in, following an extended First Nations approval process with the Siksika Nation. At Jumpbush, we are currently producing net 3.2 million cubic feet of natural gas per day ("mmcfpd"), which is expected to increase to net 4.2 mmcfpd following the installation of field compression equipment planned for early December. Over the remainder of the year, we intend to drill an additional 8 wells at Jumpbush to evaluate and earn our land base in the area and to provide preliminary direction for our 2004 infill-drilling program. In an effort to optimize gathering system construction, the next 8 wells drilled at Jumpbush will not be tied in before mid 2004. All production at Jumpbush is being processed at our existing underutilized facilities in the area with current net capacity of 8.4 mmcfpd. Additional plant capacity may be constructed on a staged basis in 2004 as we add incremental production from this area.

On September 19, 2003, Petrobank acquired Monolith Oil Corp. with properties focused in the Nevis and Red Willow areas of east central Alberta. The third quarter results only include results from these properties subsequent to the closing date, and as a result, fourth quarter Canadian production is expected to increase sharply. This acquisition created a significant inventory of high impact natural gas opportunities, including six wells we are planning to drill by the end of the year. We plan to tie-in these wells in the first quarter of 2004. We also anticipate an improvement in Petrobank's netback in the fourth quarter as a result of including a full quarter's production from the Monolith properties. The average netback on the Monolith properties for the third quarter was $23.97 per boe, which was approximately 55% higher than Petrobank's reported netback on a consolidated basis. The Monolith volumes generate higher net prices per boe as they are primarily gas, and the operating costs are approximately $5.00 per boe, less than Petrobank's existing average.

We completed our 20 well drilling program with 18 cased oil wells on our Western Saskatchewan properties. Since bringing these wells on production, we have experienced higher water cuts than initially anticipated. Current production from these properties is 750 bopd. Petrobank is evaluating the implementation of a waterflood in these reservoirs to capture proven undeveloped reserves.

Canadian production is currently 6,500 boepd, a 62% increase from average third quarter production. Petrobank completed the sale of approximately 70 boepd of production from our Ferrybank property at the beginning of the fourth quarter. Following the tie-in of two more wells and installation of compression at Jumpbush, addition of two new oil wells at Red Willow, and optimization of the gas gathering systems at Nevis and Red Willow, we expect to increase Canadian production to approximately 7,000 boepd by the end of this year.

Orion Heavy Oil Business Unit

In October 2003, we filed our application for approval of the WHITESANDS Experimental Pilot Project with the Alberta Energy and Utilities Board and Alberta Environment. The WHITESANDS project will be the first field scale test of Petrobank's patented THAI™ (Toe-to-Heel-Air-Injection) in-situ heavy oil recovery technology. THAI™ is a new in-situ combustion technology for the recovery of bitumen and heavy oil that combines a vertical air injection well with a horizontal production well. Following receipt of regulatory approval, which is anticipated prior to the end of this year, Petrobank plans to initiate the WHITESANDS project on our 42 sections of 100 percent-owned oil sands leases near Conklin, Alberta. The Company is currently evaluating other opportunities to apply the THAI™ technology, both in Canada and internationally. As well, we are investigating different possibilities for structuring third party financial partnerships in the WHITESANDS project, which would allow us to test the commercial viability of the process as soon as possible.

·MANAGEMENT'S DISCUSSION AND ANALYSIS·

Gas volumes have been converted to barrels of oil equivalent ("boe") so that 6 mcf of gas equals 1 boe. This report contains financial terms that are considered non-GAAP measures such as cash flow from operations, cash flow per share, net debt, and operating netback. These measures are commonly utilized in the oil and gas industry and are considered informative for our shareholders. Specifically, cash flow from operations and cash flow per share reflect cash generated from operating activities before changes in non-cash working capital. We consider these measures important as they demonstrate our ability to generate sufficient cash to fund future growth opportunities and repay debt. All amounts are in Canadian dollars, unless otherwise stated.

Petrobank acquired Monolith Oil Corp. ("Monolith") on September 19, 2003 for $39.3 million. The September 30, 2003 balance sheet reflects the cost of the Monolith acquisition but the results of operations for the third quarter of 2003 only include results from the acquired properties subsequent to the closing date. Production from these properties averaged 2,570 boepd between the closing date and the end of the third quarter, but only contributed 335 boepd to average third quarter production.

Petrobank generated cash flow from operations in the third quarter of 2003 of $5.8 million, consistent with the same period last year. Capital expenditures during the quarter totaled $28.1 million, including $13.3 million of expenditures in Canada and $14.8 million in Colombia.

Production

Oil and NGL production during the third quarter averaged 2,909 barrels per day (bpd) in Canada, a 12% increase from the 2,596 bpd produced in the third quarter of 2002 and a 5% increase from the second quarter of 2003. Third quarter natural gas production of 6.6 million cubic feet per day (mmcfpd) decreased 50% from the 13.1 mmcfpd produced in the third quarter of 2002 and 18% from the 8.1 mmcfpd produced in the second quarter of 2003. The decrease in natural gas production is primarily a result of the sale of the Company's Zama/Larne and Whiterose properties in May 2003. Fourth quarter natural gas production is forecasted to increase significantly through the inclusion of the Monolith properties for the entire quarter and the recent tie-in of the Company's 2003 drilling program at Jumpbush.

Colombian oil production increased from 1,028 bopd in the second quarter of 2003 to 1,166 bopd in the third quarter. During the year the Company has experienced intermittent production interruptions and shortfalls in the Ecopetrol baseline production in the Orito Block. The Company and Ecopetrol have taken steps to address this issue, and Ecopetrol has recently re-structured its management in the Orito production office. With some production still affected by ongoing repair operations, the Company is currently producing 1,750 bopd from Colombia and expects to exit 2003 at approximately 3,000 bopd. We are currently drilling our sixth Caballos well and plan to carry out two additional well workovers that we expect to have on production before the end of the year. Petrobank also believes that Ecopetrol will meet its baseline production obligation between now and the end of the year.

Realized Sales Prices

The average Canadian oil and NGL price received in the third quarter was $27.19 per barrel, a 17% decrease from the $32.74 per barrel received in the third quarter of 2002. Canadian oil and NGL prices averaged $31.78 per barrel, before hedging losses of $4.59 per barrel, representing a U.S.$7.17 discount to average WTI prices in the quarter. The average natural gas price received in the third quarter was $4.98 per mcf, a 37% increase from $3.63 per mcf in the third quarter of 2002. The natural gas price in the quarter reflects the negative impact of the Company's long-term physical gas sales contracts. Oil sales prices in Colombia averaged $31.37 per barrel in the third quarter, representing a U.S.$7.47 discount to WTI. Incremental unhedged gas volumes associated with the Company's drilling program at Jumpbush and the acquired Monolith properties are expected to

increase Petrobank's average realized prices. In November 2003, the Company entered into two fixed-price physical sale contracts for the 2004 calendar year. Under these contracts, the Company has agreed to sell 300 barrels of oil per day at a West Texas Intermediate price of US$27.68 and 300 barrels of oil per day at a West Texas Intermediate price of US$27.74.

Royalties

Royalties decreased from $2.6 million in the third quarter of 2002 to $2.2 million in the current period. Colombian royalties are included in the current quarter at a rate of 8%. Canadian royalties as a percentage of revenue decreased from 22% in the third quarter of 2002 to 19% in the current period. The Company's average Canadian royalty rate is expected to increase with the addition of gas production from the Monolith properties for the entire fourth quarter.

Production Expenses

Production expenses in Canada increased 8% from $6.55 per boe in the third quarter of 2002 to $7.06 per boe in the current period. This increase is largely a result of the fixed nature of certain operating costs combined with lower Canadian production volumes. Production expenses in Colombia averaged $9.24 per barrel in the quarter and are expected to decline on a per unit basis as production levels increase. Production expenses remain high in Colombia as we have experienced delays in Ecopetrol assuming operatorship of wells we have worked over or drilled. This has resulted in continued rental of equipment which could otherwise have been purchased, and the payment of both actual operating costs incurred by Petrobank and the per-barrel operating fee charged by Ecopetrol. We anticipate a resolution of this issue in December.

General and Administrative Expenses

General and administrative expenses increased to $1.4 million in the third quarter of 2003 from $0.9 million in the comparable 2002 period. The increase relates to incremental overhead associated with the Company's Colombian operations. Colombian operations have been staffed to facilitate a more aggressive capital program. We have been taking a "go slow" approach since the second quarter as we refine our drilling program and complete our reservoir simulation study. G&A per boe will decline to more reasonable levels as production increases.

Depletion, Depreciation and Site Restoration Expense

Depletion, depreciation and site restoration expense for the third quarter increased to $6.4 million ($13.54 per boe) from $4.2 million ($9.62 per boe) for the same period in 2002. This increase is due partly to the acquisition of Monolith and partly due to higher than anticipated costs of executing our initial investment program in Colombia.

Interest on Subordinated Notes

Interest on subordinated notes totaled $2.8 million for the third quarter of 2003, an increase from the $1.5 million in the comparative period. This increase is due to the issuance of an additional $40 million of notes in May 2003.

Income Taxes

Petrobank acquired only minimal tax pools as part of the Monolith acquisition and as a result, recorded a future tax liability of $12.3 million. Petrobank does not anticipate a cash tax liability in either Canada or Colombia for the next several years.

Capital Expenditures

Capital expenditures in Canada during the quarter were concentrated on drilling at our Jumpbush and Western Saskatchewan properties. Colombian expenditures were focused on drilling, completions and workovers in Orito along with a U.S.$0.8 million payment relating to the relinquishment of the Company's commitments on our exploration blocks. Although the Company has experienced costly technical difficulties associated with initial drilling and completion operations

at Orito, our latest Caballos well (DEV-5) was drilled and completed on budget and on time at a total cost of U.S.$3.0 million. Production results from this well have also exceeded our expectations and, as a result, a sixth Caballos well is currently being drilled 500 meters from the DEV-5 location.

Liquidity and Capital Resources

At September 30, 2003 net debt totaled $132.9 million, including subordinated notes reflected as equity on the balance sheet. This balance reflects the cost of the Monolith acquisition yet results of operations only include the effect of the Monolith properties from their September 19, 2003 closing date. As part of the Monolith consideration, Petrobank issued a $14.5 million debenture maturing on January 31, 2004. We plan to settle this debenture with incremental cash flows from the Monolith properties. Petrobank's credit facility was increased to $47.5 million following the Monolith acquisition, and was $12.9 million drawn at the end of the quarter.

OUTLOOK

We are presently in the process of finalizing our 2004 capital budget. A preliminary review of our existing projects indicates that we have a 24 to 36 month inventory of drilling opportunities in both Canada and Colombia. Our project inventory in Canada has expanded rapidly with recent successes at Jumpbush and with our ongoing evaluation of the Nevis and Red Willow properties. Over the near-term, capital constraints are expected to result in the deferral of certain projects in Colombia with the next round of planned activity focused on our Orito block. Orito activities will centre on drilling infill Caballos locations in the North dome of the field where productivity is proven, and on installing additional electrical submersible pumps that have the ability to increase productivity in the near term and are essential to our future waterflood plans. In Canada, our next round of drilling at Jumpbush will direct our 2004 infill-drilling program and related facility expenditures, which may include a plant expansion. Our first 6 wells on the recently acquired Nevis and Red Willow properties are planned to be drilled in the fourth quarter and a number of follow-up locations are planned for 2004. Lastly, with the submission of our WHITESANDS experimental pilot project application, we expect to commence a field test of the THAI™ technology in 2004. We are excited about the broad range of opportunities available to Petrobank and look forward to updating shareholders on our progress.

This Report contains forward-looking statements that reflect management's objectives and expectations as at the date of this report. These objectives and expectations involve risks and uncertainties that are common to the oil and natural gas industry. There is no guarantee that these objectives will be met, nor that the expected operating and commodity price conditions will occur. The Company's actual results may differ materially from those anticipated in these forward-looking statements.

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· Highlights ·

	Three months ended September 30, 2003	2002	% change	Nine months ended September 30, 2003	2002	% change
Financial						
($000s, except where noted)						
Oil and natural gas revenue	**13,655**	12,208	**12**	**46,031**	37,566	**23**
Cash flow from operations [1]	**5,842**	5,806	**1**	**20,557**	17,206	**19**
Per share – basic $ [2]	**0.08**	0.11	**(27)**	**0.33**	0.36	**(8)**
Per share – diluted $ [2]	**0.08**	0.11	**(27)**	**0.32**	0.31	**3**
Net income (loss)	**(600)**	1,573		**3,872**	4,815	**(20)**
Net loss attributable to common shareholders	**(3,425)**	(9)		**(2,768)**	(259)	
Per share – basic $	**(0.07)**	-		**(0.06)**	(0.01)	
Per share – diluted $	**(0.07)**	-		**(0.06)**	(0.01)	
Capital expenditures	**28,065**	5,813	**383**	**88,722**	17,608	**404**
Net debt [3]	**132,934**	37,609	**253**	**132,934**	37,609	**253**
Common shares outstanding (000s)						
Basic	**54,417**	45,095	**21**	**54,417**	45,095	**21**
Diluted	**59,241**	50,119	**18**	**59,241**	50,119	**18**
Operations [4]						
Canadian operating netback ($/boe except where noted)						
Oil and NGLs revenue ($/bbl)	**27.19**	32.74	**(17)**	**29.43**	31.06	**(5)**
Natural gas revenue ($/mcf)	**4.98**	3.63	**37**	**6.42**	3.61	**78**
Oil and natural gas revenue	**27.92**	27.73	**1**	**32.48**	26.35	**23**
Royalties	**5.35**	5.97	**(10)**	**7.23**	5.56	**30**
Production expenses	**7.06**	6.55	**8**	**7.45**	6.36	**17**
Operating netback	**15.51**	15.21	**2**	**17.80**	14.43	**23**
Colombian operating netback ($/bbl)						
Oil revenue	**31.37**			**32.50**		
Royalties	**2.44**			**2.57**		
Production expenses	**9.24**			**8.03**		
Operating netback	**19.69**			**21.90**		
Average daily production						
Canada - oil and NGLs (bbls)	**2,909**	2,596	**12**	**2,809**	2,613	**8**
Canada - natural gas (mcf)	**6,581**	13,134	**(50)**	**8,502**	15,652	**(46)**
Total Canada (boe)	**4,005**	4,785	**(16)**	**4,226**	5,222	**(19)**
Colombia - oil (bbls)	**1,166**	-		**965**	-	
Total Company (boe)	**5,171**	4,785	**8**	**5,191**	5,222	**(1)**

(1) Cash flow from operations before changes in non-cash working capital.
(2) Calculated based on cash flow from operations before changes in non-cash working capital less preferred share dividends and interest paid on subordinated notes.
(3) Includes working capital (deficiency) and subordinated notes reflected as equity on the balance sheet.
(4) 6 Mcf of natural gas is equivalent to 1 barrel of oil equivalent (BOE).

· Consolidated Balance Sheets ·

(Unaudited, Thousands of Canadian dollars)

As at	September 30, 2003	December 31, 2002
Assets		
Current assets		
Cash and cash equivalents	$ -	$ 12,224
Accounts receivable and other current assets	16,851	11,521
Inventory	3,467	-
	20,318	23,745
Capital assets (note 2)	235,780	126,873
	$ 256,098	$ 150,618
Liabilities and Shareholders' Equity		
Current liabilities		
Accounts payable and accrued liabilities	$ 32,987	$ 28,896
Debenture (note 2)	14,500	-
Bank debt (note 4)	12,900	-
	60,387	28,896
Obligations under gas hedging contracts	7,491	8,097
Future income tax liability (note 2)	12,300	-
Future site restoration liability (note 2)	2,523	613
	82,701	37,606
Shareholders' equity		
Subordinated notes	92,865	57,344
Common shares (note 3)	75,692	48,054
Retained earnings	4,840	7,614
	173,397	113,012
	$ 256,098	$ 150,618

See accompanying notes to these consolidated financial statements

· Consolidated Statements of Income and Retained Earnings ·

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

	Three months ended September 30,		Nine months ended September 30,	
	2003	2002	2003	2002
Revenues				
Oil and natural gas	**$ 13,655**	$ 12,208	**$ 46,031**	$ 37,566
Royalties	**(2,233)**	(2,629)	**(9,023)**	(7,928)
	11,422	9,579	**37,008**	29,638
Expenses				
Production	**3,595**	2,885	**10,708**	9,069
General and administrative	**1,409**	946	**4,496**	2,892
Interest on bank debt	**85**	-	**224**	-
Depletion, depreciation and site restoration	**6,442**	4,233	**16,685**	13,045
	11,531	8,064	**32,113**	25,006
Income (loss) before other items and taxes	**(109)**	1,515	**4,895**	4,632
Other income (expense)	**(108)**	315	**(78)**	362
Capital tax expense	**(383)**	(257)	**(945)**	(833)
Unusual gain	**-**	-	**-**	654
Net income (loss)	**(600)**	1,573	**3,872**	4,815
Interest on subordinated notes	**(2,825)**	(1,541)	**(6,640)**	(4,560)
Preferred share dividends and related taxes	**-**	(41)	**-**	(514)
Net loss attributable to common shareholders	**(3,425)**	(9)	**(2,768)**	(259)
Retained earnings, beginning of period	**8,271**	14,312	**7,614**	14,562
Repurchase of securities	**(6)**	(6,509)	**(6)**	(6,509)
Retained earnings, end of period	**$ 4,840**	$ 7,794	**$ 4,840**	$ 7,794
Loss per basic and diluted share (note 3)	**$ (0.07)**	$ -	**$ (0.06)**	$ (0.01)

See accompanying notes to these consolidated financial statements

· Consolidated Statements of Cash Flow ·

(Unaudited, Thousands of Canadian dollars)

	Three months ended September 30,		Nine months ended September 30,	
	2003	2002	**2003**	2002
Operating Activities				
Net income (loss)	**$ (600)**	$ 1,573	**$ 3,872**	$ 4,815
Depletion, depreciation and site restoration	**6,442**	4,233	**16,685**	13,045
Unusual gain	**-**	-	**-**	(654)
Cash flow from operations	**5,842**	5,806	**20,557**	17,206
Changes in non-cash working capital	**(1,233)**	(4,697)	**(8,411)**	5,048
	4,609	1,109	**12,146**	22,254
Financing Activities				
Increase in bank debt	**12,900**	-	**12,900**	-
Issuance of subordinated notes	**-**	-	**34,410**	-
Issuance of common shares and share purchase warrants (note 3)	**11,378**	3,391	**12,632**	4,013
Repurchase of securities	**-**	(6,509)	**-**	(6,509)
Preferred share dividends and related taxes	**-**	(41)	**-**	(514)
Interest on subordinated notes	**(2,280)**	(1,371)	**(5,529)**	(4,068)
Amortization of obligations under gas hedging contracts	**(204)**	-	**(606)**	(217)
Settlement of obligations under gas hedging contracts	**-**	(894)	**-**	(894)
Changes in non-cash working capital	**-**	(544)	**-**	(878)
	21,794	(5,968)	**53,807**	(9,067)
Investing Activities				
Expenditures on capital assets	**(28,065)**	(5,813)	**(88,722)**	(17,608)
Disposition of capital assets	**-**	-	**16,626**	3,443
Acquisitions (note 2)	**(8,573)**	-	**(8,573)**	(42)
Proceeds on disposition of temporary investment	**-**	-	**-**	1,654
Site restoration expenditures	**-**	(406)	**(27)**	(705)
Changes in non-cash working capital	**1,120**	(1,580)	**2,519**	682
	(35,518)	(7,799)	**(78,177)**	(12,576)
Net change in cash position	**(9,115)**	(12,658)	**(12,224)**	611
Cash and cash equivalents, beginning of period	**9,115**	38,580	**12,224**	25,311
Cash and cash equivalents, end of period	**$ -**	$ 25,922	**$ -**	$ 25,922

See accompanying notes to these consolidated financial statements

As at and for the three and nine month periods ended September 30, 2003
(All tabular amounts are expressed in thousands of Canadian dollars, except share amounts)

Note 1 – Significant Accounting Policies

These interim consolidated financial statements as at and for the three and nine month periods ended September 30, 2003 should be read in conjunction with the audited consolidated financial statements as at and for the year ended December 31, 2002. The notes to these interim consolidated financial statements do not conform in all respects to the note disclosure requirements of generally accepted accounting policies for annual financial statements. These interim consolidated financial statements are prepared using the same accounting policies and methods of computation as disclosed in the audited consolidated financial statements as at and for the year ended December 31, 2002. These interim consolidated financial statements include disclosure of segmented information in Note 6, which was not provided in the December 31, 2002 consolidated financial statements, as the Company did not have results from operations in Colombia during the year ended December 31, 2002.

Note 2- Acquisition

On September 19, 2003 the Company acquired Monolith Oil Corp. ("Monolith"), a privately owned oil and natural gas company. The purchase price consideration of $39.3 million included, acquired non-cash working capital deficit of $1.2 million, 5,209,551 ($15.0 million) Petrobank common shares, and a $14.5 million debenture. The debenture is secured by Petrobank's Canadian assets but subordinate to Petrobank's secured credit facility, bears interest at 9% per annum payable monthly, and matures on January 31, 2004. The acquisition has been accounted for using the purchase method as follows:

Purchase price:		
Net cash paid including transaction costs ($400)	$	8,573
Debenture issued		14,500
Common shares issued		15,000
Non-cash working capital deficit acquired		1,186
	$	39,259

Allocation of purchase price:		
Capital assets	$	52,534
Future income tax liability		(12,300)
Future site restoration liability		(975)
	$	39,259

The allocation of the purchase price to the fair values of assets acquired and liabilities assumed is subject to change as additional information becomes available.

Note 3 – Share Capital

The Company had 54,416,516 common shares, 1,420,300 share purchase warrants, and 3,403,881 stock options outstanding at September 30, 2003.

Common Share Continuity	Number	Amount
Balance at December 31, 2002	45,313,795	$ 48,054
Exercise of stock options	277,703	479
Exercise of share purchase warrants	2,760	7
Issuance of share purchase warrants	-	768
Balance at June 30, 2003	45,594,258	49,308
Exercise of stock options	183,750	329
Repurchased pursuant to exempt issuer bid	(3,221)	(3)
Exercise of share purchase warrants	654,400	1,636
Issued pursuant to corporate acquisition (note 2)	5,209,551	15,000
Issuance of flow-through common shares [1]	2,777,778	9,422
Balance at September 30, 2003	54,416,516	$ 75,692

[1] On September 24, 2003 the Company issued 2,777,778 flow-through common shares at a price of $3.60 per share, for net proceeds of $9.4 million.

Stock Option Continuity	Number	Weighted-Average Exercise Price
Balance at December 31, 2002	4,195,484	$ 2.08
Granted	805,550	3.38
Exercised	(277,703)	(1.72)
Cancelled	(925,500)	(2.31)
Balance at June 30, 2003	3,797,831	2.32
Granted	199,250	2.74
Exercised	(183,750)	(1.79)
Cancelled	(409,450)	(2.20)
Balance at September 30, 2003	3,403,881	$ 2.39

Share Purchase Warrant Continuity	Number	Weighted-Average Exercise Price
Balance at December 31, 2002	777,720	$ 2.50
Exercised	(2,760)	(2.50)
Issued	1,420,300	4.00
Balance at June 30, 2003	2,195,260	3.47
Exercised	(654,400)	(2.50)
Expired	(120,560)	(2.50)
Balance at September 30, 2003	1,420,300	$ 4.00

Earnings Per Share

Loss per share has been calculated based on the weighted average number of common shares outstanding for the three month period ended September 30, 2003 of 46,966,016 (2002 – 38,413,000) and for the nine month period of 45,952,492 (2002 – 35,384,000). Loss per share is based on net loss attributable to common shareholders.

Stock Based Compensation

The Company accounts for its stock based compensation plans using intrinsic values whereby no costs are recognized in the statements of operations for stock options granted at market price to employees and directors. Had compensation expense associated with the Company's stock option plan been recognized using the fair value method for stock option grants after January 1, 2002, the Company's loss attributable to common shareholders for the three months ended September 30, 2003 would have been increased by $163,000 (2002 – loss increased by $72,000), and for the nine months ended September 30, 2003 net loss attributable to common shareholders would have been increased by $435,000 (2002 – loss increased by $111,000) and net loss per share would have approximated reported amounts.

The fair value of stock options granted during the reported periods are estimated using the Black Scholes option pricing model using the following assumptions:

Three months ended September 30,	2003	2002
Risk free interest rate	4.0%	4.0%
Dividend rate on common shares	0%	0%
Expected life (years) of stock options	4	4
Expected volatility of common share price	30%	20%

Note 4 – Bank Debt

Upon acquisition of Monolith, the Company's borrowing base under its credit facility was increased to $47.5 million. The facility is a revolving demand loan under which the Company can borrow at bank prime plus 0.125 percent or Bankers' Acceptance fee rates plus 1.625 percent. Advances under the facility are collateralized by a $100 million demand debenture on all present and future Canadian assets of the Company as well as a general assignment of the Company's book debts, a negative pledge to provide fixed charges on major producing petroleum properties and an assignment of material contracts.

Note 5 – Commitments and Contingencies

The Company's remaining work commitments on our incremental production blocks at Orito and Neiva in Colombia are estimated at U.S.$1.0 million, subject to Ecopetrol approval, and are required to be completed by June 2004. In October 2003, the Company signed a new exploration contract on a 400,000 acre block ("Bloque Colombia") in the Upper Magdalena Valley, 70 kilometers northeast of the Company's Neiva block. Petrobank has a one-third, non-operated interest in the block with an estimated U.S.$0.3 million phase-one work commitment that is required to be completed by July 2004. After completion of the phase-one work commitment the Company has the option to relinquish the block, drill a well, or shoot 120 kilometers of 2D seismic.

Note 6 – Segmented Information

The Company commenced commercial production from our Colombian operations in January 2003 and accordingly segmented results are presented below for the three and nine month periods ending September 30, 2003.

Three months ended September 30, 2003	Canada	Colombia	Total
Revenues			
Oil and natural gas	$ 10,290	$ 3,365	$ 13,655
Royalties	(1,972)	(261)	(2,233)
	8,318	3,104	11,422
Expenses			
Production	2,603	992	3,595
General and administrative	970	439	1,409
Depletion, depreciation and site restoration	4,297	2,145	6,442
Segmented income (loss)	$ 448	$ (472)	(24)
Non-segmented items			
Interest on bank debt			(85)
Other expense			(108)
Capital tax expense			(383)
Net loss			(600)
Interest on subordinated notes			2,825
Net loss attributable to common shareholders			$ (3,425)
Identifiable assets	$182,516	$ 73,582	$256,098
Capital expenditures	$ 13,257	$ 14,808	$ 28,065

Nine months ended September 30, 2003	Canada	Colombia	Total
Revenues			
Oil and natural gas	$ 37,471	$ 8,560	$ 46,031
Royalties	(8,346)	(677)	(9,023)
	29,125	7,883	37,008
Expenses			
Production	8,594	2,114	10,708
General and administrative	3,131	1,365	4,496
Depletion, depreciation and site restoration	12,075	4,610	16,685
Segmented income (loss)	$ 5,325	$ (206)	5,119
Non-segmented items			
Interest on bank debt			(224)
Other expense			(78)
Capital tax expense			(945)
Net income			3,872
Interest on subordinated notes			6,640
Net loss attributable to common shareholders			$ (2,768)
Identifiable assets	$182,516	$ 73,582	$256,098
Capital expenditures	$ 32,375	$ 56,347	$ 88,722

Note 7 – Related Party Transaction

In July 2003, the Company closed its previously announced acquisition of the THAI™ and CAPRI™ heavy oil technologies indirectly from two directors of the Company. One of these directors recovered his original investment ($226,000) and the other received cash of $189,000 and retained a 7.5% net profits interest in any future third party licensing royalties generated from the technologies. Currently, the technologies are unproven, but Petrobank plans to test the THAI™ technology in the field in 2004.

Note 8 – Subsequent Event

In November 2003, the Company committed to fixed price physical crude oil deliveries in Canada for the period January 1, 2004 through December 31, 2004 of 300 barrels of oil per day at a West Texas Intermediate price of US$27.68 and 300 barrels of oil per day at a West Texas Intermediate price of US$27.74 per barrel.

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·MANAGEMENT'S DISCUSSION AND ANALYSIS·

Gas volumes have been converted to barrels of oil equivalent ("boe") so that 6 mcf of gas equals 1 boe. This report contains financial terms that are considered non-GAAP measures such as cash flow from operations, cash flow per share, net debt, and operating netback. These measures are commonly utilized in the oil and gas industry and are considered informative for our shareholders. Specifically, cash flow from operations and cash flow per share reflect cash generated from operating activities before changes in non-cash working capital. We consider these measures important as they demonstrate our ability to generate sufficient cash to fund future growth opportunities and repay debt. All amounts are in Canadian dollars, unless otherwise stated.

Petrobank acquired Monolith Oil Corp. ("Monolith") on September 19, 2003 for $39.3 million. The September 30, 2003 balance sheet reflects the cost of the Monolith acquisition but the results of operations for the third quarter of 2003 only include results from the acquired properties subsequent to the closing date. Production from these properties averaged 2,570 boepd between the closing date and the end of the third quarter, but only contributed 335 boepd to average third quarter production.

Petrobank generated cash flow from operations in the third quarter of 2003 of $5.8 million, consistent with the same period last year. Capital expenditures during the quarter totaled $28.1 million, including $13.3 million of expenditures in Canada and $14.8 million in Colombia.

Production

Oil and NGL production during the third quarter averaged 2,909 barrels per day (bpd) in Canada, a 12% increase from the 2,596 bpd produced in the third quarter of 2002 and a 5% increase from the second quarter of 2003. Third quarter natural gas production of 6.6 million cubic feet per day (mmcfpd) decreased 50% from the 13.1 mmcfpd produced in the third quarter of 2002 and 18% from the 8.1 mmcfpd produced in the second quarter of 2003. The decrease in natural gas production is primarily a result of the sale of the Company's Zama/Larne and Whiterose properties in May 2003. Fourth quarter natural gas production is forecasted to increase significantly through the inclusion of the Monolith properties for the entire quarter and the recent tie-in of the Company's 2003 drilling program at Jumpbush.

Colombian oil production increased from 1,028 bopd in the second quarter of 2003 to 1,166 bopd in the third quarter. During the year the Company has experienced intermittent production interruptions and shortfalls in the Ecopetrol baseline production in the Orito Block. The Company and Ecopetrol have taken steps to address this issue, and Ecopetrol has recently re-structured its management in the Orito production office. With some production still affected by ongoing repair operations, the Company is currently producing 1,750 bopd from Colombia and expects to exit 2003 at approximately 3,000 bopd. We are currently drilling our sixth Caballos well and plan to carry out two additional well workovers that we expect to have on production before the end of the year. Petrobank also believes that Ecopetrol will meet its baseline production obligation between now and the end of the year.

Realized Sales Prices

The average Canadian oil and NGL price received in the third quarter was $27.19 per barrel, a 17% decrease from the $32.74 per barrel received in the third quarter of 2002. Canadian oil and NGL prices averaged $31.78 per barrel, before hedging losses of $4.59 per barrel, representing a U.S.$7.17 discount to average WTI prices in the quarter. The average natural gas price received in the third quarter was $4.98 per mcf, a 37% increase from $3.63 per mcf in the third quarter of 2002. The natural gas price in the quarter reflects the negative impact of the Company's long-term physical gas sales contracts. Oil sales prices in Colombia averaged $31.37 per barrel in the third quarter, representing a U.S.$7.47 discount to WTI. Incremental unhedged gas volumes associated with the Company's drilling program at Jumpbush and the acquired Monolith properties are expected to increase Petrobank's average realized prices. In November 2003, the

Company entered into two fixed-price physical sale contracts for the 2004 calendar year. Under these contracts, the Company has agreed to sell 300 barrels of oil per day at a West Texas Intermediate price of US$27.68 and 300 barrels of oil per day at a West Texas Intermediate price of US$27.74.

Royalties

Royalties decreased from $2.6 million in the third quarter of 2002 to $2.2 million in the current period. Colombian royalties are included in the current quarter at a rate of 8%. Canadian royalties as a percentage of revenue decreased from 22% in the third quarter of 2002 to 19% in the current period. The Company's average Canadian royalty rate is expected to increase with the addition of gas production from the Monolith properties for the entire fourth quarter.

Production Expenses

Production expenses in Canada increased 8% from $6.55 per boe in the third quarter of 2002 to $7.06 per boe in the current period. This increase is largely a result of the fixed nature of certain operating costs combined with lower Canadian production volumes. Production expenses in Colombia averaged $9.24 per barrel in the quarter and are expected to decline on a per unit basis as production levels increase. Production expenses remain high in Colombia as we have experienced delays in Ecopetrol assuming operatorship of wells we have worked over or drilled. This has resulted in continued rental of equipment which could otherwise have been purchased, and the payment of both actual operating costs incurred by Petrobank and the per-barrel operating fee charged by Ecopetrol. We anticipate a resolution of this issue in December.

General and Administrative Expenses

General and administrative expenses increased to $1.4 million in the third quarter of 2003 from $0.9 million in the comparable 2002 period. The increase relates to incremental overhead associated with the Company's Colombian operations. Colombian operations have been staffed to facilitate a more aggressive capital program. We have been taking a "go slow" approach since the second quarter as we refine our drilling program and complete our reservoir simulation study. G&A per boe will decline to more reasonable levels as production increases.

Depletion, Depreciation and Site Restoration Expense

Depletion, depreciation and site restoration expense for the third quarter increased to $6.4 million ($13.54 per boe) from $4.2 million ($9.62 per boe) for the same period in 2002. This increase is due partly to the acquisition of Monolith and partly due to higher than anticipated costs of executing our initial investment program in Colombia.

Interest on Subordinated Notes

Interest on subordinated notes totaled $2.8 million for the third quarter of 2003, an increase from the $1.5 million in the comparative period. This increase is due to the issuance of an additional $40 million of notes in May 2003.

Income Taxes

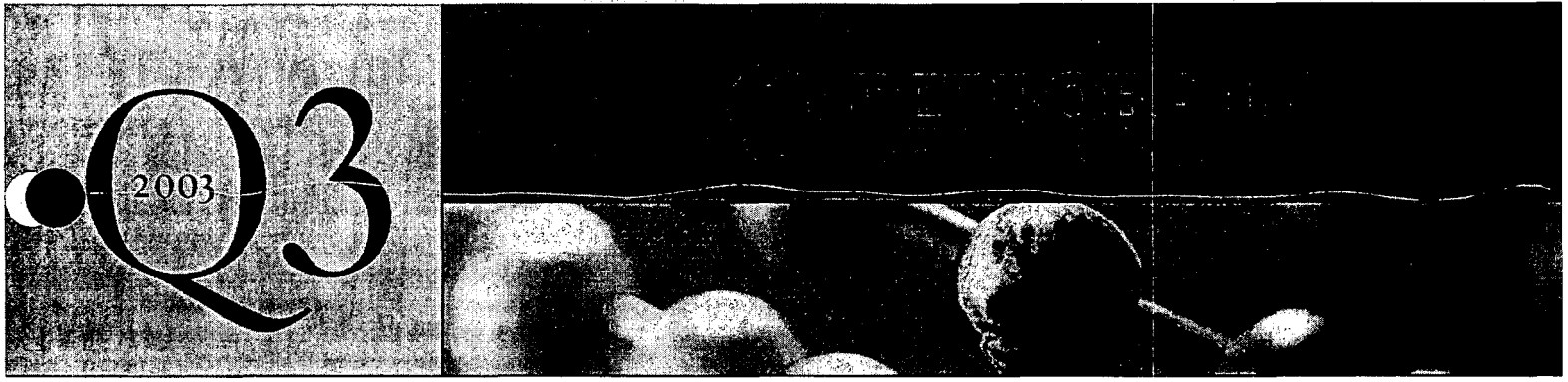
Petrobank acquired only minimal tax pools as part of the Monolith acquisition and as a result, recorded a future tax liability of $12.3 million. Petrobank does not anticipate a cash tax liability in either Canada or Colombia for the next several years.

Capital Expenditures

Capital expenditures in Canada during the quarter were concentrated on drilling at our Jumpbush and Western Saskatchewan properties. Colombian expenditures were focused on drilling, completions and workovers in Orito along with a U.S.$0.8 million payment relating to the relinquishment of the Company's commitments on our exploration blocks. Although the Company has experienced costly technical difficulties associated with initial drilling and completion operations at Orito, our latest Caballos well (DEV-5) was drilled and completed on budget and on time at a total cost of U.S.$3.0 million. Production results from this well have also exceeded our expectations and, as a result, a sixth Caballos well is currently being drilled 500 meters from the DEV-5 location.

Liquidity and Capital Resources

At September 30, 2003 net debt totaled $132.9 million, including subordinated notes reflected as equity on the balance sheet. This balance reflects the cost of the Monolith acquisition yet results of operations only include the effect of the Monolith properties from their September 19, 2003 closing date. As part of the Monolith consideration, Petrobank issued a $14.5 million debenture maturing on January 31, 2004. We plan to settle this debenture with incremental cash flows from the Monolith properties. Petrobank's credit facility was increased to $47.5 million following the Monolith acquisition, and was $12.9 million drawn at the end of the quarter.



· Highlights ·

	Three months ended September 30, 2003	2002	% change	Nine months ended September 30, 2003	2002	% change
Financial						
($000s, except where noted)						
Oil and natural gas revenue	**13,655**	12,208	**12**	**46,031**	37,566	**23**
Cash flow from operations [1]	**5,842**	5,806	**1**	**20,557**	17,206	**19**
Per share – basic $ [2]	**0.08**	0.11	**(27)**	**0.33**	0.36	**(8)**
Per share – diluted $ [2]	**0.08**	0.11	**(27)**	**0.32**	0.31	**3**
Net income (loss)	**(600)**	1,573		**3,872**	4,815	**(20)**
Net loss attributable to common shareholders	**(3,425)**	(9)		**(2,768)**	(259)	
Per share – basic $	**(0.07)**	-		**(0.06)**	(0.01)	
Per share – diluted $	**(0.07)**	-		**(0.06)**	(0.01)	
Capital expenditures	**28,065**	5,813	**383**	**88,722**	17,608	**404**
Net debt [3]	**132,934**	37,609	**253**	**132,934**	37,609	**253**
Common shares outstanding (000s)						
Basic	**54,417**	45,095	**21**	**54,417**	45,095	**21**
Diluted	**59,241**	50,119	**18**	**59,241**	50,119	**18**
Operations [4]						
Canadian operating netback ($/boe except where noted)						
Oil and NGLs revenue ($/bbl)	**27.19**	32.74	**(17)**	**29.43**	31.06	**(5)**
Natural gas revenue ($/mcf)	**4.98**	3.63	**37**	**6.42**	3.61	**78**
Oil and natural gas revenue	**27.92**	27.73	**1**	**32.48**	26.35	**23**
Royalties	**5.35**	5.97	**(10)**	**7.23**	5.56	**30**
Production expenses	**7.06**	6.55	**8**	**7.45**	6.36	**17**
Operating netback	**15.51**	15.21	**2**	**17.80**	14.43	**23**
Colombian operating netback ($/bbl)						
Oil revenue	**31.37**			**32.50**		
Royalties	**2.44**			**2.57**		
Production expenses	**9.24**			**8.03**		
Operating netback	**19.69**			**21.90**		
Average daily production						
Canada - oil and NGLs (bbls)	**2,909**	2,596	**12**	**2,809**	2,613	**8**
Canada - natural gas (mcf)	**6,581**	13,134	**(50)**	**8,502**	15,652	**(46)**
Total Canada (boe)	**4,005**	4,785	**(16)**	**4,226**	5,222	**(19)**
Colombia - oil (bbls)	**1,166**	-		**965**	-	
Total Company (boe)	**5,171**	4,785	**8**	**5,191**	5,222	**(1)**

(1) Cash flow from operations before changes in non-cash working capital.
(2) Calculated based on cash flow from operations before changes in non-cash working capital less preferred share dividends and interest paid on subordinated notes.
(3) Includes working capital (deficiency) and subordinated notes reflected as equity on the balance sheet.
(4) 6 mcf of natural gas is equivalent to 1 barrel of oil equivalent (boe).

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· Report to Shareholders ·

Petrobank Energy and Resources Ltd. ("Petrobank") is pleased to provide this operational update of our Canadian and Colombian activities as well as our third quarter financial results.

OPERATIONAL UPDATE

Latin American Business Unit

During the quarter in Colombia, we drilled our fifth Caballos well ("DEV-5") on the Orito block with our re-engineered drilling and completion program. This was Petrobank's first Caballos well drilled into the Northern producing region of the field, and we are encouraged by its results. The well was drilled on budget, at a total cost of US$3.0 million, and is producing at a gross rate of 700 barrels of oil per day, exceeding initial expectations. Based on the results of this new well, we are currently drilling our sixth Caballos well ("DEV-6"), 500 meters from the DEV-5 location.

The guerilla activities in the Putumayo region, referred to in our press release dated November 19, 2003, have impacted production from the Orito Block. Including production from our DEV-5 well, we were producing approximately 2,200 net barrels of oil per day ("bopd") from our Colombian properties as of November 18, 2003. We are currently producing 1,750 bopd net. Ecopetrol and Petrobank are working together to re-establish our pre-existing production level. Assuming continued success at our DEV-6 location, and completion of several planned workovers, we expect to exit 2003 at approximately 3,000 net bopd.

To date, production in Colombia has been negatively impacted by both Petrobank operational difficulties and shortfalls or interruptions in Ecopetrol's baseline production levels in the Orito Block. We are working with Ecopetrol to increase their maintenance program associated with the baseline production. We believe these issues will be addressed and resolved in the near future, generating an increase in net production.

We continue to be confident in the significant resource potential of our Colombian assets as indicated by our recent drilling success at DEV-5. We are continuing to refine our internal reservoir simulation model to design an optimal field-wide secondary recovery plan. In addition, there are a number of exciting delineation opportunities that we would like to explore in 2004, which may increase our initial assessment of original oil in place and recoverable reserves.

To complement our incremental production contracts at Orito and Neiva, Petrobank continues to evaluate other Colombian development and exploration opportunities. Petrobank, along with two industry partners, signed an association (exploration) contract on a large exploratory block (Bloque Colombia). This block is in the country's Upper Magdalena Valley basin, northeast of our Neiva block. At a low initial cost (US$0.3 million net), this contract gives Petrobank the opportunity to evaluate and participate in a high impact exploration play with significant follow up opportunities.

Canadian Business Unit

In Canada, we completed our first phase of drilling at Jumpbush with 20 of 21 wells being cased for natural gas. Production from 17 of these wells has just been tied in, following an extended First Nations approval process with the Siksika Nation. At Jumpbush, we are currently producing net 3.2 million cubic feet of natural gas per day ("mmcfpd"), which is expected to increase to net 4.2 mmcfpd following the installation of field compression equipment planned for early December. Over the remainder of the year, we intend to drill an additional 8 wells at Jumpbush to evaluate and earn our land base in the area and to provide preliminary direction for our 2004 infill-drilling program. In an effort to optimize gathering system construction, the next 8 wells drilled at Jumpbush will not be tied in before mid 2004. All production at Jumpbush is being processed at our existing underutilized facilities in the area with current net capacity of 8.4 mmcfpd. Additional plant capacity may be constructed on a staged basis in 2004 as we add incremental production from this area.

On September 19, 2003, Petrobank acquired Monolith Oil Corp. with properties focused in the Nevis and Red Willow areas of east central Alberta. The third quarter results only include results from these properties subsequent to the closing date, and as a result, fourth quarter Canadian production is expected to increase sharply. This acquisition created a significant inventory of high impact natural gas opportunities, including six wells we are planning to drill by the end of the year. We plan to tie-in these wells in the first quarter of 2004. We also anticipate an improvement in Petrobank's netback in the fourth quarter as a result of including a full quarter's production from the Monolith properties. The average netback on the Monolith properties for the third quarter was $23.97 per boe, which was approximately 55% higher than Petrobank's reported netback on a consolidated basis. The Monolith volumes generate higher net prices per boe as they are primarily gas, and the operating costs are approximately $5.00 per boe, less than Petrobank's existing average.

We completed our 20 well drilling program with 18 cased oil wells on our Western Saskatchewan properties. Since bringing these wells on production, we have experienced higher water cuts than initially anticipated. Current production from these properties is 750 bopd. Petrobank is evaluating the implementation of a waterflood in these reservoirs to capture proven undeveloped reserves.

Canadian production is currently 6,500 boepd, a 62% increase from average third quarter production. Petrobank completed the sale of approximately 70 boepd of production from our Ferrybank property at the beginning of the fourth quarter. Following the tie-in of two more wells and installation of compression at Jumpbush, addition of two new oil wells at Red Willow, and optimization of the gas gathering systems at Nevis and Red Willow, we expect to increase Canadian production to approximately 7,000 boepd by the end of this year.

Orion Heavy Oil Business Unit

In October 2003, we filed our application for approval of the WHITESANDS Experimental Pilot Project with the Alberta Energy and Utilities Board and Alberta Environment. The WHITESANDS project will be the first field scale test of Petrobank's patented THAI™ (Toe-to-Heel-Air-Injection) in-situ heavy oil recovery technology. THAI™ is a new in-situ combustion technology for the recovery of bitumen and heavy oil that combines a vertical air injection well with a horizontal production well. Following receipt of regulatory approval, which is anticipated prior to the end of this year, Petrobank plans to initiate the WHITESANDS project on our 42 sections of 100 percent-owned oil sands leases near Conklin, Alberta. The Company is currently evaluating other opportunities to apply the THAI™ technology, both in Canada and internationally. As well, we are investigating different possibilities for structuring third party financial partnerships in the WHITESANDS project, which would allow us to test the commercial viability of the process as soon as possible.

·MANAGEMENT'S DISCUSSION AND ANALYSIS·

Gas volumes have been converted to barrels of oil equivalent ("boe") so that 6 mcf of gas equals 1 boe. This report contains financial terms that are considered non-GAAP measures such as cash flow from operations, cash flow per share, net debt, and operating netback. These measures are commonly utilized in the oil and gas industry and are considered informative for our shareholders. Specifically, cash flow from operations and cash flow per share reflect cash generated from operating activities before changes in non-cash working capital. We consider these measures important as they demonstrate our ability to generate sufficient cash to fund future growth opportunities and repay debt. All amounts are in Canadian dollars, unless otherwise stated.

Petrobank acquired Monolith Oil Corp. ("Monolith") on September 19, 2003 for $39.3 million. The September 30, 2003 balance sheet reflects the cost of the Monolith acquisition but the results of operations for the third quarter of 2003 only include results from the acquired properties subsequent to the closing date. Production from these properties averaged 2,570 boepd between the closing date and the end of the third quarter, but only contributed 335 boepd to average third quarter production.

Petrobank generated cash flow from operations in the third quarter of 2003 of $5.8 million, consistent with the same period last year. Capital expenditures during the quarter totaled $28.1 million, including $13.3 million of expenditures in Canada and $14.8 million in Colombia.

Production

Oil and NGL production during the third quarter averaged 2,909 barrels per day (bpd) in Canada, a 12% increase from the 2,596 bpd produced in the third quarter of 2002 and a 5% increase from the second quarter of 2003. Third quarter natural gas production of 6.6 million cubic feet per day (mmcfpd) decreased 50% from the 13.1 mmcfpd produced in the third quarter of 2002 and 18% from the 8.1 mmcfpd produced in the second quarter of 2003. The decrease in natural gas production is primarily a result of the sale of the Company's Zama/Larne and Whiterose properties in May 2003. Fourth quarter natural gas production is forecasted to increase significantly through the inclusion of the Monolith properties for the entire quarter and the recent tie-in of the Company's 2003 drilling program at Jumpbush.

Colombian oil production increased from 1,028 bopd in the second quarter of 2003 to 1,166 bopd in the third quarter. During the year the Company has experienced intermittent production interruptions and shortfalls in the Ecopetrol baseline production in the Orito Block. The Company and Ecopetrol have taken steps to address this issue, and Ecopetrol has recently re-structured its management in the Orito production office. With some production still affected by ongoing repair operations, the Company is currently producing 1,750 bopd from Colombia and expects to exit 2003 at approximately 3,000 bopd. We are currently drilling our sixth Caballos well and plan to carry out two additional well workovers that we expect to have on production before the end of the year. Petrobank also believes that Ecopetrol will meet its baseline production obligation between now and the end of the year.

Realized Sales Prices

The average Canadian oil and NGL price received in the third quarter was $27.19 per barrel, a 17% decrease from the $32.74 per barrel received in the third quarter of 2002. Canadian oil and NGL prices averaged $31.78 per barrel, before hedging losses of $4.59 per barrel, representing a U.S.$7.17 discount to average WTI prices in the quarter. The average natural gas price received in the third quarter was $4.98 per mcf, a 37% increase from $3.63 per mcf in the third quarter of 2002. The natural gas price in the quarter reflects the negative impact of the Company's long-term physical gas sales contracts. Oil sales prices in Colombia averaged $31.37 per barrel in the third quarter, representing a U.S.$7.47 discount to WTI. Incremental unhedged gas volumes associated with the Company's drilling program at Jumpbush and the acquired Monolith properties are expected to increase Petrobank's average realized prices. In November 2003, the Company entered into two fixed-price physical sale contracts for the 2004 calendar year. Under these contracts, the Company has agreed to sell 300 barrels of oil per day at a West Texas Intermediate price of US$27.68 and 300 barrels of oil per day at a West Texas Intermediate price of US$27.74.

Royalties

Royalties decreased from $2.6 million in the third quarter of 2002 to $2.2 million in the current period. Colombian royalties are included in the current quarter at a rate of 8%. Canadian royalties as a percentage of revenue decreased from 22% in the third quarter of 2002 to 19% in the current period. The Company's average Canadian royalty rate is expected to increase with the addition of gas production from the Monolith properties for the entire fourth quarter.

Production Expenses

Production expenses in Canada increased 8% from $6.55 per boe in the third quarter of 2002 to $7.06 per boe in the current period. This increase is largely a result of the fixed nature of certain operating costs combined with lower Canadian production volumes. Production expenses in Colombia averaged $9.24 per barrel in the quarter and are expected to decline on a per unit basis as production levels increase. Production expenses remain high in Colombia as we have experienced delays in Ecopetrol assuming operatorship of wells we have worked over or drilled. This has resulted in continued rental of equipment which could otherwise have been purchased, and the payment of both actual operating costs incurred by Petrobank and the per-barrel operating fee charged by Ecopetrol. We anticipate a resolution of this issue in December.

General and Administrative Expenses

General and administrative expenses increased to $1.4 million in the third quarter of 2003 from $0.9 million in the comparable 2002 period. The increase relates to incremental overhead associated with the Company's Colombian operations. Colombian operations have been staffed to facilitate a more aggressive capital program. We have been taking a "go slow" approach since the second quarter as we refine our drilling program and complete our reservoir simulation study. G&A per boe will decline to more reasonable levels as production increases.

Depletion, Depreciation and Site Restoration Expense

Depletion, depreciation and site restoration expense for the third quarter increased to $6.4 million ($13.54 per boe) from $4.2 million ($9.62 per boe) for the same period in 2002. This increase is due partly to the acquisition of Monolith and partly due to higher than anticipated costs of executing our initial investment program in Colombia.

Interest on Subordinated Notes

Interest on subordinated notes totaled $2.8 million for the third quarter of 2003, an increase from the $1.5 million in the comparative period. This increase is due to the issuance of an additional $40 million of notes in May 2003.

Income Taxes

Petrobank acquired only minimal tax pools as part of the Monolith acquisition and as a result, recorded a future tax liability of $12.3 million. Petrobank does not anticipate a cash tax liability in either Canada or Colombia for the next several years.

Capital Expenditures

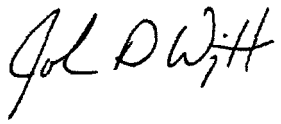
Capital expenditures in Canada during the quarter were concentrated on drilling at our Jumpbush and Western Saskatchewan properties. Colombian expenditures were focused on drilling, completions and workovers in Orito along with a U.S.$0.8 million payment relating to the relinquishment of the Company's commitments on our exploration blocks. Although the Company has experienced costly technical difficulties associated with initial drilling and completion operations at Orito, our latest Caballos well (DEV-5) was drilled and completed on budget and on time at a total cost of U.S.$3.0 million. Production results from this well have also exceeded our expectations and, as a result, a sixth Caballos well is currently being drilled 500 meters from the DEV-5 location.

Liquidity and Capital Resources

At September 30, 2003 net debt totaled $132.9 million, including subordinated notes reflected as equity on the balance sheet. This balance reflects the cost of the Monolith acquisition yet results of operations only include the effect of the Monolith properties from their September 19, 2003 closing date. As part of the Monolith consideration, Petrobank issued a $14.5 million debenture maturing on January 31, 2004. We plan to settle this debenture with incremental cash flows from the Monolith properties. Petrobank's credit facility was increased to $47.5 million following the Monolith acquisition, and was $12.9 million drawn at the end of the quarter.

OUTLOOK

We are presently in the process of finalizing our 2004 capital budget. A preliminary review of our existing projects indicates that we have a 24 to 36 month inventory of drilling opportunities in both Canada and Colombia. Our project inventory in Canada has expanded rapidly with recent successes at Jumpbush and with our ongoing evaluation of the Nevis and Red Willow properties. Over the near-term, capital constraints are expected to result in the deferral of certain projects in Colombia with the next round of planned activity focused on our Orito block. Orito activities will centre on drilling infill Caballos locations in the North dome of the field where productivity is proven, and on installing additional electrical submersible pumps that have the ability to increase productivity in the near term and are essential to our future waterflood plans. In Canada, our next round of drilling at Jumpbush will direct our 2004 infill-drilling program and related facility expenditures, which may include a plant expansion. Our first 6 wells on the recently acquired Nevis and Red Willow properties are planned to be drilled in the fourth quarter and a number of follow-up locations are planned for 2004. Lastly, with the submission of our WHITESANDS experimental pilot project application, we expect to commence a field test of the THAI™ technology in 2004. We are excited about the broad range of opportunities available to Petrobank and look forward to updating shareholders on our progress.



John D. Wright
President and Chief Executive Officer
November 28, 2003

This Report contains forward-looking statements that reflect management's objectives and expectations as at the date of this report. These objectives and expectations involve risks and uncertainties that are common to the oil and natural gas industry. There is no guarantee that these objectives will be met, nor that the expected operating and commodity price conditions will occur. The Company's actual results may differ materially from those anticipated in these forward-looking statements.

· Consolidated Balance Sheets ·

(Unaudited, Thousands of Canadian dollars)

As at	September 30, 2003	December 31, 2002
Assets		
Current assets		
Cash and cash equivalents	$ -	$ 12,224
Accounts receivable and other current assets	16,851	11,521
Inventory	3,467	-
	20,318	23,745
Capital assets (note 2)	235,780	126,873
	$ 256,098	$ 150,618
Liabilities and Shareholders' Equity		
Current liabilities		
Accounts payable and accrued liabilities	$ 32,987	$ 28,896
Debenture (note 2)	14,500	-
Bank debt (note 4)	12,900	-
	60,387	28,896
Obligations under gas hedging contracts	7,491	8,097
Future income tax liability (note 2)	12,300	-
Future site restoration liability (note 2)	2,523	613
	82,701	37,606
Shareholders' equity		
Subordinated notes	92,865	57,344
Common shares (note 3)	75,692	48,054
Retained earnings	4,840	7,614
	173,397	113,012
	$ 256,098	$ 150,618

See accompanying notes to these consolidated financial statements

· Consolidated Statements of Income and Retained Earnings ·

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

	Three months ended September 30,		Nine months ended September 30,	
	2003	2002	2003	2002
Revenues				
Oil and natural gas	**$ 13,655**	$ 12,208	**$ 46,031**	$ 37,566
Royalties	**(2,233)**	(2,629)	**(9,023)**	(7,928)
	11,422	9,579	**37,008**	29,638
Expenses				
Production	**3,595**	2,885	**10,708**	9,069
General and administrative	**1,409**	946	**4,496**	2,892
Interest on bank debt	**85**	-	**224**	-
Depletion, depreciation and site restoration	**6,442**	4,233	**16,685**	13,045
	11,531	8,064	**32,113**	25,006
Income (loss) before other items and taxes	**(109)**	1,515	**4,895**	4,632
Other income (expense)	**(108)**	315	**(78)**	362
Capital tax expense	**(383)**	(257)	**(945)**	(833)
Unusual gain	**-**	-	**-**	654
Net income (loss)	**(600)**	1,573	**3,872**	4,815
Interest on subordinated notes	**(2,825)**	(1,541)	**(6,640)**	(4,560)
Preferred share dividends and related taxes	**-**	(41)	**-**	(514)
Net loss attributable to common shareholders	**(3,425)**	(9)	**(2,768)**	(259)
Retained earnings, beginning of period	**8,271**	14,312	**7,614**	14,562
Repurchase of securities	**(6)**	(6,509)	**(6)**	(6,509)
Retained earnings, end of period	**$ 4,840**	$ 7,794	**$ 4,840**	$ 7,794
Loss per basic and diluted share (note 3)	**$ (0.07)**	$ -	**$ (0.06)**	$ (0.01)

See accompanying notes to these consolidated financial statements

· Consolidated Statements of Cash Flow ·

(Unaudited, Thousands of Canadian dollars)

	Three months ended September 30,		Nine months ended September 30,	
	2003	2002	**2003**	2002
Operating Activities				
Net income (loss)	**$ (600)**	$ 1,573	**$ 3,872**	$ 4,815
Depletion, depreciation and site restoration	**6,442**	4,233	**16,685**	13,045
Unusual gain	**-**	-	**-**	(654)
Cash flow from operations	**5,842**	5,806	**20,557**	17,206
Changes in non-cash working capital	**(1,233)**	(4,697)	**(8,411)**	5,048
	4,609	1,109	**12,146**	22,254
Financing Activities				
Increase in bank debt	**12,900**	-	**12,900**	-
Issuance of subordinated notes	**-**	-	**34,410**	-
Issuance of common shares and share purchase warrants (note 3)	**11,378**	3,391	**12,632**	4,013
Repurchase of securities	**-**	(6,509)	**-**	(6,509)
Preferred share dividends and related taxes	**-**	(41)	**-**	(514)
Interest on subordinated notes	**(2,280)**	(1,371)	**(5,529)**	(4,068)
Amortization of obligations under gas hedging contracts	**(204)**	-	**(606)**	(217)
Settlement of obligations under gas hedging contracts	**-**	(894)	**-**	(894)
Changes in non-cash working capital	**-**	(544)	**-**	(878)
	21,794	(5,968)	**53,807**	(9,067)
Investing Activities				
Expenditures on capital assets	**(28,065)**	(5,813)	**(88,722)**	(17,608)
Disposition of capital assets	**-**	-	**16,626**	3,443
Acquisitions (note 2)	**(8,573)**	-	**(8,573)**	(42)
Proceeds on disposition of temporary investment	**-**	-	**-**	1,654
Site restoration expenditures	**-**	(406)	**(27)**	(705)
Changes in non-cash working capital	**1,120**	(1,580)	**2,519**	682
	(35,518)	(7,799)	**(78,177)**	(12,576)
Net change in cash position	**(9,115)**	(12,658)	**(12,224)**	611
Cash and cash equivalents, beginning of period	**9,115**	38,580	**12,224**	25,311
Cash and cash equivalents, end of period	**$ -**	$ 25,922	**$ -**	$ 25,922

See accompanying notes to these consolidated financial statements

As at and for the three and nine month periods ended September 30, 2003
(All tabular amounts are expressed in thousands of Canadian dollars, except share amounts)

Note 1 – Significant Accounting Policies

These interim consolidated financial statements as at and for the three and nine month periods ended September 30, 2003 should be read in conjunction with the audited consolidated financial statements as at and for the year ended December 31, 2002. The notes to these interim consolidated financial statements do not conform in all respects to the note disclosure requirements of generally accepted accounting policies for annual financial statements. These interim consolidated financial statements are prepared using the same accounting policies and methods of computation as disclosed in the audited consolidated financial statements as at and for the year ended December 31, 2002. These interim consolidated financial statements include disclosure of segmented information in Note 6, which was not provided in the December 31, 2002 consolidated financial statements, as the Company did not have results from operations in Colombia during the year ended December 31, 2002.

Note 2- Acquisition

On September 19, 2003 the Company acquired Monolith Oil Corp. ("Monolith"), a privately owned oil and natural gas company. The purchase price consideration of $39.3 million included, acquired non-cash working capital deficit of $1.2 million, 5,209,551 ($15.0 million) Petrobank common shares, and a $14.5 million debenture. The debenture is secured by Petrobank's Canadian assets but subordinate to Petrobank's secured credit facility, bears interest at 9% per annum payable monthly, and matures on January 31, 2004. The acquisition has been accounted for using the purchase method as follows:

Purchase price:		
Net cash paid including transaction costs ($400)	$	8,573
Debenture issued		14,500
Common shares issued		15,000
Non-cash working capital deficit acquired		1,186
	$	39,259

Allocation of purchase price:		
Capital assets	$	52,534
Future income tax liability		(12,300)
Future site restoration liability		(975)
	$	39,259

The allocation of the purchase price to the fair values of assets acquired and liabilities assumed is subject to change as additional information becomes available.

Note 3 – Share Capital

The Company had 54,416,516 common shares, 1,420,300 share purchase warrants, and 3,403,881 stock options outstanding at September 30, 2003.

Common Share Continuity	Number	Amount
Balance at December 31, 2002	45,313,795	$ 48,054
Exercise of stock options	277,703	479
Exercise of share purchase warrants	2,760	7
Issuance of share purchase warrants	-	768
Balance at June 30, 2003	45,594,258	49,308
Exercise of stock options	183,750	329
Repurchased pursuant to exempt issuer bid	(3,221)	(3)
Exercise of share purchase warrants	654,400	1,636
Issued pursuant to corporate acquisition (note 2)	5,209,551	15,000
Issuance of flow-through common shares [(1)]	2,777,778	9,422
Balance at September 30, 2003	54,416,516	$ 75,692

[(1)] On September 24, 2003 the Company issued 2,777,778 flow-through common shares at a price of $3.60 per share, for net proceeds of $9.4 million.

Stock Option Continuity	Number	Weighted-Average Exercise Price
Balance at December 31, 2002	4,195,484	$ 2.08
Granted	805,550	3.38
Exercised	(277,703)	(1.72)
Cancelled	(925,500)	(2.31)
Balance at June 30, 2003	3,797,831	2.32
Granted	199,250	2.74
Exercised	(183,750)	(1.79)
Cancelled	(409,450)	(2.20)
Balance at September 30, 2003	3,403,881	$ 2.39

Share Purchase Warrant Continuity	Number	Weighted-Average Exercise Price
Balance at December 31, 2002	777,720	$ 2.50
Exercised	(2,760)	(2.50)
Issued	1,420,300	4.00
Balance at June 30, 2003	2,195,260	3.47
Exercised	(654,400)	(2.50)
Expired	(120,560)	(2.50)
Balance at September 30, 2003	1,420,300	$ 4.00

Earnings Per Share

Loss per share has been calculated based on the weighted average number of common shares outstanding for the three month period ended September 30, 2003 of 46,966,016 (2002 – 38,413,000) and for the nine month period of 45,952,492 (2002 – 35,384,000). Loss per share is based on net loss attributable to common shareholders.

Stock Based Compensation

The Company accounts for its stock based compensation plans using intrinsic values whereby no costs are recognized in the statements of operations for stock options granted at market price to employees and directors. Had compensation expense associated with the Company's stock option plan been recognized using the fair value method for stock option grants after January 1, 2002, the Company's loss attributable to common shareholders for the three months ended September 30, 2003 would have been increased by $163,000 (2002 - loss increased by $72,000), and for the nine months ended September 30, 2003 net loss attributable to common shareholders would have been increased by $435,000 (2002 – loss increased by $111,000) and net loss per share would have approximated reported amounts.

The fair value of stock options granted during the reported periods are estimated using the Black Scholes option pricing model using the following assumptions:

Three months ended September 30,	2003	2002
Risk free interest rate	4.0%	4.0%
Dividend rate on common shares	0%	0%
Expected life (years) of stock options	4	4
Expected volatility of common share price	30%	20%

Note 4 – Bank Debt

Upon acquisition of Monolith, the Company's borrowing base under its credit facility was increased to $47.5 million. The facility is a revolving demand loan under which the Company can borrow at bank prime plus 0.125 percent or Bankers' Acceptance fee rates plus 1.625 percent. Advances under the facility are collateralized by a $100 million demand debenture on all present and future Canadian assets of the Company as well as a general assignment of the Company's book debts, a negative pledge to provide fixed charges on major producing petroleum properties and an assignment of material contracts.

Note 5 – Commitments and Contingencies

The Company's remaining work commitments on our incremental production blocks at Orito and Neiva in Colombia are estimated at U.S.$1.0 million, subject to Ecopetrol approval, and are required to be completed by June 2004. In October 2003, the Company signed a new exploration contract on a 400,000 acre block ("Bloque Colombia") in the Upper Magdalena Valley, 70 kilometers northeast of the Company's Neiva block. Petrobank has a one-third, non-operated interest in the block with an estimated U.S.$0.3 million phase-one work commitment that is required to be completed by July 2004. After completion of the phase-one work commitment the Company has the option to relinquish the block, drill a well, or shoot 120 kilometers of 2D seismic.

Note 6 – Segmented Information

The Company commenced commercial production from our Colombian operations in January 2003 and accordingly segmented results are presented below for the three and nine month periods ending September 30, 2003.

Three months ended September 30, 2003	Canada	Colombia	Total
Revenues			
Oil and natural gas	$ 10,290	$ 3,365	$ 13,655
Royalties	(1,972)	(261)	(2,233)
	8,318	3,104	11,422
Expenses			
Production	2,603	992	3,595
General and administrative	970	439	1,409
Depletion, depreciation and site restoration	4,297	2,145	6,442
Segmented income (loss)	$ 448	$ (472)	(24)
Non-segmented items			
Interest on bank debt			(85)
Other expense			(108)
Capital tax expense			(383)
Net loss			(600)
Interest on subordinated notes			2,825
Net loss attributable to common shareholders			$ (3,425)
Identifiable assets	$182,516	$ 73,582	$256,098
Capital expenditures	$ 13,257	$ 14,808	$ 28,065

Nine months ended September 30, 2003	Canada	Colombia	Total
Revenues			
Oil and natural gas	$ 37,471	$ 8,560	$ 46,031
Royalties	(8,346)	(677)	(9,023)
	29,125	7,883	37,008
Expenses			
Production	8,594	2,114	10,708
General and administrative	3,131	1,365	4,496
Depletion, depreciation and site restoration	12,075	4,610	16,685
Segmented income (loss)	$ 5,325	$ (206)	5,119
Non-segmented items			
Interest on bank debt			(224)
Other expense			(78)
Capital tax expense			(945)
Net income			3,872
Interest on subordinated notes			6,640
Net loss attributable to common shareholders			$ (2,768)
Identifiable assets	$182,516	$ 73,582	$256,098
Capital expenditures	$ 32,375	$ 56,347	$ 88,722

Note 7 – Related Party Transaction

In July 2003, the Company closed its previously announced acquisition of the THAI™ and CAPRI™ heavy oil technologies indirectly from two directors of the Company. One of these directors recovered his original investment ($226,000) and the other received cash of $189,000 and retained a 7.5% net profits interest in any future third party licensing royalties generated from the technologies. Currently, the technologies are unproven, but Petrobank plans to test the THAI™ technology in the field in 2004.

Note 8 – Subsequent Event

In November 2003, the Company committed to fixed price physical crude oil deliveries in Canada for the period January 1, 2004 through December 31, 2004 of 300 barrels of oil per day at a West Texas Intermediate price of US$27.68 and 300 barrels of oil per day at a West Texas Intermediate price of US$27.74 per barrel.

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November 28, 2003

Alberta Securities Commission
British Columbia Securities Commission
Saskatchewan Financial Services Commission
The Manitoba Securities Commission
Ontario Securities Commission
Commission des valeurs mobilières du Québec
Nova Scotia Securities Commission
TSX

Dear Sirs:

Subject: Petrobank Energy and Resources Ltd.

We confirm that the following material was sent by pre-paid mail on November 28, 2003 to the registered shareholders of the common shares of the subject Corporation:

1. Third Quarter Report for the three and nine months ended September 30, 2003

In compliance with security regulations, we are providing this material to you in our capacity as agent for the subject Corporation.

We also confirm that a copy of the above was mailed to all non-registered shareholders of the subject Corporation whose names appear on the Corporation's Supplemental Mailing List as defined in the Canadian Securities Administrators' National Instrument 54-102.

Yours truly,

"signed by"

Tracy Williams
Mailing Professional
ClientServicesMailings@Computershare.com

cc: Petrobank Energy and Resources Ltd.
Attention: Corey Ruttan

Tw\43776

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ENERGY AND RESOURCES LTD.

NEWS RELEASE

PETROBANK ANNOUNCES PLANNED PROPERTY DISPOSITION AND OPERATIONAL UPDATE

Calgary, Alberta - January 9, 2004 - Petrobank Energy and Resources Ltd. ("Petrobank") announces that it has entered into an agreement to dispose of the Wapella property in Southeast Saskatchewan, effective December 31, 2003, for total proceeds of $36 million. The property is producing approximately 1,400 barrels of oil per day ("bopd"), which represents proceeds of $25,700 per flowing barrel of oil produced. The transaction is scheduled to close on January 28, 2004 and is subject to the purchaser (NAV Energy Trust) completing its currently contemplated financing. The proceeds from the disposition will be used in the short term, to repay bank debt. In addition, this disposition will allow Petrobank to accelerate the development of our prospect rich Jumpbush, Nevis and Red Willow properties.

OPERATIONAL UPDATE

Canadian Business Unit

At Jumpbush, we have completed the final 8 wells of our 2003 drilling program, resulting in an additional 6 cased natural gas wells. These wells were drilled to orient our next phase of drilling with an expected 30 wells to be drilled in the summer of 2004. Based on test results, the most recently completed 6 wells are expected to add 1-2 mmcf per day of initial productive capacity (70% working interest) and will be tied-in concurrent with the summer 2004 drilling program.

We have recently completed drilling our first 4 wells on the Nevis and Red Willow properties acquired in August 2003, resulting in 3 gas wells and 1 oil well. Completion of these wells is underway and the resulting production additions are expected later in January.

Canadian production is currently 6,300 boepd (including 1,400 bopd from Wapella), compared to our previously announced 2003 exit target of 7,000 boepd. Upon resolution of certain facility restrictions, unexpected downtime, and the tie in of our recent Nevis and Red Willow drilling program we expect to be producing approximately 5,400 boepd following the Wapella property disposition.

Our 2004 capital expenditure plan for the Canadian Business Unit is currently estimated at $35 million and is to be focused at Jumpbush, Nevis and Red Willow, where we expect to drill approximately 50 wells.

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Colombian Business Unit

Recent activity in Colombia has been focused on drilling the O-114 (DEV-6) Caballos well on the Orito block, which was drilled as a follow up to our recent success at O-115 (DEV-5). The testing of O-114 is underway with initial results to date of 85 bopd. We are assessing this poor well performance and expect to take steps to improve the well's deliverability through stimulation and/or recompletion. The O-115 well is currently producing at a rate of 500 bopd, which has decreased from initial rates of 700 bopd.

Our O-112 (DEV-3) and O-113 (DEV-4) wells were shut in as a precautionary measure following the guerilla activities occurring in the Putumayo region, referred to in our press release dated November 19, 2003. Production from the O-112 well has been restored and through a chemical treatment increased to a current rate of 450 bopd. Attempts to restore production from O-113, initially a free-flowing oil well, have been only partially successful with a current rate of 175 bopd after installation of jet pumping equipment. Well remediation efforts continue, in an attempt to restore production to the prior level of 400 bopd. In addition to these wells being worked on by Petrobank, remediation and repair efforts consequential to the guerilla incident continue on a number of wells and facilities within the Ecopetrol operated field. Associated baseline production losses continue to reduce Petrobank's net production, and these remediation activates have impaired our flexibility to workover additional wells at this time. At Neiva we have also experienced recent baseline production shortfalls. We continue to work with Ecopetrol at Orito and Neiva to resolve these shortfalls in baseline production.

Current productive capability is estimated at 2,000 bopd (net), which is lower than our anticipated 2003 exit rate of 3,000 bopd (net). This is a result of lower than anticipated results from the O-114 well, production losses from the O-113 well and baseline shortfalls. The 2004 capital expenditure plan is focused on Caballos drilling and the implementation of a pilot scale waterflood.

We are pleased to announce the appointment of Steven J. Benedetti as Vice President Latin America and General Manager of our Colombian subsidiary, based in Bogotá, Colombia. Steve graduated from Texas Christian University in 1976 with a Masters Degree in Geology, and brings more than 27 years of upstream oil and gas experience in North America and international locations to Petrobank. He has spent the last 10 years of his career working in Latin America and has held Country Manager positions in both Argentina and Venezuela.

Heavy Oil Business Unit

Three stratigraphic core wells drilled in the last quarter of 2003 on the WHITESANDS THAI™ pilot project area each encountered over 20 meters of high quality McMurray formation oil sands reservoir. These results further confirmed the significant resource potential of the leases and a suitable site for the pilot project. We are currently updating our independent resource evaluation.

The WHITESANDS THAI™ pilot project application, submitted in October 2002 to the AEUB, is in the final stages of the regulatory review process with approval anticipated early in the first quarter of 2004.

Petrobank is proceeding with a lead arranger towards a financing, in a subsidiary, of the estimated $30 million capital cost of the WHITESANDS THAI™ pilot project.

2004 Commodity Price Hedging

Following the sale of Wapella, Petrobank will have fixed price crude oil sales contracts for 1,000 barrels of oil per day at a West Texas Intermediate price of US$24.00 per barrel and 300 barrels of oil per day at a West Texas Intermediate price of US$27.74 per barrel. In addition to the commitment to deliver 2,225 GJ per day of natural gas at a wellhead price of $3.27 per GJ we have entered into an AECO based costless collar on 10,551 GJ per day with a floor price of $5.00 per GJ and a ceiling of $5.94 per GJ.

This news release contains forward-looking statements that reflect management's objectives and expectations as at the date of this report. These objectives and expectations involve risks and uncertainties that are common to the oil and natural gas industry. There is no guarantee that these objectives will be met, nor that the expected operating and commodity price conditions will occur. The Company's actual results may differ materially from those anticipated in these forward-looking statements.

FOR FURTHER INFORMATION PLEASE CONTACT:

John D. Wright, President and Chief Executive Officer
Telephone: (403) 750-4400

David Rain, Vice President Finance and Chief Financial Officer
Telephone: (403) 750-4400

Corey Ruttan, Director Corporate Finance and Investor Relations
Telephone: (403) 750-4400



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MATERIAL CHANGE REPORT

Item 1. Reporting Issuer:

Petrobank Energy and Resources Ltd.
2600, 240 - 4th Avenue SW
Calgary, AB T2P 4H4

Item 2. Date of Material Change:

January 8, 2004

Item 3. News Release:

A Press Release reporting the material change was issued by the Issuer on January 9, 2004, through CCN Matthews.

Item 4. Summary of Material Change:

Petrobank Energy and Resources Ltd. ("Petrobank") announced that it has entered into an agreement to dispose of the Wapella property in southeast Saskatchewan, effective December 31, 2003, for total proceeds of $36 million. The property is producing approximately 1,400 barrels of oil per day ("bopd"), which represents proceeds of $25,700 per flowing barrel of oil produced. The transaction is scheduled to close on January 28, 2004 and is subject to the purchaser (NAV Energy Trust) completing its currently contemplated financing. The proceeds from the disposition will be used in the short term, to repay bank debt.

Petrobank also announced 2003 production exit rates relating to its Canadian and Colombian operations. Petrobank exited 2003 with Canadian production of 6,300 boepd (including 1,400 bopd from Wapella), compared to its previously announced 2003 exit target of 7,000 boepd, and Colombian productive capability estimated at 2,000 bopd (net), which is lower than its previously announced 2003 exit rate of 3,000 bopd (net).

Item 5. Full Description of Material Change:

See the attached Press Release of Petrobank dated January 9, 2004 which is incorporated herein by reference.

Item 6. Reliance on Section 146(2) of the Securities Act (Alberta):

Not applicable

Item 7. Omitted Information:

Not applicable

Item 8. Senior Officer:

David Rain, VP Finance and Chief Financial Officer
Telephone: (403) 750-4400

Item 9. Statement of Senior Officer

The foregoing accurately discloses the material change referred to herein.

Dated as of January 9, 2004 at Calgary, Alberta.

Petrobank Energy and Resources Ltd.

By: Signed "*David Rain*"

Copy: Toronto Stock Exchange

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NEWS RELEASE

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OPERATIONAL UPDATE

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NEWS RELEASE

PETROBANK INITIATES $30 MILLION WHITESANDS PILOT PROJECT FINANCING

Calgary, Alberta – January 15, 2004 - Petrobank Energy and Resources Ltd. ("Petrobank") is pleased to announce that it has entered into an agency agreement with TD Securities Inc. and Tristone Capital Inc., on behalf of its subsidiary WHITESANDS INSITU Ltd. ("WHITESANDS"), to arrange equity financing for the estimated $30 million capital cost of the WHITESANDS THAI™ pilot project. The financing is to be effected by the issuance of up to a 40% equity interest in WHITESANDS. This financing will be negotiated on a "best efforts" private placement basis with closing expected in the first quarter of 2004, subject to receipt of regulatory approvals.

WHITESANDS owns 45 sections of oil sands leases in the Christina Lake region of Alberta and has rights to use Petrobank's patented THAI™ technology. Initial resource estimates on these leases previously indicated a potential 500 million barrels of original bitumen in place. Recent independent evaluation of our seismic and drilling activity over our pilot site indicates a potential in-place resource in excess of 200 million barrels on this 4-section area of the block. Integrating the existing geological and geophysical data covering the remainder of the lands now suggests a total in-place bitumen resource of approximately 1 billion barrels.

The WHITESANDS project will be the first field scale test of the patented THAI™ (Toe-to-Heel-Air-Injection) *in-situ* heavy oil recovery technology. THAI™ is a revolutionary combustion technology for the *in-situ* recovery of bitumen and heavy oil that combines a vertical air injection well with a horizontal production well. THAI™ integrates existing proven technologies and provides the opportunity to create a step change in the development of heavy oil resources globally. THAI™ has many potential benefits over other in-situ recovery methods, such as SAGD (Steam Assisted Gravity Drainage). These indicated benefits include higher resource recovery, lower production and capital costs, minimal usage of natural gas and fresh water, a partially upgraded crude oil product, reduced diluent requirements for transportation, and lower greenhouse gas emissions. The THAI™ process also has the potential to operate in lower pressure, lower quality, thinner and deeper reservoirs than current steam–based recovery processes. Petrobank owns all the intellectual property rights to the THAI™ and related CAPRI™ technologies.

The WHITESANDS THAI™ pilot project application, submitted in October 2003 to the AEUB, is in the final stages of the regulatory review process with approval anticipated early in the first quarter of 2004. Upon completion of this financing and receipt of AEUB approval, we will finalize design and commence construction of the WHITESANDS THAI™ pilot project. We anticipate first results from this pilot project in 2005. Details on the THAI™ and CAPRI™ technologies, along with our experimental pilot project application are available on Petrobank's website at www.petrobank.com.

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NEWS RELEASE

Certain statements in this press release are "forward-looking statements" within the meaning of the United States Private Securities Litigation Reform Act of 1995. Specifically, this press release contains forward-looking statements relating to, prospects for technologies which remain unproven and the expected amount and timing of capital projects. 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: the ability to economically test, develop and utilize the technologies described herein, the feasibility of the technologies, general economic, market and business conditions; fluctuations in oil and gas prices; the results of exploration and development of drilling and related activities; fluctuation in foreign currency exchange rates; the uncertainty of reserve estimates; changes in environmental and other regulations; risks associated with oil and gas operations; and other factors, many of which are beyond the control of the Company. 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 forecast.

This news release shall not constitute an offer to sell or the solicitation of any offer to buy the securities in any jurisdiction. The securities offered will not be and have not been registered under the United States Securities Act of 1933 and may not be offered or sold in the United States absent registration or an applicable exemption from the registration requirement.

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Telephone: (403) 750-4400

www.petrobank.com

PETROBANK
ENERGY AND RESOURCES LTD.

NEWS RELEASE

PETROBANK CLOSES WAPELLA DISPOSITION AND SETTLES DEBENTURE

Calgary, Alberta - January 28, 2004 - Petrobank Energy and Resources Ltd. ("Petrobank") is pleased to announce the completion of the sale of the Wapella property in Southeast Saskatchewan, effective December 31, 2003, for cash proceeds of $36 million. The proceeds from the disposition have been used to repay bank debt and to settle in advance the 9% debenture issued on the Monolith acquisition completed last September. The principal amount of this debenture was reduced from $14.5 million to $14.0 million as a result of purchase price adjustments associated with the Monolith transaction. Petrobank has paid $1.5 million of this principal amount into escrow and is thereby seeking to further reduce the ultimate amount payable under this debenture through an arbitration process.

FOR FURTHER INFORMATION PLEASE CONTACT:

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WHITESANDS INSITU Ltd.

NEWS RELEASE

Petrobank Receives Approval To Test Revolutionary THAI™ Heavy Oil Recovery Technology

Calgary, AB – February 23, 2004: Petrobank Energy and Resources Ltd. ("Petrobank") announces that it has received approval for its WHITESANDS Pilot Project from the Alberta Energy and Utilities Board (AEUB) and Alberta Environment (AENV). The WHITESANDS pilot project has also been granted Scientific Research and Experimental Development (SR&ED) tax status from Canada Customs and Revenue Agency. This project will be the first field-scale application of the patented Toe-to-Heel-Air-Injection (THAI™) *in-situ* heavy oil recovery technology.

THAI™ is a revolutionary combustion technology for the *in-situ* recovery of bitumen and heavy oil that combines a vertical air injection well with a horizontal production well. THAI™ integrates existing proven technologies and provides the opportunity to create a step change in the development of heavy oil resources globally.

THAI™ has many potential benefits over existing *in-situ* recovery methods, such as SAGD (Steam Assisted Gravity Drainage). These benefits include higher resource recovery, lower production and capital costs, minimal usage of natural gas and fresh water, a partially upgraded crude oil product, reduced diluent requirements for transportation, and lower greenhouse gas emissions. The THAI™ process also has the potential to operate in lower pressure, lower quality, thinner and deeper reservoirs than current steam–based recovery processes. Petrobank owns all the intellectual property rights associated with the THAI™ technology.

"We are gratified that the rigorous AEUB and AENV technical and environmental review of the WHITESANDS Project culminated in this approval, providing further recognition of the technical feasibility of the THAI™ process. This reinforces our confidence in the technology's ultimate commercial potential," said Chris J. Bloomer, President and CEO, WHITESANDS INSITU Ltd.

WHITESANDS INSITU Ltd. (WHITESANDS) - a subsidiary of Petrobank - owns 45 sections of oil sands leases in the Christina Lake region of Alberta and has rights to use Petrobank's patented THAI™ technology. A recent independent evaluation of seismic and drilling activity indicates a potential in-place resource in excess of 200 million barrels over the 4-section pilot project area. Integrating the existing geological and geophysical data covering the remainder of the WHITESANDS lands indicates a total potential in-place bitumen resource of approximately 1 billion barrels.

WHITESANDS is currently arranging equity financing for the estimated $30 million capital cost of the pilot project. Petrobank anticipates effecting this financing by issuing up to a 40% equity interest in WHITESANDS. Pilot design is being finalized and construction will commence mid-2004 with first results expected in early-2005. With positive results from the pilot, we expect to immediately begin the design and implementation of a commercial project.

"Petrobank's strategy is to leverage the THAI™ technology into large resource opportunities both domestically and internationally. The potential impact of the technology on global heavy oil reserves is staggering, considering the opportunity to not only increase the profitability of heavy oil and bitumen production, but also to significantly increase the economically exploitable resource base worldwide," said John D. Wright, President and CEO, Petrobank Energy and Resources Ltd.

Additional information on THAI™ technology along with key information about the pilot project application are available on Petrobank's website at www.petrobank.com.

Certain statements in this press release are "forward-looking statements" within the meaning of the United States Private Securities Litigation Reform Act of 1995. Specifically, this press release contains forward-looking statements relating to, prospects for technologies which remain unproven and the expected amount and timing of capital projects. 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: the ability to economically test, develop and utilize the technologies described herein, the feasibility of the technologies, general economic, market and business conditions; fluctuations in oil and gas prices; the results of exploration and development of drilling and related activities; fluctuation in foreign currency exchange rates; the uncertainty of reserve estimates; changes in environmental and other regulations; risks associated with oil and gas operations; and other factors, many of which are beyond the control of the Company. 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 forecast.

For more information please contact:

John D. Wright, President and CEO – Petrobank Energy and Resources Ltd., or
Chris J. Bloomer, President and CEO - WHITESANDS INSITU Ltd..
Telephone: (403) 750-4400

ALTERNATIVE MONTHLY EARLY WARNING REPORT
PURSUANT TO SECTION 4.5 OF
NATIONAL INSTRUMENT 62-103

The following is the report required by section 4 of National Instrument 62-103:

1. **Name and address of the eligible institutional investor:**

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Deans Knight Capital Management Ltd.
Suite 730 - 999 West Hastings Street
Vancouver, British Columbia V6C 2W2

(the "Eligible Institutional Investor")

2. **Name of reporting issuer with respect to which this report is filed:**

Petrobank Energy and Resources Ltd.
2200, 400 - 3 Ave SW
Calgary, Alberta
T2P 4H2

(the "Reporting Issuer")

3. **Month with respect to which this report is filed:**

February 2004

4. **Net increase or decrease in the number or principal amount of securities, and in the eligible institutional investor's securityholding percentage in the class of securities, since the last report filed by the eligible institutional investor:**

Since the last report filed in September 2002, the Eligible Institutional Investor has increased its holdings in the common shares of the Reporting Issuer (the "Shares") by 3,812,500, representing an increase of, approximately, 2.4% of the outstanding Shares of the Reporting Issuer.

5. **Designation and number or principal amount of securities and the eligible institutional investor's securityholding percentage in the class of securities at the end of the month for which this report is made:**

The Eligible Institutional Investor has, direct or indirect, control or direction over 8,168,200 common shares of the Reporting Issuer ("Shares") and 490,000 purchase warrants of the Reporting Issuer (the "Warrants"). Upon conversion of the Warrants, the securityholding percentage of the Eligible Institutional Investor would be 15.7% of the outstanding Shares.

Wayne Deans and Doug Knight (the "Joint Actors") may be considered to be joint actors of the Eligible Institutional Investor because they hold more than 10% of the outstanding voting

securities of Deans Knight and therefore are "associates" of the Eligible Institutional Investor. Wayne Deans and Doug Knight own, directly or indirectly, 10,000 and 100,000 Shares, respectively of the Reporting Issuer. The securityholding percentage of the Joint Actors would be 0.2% of the outstanding Shares.

The aggregate securityholding percentage of the Eligible Institutional Investor and the Joint Actor would be 15.9% of the outstanding Shares.

6. **Designation and number or principal amount of securities and the percentage of outstanding securities referred to in item 5 over which:**

   (a) the eligible institutional investor, either alone or together with any joint actors, has ownership and control:

   The Shares described in item 5 are controlled but not owned by the Eligible Institutional Investor. The Joint Actors control and beneficially own their respective Shares.

   (b) the eligible institutional investor, either alone or together with any joint actors, has exclusive or shared control but does not have ownership:

   See 6(a) above.

   (c) the eligible institutional investor, either alone or together with any joint actors, has exclusive or shared control but does not have ownership:

   See 6(a) above.

7. **Purpose of the eligible institutional investor and any joint actors in acquiring or disposing of ownership of, or control over, the securities, including any future intention to acquire ownership of, or control over, additional securities of the reporting issuer:**

   The Shares were acquired and are being held for investment purposes only, and not for the purpose of exercising control or direction over the Reporting Issuer. The Eligible Institutional Investor and the Joint Actors may from time to time acquire additional shares, dispose of some or all of the existing or additional shares or may continue to hold the shares.

8. **The general nature and the material terms of any agreement, other than lending arrangements, with respect to securities of the reporting issuer entered into by the eligible institutional investor, or any joint actor, and the issuer of the securities or any other person or company in connection with any transaction or occurrence resulting in the change in ownership or control giving rise to the report, including agreements with respect to the acquisition, holding, disposition or voting of any of the securities:**

   There are no such agreements and therefore this item is not applicable.

9. **The names of any joint actors in connection with the disclosure required by this report:**

   See 5 above.

10. **If applicable, a description of any change in any material fact set out in a previous report by the eligible institutional investor:**

    Not applicable.

11. **Statement regarding eligibility to file reports under Part 4 of National Instrument 62-103 in respect of reporting issuer:**

    The Eligible Institutional Investor is eligible to file reports under Part 4 of National Instrument 62-103 in respect of the Reporting Issuer and does not presently intend to: (a) make a formal take-over bid for any shares of the Reporting Issuer; or (b) propose a reorganization, amalgamation, merger arrangement or similar business combination with the Reporting Issuer which would result in Eligible Institutional Investor's client accounts controlling the Reporting Issuer, alone or collectively.

DATED the 8th day of March, 2004

DEANS KNIGHT CAPITAL MANAGEMENT LTD.

By: "Doug Knight"
Authorized Signatory

Doug Knight
Name

Director
Title

PETROBANK
ENERGY AND RESOURCES LTD.

NEWS RELEASE

PETROBANK ANNOUNCES OPERATIONAL UPDATE AND FOURTH QUARTER RESULTS

Calgary, Alberta – March 31, 2004 - Petrobank Energy and Resources Ltd. ("Petrobank") is pleased to provide this operational update of our Canadian, Latin American and Heavy Oil Business Units as well as our fourth quarter financial results.

OPERATIONAL UPDATE

Canadian Business Unit

In Canada, Petrobank drilled a total of 12 wells (8.2 net) in the fourth quarter of 2003. The fourth quarter drilling occurred at Jumpbush, Red Willow, Hamburg and Little Bow and resulted in 10 cased gas wells (6.8 net), and 2 dry and abandoned wells (1.4 net). An additional 6 wells (6 net) were drilled at Nevis in the first quarter of 2004. This drilling resulted in 3 cased oil wells and 3 cased gas wells. Petrobank anticipates having most of the gas from this drilling program tied-in and producing by the end of the second quarter. The 3 oil wells drilled in the first quarter were placed on production in the final week of March.

Petrobank completed a 112 km seismic program over our coal bed methane ("CBM") project in Princeton British Columbia (Petrobank 60%) during the quarter. Initial indications are that this prospect contains between 250 and 500 Bcf of initial-gas-in-place. Further work is required to assess whether we can recover a significant portion of this gas at economic rates. We expect to drill a test well on this property this summer and then move to a 4-well pilot project in the fourth quarter of 2004 to test the commercial viability of this CBM resource. In addition to our CBM project in Princeton, we have begun testing our CBM potential in the Jumpbush area of Southern Alberta, and successfully flowed gas at rates of approximately 100 mcf/d from a single coal zone in a well with multiple coal intervals. Initial mapping of these coal beds indicates a potential initial-gas-in-place resource of up to 300 Bcf. To further evaluate the CBM gas potential at Jumpbush, we plan to re-complete and produce the coal sections in 5 existing wells.

The nature of our Canadian asset base has changed from a year ago with the acquisition of the Nevis and Red Willow properties from Monolith in September 2003 and the disposition of the Wapella property in January 2004. This new production has higher netbacks, and is characterized by high deliverability, high decline natural gas, offering multi-zone potential. Current production in Canada is approximately 4,500 boepd. In March, despite improved performance at Shekilie, Red Willow and Nevis, we suffered a loss of 500 boe/day due to pipeline restrictions and competitive drainage at our most prolific Nevis gas well. We are in the process of installing our own pipeline and compression at this well, in an attempt to partially restore this lost production.

The balance of our 2004 capital program involves further drilling in the Nevis, Red Willow, Jumpbush, Eyehill, and Princeton areas. We are planning 15 wells at Nevis and Red Willow, primarily targeting the Mannville zones, although some wells will be further deepened to test Devonian targets. The 2004 program at Jumpbush includes up to 30 shallow gas wells, targeting both conventional natural gas and coal bed methane. There are also as many as 7 wells planned in the greater Eyehill area of West Central Saskatchewan. Apart from further developing our current Eyehill pool, these wells will be testing concepts for both a new pool, and a step-out to our existing pool that could double its size. We are very positive about the large volume of opportunities to pursue at Nevis, Red Willow, Jumpbush and Eyehill. Furthermore, the large CBM resource at both Princeton and Jumpbush offers the potential for significant reserve and production additions in the future.

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Canadian Reserve Update

Petrobank's independent reserve engineers, Gilbert Laustsen Jung Associates Ltd. ("GLJ"), have completed their Canadian reserve evaluation as at January 1, 2004. After accounting for dispositions totaling 4.8 million boe, Petrobank's Canadian proved reserves year over year decreased by 25% to 7.5 million boe converting gas on a 6 mcf per barrel basis. Canadian total proved plus probable reserves decreased by 17% to 11.3 million boe, after accounting for dispositions of 6.8 million boe. Based on the GLJ price forecast effective April 1, 2004, the Company's proven plus probable reserves have a net present value before tax at a 10% discount rate of $119.4 million. Petrobank's Canadian reserves are summarized as follows:

Canadian Reserve Balances

	Reserve Volumes			
	Liquids (Mbbls)	Gas (Bcf)	Mboe (6:1)	NPV(10%) ($MM)
Proved Producing	4,827	19.4	8,067	96.3
Total Proved	6,148	28.0	10,821	117.1
Total Proved + Probable	9,470	39.2	15,995	156.2

Canadian Reserve Balances Proforma (without Wapella)

	Reserve Volumes			
	Liquids (Mbbls)	Gas (Bcf)	Mboe (6:1)	NPV(10%) ($MM)
Proved Producing	2,199	19.4	5,439	73.6
Total Proved	2,795	28.0	7,468	90.6
Total Proved + Probable	4,780	39.2	11,305	119.4

The Company's reserves were evaluated using GLJ's April 1, 2004 price forecast. Cash flows are prior to income taxes and general and administrative expenses. Undeveloped land values are not included. Well abandonment and lease reclamation costs have been included for all the Company's producing and non-producing wells.

The Wapella property was sold for $36 million effective December 31, 2003 but closed in January 2004. Consequently, the pro-forma reserve information is included to reflect this major disposition.

Canadian Reserve Reconciliation

	Total Proved	Proven + Probable[(1)]
January 1, 2003 reserves	9,973	13,694
2002 Production	(1,699)	(1,699)
Revisions	(528)	(375)
Dispositions	(1,446)	(2,105)
Acquisitions	2,847	3,561
Additions	1,674	2,919
January 1, 2004 reserves	10,821	15,995
Disposition Wapella	(3,353)	(4,690)
Proforma January 1, 2004 reserves	7,468	11,305

(1) January 1, 2003 probable reserves are risked at 50 percent to allow comparison to the new definition of proved plus probable under NI 51-101.

Latin American Business Unit

In Colombia, we completed our sixth Orito Caballos well (Orito-114) during the quarter, which was drilled as a follow up to the Orito-115 well. The new well came in low to our prognosis and produced significant quantities of water from the lower Caballos reservoir. We are currently evaluating the rationale to plug back the well and isolate shallower Caballos zones that produced oil during early testing.

We have recently installed a jet pump on our Orito-112 well and an electrical submersible pump on our Orito-113 well resulting in production rates of 500 and 300 barrels of oil per day, respectively. The majority of the field's production affected by previously reported guerilla activities in the Putumayo region has been restored and we continue to work with Ecopetrol to improve production in the field. Current production from our Orito and Neiva blocks is approximately 1,800 bopd.

Although results to date in Colombia have been mixed and significantly more costly than anticipated, we remain confident in the potential of our Colombian assets and are finalizing a reservoir simulation of the Orito Caballos reservoir, which will guide our capital expenditures going forward. We have confirmed that this single zone in the Orito field initially contained approximately 850 million barrels of original-oil-in-place, of which only 185 million barrels have been produced to date. We are assessing the ability to increase the overall field recovery through the implementation of a program combining infill drilling, water-flooding and high-volume lift pumps. There are also a number of field extension prospects which could significantly increase the overall reserve base and productivity of the block. Other efforts to date have resulted in a re-engineered drilling and completions program that should generate future cost savings. In addition, we have gained valuable technical information that has resulted in the refinement of our reservoir simulation model, incorporating both a tilted oil water contact and a gradational "volatile oil" concept evidenced by our Orito 112 and 113 wells where we are producing 43 degree API crude oil. These findings have increased our comfort in the Orito field's ultimate resource potential.

We expect to recommence drilling operations on the Orito Block in the third quarter of 2004 upon finalization of our reservoir simulation model and the receipt of required regulatory approvals.

To complement our Incremental Production Contracts, we continue to evaluate other high impact opportunities in selected regions of Colombia. The Central Colombia Block is an example of this strategy where we acquired a one-third interest in this 390,000-acre exploration contract, situated in the Upper Magdalena Basin. A large structural prospect has been identified on the block, which can be evaluated without additional geological or geophysical work through the drilling of a relatively low cost (U.S.$1.5 million net) exploratory well.

Colombian Reserves

The Colombian reserves evaluation as at January 1, 2004, summarized below includes GLJ's assessment of total proved and probable reserves but excludes the impact of our reservoir simulation, which is currently being finalized. We expect to incorporate this simulation work into our future reserve assessments.

Petrobank's Colombian total proved reserves year over year decreased by 12% to 4.1 million barrels. Colombian total proved plus probable reserves increased by 6% to 6.8 million barrels. Based on the GLJ price forecast effective April 1, 2004, the Company's proven plus probable reserves have a net present value before tax at a 10% discount rate of U.S.$60.9 million.

Colombian Reserve Balances

	Crude Oil (Mbbls)	NPV(10%) ($U.S.MM)
Proved Producing	2,149	26.1
Total Proved	4,062	40.1
Total Proved + Probable	6,836	60.9

Colombian Reserve Reconciliation

	Total Proved	Proven + Probable
January 1, 2003 reserves	4,619	6,475
2003 Production	(390)	(390)
Revisions	(1,381)	(664)
Additions	1,214	1,415
January 1, 2004 reserves	4,062	6,836

Heavy Oil Business Unit

The WHITESANDS Pilot Project received approval from the Alberta Energy and Utilities Board (AEUB) and Alberta Environment (AENV) on February 22. 2004. This approval was the culmination of rigorous technical and environmental scrutiny by the regulatory authorities, which evaluated not only the project's compliance with oil sands regulations, but also its technical merits. Detailed engineering for the pilot is underway and construction is forecast to commence mid-2004 with first results expected in early-2005. With positive results from the pilot, we expect to immediately begin the design and implementation of a commercial project.

On January 15, 2004, Petrobank entered into an agency agreement with TD Securities Inc. and Tristone Capital Inc., on behalf of our subsidiary, WHITESANDS INSITU Ltd. (WHITESANDS) to arrange private equity financing for the estimated $30 million capital cost of the pilot project. The financing is to be effected by the issuance of up to a 40% equity interest in WHITESANDS. The financing process has entered into the technical due diligence phase with potential investors. As part of this process, an independent panel of experts has been formed to advise interested investors and to evaluate the THAI™ process and the pilot project. We anticipate that the panel's report will be made available in the near future on the Company's website in the near future or by request.

WHITESANDS owns 45 sections of oil sands leases in the Christina Lake region of Alberta. Fekete Associates have recently completed a geological evaluation of the leases, which indicates a bitumen resource of 850 million barrels in the middle McMurray formation and an additional 250 million barrels in the upper McMurray. This bitumen resource is sufficient to support a significant THAI commercial development and, in the absence of this "step-change" technology, would also be attractive for a large-scale commercial Steam-Assisted-Gravity-Drainage (SAGD) project.

The THAI™ and CAPRI™ technologies have the potential to revolutionize the heavy oil extraction business. Petrobank shareholders stand to benefit enormously from the commercial opportunity on our existing land base combined with our future ability to license the technologies and capture additional resources internationally.

FINANCIAL REVIEW

Gas volumes have been converted to barrels of oil equivalent ("boe") so that 6 mcf of gas equals 1 boe. This report contains financial terms that are considered non-GAAP measures such as cash flow from operations, cash flow per share, net debt, and operating netback. These measures are commonly utilized in the oil and natural gas industry and management considers them to be informative for our shareholders. Cash flow from operations and cash flow per share reflect cash generated from operating activities before changes in other non-cash items. We consider these measures important as they reflect the Company's ability to generate cash from operations to meet future growth opportunities while servicing future debt obligations. All amounts are in Canadian dollars, unless otherwise stated. Readers should refer to the attached financial statements, presented in accordance with accounting principles generally accepted in Canada, as at and for the period ended December 31, 2003.

Recent Significant Transactions

Petrobank acquired Monolith Oil Corp. ("Monolith") on September 19, 2003 for $39.6 million. The results of operations for the year only reflect results from the acquired properties subsequent to the closing date. Production from these properties averaged 2,325 barrels of oil equivalent per day (boepd) between the closing date and the end of the year, but only contributed 663 boepd to average 2003 production. A portion of the Monolith consideration was a Debenture in the amount of $14.0 million, which was repaid by the Company in January 2004.

Petrobank issued $10.0 million of flow through shares in September and renounced related tax benefits to those shareholders in December. The result of this transaction and the Monolith acquisition resulted in a future tax liability being recognized on the consolidated balance sheet as at December 31, 2003.

Petrobank disposed of its Wapella property in January 2004 for cash proceeds of $36.0 million. These proceeds were used to repay the Debenture described above and to repay a portion of the Company's outstanding bank debt. Pro forma this transaction, the Company's net debt as at December 31, 2003 was $115 million. Net debt is defined as debt plus any working capital deficiency and the book value of the Company's subordinated notes. Wapella's production was approximately 1,400 bpd when it was sold.

Production

Oil and NGL production in Canada during the fourth quarter averaged 2,931 barrels per day (bpd), virtually unchanged from the 2,909 bpd produced in the third quarter of 2003 and an 11% increase from the fourth quarter of 2002. Fourth quarter natural gas production of 17.7 million cubic feet per day (mmcfpd) increased 57% from the 11.2 mmcfpd produced in the fourth quarter of 2002 and 169% from the 6.6 mmcfpd produced in the third quarter of 2003. The large increase from the third quarter reflects the Monolith acquired production, of which 90% is natural gas. Total Canadian production for the fourth quarter was 5,881 boepd, a 30% increase from the same period last year.

Colombian oil production increased from 1,166 bpd in the third quarter of 2003 to 1,374 bpd in the fourth quarter. The Company did not commence production in Colombia until 2003. Petrobank experienced production interruptions in the fourth quarter related to a security incident, which affected Orito operations. The Company was forced to shut down certain wells and experienced difficulties bringing this production back on line once operations were restored.

Realized Sales Prices

The average Canadian oil and NGL price received in the fourth quarter was $25.78 per barrel, a 5% decrease from the $27.19 per barrel received in the third quarter of 2003. Canadian oil and NGL prices averaged $30.62 per barrel, before hedging losses of $4.84 per barrel, representing a U.S.$7.91 discount to average WTI prices in the quarter. The average natural gas price received in

the fourth quarter was $5.61 per mcf, a 13% increase from $4.98 per mcf in the third quarter of 2003. Although the natural gas price in the quarter reflects the negative impact of the Company's long-term physical gas sales contracts, that impact was reduced due to the addition of the un-contracted Monolith volumes. Oil sales prices in Colombia averaged U.S.$24.06 per barrel in the fourth quarter, representing a U.S.$7.12 discount to WTI. At the end of the year, Petrobank's calendar 2003 oil price swaps on 1,500 bpd at an average price of U.S.$23.77 expired. In 2004, 1,000 bpd of new swaps at U.S.$24.00 WTI became effective. In addition, the Company has the following hedge contracts for calendar 2004: 300 bpd fixed price oil sales contract at an average price of U.S.$27.74 per barrel; and, a natural gas collar on 10,551 GJ/day with AECO prices between $5.00 and $5.94 per GJ (gigajoule).

Royalties

Royalties increased from $2.2 million in the third quarter of 2003 to $3.1 million in the current period. This increase coincided with an increase in revenues from $13.7 million to $20.1 million, over the same period. Colombian royalties are included in the current quarter at a rate of 8%. Canadian royalties as a percentage of revenue decreased from 19% in the third quarter of 2003 to 17% in the current period. The decrease in effective Canadian royalty rates reflects a revision of prior period estimates. We anticipate Canadian royalty rates to increase to approximately 21% in 2004.

Production Expenses

Production expenses in Canada increased 7% from $7.06 per boe in the third quarter of 2003 to $7.55 per boe in the current period. This increase is largely a result of workover and well servicing costs recorded during the quarter, which are not anticipated to recur at these same levels in 2004. Production expenses in Colombia averaged $15.62 per barrel in the quarter. Production expenses remain high in Colombia for a number of reasons including Ecopetrol's delays in assuming operatorship of wells, for which Petrobank still pays a fixed operating fee per barrel of oil produced, and costs related to the security incident in November. These high well operating costs will continue into April of 2004 when we anticipate these wells will be equipped with permanent surface equipment and operatorship assumed by Ecopetrol.

General and Administrative Expenses

General and administrative expenses were flat compared to the third quarter at $1.4 million, but increased from $0.9 million in the same period in 2002. The increase from 2002 relates to incremental overhead associated with the Company's Colombian operations. Colombian operations were staffed to facilitate a more aggressive capital program than that which is currently underway. We are currently evaluating existing well, geological and petrophysical data in Orito and developing a 2004 capital program based on our reservoir simulation model.

Depletion, Depreciation and Site Restoration Expense

Depletion, depreciation and site restoration expense for the fourth quarter increased to $10.7 million ($16.00 per boe) from $6.4 million ($13.54 per boe) for the third quarter. This increase is due partly to the shorter reserve life of the Monolith assets and finalization of year-end reserve assessments prepared by our independent reservoir engineers. This expense also increased from $10.14 per boe from the comparative period in 2002 reflecting the impact of our Colombian drilling program in 2003.

Impairment Expense

We recorded a $16.9 million impairment expense related to our Colombian ($15.0 million) and other international cost centres ($1.9 million) in the fourth quarter as a result of applying the existing CICA Full Cost Guideline ceiling test rules. We will be adopting the new CICA Full Cost Guideline in the first quarter of 2004. Application of the ceiling test calculation under the new guideline would not have resulted in an incremental write-down as at December 31, 2003.

Interest on Subordinated Notes

Interest on subordinated notes during the fourth quarter of $2.8 million was reflected net of a future tax recovery of $1.1 million. This expense compared to $2.8 million in the third quarter and $1.5 million in the same period last year. The increase from 2002 relates to an issuance of $40.0 million of notes in May of 2003.

Income Taxes

Petrobank acquired minimal tax pools with the Monolith corporate acquisition and as a result, recorded a future tax liability of $12.0 million. Petrobank has also reflected an additional liability of $3.5 million associated with the issuance of $10.0 million of flow through shares and the related renouncement of a similar amount of tax benefits to those shareholders. In the fourth quarter, we recorded a future tax recovery against these balances of $0.5 million in capital and future income taxes and $1.1 million as an offset to interest on subordinated notes. Petrobank does not anticipate a cash tax liability in either Canada or Colombia for at least the next two years.

Capital Expenditures

Consolidated capital expenditures during the quarter were $27.3 million, comprised of $12.3 million in Canada and $15.0 million in Colombia. In Canada, activity was concentrated on drilling at our Jumpbush and Red Willow properties, as well as drilling test wells and ongoing engineering work in support of our heavy oil technology pilot project. Colombian expenditures were focused on drilling, completions and workovers in Orito. Capital activity in Colombia in the first quarter of 2004 will be substantially reduced as we take a measured approach to assessing our most productive future drilling opportunities. Canadian activity in 2004 will focus on drilling new wells at our Jumpbush and Nevis/Red Willow properties, which are gas focused.

Liquidity and Capital Resources

At December 31, 2003 net debt totaled $151.0 million, including the book value of outstanding subordinated notes. This balance was reduced with proceeds from the sale of Wapella in January 2004 of $36 million. Petrobank's borrowing base under its senior secured credit facility is currently $36.1 million and our subordinated notes are not callable and mature in July 2006.

Management Change

Effective March 31st, David J. Rain has resigned from his position as Chief Financial Officer to pursue other business opportunities. We would like to thank Dave for his devoted efforts over the past four years and wish him all the best in his future endeavors. We are pleased to announce that Chris J. Bloomer will be assuming the role of Chief Financial Officer along with his current responsibilities as Vice President, Heavy Oil.

OUTLOOK

While we recognize that 2003 was a difficult year for our shareholders, we have evolved our existing asset base and advanced key, high-impact projects in each of our business units. In addition to our substantial inventory of conventional Canadian drilling opportunities, we have two large coal bed methane prospects, which will be assessed over the next 12 to 24 months. In Colombia, we are refining our Orito reservoir model, which we will use to direct a focused drilling program aimed at generating significant increases in reserves and productivity. Finally, the WHITESANDS pilot project is poised to create a step change in heavy oil production, upon which we intend to capitalize both domestically and internationally. Petrobank provides shareholders with a unique opportunity, where, relative to our market capitalization, we have the ability to provide significant value creation through the successful execution of any one of the high impact projects contained within each of our three business units. Over the near-term, our development pace will be dictated by available capital and, for the long-term, we remain committed to the success of each of our business units and the value we can create for our shareholders.

Certain statements in this press release are "forward-looking statements" within the meaning of the United States Private Securities Litigation Reform Act of 1995. Specifically, this press release contains forward-looking statements relating to, prospects for technologies which remain unproven and the expected amount and timing of capital projects. 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: the ability to economically test, develop and utilize the technologies described herein, the feasibility of the technologies, general economic, market and business conditions; fluctuations in oil and gas prices; the results of exploration and development of drilling and related activities; fluctuation in foreign currency exchange rates; the uncertainty of reserve estimates; changes in environmental and other regulations; risks associated with oil and gas operations; and other factors, many of which are beyond the control of the Company. 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 forecast.

For more information please contact:

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Chris J. Bloomer, Vice-President Heavy Oil and CFO, or
Corey Ruttan, Director Corporate Finance and Investor Relations
Telephone: (403) 750-4400

· Highlights ·

	Three months ended December 31, 2003	2002	% change	Twelve months December 31, 2003	2002	% change
Financial						
($000s, except where noted)						
Oil and natural gas revenue	**20,080**	12,892	**56**	**66,111**	50,458	**31**
Cash flow from operations [1]	**8,701**	5,600	**55**	**29,258**	22,806	**28**
Per share – basic $ [2]	**0.12**	0.09	**33**	**0.45**	0.45	**-**
Per share – diluted $ [2]	**0.12**	0.09	**33**	**0.44**	0.40	**10**
Net income (loss)	**(18,563)**	1,376		**(14,691)**	6,191	
Net loss attributable to common shareholders	**(20,343)**	(171)		**(23,111)**	(430)	
Per share – basic $	**(0.37)**	-		**(0.48)**	(0.01)	
Per share – diluted $	**(0.37)**	-		**(0.48)**	(0.01)	
Capital expenditures	**27,338**	28,620	**(4)**	**116,060**	46,228	**151**
Proforma net debt [3]	**114,955**	62,495	**84**	**114,955**	62,495	**84**
Common shares outstanding (000s)						
Basic	**54,503**	45,314	**20**	**54,503**	45,314	**20**
Diluted	**59,599**	50,287	**19**	**59,599**	50,287	**19**
Operations [4]						
Canadian operating netback ($/boe except where noted)						
Oil and NGLs revenue ($/bbl)	**25.78**	31.27	**(18)**	**28.48**	31.11	**(8)**
Natural gas revenue ($/mcf)	**5.61**	5.09	**10**	**6.08**	3.89	**56**
Oil and natural gas revenue	**29.72**	30.96	**(4)**	**31.60**	27.39	**15**
Royalties	**5.12**	6.78	**(24)**	**6.56**	5.84	**12**
Production expenses	**7.55**	7.78	**(3)**	**7.48**	6.68	**12**
Operating netback	**17.05**	16.40	**4**	**17.56**	14.87	**18**
Colombian operating netback ($/bbl)						
Oil revenue	**31.66**			**32.22**		
Royalties	**2.53**			**2.56**		
Production expenses	**15.62**			**10.48**		
Operating netback	**13.51**			**19.18**		
Average daily production						
Canada - oil and NGLs (bbls)	**2,931**	2,652	**11**	**2,840**	2,623	**8**
Canada - natural gas (mcf)	**17,702**	11,244	**57**	**10,821**	14,541	**(26)**
Total Canada (boe)	**5,881**	4,526	**30**	**4,643**	5,047	**(8)**
Colombia - oil (bbls)	**1,374**			**1,068**		
Total Company (boe)	**7,255**	4,526	**60**	**5,711**	5,047	**13**

(1) Cash flow from operations before changes in non-cash working capital.

(2) Calculated based on cash flow from operations before changes in non-cash working capital less preferred share dividends and interest paid on subordinated notes.

(3) Includes working capital (deficiency), subordinated notes reflected as equity on the balance sheet net of proceeds received on the January 2004 property disposition of $36 million.

(4) 6 mcf of natural gas is equivalent to 1 barrel of oil equivalent (boe).

Consolidated Balance Sheets

(Unaudited, thousands of Canadian dollars)

As at December 31,	2003	2002
Assets		
Current assets		
Cash and cash equivalents	$ -	$ 12,224
Accounts receivable and other current assets	21,528	11,521
		-
	21,528	23,745
Capital assets (note 4)	232,007	126,873
	$ 253,535	$ 150,618
Liabilities and Shareholders' Equity		
Current liabilities		
Accounts payable and accrued liabilities	$ 34,937	$ 28,896
Debenture (note 3)	14,014	-
Bank debt (note 5)	30,102	-
	79,053	28,896
Obligations under gas sale and transportation contracts (note 6)	7,287	8,097
Site restoration liability	2,807	613
Future income tax liability (notes 3, 7, 8 and 9)	13,920	
	103,067	37,606
Shareholders' equity		
Subordinated notes (note 7)	93,430	57,344
Common shares (note 8)	72,355	48,054
Contributed surplus (note 8)	186	
Retained earnings (deficit)	(15,503)	7,614
	150,468	113,012
	$ 253,535	$ 150,618

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 December 31,		Twelve months ended December 31,	
	2003	2002	**2003**	2002
Revenues				
Oil and natural gas	**$ 20,080**	$ 12,892	**$ 66,111**	$ 50,458
Royalties	**(3,088)**	(2,823)	**(12,111)**	(10,751)
	16,992	10,069	**54,000**	39,707
Expenses				
Production	**6,062**	3,238	**16,770**	12,307
General and administrative	**1,444**	892	**5,940**	3,784
Interest	**547**	-	**771**	-
Depletion, depreciation and site restoration	**10,678**	4,224	**27,363**	17,269
Impairment (note 4)	**16,900**	-	**16,900**	-
	35,631	8,354	**67,744**	33,360
Income (loss) before other items and taxes	**(18,639)**	1,715	**(13,744)**	6,347
Other income (expense)	**30**	(78)	**(48)**	284
Gain on sale of temporary investment	**-**	-	**-**	654
Income (loss) before taxes	**(18,609)**	1,637	**(13,792)**	7,285
Capital and future income taxes (note 9)	**46**	(261)	**(899)**	(1,094)
Net income (loss)	**(18,563)**	1,376	**(14,691)**	6,191
Interest on subordinated notes, net of tax (note 7)	**(1,780)**	(1,547)	**(8,420)**	(6,107)
Preferred share dividends and related taxes	**-**	-	**-**	(514)
Net loss attributable to common shareholders	**(20,343)**	(171)	**(23,111)**	(430)
Retained earnings, beginning of period	**4,840**	7,794	**7,614**	14,562
Repurchase of securities (note 8)	**-**	(9)	**(6)**	(6,518)
Retained earnings, end of period	**$ (15,503)**	$ 7,614	**$ (15,503)**	$ 7,614
Basic and diluted loss per share (note 8)	**$ (0.37)**	$ -	**$ (0.48)**	$ (0.01)

See accompanying notes to these consolidated financial statements

Consolidated Statements of Cash Flow

(Unaudited, thousands of Canadian dollars)

	Three months ended December 31,		Twelve months ended December 31,	
	2003	2002	**2003**	2002
Operating Activities				
Net income (loss)	**$ (18,563)**	$ 1,376	**$ (14,691)**	$ 6,191
Depletion, depreciation and site restoration	**10,678**	4,224	**27,363**	17,269
Impairment	**16,900**	-	**16,900**	-
Gain on sale of temporary investment	**-**	-	**-**	(654)
Future income tax recovery (note 9)	**(500)**	-	**(500)**	-
Stock based compensation expense (note 8)	**186**	-	**186**	-
Cash flow from operations	**8,701**	5,600	**29,258**	22,806
Changes in non-cash working capital (note 12)	**(361)**	(320)	**(8,772)**	4,728
	8,340	5,280	**20,486**	27,534
Financing Activities				
Increase in bank debt	**17,202**	-	**30,102**	-
Issuance of subordinated notes (note 7)	**-**	-	**34,410**	-
Issuance of common shares and share purchase warrants (notes 7 and 8)	**145**	416	**12,786**	4,450
Interest on subordinated notes	**(2,277)**	(1,371)	**(7,806)**	(5,439)
Amortization of obligations under gas sale and transportation contracts (note 6)	**(204)**	(202)	**(810)**	(419)
Settlement of obligations under gas sale and transportation contracts (note 6)	**-**	-	**-**	(894)
Repurchase of securities (note 8)	**-**	-	**(9)**	(6,530)
Preferred share dividends and related taxes	**-**	-	**-**	(514)
Changes in other non-cash items (note 12)	**-**	-	**-**	(878)
	14,866	(1,157)	**68,673**	(10,224)
Investing Activities				
Expenditures on capital assets	**(27,338)**	(28,620)	**(116,060)**	(46,228)
Proceeds on disposition of capital assets (note 4)	**3,822**	(109)	**20,448**	3,334
Corporate acquisitions (note 3)	**-**	-	**(8,573)**	(42)
Proceeds on disposition of temporary investment	**-**	-	**-**	1,654
Site restoration expenditures	**(5)**	(424)	**(32)**	(1,129)
Changes in non-cash items (note 12)	**315**	11,332	**2,834**	12,014
	(23,206)	(17,821)	**(101,383)**	(30,397)
Net change in cash position	**-**	(13,698)	**(12,224)**	(13,087)
Cash and cash equivalents, beginning of period	**-**	25,922	**12,224**	25,311
Cash and cash equivalents, end of period	**$ -**	$ 12,224	**$ -**	$ 12,224

See accompanying notes to these consolidated financial statements

· Notes to the Consolidated Financial Statements ·

As at and for the years ended December 31, 2003 and 2002
(All tabular amounts expressed in thousands of Canadian dollars, except share amounts)

1. DESCRIPTION OF BUSINESS

Petrobank Energy and Resources Ltd. (the "Company" or "Petrobank"), is a public company listed on the Toronto Stock Exchange and incorporated under the Business Corporations Act (Alberta). Petrobank is engaged in the exploration for and development and production of oil and natural gas in the country of Colombia and in the Western Canadian Sedimentary Basin and is continuing the evaluation of other international oil and natural gas opportunities. During 2003, Petrobank acquired the intellectual property rights to the THAI™ and CAPRI™ heavy oil recovery technologies and has received regulatory approval to proceed with a pilot project to field test the THAI™ technology.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

These consolidated financial statements are prepared in accordance with Canadian generally accepted accounting principles and include the accounts of the Company and its subsidiaries.

MEASUREMENT UNCERTAINTY

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities as at the date of the consolidated balance sheets as well as the reported amounts of revenues, expenses, and cash flows during the periods presented. Such estimates relate primarily to unsettled transactions and events as of the date of the consolidated financial statements. Actual results could differ materially from estimated amounts.

Amounts recorded for depreciation, depletion and site restoration costs and amounts used for ceiling test calculations are based on estimates of oil and natural gas reserves and future costs required to develop those reserves that are subject to measurement uncertainty. Changes in these estimates could materially impact the consolidated financial statements of future periods.

CAPITAL ASSETS

The Company accounts for its oil and natural gas operations in accordance with the Canadian Institute of Chartered Accountants' existing guideline on full cost accounting in the oil and natural gas industry whereby all costs related to the acquisition of oil and natural gas properties are capitalized. Such costs include land and lease acquisition costs, annual charges on non-producing properties, geological and geophysical costs, and costs of drilling and equipping productive and non-productive wells.

Gains and losses are not recognized upon disposition of oil and natural gas properties unless crediting the proceeds against accumulated costs would result in a change in the rate of depletion of more than 20%.

Capitalized costs are accumulated in cost centres on a country-by-country basis and are depreciated and depleted using the unit of production method based upon estimated proved reserves as determined by independent engineers. Included in costs subject to depletion are estimated costs to develop proved reserves. Reserve and production volumes of oil and natural gas are converted to common units on the basis of their approximate relative energy content. Costs relating to undeveloped properties may be excluded from the depletion base until it is determined whether or not proved reserves exist or if impairment of such costs has occurred. Depreciation of office equipment is provided at 30% using the declining balance method.

The net capitalized costs in each cost centre may not exceed a calculated ceiling. The ceiling is equal to the estimated undiscounted future net revenues, based on year-end prices and costs, derived from proved reserves, less the estimated development and site restoration costs, plus the lower of cost less impairment, and estimated fair value of undeveloped properties. Consolidated net capitalized costs less future income tax liabilities are subject to a second ceiling test whereby the consolidated ceiling is equal to the sum of the cost centre amounts less general and administrative, financing and income tax costs. These ceiling tests are cost recovery tests and are not intended to be estimates of fair value.

The Canadian Institute of Chartered Accountants has issued a new full cost guideline which the Company will prospectively adopt in 2004. The Company does not capitalize general and administrative or interest costs.

SITE RESTORATION

Estimated site restoration costs are provided for in the current period using the unit-of-production method based on estimated proved reserves. The annual charge is accounted for as an expense and the accumulated provision is reflected as a long-term liability. Actual site restoration expenditures are deducted from the liability balance in the year incurred. Future costs are estimated based upon current legislation, technology and industry standards.

DERIVATIVE FINANCIAL INSTRUMENTS

The Company may utilize derivative financial instruments in its management of exposures to fluctuations in crude oil and natural gas prices, foreign currency exchange rates and interest rates. The Company does not enter into derivative financial instruments for trading or speculative purposes. The Company formally documents all relationships between hedging instruments and hedged items, as well as its risk management objective and strategy for undertaking various hedge transactions. This process includes linking all derivatives to specific assets and liabilities on the balance sheet or to specific firm commitments or forecasted transactions. The Company also formally assesses, both at inception and on an ongoing basis, whether the derivatives that are used in hedging transactions are highly effective in offsetting changes in fair values or cash flows of hedged items. Gains and losses on contracts that constitute effective hedges are deferred and recognized in income when the related transactions occur.

JOINT OPERATIONS

The majority of the Company's oil and natural gas operations are conducted jointly with others and accordingly these consolidated financial statements reflect only the Company's proportionate interest in such activities.

REVENUE RECOGNITION

Revenues from the sale of crude oil, natural gas and natural gas liquids are recognized when title passes to the customer.

FOREIGN CURRENCY TRANSLATION

The Company translates foreign currency denominated monetary assets and liabilities of its integrated foreign subsidiaries at the exchange rate in effect at the balance sheet date and non-monetary assets and liabilities are translated at historical exchange rates. Revenues and expenses are translated at estimated transaction date exchange rates except depletion and depreciation expense, which is translated at the same historical exchanges rates as the related assets. Exchange gains or losses are included in the determination of net income as other income (expense).

EARNINGS PER SHARE

The Company computes diluted earnings per share using the treasury stock method. This method assumes that the proceeds on exercise of in-the-money stock options and share purchase warrants are used to repurchase the Company's common shares at the average market price during the relevant period.

STOCK BASED COMPENSATION

During the fourth quarter of 2003, the Company adopted the fair-value method of accounting for stock options granted to employees and directors during 2003. Stock based compensation expense is recorded and reflected as general and administrative expense for all options granted after January 1, 2003, with a corresponding amount reflected in contributed surplus. Stock based compensation expense is calculated as the estimated fair value of the related stock option at the time of the grant amortized over the vesting period of the option. For options granted between January 1, 2002 and January 1, 2003, we continue to disclose the pro forma earnings impact of related stock based compensation expense as if the fair-value method had been adopted at the beginning of that period (see Note 8). When stock options are exercised, the amounts previously recorded as contributed surplus are reclassified to common share capital.

INCOME TAXES

The Company accounts for income taxes using the liability method. Under this method, the Company records a future income tax asset or liability to reflect any difference between the accounting and tax bases of assets and liabilities. Future income tax assets are only recognized to the extent it is more likely than not sufficient future taxable income will be available to allow the future income tax asset to be realized.

FLOW-THROUGH COMMON SHARES

The Company has financed a portion of its exploration activities in Canada through the issuance of flow through shares. Under the terms of these shares, the tax attributes of the related expenditures are renounced to subscribers. To recognize the foregone tax benefits, share capital is reduced and a future income tax liability is recorded in the period in which the related tax attributes are effectively renounced.

SUBORDINATED NOTES

The subordinated notes are reflected as equity on the balance sheet and the interest thereon is excluded from the determination of net income as the Company has the option to issue common shares to settle both interest and principal payments. The Canadian Institute of Chartered Accountants recently issued an Exposure Draft that, when implemented, will require securities such as Petrobank's subordinated notes to be presented as liabilities. This revision will become effective for all fiscal years beginning on or after November 1, 2004.

CASH AND CASH EQUIVALENTS

Cash and cash equivalents include securities with a maturity of three months or less when purchased.

3. CORPORATE ACQUISITIONS

On September 19, 2003, the Company acquired Monolith Oil Corp. ("Monolith"), a privately owned oil and natural gas company, for the consideration noted below. The debenture was secured by Petrobank's Canadian assets but subordinate to Petrobank's secured credit facility, accrued interest at 9% per annum payable monthly, and was due to mature on January 31, 2004. On January 28, 2004, the principal amount of the debenture was reduced from $14.5 million to $14.0 million pursuant to the terms of the related acquisition agreement that allowed Petrobank to offset any increases in assumed working capital deficiency against the principal balance of the debenture. Petrobank settled the adjusted debenture amount with $12.5 million of cash paid to the former Monolith shareholders and $1.5 million deposited into escrow. A recovery of the escrowed amount is being sought by Petrobank to offset estimated incremental liabilities assumed on the acquisition. The acquisition has been accounted for using the purchase method as follows, which is subject to change following the outcome of the recovery process, the results of which are not currently determinable.

Purchase price:		
Net cash paid including transaction costs ($400)	$	8,573
Debenture issued		14,014
Common shares issued (5,209,551)		15,000
Non-cash working capital deficiency acquired		1,972
	$	39,559

Allocation of purchase price:		
Capital assets	$	52,534
Future income tax liability		(12,000)
Future site restoration liability		(975)
	$	39,559

On January 15, 2002, Petrobank acquired a private company for total consideration of $1.0 million including a cash payment of $42,000, issuance of 250,000 Petrobank common shares and the assumption of a liability of $0.6 million. This liability was payable indirectly to two of the Company's directors and was settled in February 2003.

4. CAPITAL ASSETS

December 31, 2003	Cost	Accumulated Depletion and Depreciation	Net Book Value
Oil and natural gas properties			
Canada	**$212,417**	**$46,361**	**$166,056**
Colombia	**86,977**	**22,577**	**64,400**
Corporate and other	**4,587**	**3,036**	**1,551**
	$303,981	**$71,974**	**$232,007**

December 31, 2002	Cost	Accumulated Depletion and Depreciation	Net Book Value
Oil and natural gas properties			
Canada	$135,340	$27,814	$107,526
Colombia	15,635	-	15,635
Corporate and other	4,860	1,148	3,712
	$155,835	$28,962	$126,873

At December 31, 2003, oil and natural gas properties included $27.8 million (2002 - $30.5 million) relating to unproved properties in Canada, and $4.4 million (2002 - $2.5 million) related to international unproved properties, primarily in Colombia, that have been excluded from the depletion calculation. Colombian costs incurred through December 31, 2002 totaling $15.6 million were excluded from the depletion calculation in 2002, as oil sales from that country did not commence until 2003.

The 2003 impairment expense relates to the Company's Colombian and other international cost centres, and represents the write-down of the carrying value of the impaired properties to their estimated recoverable amount pursuant to the Company's accounting policy described in note 1. The Company would not have had any further impairment charges had the new full cost accounting guideline been adopted in 2003.

Dispositions

The Company completed a number of non-core property dispositions during 2003 for total proceeds of $20.4 million, the most significant of which was the second quarter disposition of our Zama/Larne property in Northwest Alberta for proceeds of $16.6 million. On January 28, 2004, the Company closed the sale of its Wapella property in Southeast Saskatchewan for total cash proceeds of $36.0 million (see note 14).

5. BANK DEBT

The Company's borrowing base under its secured bank credit facility at December 31, 2003 was $47.5 million. The facility is a revolving demand loan under which the Company can borrow at bank prime plus 0.125 percent or Bankers' Acceptance fee rates plus 1.625 percent. Advances under the facility are collateralized by a $100 million demand debenture on all present and future Canadian assets of the Company as well as a general assignment of the Company's book debts, a negative pledge to provide fixed charges on major producing petroleum properties in Canada and an assignment of material contracts. Following the sale of the Company's Wapella property in January 2004, the borrowing base under this credit facility was reduced to $36.1 million. A further redetermination of the borrowing base is expected by May 31, 2004 in connection with the bank's regular annual review.

Interest paid approximated interest expense for the years ended December 31, 2003 and 2002.

6. OBLIGATIONS UNDER GAS SALE AND TRANSPORTATION CONTRACTS

The Company assumed certain physical natural gas sales and transportation obligations upon the acquisition of Barrington Petroleum Ltd. in 2001 (see note 11). The Company recorded a liability for these obligations at that time, which is being amortized to oil and natural gas revenues over the term of the related contracts. This liability was reduced by $0.9 million in 2002 for cash payments made to settle a portion of the outstanding obligations.

7. SUBORDINATED NOTES

Petrobank's subordinated notes are unsecured and subordinate to the Company's existing credit facility and any other senior debt that may be outstanding from time to time. Interest on the notes is payable quarterly at a rate of 9% per annum and the notes mature on July 31, 2006. Interest on subordinated notes in 2003 is reflected net of a future tax recovery of $1.1 million. In certain circumstances, the notes may be repaid at their face value prior to their maturity date and the Company has the option of issuing common shares, at prevailing market prices, to settle quarterly interest payments as well as the principal amount. The notes were recorded at fair value on issuance and the discount to face value is being amortized to interest on subordinated notes over the term of the notes creating an effective interest rate of 12%.

On May 5, 2003, the Company closed a subordinated note financing, resulting in the issuance of $40.0 million face value of subordinated notes and 1,420,300 common share purchase warrants for proceeds, net of discount, issuance costs and agents' commissions, of $35.2 million. The net proceeds were allocated between the subordinated notes ($34.4 million) and the common share purchase warrants ($0.8 million). The common share purchase warrants are exercisable for common shares at $4.00 per share and expire on May 6, 2006 (note 8).

	Carrying Amount	Principal Amount
Balance at December 31, 2001	$56,676	$60,438
Amortization of discount	668	-
Balance at December 31, 2002	57,344	60,438
Issued	34,410	40,000
Amortization of discount	1,676	-
Balance at December 31, 2003	**$93,430**	**$100,438**

8. SHARE CAPITAL

Authorized

Unlimited number of common shares
Unlimited number of preferred shares, issuable in series

Common Shares

	Number	Amount
Balance at December 31, 2001	33,557,140	$30,341
Issued pursuant to corporate acquisition	250,000	387
Exercise of stock options	775,249	1,250
Repurchased pursuant to issuer bid [1]	(10,927)	(12)
Exercise of warrants	2,133,333	3,200
Issued pursuant to share capital restructuring	8,609,000	12,888
Balance at December 31, 2002	45,313,795	48,054
Exercise of stock options	547,583	964
Issuance of share purchase warrants (note 7)	-	768
Exercise of warrants	657,160	1,643
Repurchased pursuant to issuer bid [1]	(3,221)	(3)
Issued pursuant to corporate acquisition (note 3)	5,209,551	15,000
Issued pursuant to flow through offering (net of costs and future income taxes)[2]	2,777,778	5,929
Balance at December 31, 2003	**54,502,646**	**$72,355**

[1] The amount associated with share repurchases reflects the average issuance price of common shares. The excess of the amounts paid for these shares over the average issuance price is reflected as a reduction of retained earnings.
[2] On September 24, 2003, Petrobank issued 2,777,778 flow-through common shares for total gross proceeds of $10.0 million. As at December 31, 2003 the Company made a full renunciation of $10.0 million of tax benefits to those shareholders, and recorded a

$3.5 million future income tax liability related to the forgone tax benefits. As at December 31, 2003, the Company had incurred $2.0 million of eligible expenditures related to the renunciation, and the remaining eligible expenditures must be incurred by December 31, 2004.

Share Purchase Warrants

As at December 31, 2003, the Company had 1,420,300 share purchase warrants outstanding that allow the holders to purchase an equivalent number of common shares at $4.00 per share on or before May 6, 2006.

	Number	Weighted-Average Exercise Price
Balance at December 31, 2002	777,720	$ 2.50
Issued (note 7)	1,420,300	4.00
Exercised	(657,160)	(2.50)
Expired	(120,560)	(2.50)
Balance at December 31, 2003	**1,420,300**	**$ 4.00**

Stock Options

The Company has established a stock option plan whereby the Company may grant options to its directors, officers, employees, consultants and underwriters. The Company's shareholders have approved the issuance of up to 4.6 million stock options under this plan. The number of stock options available for grant under the plan has been reduced to 4.2 million at December 31, 2003 due to the exercise of some stock options. At the next meeting of shareholders, the Company intends to request approval to increase the number of stock options available for grant under the plan to 10% of the number of common shares outstanding. The exercise price of each option is no less than the market price of the Company's stock on the date of the grant. Stock option terms are determined by the Company's Board of Directors but typically, options vest evenly over a period of four years from the date of grant and expire five years after the date of grant. The following is a continuity of stock options outstanding:

	2003		2002	
	Stock Options	**Weighted-Average Exercise Price**	Stock Options	Weighted-Average Exercise Price
Opening	**4,195,484**	**$2.08**	2,823,334	$1.73
Granted	**1,373,550**	**3.07**	3,359,500	2.21
Exercised	**(547,583)**	**1.76**	(775,249)	(1.61)
Cancelled	**(1,344,950)**	**2.28**	(1,212,101)	(1.94)
Closing	**3,676,501**	**$2.42**	4,195,484	$2.08

The following summarizes information about stock options outstanding as at December 31, 2003:

Range of Exercise Prices $	Number Outstanding At Dec. 31, 2003	Weighted-Average Remaining Contractual Life (Years)	Weighted-Average Exercise Price	Number Exercisable At Dec. 31, 2003	Weighted-Average Exercise Price
1.35 - 1.99	1,148,000	2.4	$1.64	633,500	$1.65
2.00 - 2.74	1,503,251	4.1	2.45	283,626	2.36
2.75 - 3.40	1,025,250	4.2	3.25	66,250	3.05
	3,676,501	3.6	$2.42	983,376	$1.95

Loss Per Share

Basic and diluted loss per share have been calculated based on net loss attributable to common shareholders divided by the weighted average number of shares outstanding for the year of 48,103,924 (2002 –37,441,521).

Stock Based Compensation

In 2003, the Company adopted the fair value based method of accounting for its stock based compensation plan whereby the fair value of stock options granted after January 1, 2003 is recognized as general and administrative expense and as contributed surplus (2003 - $186,000).

Had compensation expense associated with the Company's stock option plan been recognized using the fair value based method for all option grants after January 1, 2002, the Company's pro forma net loss attributable to common shareholders for the years ended December 31, 2003 and 2002 would have increased by $394,000 and $224,000, respectively and loss per share would increased to $0.49 and $0.02 per share, respectively.

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

	2003	2002
Risk free interest rate	4.0% - 4.5%	3.5%
Dividend rate	0%	0%
Expected life (years)	4.0	4.0
Expected volatility	30%	30%

The average value per option granted in 2003 was $0.93 as at the date of grant.

Share Capital Restructuring

In August 2002, an independent committee of the Board of Directors reached an agreement to repurchase certain outstanding securities held by certain members of management and the Board. This agreement resulted in the repurchase of the Company's outstanding 8.6 million preferred shares (6% dividend rate) and cancellation of an equivalent number of common share purchase warrants in exchange for issuance of 8.6 million common shares. The Company also made a $1.0 million cash payment to settle $1.9 million of future dividend entitlements on preferred shares. In addition, the Company paid $5.5 million to repurchase 8,475,667 outstanding common share purchase warrants from the holders of those warrants who agreed to exercise their remaining 2,133,333 common share purchase warrants for $3.2 million. Payments relating to the repurchase of common share purchase warrants and settlement of future dividend rights totaling $6.5 million were reflected as a reduction of retained earnings in 2002.

9. INCOME TAXES

The provision for income taxes differs from the amount that would have been expected by applying statutory corporate income tax rates to income (loss) before taxes. The principal reasons for this difference are as follows:

	2003	2002
Income (loss) before taxes	**$ (13,792)**	$7,285
Statutory income tax rate	**41.50%**	43.20%
Expected tax expense (recovery)	**$ (5,724)**	$3,147
Increase (decrease) in income tax provision resulting from:		
Non-deductible crown charges, net of royalty credits	**2,573**	2,797
Resource allowance	**(1,892)**	(2,538)
Future tax asset not recognized (recognized)	**4,214**	(3,184)
Non-taxable portion of capital gain	**-**	(141)
Other	**329**	(81)
Future income tax recovery	**(500)**	-
Capital taxes	**1,399**	1,094
Capital and future income tax provision	**$ 899**	$1,094

The components of the Company's future income tax assets and liabilities arising from temporary differences are as follows:

As at December 31,	2003		2002	
	Future Income Tax Assets	Future Income Tax Liabilities	Future Income Tax Assets	Future Income Tax Liabilities
Non-capital losses	**$18,194**	**$ -**	$15,680	$ -
Obligations under gas sale and transportation contracts	**2,523**	**-**	2,623	-
Future site restoration	**959**	**-**	199	-
Capital assets	**-**	**26,774**	6,847	7,112
Subordinated notes	**14**	**-**	-	1,772
Other	**250**	**-**	38	-
	21,940	**26,774**	25,387	8,884
Valuation allowance	**(9,086)**	**-**	(16,503)	-
	$12,854	**$26,774**	$8,884	$8,884

The Company has reflected its future income tax liability net of future tax assets on the consolidated balance sheet. Income taxes paid approximate capital tax expense for the years ended December 31, 2003 and 2002.

10. RELATED PARTY TRANSACTIONS

In July 2003, the Company acquired the THAI™ and CAPRI™ patented heavy oil recovery technologies indirectly from two directors of the Company, and a third party, pursuant to an agreement made by an independent committee of the Board of Directors. One of these directors recovered his $226,000 investment and the other received cash of $189,000 on his $226,000 investment and retained a 7.5% net profits interest in any future third party licensing royalties generated from the technologies. Currently, the technologies are unproven, but Petrobank plans to commence a pilot test of the THAI™ technology in Petrobank's WHITESANDS INSITU Ltd. subsidiary in 2004.

In January 2003, the Company paid a $200,000 commitment fee to secure a $10 million credit facility from a company controlled by a director of Petrobank. Any balances outstanding under the facility would bear interest at 12% per annum and would be subordinate to Petrobank's existing secured bank debt (note 5). To date, the Company has not drawn on this facility, which expires on December 30, 2004.

11. FINANCIAL INSTRUMENTS AND FINANCIAL RISK MANAGEMENT

The nature of oil and natural gas operations and the issuance of debt expose the Company to fluctuations in commodity prices, foreign currency exchange rates and interest rates. The Company manages these risks by operating in a manner that minimizes its exposure to the extent practical, and through the periodic use of derivative instruments. The Board of Directors periodically reviews the results of all derivative activities and all outstanding positions.

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. The majority of the Company's Canadian production is sold to various large creditworthy counterparties. All Colombian oil production during 2003 was sold to the Colombian state oil company, Ecopetrol. The Company's maximum credit exposure to customers is revenue from two month's sales. While counterparties to derivative instruments expose the Company to losses in the event of non-performance, the Company currently only deals with large creditworthy institutions, and does not anticipate non-performance by these counterparties.

Commodity Price Risk Management

Financial Derivative and Physical Oil Sale Contracts

At December 31, 2003, the following financial derivative contracts and fixed price sale contracts were outstanding:

Contract	Daily Volume	Term	Benchmark	Price
Crude oil swap[1]	1,000 bbls	January – December 2004	WTI	U.S.$24.00
Crude oil fixed price sale	300 bbls	January – December 2004	WTI	U.S.$27.74
Crude oil fixed price sale[2]	300 bbls	January – December 2004	WTI	U.S.$27.68
Natural gas collar[1]	10,551 GJ	January – December 2004	AECO	$5.00-$5.94

[1] The fair value liability of these contracts is supported by U.S.$1.8 million of credit and U.S.$2.0 million of cash deposited with two counterparties. This collateral is adjusted as the fair value of the related liability changes.
[2] In January 2004, the purchaser of the Company's Wapella property assumed this contract.

Long-term Physical Gas Sale and Transportation Contracts

The Company is committed to deliver 2,225 GJ per day of natural gas under an escalating price contract that expires October 31, 2012. The wellhead price under this contract, at December 31, 2003, was set at $3.26 per GJ. The contract provides for an annual price escalation between 4% and 10%, based on hydroelectric and natural gas price inflation. Broader price redeterminations are to be made in 2007 and 2012, resulting in a new price that can vary from 65% to 135% of the previous year's price based on prevailing natural gas prices. The 4% minimum annual price escalation was assumed when calculating the fair value of this contract at December 31, 2003.

The Company holds 5,275 GJ per day of firm transportation service on the ANG and PGT pipeline systems through October 31, 2005. The Company may choose to ship gas on these pipelines to the Malin, Oregon delivery point, and receive the related market price less relevant transportation charges. The Company may elect not to ship gas on these pipelines by paying the relevant firm service transportation charges of $0.52 per GJ.

Fair Value of Financial Instruments

The estimated fair values of the following financial instruments at December 31, 2003 are:

	Carrying Value	Fair Value
Liabilities		
Financial derivative and physical oil sale contracts	$-	$5,208
Physical gas sale and transportation contracts	$7,287	$1,744
Subordinated notes	$93,430	$93,417

The fair values of the Company's remaining financial instruments at December 31, 2003 approximate their carrying values. Fair values of financial derivative contracts, physical sale contracts and transportation contracts are determined based on the estimated cash payment or receipt necessary to settle the contracts at December 31, 2003. Cash payments are calculated based on discounted cash flow analysis using prevailing market prices at the time. The estimated fair value of the subordinated notes is based on public trading values on January 2, 2004.

12. CHANGES IN OTHER NON-CASH ITEMS

	2003	2002
Accounts receivable and other current assets	$(10,007)	$ 9,274
Accounts payable and accrued liabilities	6,041	7,200
Non-cash working capital deficiency acquired	(1,972)	(610)
	$ (5,938)	$ 15,864
Attributable to operating activities	$ (8,772)	$ 4,728
Attributable to financing activities	$ -	$ (878)
Attributable to investing activities	$ 2,834	$ 12,014

13. COMMITMENTS AND CONTINGENCIES

In Colombia, the Company has fulfilled its commitments on the Orito block and has U.S.$2.0 million of remaining work commitments on the Neiva block that are required to be completed by June 2004. In October 2003, the Company signed a new exploration contract on a 390,000-acre block ("Bloque Colombia") in the Upper Magdalena Valley, 70 kilometers northeast of our Neiva block. Petrobank has a one-third, non-operated interest in the block with an estimated U.S.$0.3 million (net) phase-one work commitment that is required to be completed by October 2004. After completion of the phase-one work commitment, the Company and its joint venture partners have the option to relinquish the block, drill a well at an estimated net cost of U.S.$1.5 million, or shoot 120 kilometers of 2D seismic.

Petrobank is committed to payments under operating leases for office space, net of sub-lease arrangements, as follows:

2004	$550
2005	550
2006	180
	$1,280

The Company is party to certain legal actions relating to disputes with industry participants, the outcome of which cannot be reasonably determined. In the opinion of management, the resolution of these matters will not have a material effect on the Company's financial position or results of operations.

The Company has entered into certain types of contracts, particularly those related to divestiture transactions that require us to indemnify parties against possible third party claims. These obligations are typically limited to the amount of sales proceeds and expire within one year in the case of property dispositions. Management does not expect payments, if any, related to such matters to have a material effect on the Company's financial position or results of operations.

14. SUBSEQUENT EVENTS

On January 28, 2004, the Company closed the sale of its Wapella property in Southeast Saskatchewan for total cash proceeds of $36.0 million. The proceeds were used to repay the $14.0 million debenture (note 3) and to reduce the outstanding balance under the Company's secured bank credit facility (note 5).

15. SEGMENTED INFORMATION

The Company commenced commercial production from its Colombian operations in January 2003 and accordingly segmented results are presented below as at and for the twelve-month period ended December 31, 2003 along with capital expenditure information for the year ended December 31, 2002:

2003	Canada and Other	Colombia	Total
Revenues			
Oil and natural gas	$ 53,551	$ 12,560	$ 66,111
Royalties	(11,114)	(997)	(12,111)
	42,437	11,563	54,000
Expenses			
Production	12,683	4,087	16,770
General and administrative	4,012	1,928	5,940
Depletion, depreciation and site restoration	19,786	7,577	27,363
Impairment	1,900	15,000	16,900
Segmented income (loss)	$ 4,056	$ (17,029)	(12,973)
Non-segmented items			
Interest			(771)
Other expense			(48)
Capital and future income tax expense			(899)
Net loss			(14,691)
Interest on subordinated notes			(8,420)
Net loss attributable to common shareholders			$ (23,111)
Identifiable assets	$ 187,396	$ 66,139	$ 253,535
Net capital expenditures	$ 24,270	$ 71,342	$ 95,612
2002			
Net capital expenditures	$ 27,259	$ 15,635	$ 42,894

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April 19, 2004

Alberta Securities Commission
British Columbia Securities Commission
The Manitoba Securities Commission
Office of the Administrator, New Brunswick
Securities Commission of Newfoundland
Nova Scotia Securities Commission
Ontario Securities Commission
L'Autorité des marchés financiers
Saskatchewan Financial Services Commission
TSX

Dear Sirs:

Subject: Petrobank Energy & Resources Ltd.

We advise the following with respect to the upcoming Meeting of Shareholders for the subject Corporation:

1.	Meeting Type	:	Annual General Special (Non-Routine)
2.	Security Description of Voting Issue	:	Common
3.	CUSIP Number	:	716 45P 106
4.	Record Date	:	May 14, 2004
5.	Meeting Date	:	June 17, 2004
6.	Meeting Location	:	Calgary, AB

Yours truly,

"signed by"
Kim Tran
Meeting Specialist
Stock Transfer Department
Direct Dial No: 1-866-331-6361
Email: kim.tran@computershare.com

cc: Petrobank Energy & Resources Ltd.
Attention: Corey Ruttan

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NEWS RELEASE

PETROBANK'S CANADIAN ACQUISITIONS GAIN MOMENTUM, COLOMBIAN PRODUCTION INCREASES, AND WHITESANDS PROJECT ON TRACK

Calgary, Alberta – May 14, 2004 - Petrobank Energy and Resources Ltd. ("Petrobank") is pleased to provide this operational update of our Canadian, Latin American and Heavy Oil Business Units as well as our first quarter financial results.

OPERATIONAL UPDATE

Canadian Business Unit

First quarter Canadian production averaged 4,713 boe per day consisting of 2,035 barrels per day of liquids and 16,069 mcf per day of natural gas. This included 635 barrels of oil per day from our Wapella and Epping properties, which were sold during the period. Excluding these properties, production averaged 4,078 boe per day during the quarter. Due to a competitive drainage issue, we were restricted from producing our most prolific Nevis well during a portion of the first quarter. During the quarter, we drilled 9 wells (7.3 net), 6 were cased for gas and 3 for oil, and including these wells, a total of 27 wells were completed or re-completed. Field operations have been focused on adding behind-pipe reserves and production at Shekilie, Jumpbush, Nevis, and Red Willow and in the first part of May production has averaged 4,700 boe per day.

Our latest phase of drilling and completions at Jumpbush validated the balance of our lands and confirmed our ability to identify new, potentially prolific Belly River trends from seismic. Ten of our more productive wells in the area have tested significant gas volumes and are awaiting approval to be tied in. A further 30 well drilling program has been submitted for approval to the Siksika First Nation.

Our most active areas in the first quarter were the recently acquired Nevis and Red Willow areas where we drilled 6 new wells (6 net), 3 of which were cased for oil and 3 for gas. The new oil wells recently began production, and we are planning pipelines for these new gas wells, as well as other behind-pipe reserves. Including these locations, a total of 15 wells were completed or re-completed during the quarter at Nevis and Red Willow. Our most prolific Nevis gas well was previously being rate restricted and competitively drained. This May, we installed pipeline and compression to address the related production loss and recover the majority of this lost production. A first quarter Nevis well and a second quarter Red Willow well discovered two new Glauconite oil pools. Both wells are producing at restricted rates of 125 barrels per day and will be further delineated later this year. The Nevis oil pool commenced production in March and the Red Willow production commenced in early May.

Petrobank is also advancing two high impact CBM projects. At Jumpbush, we plan to complete the remaining two Belly River coal zones in our existing CBM test well, which exhibited an initial water-free flow rate of 100 mcf per day of gas from the first coal zone. In addition, we plan to test all three coal zones in at least four nearby wells. At Princeton, British Columbia, the approval process for our first CBM test well is proceeding, including consultation with the public and the Upper Similkameen First Nation.

Latin American Business Unit

In Colombia, we produced an average of 1,702 barrels of oil per day from our Orito and Neiva blocks in the first quarter, marking the highest quarterly average since production commenced in January 2003. Another milestone was achieved when we elected to proceed to the complimentary phases on both the Neiva and Orito blocks, having completed our initial work commitments. Advancing to the complementary phase extends the term of our Orito and Neiva incremental production contracts by 19 years, adding flexibility to our future development plans. We are in the process of submitting our development plan for Orito and had previously committed to approximately $2 million of further development at Neiva.

Concurrently, we have approached Ecopetrol in an effort to improve the fiscal terms at Neiva to permit a broader development program.

At Orito, Ecopetrol has now assumed operatorship of all wells drilled and intervened by Petrobank (except Orito-115), resulting in a significant operating cost savings. An increase in the water cut at Orito-115 has reduced the well's production to approximately 250 bopd and we are evaluating potential remedial work before turning the well over to Ecopetrol to operate.

A security incident in November 2003 continued to affect operations at Orito during the first month of the year but production has since been restored at the affected wells. A recent strike at the state oil company, Ecopetrol has impacted Ecopetrol's operations, but to-date has not had a significant effect on Petrobank's production. Strike activities have caused OTA pipeline interruptions between Orito and the Pacific export terminal of Tumaco but this is not presently affecting Orito production due to excess storage capacity on the system.

We expect to complete our new reservoir simulation model of the main producing zone at Orito, the Caballos formation, by the end of the second quarter. This model will be used to direct our next phase of drilling which is anticipated to commence late this year. Preliminary drilling locations have been identified to verify two potentially significant expansions to the Orito field. Much of our future development plan is contingent on the success of this initial program. Lastly, we have commenced operations on our pilot waterflood in the Caballos zone, with initial results expected sometime in 2005.

Evaluation of the Central Colombia Block by Petrobank and our partners continues, and in July a decision will be made to either acquire additional seismic, drill an exploratory test well targeting a significant Caballos prospect, or relinquish the block.

We expect our production in Colombia to range between 1,500 and 1,800 bopd through the remainder of the year, as we await the results of our next drilling program. The full impact of our current operating cost reductions should be realized in the third quarter.

Heavy Oil Business Unit

The WHITESANDS Pilot Project received approval from the Alberta Energy and Utilities Board (AEUB) and Alberta Environment (AENV) in February 2004. These approvals allow us to finalize the detailed project engineering and schedule necessary for the efficient execution of the WHITESANDS pilot project. A project execution team has been assembled to be in a position to commence construction in the third quarter. The project site is accessible year round and as such is not a constraint on project timing. In addition, since the project is not overly complex and will employ conventional oil field equipment, delays related to long lead items and construction are not anticipated. With this schedule we expect to begin air injection as early as the second quarter of 2005.

Petrobank is seeking private equity financing for the estimated $30 million capital cost of the pilot project which is to be effected by the issuance of up to a 40% equity interest in Petrobank's subsidiary, WHITESANDS INSITU Ltd. Discussions are continuing with potential investors and due diligence is ongoing.

WHITESANDS owns 45 sections of oil sands leases in the Christina Lake region of Alberta. In the first quarter, Fekete Associates completed a detailed geological assessment report, which indicates that the WHITESANDS lands contain a bitumen resource of 831 million barrels in the middle McMurray formation and an additional 484 million barrels in the upper McMurray. This bitumen resource is sufficient to support a significant THAI™ commercial development and, as a secondary consideration, would also be attractive for a commercial-scale Steam Assisted Gravity Drainage (SAGD) project. The THAI™ and CAPRI™ technologies have the potential to revolutionize the heavy oil extraction business. Petrobank shareholders stand to benefit enormously from the commercial opportunity on our existing land base combined with our future ability to license the technologies and capture additional resources internationally.

OUTLOOK

Petrobank is in a unique position, with opportunities in each of our Business Units to add significant value for shareholders. Our ability to execute simultaneously on all these opportunities is constrained by our available financial resources. In Canada, our near-term activities will be focused on adding production at Jumpbush, Nevis and Red Willow. Our CBM resources will be assessed through pilot test programs. Our new reservoir simulation model will direct our next phase of drilling in Colombia and until then, expenditures will be modest. The currently contemplated financing of our WHITESANDS pilot should allow this project to proceed quickly relative to other oil sands projects, with initial results expected by mid-2005. By integrating our 2003 property acquisitions, advancing to the complementary phase of our Colombian incremental production contracts, gaining approval for our WHITESANDS project and validating our expanded land-base at Jumpbush, we have put Petrobank in a position to manage the development pace of each of our available opportunities. We have minimal contractual commitments outstanding and, as results dictate, we plan to accelerate future investment in the most promising of these projects, while maintaining a solid balance sheet.

MANAGEMENT'S DISCUSSION AND ANALYSIS

The following Management's Discussion and Analysis ("MD&A") is dated May 14, 2004 and should be read in conjunction with the unaudited consolidated financial statements of the Company for the three months ended March 31, 2004, MD&A for the year ended December 31, 2003, and the audited consolidated financial statements for the year ended December 31, 2003. Additional information for the Company can be found at www.sedar.com. In addition to historical information, the MD&A contains forward-looking statements that reflect management's objectives and expectations as at the date of this report, which involve risks and uncertainties. The Company's actual results may differ materially from those anticipated in these forward-looking statements.

Natural gas volumes have been converted to barrels of oil equivalent ("boe") so that six thousand cubic feet ("mcf") of natural gas equals one barrel based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the well head. Boes may be misleading, particularly if used in isolation. This report contains financial terms that are considered non-GAAP measures such as cash flow from operations, cash flow per share, net debt, and operating netback. These measures are commonly utilized in the oil and gas industry and are considered informative for our shareholders. Specifically, cash flow from operations and cash flow per share reflect cash generated from operating activities before changes in non-cash working capital. We consider these measures important as they demonstrate our ability to generate sufficient cash to fund future growth opportunities and repay debt. All amounts are in Canadian dollars, unless otherwise stated.

Property Dispositions

Petrobank closed the sale of its Wapella property on January 28, 2004 for net proceeds of $35.5 million. The results of operations for 2004 only include results from disposed properties up to the closing date of the transaction. Wapella production was approximately 1,400 barrels per day at the time of sale but only contributed 454 boe per day to average production in the first quarter of 2004.

On March 22, 2004, the Company closed the sale of its Epping property in Western Saskatchewan, which produced 181 barrels of heavy oil per day during the first quarter of 2004, for proceeds of 2.6 million.

Production

Oil and NGL production in Canada during the first quarter averaged 2,035 barrels per day (bpd), a decrease from the 2,931 bpd produced in the fourth quarter of 2003 and the 2,757 bpd produced in the first quarter of 2003. These decreases were primarily due to the sale of the Wapella property in January 2004. First quarter natural gas production of 16.1 million cubic feet per day (mmcfpd) increased 47 percent from 10.9 mmcfpd in the first quarter of 2003. The increase was a result of the acquisition of

Monolith Oil Corp. in September 2003 offset somewhat by the disposition of the Company's Zama/Larne property in May 2003. Total Canadian production for the first quarter was 4,713 boepd, a 3 percent increase from the same period last year.

Colombian oil sales commenced in January 2003 and averaged 695 bpd in the first quarter of 2003 increasing to an average of 1,702 bpd in the first quarter of 2004. Production in Colombia is expected to be between 1,500 and 1,800 bpd until drilling recommences, which is not expected before the third quarter of 2004.

Average Benchmark Prices

For the three months ended March 31,	2004	2003	% change
WTI crude oil (US$/bbl)	35.15	33.86	4
WTI crude oil (C$/bbl)	46.32	51.11	(9)
Bow River heavy oil differential (US$/bbl)	9.00	7.58	19
NYMEX natural gas (US$/mcf)	5.69	6.59	(14)
AECO (daily) natural gas (C$/mcf)	6.43	8.35	(23)
C$/US$ exchange rate	0.76	0.66	15

Realized Prices

Overall, commodity prices received in the first quarter were negatively impacted by the appreciation of the Canadian dollar since the first quarter of 2003. The average Canadian oil and NGL price received in the first quarter was $26.45 per barrel, a 21 percent decrease from the $33.30 per barrel received in the comparable 2003 period. Canadian oil and NGL prices averaged $33.68 per barrel, before financial hedging losses of $7.23 per barrel, representing a U.S.$9.59 discount to average WTI prices in the quarter compared to a U.S.$6.43 discount to WTI in the first quarter of 2003. The average discount increased as a result of a decrease in the average quality of barrels produced, combined with a widening of Canadian heavy crude oil differentials when compared to the comparative 2003 period. In 2004, 1,000 barrels per day of new swaps at U.S.$24.00 become effective, along with a fixed price oil sales contract for 300 bpd at an average price of U.S.$27.74 per barrel.

The average natural gas price received in the first quarter was $6.09 per mcf, a 21 percent decrease from the $7.71 per mcf received in the first quarter of 2003. Natural gas prices reflect the negative impact of the Company's long-term physical gas sales contracts, and in the current period includes the effect of the Company's natural gas price collar for 2004 on 10,551 GJ/day with AECO prices between $5.00 and $5.94 per GJ.

Oil sales prices in Colombia averaged U.S.$27.79 per barrel in the first quarter, representing a U.S.$7.36 discount to WTI compared to a discount of U.S.$8.32 per barrel in the comparable 2003 period. The average discount to WTI decreased, as our higher quality Orito oil comprised a larger portion of Colombian production in the current period.

Royalties

Royalties decreased from $4.2 million in the first quarter of 2003 to $3.5 million in the current period. Canadian royalties as a percentage of revenue decreased from 25 percent in the first quarter of 2003 to 22 percent in the current period. We anticipate Canadian royalty rates to average approximately 21 percent throughout the remainder of 2004. Colombian royalties are included in the current quarter at a rate of 8 percent.

Production Expenses

Production expenses in Canada decreased 6 percent from $7.24 per boe in the first quarter of 2003 to $6.82 per boe in the current period. Production expenses in Colombia averaged $7.89 per barrel during the quarter, a 30 percent increase from the first quarter 2003 average of $6.09 per barrel and a 49 percent decrease from the fourth quarter 2003 average of $15.62 per barrel. Fourth quarter 2003 production expenses were impacted by well workover costs and costs associated with a security incident in November that interrupted production.

General and Administrative Expenses

General and administrative expenses were $1.7 million in the first quarter of 2004 compared to $1.4 million in the first quarter of 2003. The increase relates primarily to incremental overhead associated with the Company's Colombian operations which were staffed to facilitate a more aggressive capital program than which is currently underway.

Interest on Bank Debt

The Company's credit facility was undrawn at December 31, 2002 and increased to $22.6 million drawn at March 31, 2004. As a result, interest on bank debt increased from $41,000 in the first quarter of 2003 to $0.5 million in 2004.

Depletion, Depreciation and Accretion

Depletion, depreciation and accretion expense for the first quarter of $9.0 million ($15.47 per boe) compared to $5.2 million ($10.93 per boe) in the comparable 2003 period. The increased rate was primarily due to the acquisition of the shorter reserve life Monolith assets in September of 2003, and the results of the 2003 Colombian drilling program.

Other Expenses

In January 2004, the purchaser of the Company's Wapella property assumed the Company's fixed oil sales price contract on 300 barrels of oil per day at a WTI price of $27.68 per barrel. At the time of sale, this contract had an unrecognized mark-to-market loss of $0.4 million, which was recognized as other expense upon disposition of the property.

Interest on Subordinated Notes

Interest on subordinated notes totaled $2.8 million during the first quarter ($1.9 million net of future taxes), compared to $1.5 million in the same period last year. The increase relates to the issuance of an additional $40.0 million of notes in May of 2003.

Income Taxes

At the end of the fourth quarter of 2003, Petrobank had a future income tax liability of $13.9 million due to the Monolith corporate acquisition and the issuance and renouncement of flow through shares in September 2003. In the first quarter of 2004, future tax recoveries were recorded against these balances of $0.2 million in Capital and Future Income Taxes, $1.1 million was recovered as a result of adopting the new accounting standard on asset retirement obligations, and a $0.9 million recovery was offset against Interest on Subordinated Notes.

Capital Expenditures

Consolidated capital expenditures during the quarter were $14.7 million, comprised of $8.9 million in Canada and $5.8 million in Colombia. In Canada, activity was concentrated on drilling and completions at our Jumpbush and Nevis/Red Willow properties. Colombian expenditures related to the Orito field and were focused on completions, recompletions and acquisition of required well site equipment to facilitate the transfer of operatorship of wells drilled by Petrobank to Ecopetrol.

Liquidity and Capital Resources

At March 31, 2004 net debt totaled $121.4 million, including the book value of outstanding subordinated notes ($94.0 million). The subordinated notes are not callable and mature in July 2006. Petrobank's borrowing base under its senior secured credit facility at March 31, 2004 was $36.1 million. Working capital deficit at March 31, 2004, including the $22.6 million balance drawn under the secured credit facility, totaled $27.4 million leaving $8.7 million of available borrowing capacity. Following the sale of the Company's Edmonton property in May 2004 the borrowing base will be reduced to $33.5 million.

Changes in Accounting Policies

Asset Retirement Obligations

Effective January 1, 2004 the Company retroactively adopted the new standard of the Canadian Institute of Chartered Accountants ("CICA"), "Asset Retirement Obligations". The new standard requires that the recognition of the fair value of obligations associated with the retirement of tangible long-lived assets be recorded in the period the asset is put into use, with a corresponding increase to the carrying amount of the related asset. The obligations recognized are statutory, contractual or legal obligations. The liability is accreted over time for changes in the fair value of the liability through charges to accretion, which is included in depletion, depreciation and accretion expense. The costs capitalized to the related assets are amortized to earnings in a manner consistent with the depletion and depreciation of the underlying asset. The impact of the adoption of this standard on the financial statements is described in Note 5 to the consolidated financial statements for the three months ended March 31, 2004.

Transportation Costs

Effective January 1, 2004 the Company began classifying certain transportation costs as expenses in the consolidated statements of operations. In prior periods, these costs were netted against revenues and accordingly the prior period financial statements have been reclassified for comparative purposes. The change in accounting policy has no effect on net income but increased natural gas revenues and expenses for the three months ended March 31, 2004 by $416,000 (2003 – $338,000). The reclassification translates into a $0.28 per mcf increase in natural gas prices in the current period and $0.34 per mcf in the comparative period. Also as a result, Canadian transportation expenses of $0.97 per boe were recognized in the current period (2003 - $0.82 per boe).

HIGHLIGHTS

As at and for the three months ended March 31,	2004	2003	% change
Financial			
($000s, except where noted)			
Oil and natural gas revenue	19,474	18,255	7
Cash flow from operations [1]	8,877	8,530	4
Per share – basic ($) [2]	0.12	0.16	(25)
Per share – diluted ($) [2]	0.12	0.15	(20)
Net income (loss)	(364)	3,332	
Net income (loss) attributable to common shareholders	(2,248)	1,815	
Per share – basic and diluted ($)	(0.04)	0.04	
Capital expenditures	14,713	35,961	(59)
Net debt including subordinated notes [3]	121,396	91,599	33
Shareholders' equity excluding subordinated notes	52,943	57,759	(8)
Common shares outstanding (000s)			
Basic	54,651	45,354	20
Diluted	59,649	50,544	18
Operations [4]			
Canadian operating netback ($/boe except where noted)			
Oil and NGLs revenue ($/bbl)	26.45	33.30	(21)
Natural gas revenue ($/mcf)	6.09	7.71	(21)
Combined oil equivalent revenue	32.18	38.46	(16)
Royalties	7.15	9.77	(27)
Production expenses	6.82	7.24	(6)
Transportation expenses	0.97	0.82	18
Operating netback	17.24	20.63	(16)
Colombian operating netback ($/bbl)			
Oil revenue	36.63	38.58	(5)
Royalties	2.93	3.09	(5)
Production expenses	7.89	6.09	30
Operating netback	25.81	29.40	(12)
Average daily production			
Canada - oil and NGLs (bbls)	2,035	2,757	(26)
Canada - natural gas (mcf)	16,069	10,920	47
Total Canada (boe)	4,713	4,577	3
Colombia - oil (bbls)	1,702	695	145
Total Company (boe)	6,415	5,272	22

(1) Cash flow from operations before changes in other non-cash items.
(2) Calculated based on cash flow from operations before changes in other non-cash items less preferred share dividends and interest paid on subordinated notes.
(3) Includes working capital (deficiency) and subordinated notes reflected as equity on the balance sheet.
(4) 6 Mcf of natural gas is equivalent to 1 barrel of oil equivalent (BOE).

Consolidated Balance Sheets

(Unaudited, Thousands of Canadian dollars)

As at	March 31, 2004	December 31, 2003 (As restated per Notes 2, 4 & 5)
Assets		
Current assets		
Accounts receivable and other current assets	**$ 21,893**	$ 21,528
Capital assets (Note 3)	**201,312**	235,476
	$ 223,205	$ 257,004
Liabilities and Shareholders' Equity		
Current liabilities		
Accounts payable and accrued liabilities	**$ 26,655**	$ 34,937
Bank debt	**22,628**	30,102
Debenture	**-**	14,014
	49,283	79,053
Obligations under gas sale and transportation contracts	**7,085**	7,287
Asset retirement obligations (Note 5)	**8,270**	9,602
Future income tax liability	**11,618**	12,808
	76,256	108,750
Shareholders' equity		
Subordinated notes	**94,006**	93,430
Common shares (Note 4)	**72,640**	72,355
Contributed surplus (Note 4)	**268**	186
Deficit	**(19,965)**	(17,717)
	146,949	148,254
	$ 223,205	$ 257,004

See accompanying notes to these consolidated financial statements.

Consolidated Statements of Operations and Retained Earnings

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

Three months ended March 31,	2004	2003 (As restated per Notes 2, 4 & 5)
Revenues		
Oil and natural gas	$ 19,474	$ 18,255
Royalties	(3,519)	(4,219)
	15,955	14,036
Expenses		
Production	4,148	3,365
Transportation (Note 2)	416	338
General and administrative	1,699	1,381
Interest on bank debt	478	41
Depletion, depreciation and accretion	9,033	5,186
	15,774	10,311
Income before other items and taxes	181	3,725
Other expense (Note 3)	531)	(119)
Capital and future income taxes	(14)	(274)
Net income (loss)	(364)	3,332
Interest on subordinated notes, net of future taxes	(1,884)	(1,517)
Net income (loss) attributable to common shareholders	(2,248)	1,815
Retained earnings (deficit), beginning of period	(17,717)	5,628
Retained earnings (deficit), end of period	$ (19,965)	$ 7,443
Basic and diluted earnings (loss) per share (Note 4)	$ (0.04)	$ 0.04

See accompanying notes to these consolidated financial statements.

·Consolidated Statements of Cash Flow·

(Unaudited, Thousands of Canadian dollars)

Three months ended March 31,	2004	2003 (As restated per Notes 2, 4 & 5)
Operating Activities		
Net income (loss)	**$ (364)**	$ 3,332
Depletion, depreciation and accretion	**9,033**	5,186
Non-cash stock compensation	**82**	12
Future income tax recovery	**(249)**	-
Loss recorded on disposition of sales contract (Note 3)	**375**	-
Cash flow from operations	**8,877**	8,530
Changes in other non-cash items	**(3,987)**	(1,738)
	4,890	6,792
Financing Activities		
Issuance (repayment) of bank debt	**(7,474)**	8,204
Issuance of common shares (Note 4)	**285**	71
Repayment of debenture	**(14,014)**	-
Interest on subordinated notes	**(2,249)**	(1,341)
Amortization of obligations under gas sale and transportation contracts	**(202)**	(200)
	(23,654)	6,734
Investing Activities		
Expenditures on capital assets	**(14,713)**	(35,961)
Proceeds on disposition of capital assets (Note 3)	**38,137**	-
Asset retirement obligations settled	**-**	(27)
Changes in other non-cash items	**(4,660)**	10,238
	18,764	(25,750)
Net change in cash position	**-**	(12,224)
Cash and cash equivalents, beginning of period	**-**	12,224
Cash and cash equivalents, end of period	**$ -**	$ -

See accompanying notes to these consolidated financial statements.

As at and for the three months ended March 31, 2004
(All tabular amounts are expressed in thousands of Canadian dollars, except share amounts)

Note 1 – Significant Accounting Policies

The interim consolidated financial statements as at and for the three months ended March 31, 2004 should be read in conjunction with the audited consolidated financial statements as at and for the year ended December 31, 2003. The notes to these interim consolidated financial statements do not conform in all respects to the note disclosure requirements of generally accepted accounting policies for annual financial statements. These interim consolidated financial statements are prepared using the same accounting policies and methods of computation as disclosed in the audited consolidated financial statements as at and for the year ended December 31, 2003 except as described in Note 2.

Note 2 – Changes in Accounting Policies

Asset Retirement Obligations

Effective January 1, 2004 the Company retroactively adopted the new standard of the Canadian Institute of Chartered Accountants ("CICA"), "Asset Retirement Obligations". The new standard requires that the recognition of the fair value of obligations associated with the retirement of tangible long-lived assets be recorded in the period the asset is put into use, with a corresponding increase to the carrying amount of the related asset. The obligations recognized are statutory, contractual or legal obligations. The liability is accreted over time for changes in the fair value of the liability through charges to accretion, which is included in depletion, depreciation and accretion expense. The costs capitalized to the related assets are amortized to earnings in a manner consistent with the depletion and depreciation of the underlying asset. The impact of the adoption of this standard on the financial statements is described in Note 5.

Capital Assets – Oil and Gas

Effective January 1, 2004 the Company adopted Accounting Guideline 16, "Oil and Gas Accounting - Full Cost" ("AcG-16"), which replaces Accounting Guideline 5, "Full Cost Accounting in the Oil and Gas Industry". AcG-16 modifies how the ceiling test is performed and is consistent with CICA section 3063, "Impairment of Long-lived Assets". The recoverability of a cost centre is tested by comparing the carrying value of the cost centre to the sum of the undiscounted cash flows expected from the cost centre's use and eventual disposition. If the carrying value is unrecoverable the cost centre is written down to its fair value using the expected present value approach. This approach incorporates risks and uncertainties in the expected future cash flows, which are discounted using a risk free rate. The adoption of AcG-16 had no effect on the Company's financial results.

Hedging Relationships

The CICA published an amended Accounting Guideline 13, "Hedging Relationships", effective January 1, 2004, to clarify circumstances in which hedge accounting is appropriate. All derivative instruments that do not qualify as a hedge under the guideline, or are not properly designated as a hedge, will be recorded on the balance sheet as either an asset or liability with changes in fair value recognized in earnings. The Company adopted the standard January 1, 2004 with no impact on the financial results.

Transportation Costs

Effective January 1, 2004 the Company began classifying certain transportation costs as expenses in the consolidated statements of operations. In prior periods, these costs were netted against revenues and accordingly the prior period financial statements have been reclassified for comparative purposes. The change in accounting policy has no effect on net income but increased natural gas revenues and expenses for the three months ended March 31, 2004 by $416,000 (2003 – $338,000).

Note 3 – Property Dispositions

Petrobank disposed of its Wapella property on January 28, 2004 for net proceeds of $35.5 million. As part of this sale, the purchaser assumed the Company's fixed oil sales price contract on 300 barrels of oil per day at a WTI price of $27.68 per barrel. At the time of sale, this contract had a negative fair value of $0.4 million, which was recorded as other expense.

On March 22, 2004, the Company closed the sale of its Epping property in Western Saskatchewan for net proceeds of $2.6 million.

Note 4 – Share Capital

As at March 31, 2004 the Company had outstanding 54,651,396 common shares, 1,420,300 share purchase warrants, and 3,577,001 stock options.

Common Share Continuity	Number	Amount
Balance at December 31, 2003	54,502,646	$72,355
Exercise of stock options	148,750	285
Balance at March 31, 2004	54,651,396	$72,640

Stock Option Continuity	Number	Weighted - Average Exercise Price
Balance at December 31, 2003	3,676,501	$2.42
Granted	147,500	2.74
Exercised	(148,750)	(1.92)
Expired/cancelled	(98,250)	(2.78)
Balance at March 31, 2004	3,577,001	$2.44

Earnings Per Share

Basic and diluted earnings (loss) per share have been calculated based on net income (loss) attributable to common shareholders divided by the weighted average number of common shares outstanding for the three month period ended March 31, 2004 of 54,562,599 (2003 – 45,339,439). The diluted calculation for the three month period ended March 31, 2004 includes nil (2003 – 2,223,148) additional shares for the potential impact of share purchase warrants and stock options.

Stock Based Compensation

In 2003, the Company adopted the fair value based method of accounting for its stock-based compensation plan whereby the fair value of stock options granted after January 1, 2003 is recognized as general and administrative expense and as contributed surplus. Stock based compensation costs for the three-month period ended March 31, 2004 totaled $82,000. The three month period ended March 31, 2003 has been restated to record stock-based compensation of $12,000.

Had compensation expense associated with the Company's stock option plan been recognized using the fair value based method for all option grants after January 1, 2002, the Company's net loss attributable to common shareholders for the three months ended March 31, 2004 would have increased by $72,000 and net income attributable to common shareholders for the three months ended March 31, 2003 would have decreased by $107,000. Net income (loss) per share would have approximated reported amounts.

The fair value of stock options granted has been estimated on their respective grant dates using the Black Scholes option-pricing model using the following assumptions:

Three months ended March 31,	2004	2003
Risk free interest rate	4.5%	4%
Dividend rate	0%	0%
Expected life (years)	4	4
Expected volatility	30%	30%

The average value per option granted during the period was $0.84 as at the date of grant.

Note 5 - Asset Retirement Obligations

The total future asset retirement obligation was estimated by management based on the Company's net ownership interest in all wells, gathering lines and facilities, estimated costs to reclaim and abandon the wells and facilities and the estimated timing of the costs to be incurred in future periods. The change was effective January 1, 2004 and the revision was applied retroactively. The impact was as follows:

Consolidated Balance Sheet – as at December 31, 2002

	As Reported	Change	As Restated
Assets			
Net capital assets	126,873	7,726	134,599
Liabilities and shareholders' equity			
Asset retirement obligations	-	10,325	10,325
Site restoration liability	613	(613)	-
Retained earnings	7,614	(1,986)	5,628

Consolidated Balance Sheet – as at December 31, 2003

	As Reported	Change	As Restated
Assets			
Net capital assets	232,007	3,469	235,476
Liabilities and shareholders' equity			
Asset retirement obligations	-	9,602	9,602
Site restoration liability	2,807	(2,807)	-
Future income tax liability	13,920	(1,112)	12,808
Deficit	(15,503)	(2,214)	(17,717)

Consolidated Statement of Operations and Deficit – Three months ended March 31, 2003

	As Reported	Change	As Restated
Depletion, depreciation and accretion	4,993	193	5,186
Net Income [(1)]	3,537	(193)	3,344

[(1)] Net income was further reduced by $12,000 to $3,332,000 due to the restatement of stock-based compensation costs (Note 4).

The change in accounting for asset retirement obligations did not have a material impact on net loss reported in the three-month period ended March 31, 2004.

Changes to asset retirement obligations were as follows:

Three months ended March 31,	2004	2003
Asset retirement obligation, beginning of period	9,602	10,325
Obligations incurred	303	132
Obligations settled	-	(27)
Accretion expense	216	232
Obligations related to assets sold and other	(1,851)	347
Asset retirement obligation, end of period	8,270	11,009

The total undiscounted amount of estimated cash flows required to settle the obligation is $25.4 million (2003 - $33.0 million), which has been discounted using a credit-adjusted risk free rate of 9 percent. Most of these obligations are not expected to be paid for several years extending up to 34 years in the future, and will be funded from general company resources at the time of settlement.

Note 6 – Related Party Transactions

In January 2004, the Company paid a $200,000 commitment fee to secure a $10 million credit facility from a company controlled by a director of Petrobank. Any balances outstanding under the facility would bear interest at 12 percent per annum and would be subordinate to Petrobank 's existing secured bank debt. To date, the Company has not drawn on this facility, which expires on December 30, 2004.

Note 7 – Commitments and Contingencies

In Colombia, the Company has US$2.0 million of remaining work commitments on the Neiva Block. Ecopetrol, the state oil company, has agreed to extend the deadline for completion of these work commitments from June 2004 until the end of 2004.

Note 8 – Subsequent Event

In April 2004, the Company entered into an agreement to sells its Edmonton property effective February 1, 2004 for gross proceeds of $4.5 million. The borrowing base under the Company's secured credit facility will decrease from $36.1 million to $33.5 million after closing this transaction, which is scheduled to occur in May 2004.

Note 9 – Segmented Information

Three months ended March 31,

	2004			2003		
	Canada	Colombia	Total	Canada	Colombia	Total
Revenues						
Oil and natural gas	$ 13,801	$ 5,673	$ 19,474	$ 15,842	2,413	$ 18,255
Royalties	(3,065)	(454)	(3,519)	(4,026)	(193)	(4,219)
	10,736	5,219	15,955	11,816	2,220	14,036
Expenses						
Production	2,926	1,222	4,148	2,984	381	3,365
Transportation	416	-	416	338	-	338
General and administrative	1,022	677	1,699	944	437	1,381
Depletion, depreciation and accretion	5,757	3,276	9,033	4,330	856	5,186
Segmented income	$ 615	$ 44	$ 659	$ 3,220	546	$ 3,766
Non-segmented expenses						
Interest on bank debt			(478)			(41)
Other			(531)			(119)
Capital tax and future income taxes			(14)			(274)
Net income (loss)			(364)			3,332
Interest on subordinated notes, net of future taxes			(1,884)			(1,517)
Net income (loss) attributable to common shareholders			$ (2,248)			$ 1,815
Identifiable assets	$144,018	$79,187	$223,205	$ 133,601	$ 46,185	$ 179,786
Capital expenditures	$ 8,896	$ 5,817	$ 14,713	$ 10,383	$ 25,578	$ 35,961

Certain statements in this news release are "forward-looking statements" within the meaning of the United States Private Securities Litigation Reform Act of 1995. Specifically, this press release contains forward-looking statements relating to, prospects for technologies which remain unproven and the expected amount and timing of capital projects. 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: the ability to economically test, develop and utilize the technologies described herein, the feasibility of the technologies, general economic, market and business conditions; fluctuations in oil and gas prices; the results of exploration and development of drilling and related activities; fluctuation in foreign currency exchange rates; the uncertainty of reserve estimates; changes in environmental and other regulations; risks associated with oil and gas operations; and other factors, many of which are beyond the control of the Company. 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 forecast.

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·Management's Discussion and Analysis·

The following Management's Discussion and Analysis ("MD&A") is dated May 14, 2004 and should be read in conjunction with the unaudited consolidated financial statements of the Company for the three months ended March 31, 2004, MD&A for the year ended December 31, 2003, and the audited consolidated financial statements for the year ended December 31, 2003. Additional information for the Company can be found at www.sedar.com. In addition to historical information, the MD&A contains forward-looking statements that reflect management's objectives and expectations as at the date of this report, which involve risks and uncertainties. The Company's actual results may differ materially from those anticipated in these forward-looking statements.

Natural gas volumes have been converted to barrels of oil equivalent ("boe") so that six thousand cubic feet ("mcf") of natural gas equals one barrel based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the well head. Boes may be misleading, particularly if used in isolation. This report contains financial terms that are considered non-GAAP measures such as cash flow from operations, cash flow per share, net debt, and operating netback. These measures are commonly utilized in the oil and gas industry and are considered informative for our shareholders. Specifically, cash flow from operations and cash flow per share reflect cash generated from operating activities before changes in non-cash working capital. We consider these measures important as they demonstrate our ability to generate sufficient cash to fund future growth opportunities and repay debt. All amounts are in Canadian dollars, unless otherwise stated.

Property Dispositions

Petrobank closed the sale of its Wapella property on January 28, 2004 for net proceeds of $35.5 million. The results of operations for 2004 only include results from disposed properties up to the closing date of the transaction. Wapella production was approximately 1,400 barrels per day at the time of sale but only contributed 454 boe per day to average production in the first quarter of 2004.

On March 22, 2004, the Company closed the sale of its Epping property in Western Saskatchewan, which produced 181 barrels of heavy oil per day during the first quarter of 2004, for proceeds of 2.6 million.

Production

Oil and NGL production in Canada during the first quarter averaged 2,035 barrels per day (bpd), a decrease from the 2,931 bpd produced in the fourth quarter of 2003 and the 2,757 bpd produced in the first quarter of 2003. These decreases were primarily due to the sale of the Wapella property in January 2004. First quarter natural gas production of 16.1 million cubic feet per day (mmcfpd) increased 47 percent from 10.9 mmcfpd in the first quarter of 2003. The increase was a result of the acquisition of Monolith Oil Corp. in September 2003 offset somewhat by the disposition of the Company's Zama/Larne property in May 2003. Total Canadian production for the first quarter was 4,713 boepd, a 3 percent increase from the same period last year.

Colombian oil sales commenced in January 2003 and averaged 695 bpd in the first quarter of 2003 increasing to an average of 1,702 bpd in the first quarter of 2004. Production in Colombia is expected to be between 1,500 and 1,800 bpd until drilling recommences, which is not expected before the third quarter of 2004.

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Average Benchmark Prices

For the three months ended March 31,	2004	2003	% change
WTI crude oil (US$/bbl)	35.15	33.86	4
WTI crude oil (C$/bbl)	46.32	51.11	(9)
Bow River heavy oil differential (US$/bbl)	9.00	7.58	19
NYMEX natural gas (US$/mcf)	5.69	6.59	(14)
AECO (daily) natural gas (C$/mcf)	6.43	8.35	(23)
C$/US$ exchange rate	0.76	0.66	15

Realized Prices

Overall, commodity prices received in the first quarter were negatively impacted by the appreciation of the Canadian dollar since the first quarter of 2003. The average Canadian oil and NGL price received in the first quarter was $26.45 per barrel, a 21 percent decrease from the $33.30 per barrel received in the comparable 2003 period. Canadian oil and NGL prices averaged $33.68 per barrel, before financial hedging losses of $7.23 per barrel, representing a U.S.$9.59 discount to average WTI prices in the quarter compared to a U.S.$6.43 discount to WTI in the first quarter of 2003. The average discount increased as a result of a decrease in the average quality of barrels produced, combined with a widening of Canadian heavy crude oil differentials when compared to the comparative 2003 period. In 2004, 1,000 barrels per day of new swaps at U.S.$24.00 become effective, along with a fixed price oil sales contract for 300 bpd at an average price of U.S.$27.74 per barrel.

The average natural gas price received in the first quarter was $6.09 per mcf, a 21 percent decrease from the $7.71 per mcf received in the first quarter of 2003. Natural gas prices reflect the negative impact of the Company's long-term physical gas sales contracts, and in the current period includes the effect of the Company's natural gas price collar for 2004 on 10,551 GJ/day with AECO prices between $5.00 and $5.94 per GJ.

Oil sales prices in Colombia averaged U.S.$27.79 per barrel in the first quarter, representing a U.S.$7.36 discount to WTI compared to a discount of U.S.$8.32 per barrel in the comparable 2003 period. The average discount to WTI decreased, as our higher quality Orito oil comprised a larger portion of Colombian production in the current period.

Royalties

Royalties decreased from $4.2 million in the first quarter of 2003 to $3.5 million in the current period. Canadian royalties as a percentage of revenue decreased from 25 percent in the first quarter of 2003 to 22 percent in the current period. We anticipate Canadian royalty rates to average approximately 21 percent throughout the remainder of 2004. Colombian royalties are included in the current quarter at a rate of 8 percent.

Production Expenses

Production expenses in Canada decreased 6 percent from $7.24 per boe in the first quarter of 2003 to $6.82 per boe in the current period. Production expenses in Colombia averaged $7.89 per barrel during the quarter, a 30 percent increase from the first quarter 2003 average of $6.09 per barrel and a 49 percent decrease from the fourth quarter 2003 average of $15.62 per barrel. Fourth quarter 2003 production expenses were impacted by well workover costs and costs associated with a security incident in November that interrupted production.

General and Administrative Expenses

General and administrative expenses were $1.7 million in the first quarter of 2004 compared to $1.4 million in the first quarter of 2003. The increase relates primarily to incremental overhead associated with the Company's Colombian operations which were staffed to facilitate a more aggressive capital program than which is currently underway.

Interest on Bank Debt

The Company's credit facility was undrawn at December 31, 2002 and increased to $22.6 million drawn at March 31, 2004. As a result, interest on bank debt increased from $41,000 in the first quarter of 2003 to $0.5 million in 2004.

Depletion, Depreciation and Accretion

Depletion, depreciation and accretion expense for the first quarter of $9.0 million ($15.47 per boe) compared to $5.2 million ($10.93 per boe) in the comparable 2003 period. The increased rate was primarily due to the acquisition of the shorter reserve life Monolith assets in September of 2003, and the results of the 2003 Colombian drilling program.

Other Expenses

In January 2004, the purchaser of the Company's Wapella property assumed the Company's fixed oil sales price contract on 300 barrels of oil per day at a WTI price of $27.68 per barrel. At the time of sale, this contract had an unrecognized mark-to-market loss of $0.4 million, which was recognized as other expense upon disposition of the property.

Interest on Subordinated Notes

Interest on subordinated notes totaled $2.8 million during the first quarter ($1.9 million net of future taxes), compared to $1.5 million in the same period last year. The increase relates to the issuance of an additional $40.0 million of notes in May of 2003.

Income Taxes

At the end of the fourth quarter of 2003, Petrobank had a future income tax liability of $13.9 million due to the Monolith corporate acquisition and the issuance and renouncement of flow through shares in September 2003. In the first quarter of 2004, future tax recoveries were recorded against these balances of $0.2 million in Capital and Future Income Taxes, $1.1 million was recovered as a result of adopting the new accounting standard on asset retirement obligations, and a $0.9 million recovery was offset against Interest on Subordinated Notes.

Capital Expenditures

Consolidated capital expenditures during the quarter were $14.7 million, comprised of $8.9 million in Canada and $5.8 million in Colombia. In Canada, activity was concentrated on drilling and completions at our Jumpbush and Nevis/Red Willow properties. Colombian expenditures related to the Orito field and were focused on completions, recompletions and acquisition of required well site equipment to facilitate the transfer of operatorship of wells drilled by Petrobank to Ecopetrol.

Liquidity and Capital Resources

At March 31, 2004 net debt totaled $121.4 million, including the book value of outstanding subordinated notes ($94.0 million). The subordinated notes are not callable and mature in July 2006. Petrobank's borrowing base under its senior secured credit facility at March 31, 2004 was $36.1 million. Working capital deficit at March 31, 2004, including the $22.6 million balance drawn under the secured credit facility, totaled $27.4 million leaving $8.7 million of available borrowing capacity. Following the sale of the Company's Edmonton property in May 2004 the borrowing base will be reduced to $33.5 million.

Changes in Accounting Policies

Asset Retirement Obligations

Effective January 1, 2004 the Company retroactively adopted the new standard of the Canadian Institute of Chartered Accountants ("CICA"), "Asset Retirement Obligations". The new standard requires that the recognition of the fair value of obligations associated with the retirement of tangible long-lived assets be recorded in the period the asset is put into use, with a corresponding increase to the carrying amount of the related asset. The obligations recognized are statutory, contractual or legal obligations. The liability is accreted over time for changes in the fair value of the liability through charges to accretion, which is included in depletion, depreciation and accretion expense. The costs capitalized to the related assets are amortized to earnings in a manner consistent with the depletion and depreciation of the underlying asset. The impact of the adoption of this standard on the financial statements is described in Note 5 to the consolidated financial statements for the three months ended March 31, 2004.

Transportation Costs

Effective January 1, 2004 the Company began classifying certain transportation costs as expenses in the consolidated statements of operations. In prior periods, these costs were netted against revenues and accordingly the prior period financial statements have been reclassified for comparative purposes. The change in accounting policy has no effect on net income but increased natural gas revenues and expenses for the three months ended March 31, 2004 by $416,000 (2003 – $338,000). The reclassification translates into a $0.28 per mcf increase in natural gas prices in the current period and $0.34 per mcf in the comparative period. Also as a result, Canadian transportation expenses of $0.97 per boe were recognized in the current period (2003 - $0.82 per boe).

SUMMARY OF QUARTERLY RESULTS

	2004	2003[2]				2002[2]		
	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2
Financial ($000s except where noted)								
Oil and natural gas revenue	**19,474**	20,540	13,963	14,747	18,255	13,238	12,579	13,539
Cash flow from operations	**8,877**	8,701	5,842	6,185	8,530	5,600	5,806	5,899
Per share - basic ($)	**0.12**	0.12	0.08	0.09	0.16	0.09	0.11	0.13
- diluted ($)	**0.12**	0.12	0.08	0.09	0.15	0.09	0.11	0.10
Net income (loss)	**(364)**	(18,654)	(573)	790	3,332	1,010	1,207	1,848
Net income (loss) attributable to common shareholders	**(2,248)**	(20,434)	(3,398)	(1,508)	1,815	(537)	(375)	90
Per share - basic and diluted ($)	**(0.04)**	(0.38)	(0.07)	(0.03)	0.04	(0.01)	(0.01)	-
Capital expenditures	**14,713**	27,338	28,065	24,696	35,961	28,620	5,813	4,882
Operations								
Canadian operating netbacks by product [1]								
Light/medium oil and NGLs sales price ($/bbl)	**27.50**	26.81	28.09	28.28	33.28	32.44	33.16	31.14
Royalties	**8.97**	5.89	6.01	7.28	10.79	7.76	7.93	7.20
Production expenses	**6.81**	6.22	5.24	6.99	5.84	7.04	6.32	5.10
Operating netback	**11.72**	14.70	16.84	14.01	16.65	17.64	18.91	18.84
Heavy oil sales price ($/bbl)	**24.46**	22.95	24.86	27.14	33.37	25.90	30.09	29.92
Royalties	**3.45**	2.36	4.22	3.75	5.89	4.62	4.13	4.27
Production expenses	**8.52**	11.18	6.83	9.40	8.33	8.68	5.92	8.35
Operating netback	**12.49**	9.41	13.81	13.99	19.15	12.60	20.04	17.30
Natural gas sales price ($/mcf)	**6.09**	5.89	5.49	6.73	7.71	5.42	3.94	4.23
Royalties	**1.20**	0.88	0.82	1.00	1.61	1.03	0.71	0.88
Production expenses	**1.06**	1.26	1.79	1.51	1.44	1.40	1.16	1.15
Transportation expenses	**0.28**	0.28	0.51	0.39	0.34	0.33	0.31	0.24
Operating netback	**3.55**	3.47	2.37	3.83	4.32	2.66	1.76	1.96
Oil equivalent sales price ($/boe)	**32.18**	30.57	28.75	32.06	38.46	31.79	28.57	28.08
Royalties	**7.15**	5.12	5.35	6.29	9.77	6.78	5.97	6.02
Production expenses	**6.82**	7.55	7.06	8.06	7.24	7.78	6.55	6.24
Transportation expenses	**0.97**	0.85	0.83	0.77	0.82	0.83	0.84	0.76
Operating netback	**17.24**	17.05	15.51	16.94	20.63	16.40	15.21	15.06
Colombian operating netback ($/bbl)								
Oil sales price	**36.63**	31.66	31.37	29.74	38.58	-	-	-
Royalties	**2.93**	2.53	2.44	2.40	3.09	-	-	-
Production expenses	**7.89**	15.62	9.24	7.93	6.09	-	-	-
Operating netback	**25.81**	13.51	19.69	19.41	29.40	-	-	-
Average daily production								
Canada - light/medium oil and NGLs (bbls)	**1,332**	2,147	2,097	2,097	2,225	2,180	2,242	2,216
Canada - heavy oil (bbls)	**703**	784	812	661	532	472	354	325
Canada - natural gas (mcf)	**16,069**	17,702	6,581	8,057	10,920	11,244	13,134	16,546
Total Canada (boe)	**4,713**	5,881	4,005	4,101	4,577	4,526	4,785	5,299
Colombia - oil (bbls)	**1,702**	1,374	1,166	1,028	695	-	-	-
Total Company (boe)	**6,415**	7,255	5,171	5,129	5,272	4,526	4,785	5,299

(1) Sales prices are shown after hedging costs. All hedging costs relating to oil sales are net against the Cdn. light/med oil and NGLs price.

(2) Restated for changes in accounting policies.

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· Highlights ·

As at and for the three months ended March 31,	2004	2003	% change
Financial			
($000s, except where noted)			
Oil and natural gas revenue	19,474	18,255	7
Cash flow from operations [1]	8,877	8,530	4
Per share – basic ($) [2]	0.12	0.16	(25)
Per share – diluted ($) [2]	0.12	0.15	(20)
Net income (loss)	(364)	3,332	
Net income (loss) attributable to common shareholders	(2,248)	1,815	
Per share – basic and diluted ($)	(0.04)	0.04	
Capital expenditures	14,713	35,961	(59)
Net debt including subordinated notes [3]	121,396	91,599	33
Shareholders' equity excluding subordinated notes	52,943	57,759	(8)
Common shares outstanding (000s)			
Basic	54,651	45,354	20
Diluted	59,649	50,544	18
Operations [4]			
Canadian operating netback ($/boe except where noted)			
Oil and NGLs revenue ($/bbl)	26.45	33.30	(21)
Natural gas revenue ($/mcf)	6.09	7.71	(21)
Combined oil equivalent revenue	32.18	38.46	(16)
Royalties	7.15	9.77	(27)
Production expenses	6.82	7.24	(6)
Transportation expenses	0.97	0.82	18
Operating netback	17.24	20.63	(16)
Colombian operating netback ($/bbl)			
Oil revenue	36.63	38.58	(5)
Royalties	2.93	3.09	(5)
Production expenses	7.89	6.09	30
Operating netback	25.81	29.40	(12)
Average daily production			
Canada - oil and NGLs (bbls)	2,035	2,757	(26)
Canada - natural gas (mcf)	16,069	10,920	47
Total Canada (boe)	4,713	4,577	3
Colombia - oil (bbls)	1,702	695	145
Total Company (boe)	6,415	5,272	22

(1) Cash flow from operations before changes in other non-cash items.
(2) Calculated based on cash flow from operations before changes in other non-cash items less preferred share dividends and interest paid on subordinated notes.
(3) Includes working capital (deficiency) and subordinated notes reflected as equity on the balance sheet.
(4) 6 Mcf of natural gas is equivalent to 1 barrel of oil equivalent (BOE).

·Report to Shareholders·

Petrobank Energy and Resources Ltd. ("Petrobank") is pleased to provide this operational update of our Canadian, Latin American and Heavy Oil Business Units as well as our first quarter financial results.

OPERATIONAL UPDATE

Canadian Business Unit

First quarter Canadian production averaged 4,713 boe per day consisting of 2,035 barrels per day of liquids and 16,069 mcf per day of natural gas. This included 635 barrels of oil per day from our Wapella and Epping properties, which were sold during the period. Excluding these properties, production averaged 4,078 boe per day during the quarter. Due to a competitive drainage issue, we were restricted from producing our most prolific Nevis well during a portion of the first quarter. During the quarter, we drilled 9 wells (7.3 net), 6 were cased for gas and 3 for oil, and including these wells, a total of 27 wells were completed or re-completed. Field operations have been focused on adding behind-pipe reserves and production at Shekilie, Jumpbush, Nevis, and Red Willow and in the first part of May production has averaged 4,700 boe per day.

Our latest phase of drilling and completions at Jumpbush validated the balance of our lands and confirmed our ability to identify new, potentially prolific Belly River trends from seismic. Ten of our more productive wells in the area have tested significant gas volumes and are awaiting approval to be tied in. A further 30 well drilling program has been submitted for approval to the Siksika First Nation.

Our most active areas in the first quarter were the recently acquired Nevis and Red Willow areas where we drilled 6 new wells (6 net), 3 of which were cased for oil and 3 for gas. The new oil wells recently began production, and we are planning pipelines for these new gas wells, as well as other behind-pipe reserves. Including these locations, a total of 15 wells were completed or re-completed during the quarter at Nevis and Red Willow. Our most prolific Nevis gas well was previously being rate restricted and competitively drained. This May, we installed pipeline and compression to address the related production loss and recover the majority of this lost production. A first quarter Nevis well and a second quarter Red Willow well discovered two new Glauconite oil pools. Both wells are producing at restricted rates of 125 barrels per day and will be further delineated later this year. The Nevis oil pool commenced production in March and the Red Willow production commenced in early May.

Petrobank is also advancing two high impact CBM projects. At Jumpbush, we plan to complete the remaining two Belly River coal zones in our existing CBM test well, which exhibited an initial water-free flow rate of 100 mcf per day of gas from the first coal zone. In addition, we plan to test all three coal zones in at least four nearby wells. At Princeton, British Columbia, the approval process for our first CBM test well is proceeding, including consultation with the public and the Upper Similkameen First Nation.

Latin American Business Unit

In Colombia, we produced an average of 1,702 barrels of oil per day from our Orito and Neiva blocks in the first quarter, marking the highest quarterly average since production commenced in January 2003. Another milestone was achieved when we elected to proceed to the complimentary phases on both the Neiva and Orito blocks, having completed our initial work commitments. Advancing to the complementary phase extends the term of our Orito and Neiva incremental production contracts by 19 years, adding flexibility to our future development plans. We are in the process of submitting our development plan for Orito and had previously committed to approximately $2 million of further development at Neiva. Concurrently, we have approached Ecopetrol in an effort to improve the fiscal terms at Neiva to permit a broader development program.

At Orito, Ecopetrol has now assumed operatorship of all wells drilled and intervened by Petrobank (except Orito-115), resulting in a significant operating cost savings. An increase in the water cut at Orito-115 has reduced the well's production to approximately 250 bopd and we are evaluating potential remedial work before turning the well over to Ecopetrol to operate.

A security incident in November 2003 continued to affect operations at Orito during the first month of the year but production has since been restored at the affected wells. A recent strike at the state oil company, Ecopetrol has impacted Ecopetrol's operations, but to-date has not had a significant effect on Petrobank's production. Strike activities have caused OTA pipeline interruptions between Orito and the Pacific export terminal of Tumaco but this is not presently affecting Orito production due to excess storage capacity on the system.

We expect to complete our new reservoir simulation model of the main producing zone at Orito, the Caballos formation, by the end of the second quarter. This model will be used to direct our next phase of drilling which is anticipated to commence late this year. Preliminary drilling locations have been identified to verify two potentially significant expansions to the Orito field. Much of our future development plan is contingent on the success of this initial program. Lastly, we have commenced operations on our pilot waterflood in the Caballos zone, with initial results expected sometime in 2005.

Evaluation of the Central Colombia Block by Petrobank and our partners continues, and in July a decision will be made to either acquire additional seismic, drill an exploratory test well targeting a significant Caballos prospect, or relinquish the block.

We expect our production in Colombia to range between 1,500 and 1,800 bopd through the remainder of the year, as we await the results of our next drilling program. The full impact of our current operating cost reductions should be realized in the third quarter.

Heavy Oil Business Unit

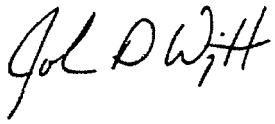
The WHITESANDS Pilot Project received approval from the Alberta Energy and Utilities Board (AEUB) and Alberta Environment (AENV) in February 2004. These approvals allow us to finalize the detailed project engineering and schedule necessary for the efficient execution of the WHITESANDS pilot project. A project execution team has been assembled to be in a position to commence construction in the third quarter. The project site is accessible year round and as such is not a constraint on project timing. In addition, since the project is not overly complex and will employ conventional oil field equipment, delays related to long lead items and construction are not anticipated. With this schedule we expect to begin air injection as early as the second quarter of 2005.

Petrobank is seeking private equity financing for the estimated $30 million capital cost of the pilot project which is to be effected by the issuance of up to a 40% equity interest in Petrobank's subsidiary, WHITESANDS INSITU Ltd. Discussions are continuing with potential investors and due diligence is ongoing.

WHITESANDS owns 45 sections of oil sands leases in the Christina Lake region of Alberta. In the first quarter, Fekete Associates completed a detailed geological assessment report, which indicates that the WHITESANDS lands contain a bitumen resource of 831 million barrels in the middle McMurray formation and an additional 484 million barrels in the upper McMurray. This bitumen resource is sufficient to support a significant THAI™ commercial development and, as a secondary consideration, would also be attractive for a commercial-scale Steam Assisted Gravity Drainage (SAGD) project. The THAI™ and CAPRI™ technologies have the potential to revolutionize the heavy oil extraction business. Petrobank shareholders stand to benefit enormously from the commercial opportunity on our existing land base combined with our future ability to license the technologies and capture additional resources internationally.

OUTLOOK

Petrobank is in a unique position, with opportunities in each of our Business Units to add significant value for shareholders. Our ability to execute simultaneously on all these opportunities is constrained by our available financial resources. In Canada, our near-term activities will be focused on adding production at Jumpbush, Nevis and Red Willow. Our CBM resources will be assessed through pilot test programs. Our new reservoir simulation model will direct our next phase of drilling in Colombia and until then, expenditures will be modest. The currently contemplated financing of our WHITESANDS pilot should allow this project to proceed quickly relative to other oil sands projects, with initial results expected by mid-2005. By integrating our 2003 property acquisitions, advancing to the complementary phase of our Colombian incremental production contracts, gaining approval for our WHITESANDS project and validating our expanded land-base at Jumpbush, we have put Petrobank in a position to manage the development pace of each of our available opportunities. We have minimal contractual commitments outstanding and, as results dictate, we plan to accelerate future investment in the most promising of these projects, while maintaining a solid balance sheet.



John D. Wright
President and Chief Executive Officer
May 14, 2004

·Management's Discussion and Analysis·

The following Management's Discussion and Analysis ("MD&A") is dated May 14, 2004 and should be read in conjunction with the unaudited consolidated financial statements of the Company for the three months ended March 31, 2004, MD&A for the year ended December 31, 2003, and the audited consolidated financial statements for the year ended December 31, 2003. Additional information for the Company can be found at www.sedar.com. In addition to historical information, the MD&A contains forward-looking statements that reflect management's objectives and expectations as at the date of this report, which involve risks and uncertainties. The Company's actual results may differ materially from those anticipated in these forward-looking statements.

Natural gas volumes have been converted to barrels of oil equivalent ("boe") so that six thousand cubic feet ("mcf") of natural gas equals one barrel based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the well head. Boes may be misleading, particularly if used in isolation. This report contains financial terms that are considered non-GAAP measures such as cash flow from operations, cash flow per share, net debt, and operating netback. These measures are commonly utilized in the oil and gas industry and are considered informative for our shareholders. Specifically, cash flow from operations and cash flow per share reflect cash generated from operating activities before changes in non-cash working capital. We consider these measures important as they demonstrate our ability to generate sufficient cash to fund future growth opportunities and repay debt. All amounts are in Canadian dollars, unless otherwise stated.

Property Dispositions

Petrobank closed the sale of its Wapella property on January 28, 2004 for net proceeds of $35.5 million. The results of operations for 2004 only include results from disposed properties up to the closing date of the transaction. Wapella production was approximately 1,400 barrels per day at the time of sale but only contributed 454 boe per day to average production in the first quarter of 2004.

On March 22, 2004, the Company closed the sale of its Epping property in Western Saskatchewan, which produced 181 barrels of heavy oil per day during the first quarter of 2004, for proceeds of 2.6 million.

Production

Oil and NGL production in Canada during the first quarter averaged 2,035 barrels per day (bpd), a decrease from the 2,931 bpd produced in the fourth quarter of 2003 and the 2,757 bpd produced in the first quarter of 2003. These decreases were primarily due to the sale of the Wapella property in January 2004. First quarter natural gas production of 16.1 million cubic feet per day (mmcfpd) increased 47 percent from 10.9 mmcfpd in the first quarter of 2003. The increase was a result of the acquisition of Monolith Oil Corp. in September 2003 offset somewhat by the disposition of the Company's Zama/Larne property in May 2003. Total Canadian production for the first quarter was 4,713 boepd, a 3 percent increase from the same period last year.

Colombian oil sales commenced in January 2003 and averaged 695 bpd in the first quarter of 2003 increasing to an average of 1,702 bpd in the first quarter of 2004. Production in Colombia is expected to be between 1,500 and 1,800 bpd until drilling recommences, which is not expected before the third quarter of 2004.

Average Benchmark Prices

For the three months ended March 31,	2004	2003	% change
WTI crude oil (US$/bbl)	35.15	33.86	4
WTI crude oil (C$/bbl)	46.32	51.11	(9)
Bow River heavy oil differential (US$/bbl)	9.00	7.58	19
NYMEX natural gas (US$/mcf)	5.69	6.59	(14)
AECO (daily) natural gas (C$/mcf)	6.43	8.35	(23)
C$/US$ exchange rate	0.76	0.66	15

Realized Prices

Overall, commodity prices received in the first quarter were negatively impacted by the appreciation of the Canadian dollar since the first quarter of 2003. The average Canadian oil and NGL price received in the first quarter was $26.45 per barrel, a 21 percent decrease from the $33.30 per barrel received in the comparable 2003 period. Canadian oil and NGL prices averaged $33.68 per barrel, before financial hedging losses of $7.23 per barrel, representing a U.S.$9.59 discount to average WTI prices in the quarter compared to a U.S.$6.43 discount to WTI in the first quarter of 2003. The average discount increased as a result of a decrease in the average quality of barrels produced, combined with a widening of Canadian heavy crude oil differentials when compared to the comparative 2003 period. In 2004, 1,000 barrels per day of new swaps at U.S.$24.00 become effective, along with a fixed price oil sales contract for 300 bpd at an average price of U.S.$27.74 per barrel.

The average natural gas price received in the first quarter was $6.09 per mcf, a 21 percent decrease from the $7.71 per mcf received in the first quarter of 2003. Natural gas prices reflect the negative impact of the Company's long-term physical gas sales contracts, and in the current period includes the effect of the Company's natural gas price collar for 2004 on 10,551 GJ/day with AECO prices between $5.00 and $5.94 per GJ.

Oil sales prices in Colombia averaged U.S.$27.79 per barrel in the first quarter, representing a U.S.$7.36 discount to WTI compared to a discount of U.S.$8.32 per barrel in the comparable 2003 period. The average discount to WTI decreased, as our higher quality Orito oil comprised a larger portion of Colombian production in the current period.

Royalties

Royalties decreased from $4.2 million in the first quarter of 2003 to $3.5 million in the current period. Canadian royalties as a percentage of revenue decreased from 25 percent in the first quarter of 2003 to 22 percent in the current period. We anticipate Canadian royalty rates to average approximately 21 percent throughout the remainder of 2004. Colombian royalties are included in the current quarter at a rate of 8 percent.

Production Expenses

Production expenses in Canada decreased 6 percent from $7.24 per boe in the first quarter of 2003 to $6.82 per boe in the current period. Production expenses in Colombia averaged $7.89 per barrel during the quarter, a 30 percent increase from the first quarter 2003 average of $6.09 per barrel and a 49 percent decrease from the fourth quarter 2003 average of $15.62 per barrel. Fourth quarter 2003 production expenses were impacted by well workover costs and costs associated with a security incident in November that interrupted production.

General and Administrative Expenses

General and administrative expenses were $1.7 million in the first quarter of 2004 compared to $1.4 million in the first quarter of 2003. The increase relates primarily to incremental overhead associated with the Company's Colombian operations which were staffed to facilitate a more aggressive capital program than which is currently underway.

Interest on Bank Debt

The Company's credit facility was undrawn at December 31, 2002 and increased to $22.6 million drawn at March 31, 2004. As a result, interest on bank debt increased from $41,000 in the first quarter of 2003 to $0.5 million in 2004.

Depletion, Depreciation and Accretion

Depletion, depreciation and accretion expense for the first quarter of $9.0 million ($15.47 per boe) compared to $5.2 million ($10.93 per boe) in the comparable 2003 period. The increased rate was primarily due to the acquisition of the shorter reserve life Monolith assets in September of 2003, and the results of the 2003 Colombian drilling program.

Other Expenses

In January 2004, the purchaser of the Company's Wapella property assumed the Company's fixed oil sales price contract on 300 barrels of oil per day at a WTI price of $27.68 per barrel. At the time of sale, this contract had an unrecognized mark-to-market loss of $0.4 million, which was recognized as other expense upon disposition of the property.

Interest on Subordinated Notes

Interest on subordinated notes totaled $2.8 million during the first quarter ($1.9 million net of future taxes), compared to $1.5 million in the same period last year. The increase relates to the issuance of an additional $40.0 million of notes in May of 2003.

Income Taxes

At the end of the fourth quarter of 2003, Petrobank had a future income tax liability of $13.9 million due to the Monolith corporate acquisition and the issuance and renouncement of flow through shares in September 2003. In the first quarter of 2004, future tax recoveries were recorded against these balances of $0.2 million in Capital and Future Income Taxes, $1.1 million was recovered as a result of adopting the new accounting standard on asset retirement obligations, and a $0.9 million recovery was offset against Interest on Subordinated Notes.

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Liquidity and Capital Resources

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Changes in Accounting Policies

Asset Retirement Obligations

Effective January 1, 2004 the Company retroactively adopted the new standard of the Canadian Institute of Chartered Accountants ("CICA"), "Asset Retirement Obligations". The new standard requires that the recognition of the fair value of obligations associated with the retirement of tangible long-lived assets be recorded in the period the asset is put into use, with a corresponding increase to the carrying amount of the related asset. The obligations recognized are statutory, contractual or legal obligations. The liability is accreted over time for changes in the fair value of the liability through charges to accretion, which is included in depletion, depreciation and accretion expense. The costs capitalized to the related assets are amortized to earnings in a manner consistent with the depletion and depreciation of the underlying asset. The impact of the adoption of this standard on the financial statements is described in Note 5 to the consolidated financial statements for the three months ended March 31, 2004.

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SUMMARY OF QUARTERLY RESULTS

	2004	2003[2]				2002[2]		
	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2
Financial ($000s except where noted)								
Oil and natural gas revenue	**19,474**	20,540	13,963	14,747	18,255	13,238	12,579	13,539
Cash flow from operations	**8,877**	8,701	5,842	6,185	8,530	5,600	5,806	5,899
Per share - basic ($)	**0.12**	0.12	0.08	0.09	0.16	0.09	0.11	0.13
- diluted ($)	**0.12**	0.12	0.08	0.09	0.15	0.09	0.11	0.10
Net income (loss)	**(364)**	(18,654)	(573)	790	3,332	1,010	1,207	1,848
Net income (loss) attributable to common shareholders	**(2,248)**	(20,434)	(3,398)	(1,508)	1,815	(537)	(375)	90
Per share - basic and diluted ($)	**(0.04)**	(0.38)	(0.07)	(0.03)	0.04	(0.01)	(0.01)	-
Capital expenditures	**14,713**	27,338	28,065	24,696	35,961	28,620	5,813	4,882
Operations								
Canadian operating netbacks by product [1]								
Light/medium oil and NGLs sales price ($/bbl)	**27.50**	26.81	28.09	28.28	33.28	32.44	33.16	31.14
Royalties	**8.97**	5.89	6.01	7.28	10.79	7.76	7.93	7.20
Production expenses	**6.81**	6.22	5.24	6.99	5.84	7.04	6.32	5.10
Operating netback	**11.72**	14.70	16.84	14.01	16.65	17.64	18.91	18.84
Heavy oil sales price ($/bbl)	**24.46**	22.95	24.86	27.14	33.37	25.90	30.09	29.92
Royalties	**3.45**	2.36	4.22	3.75	5.89	4.62	4.13	4.27
Production expenses	**8.52**	11.18	6.83	9.40	8.33	8.68	5.92	8.35
Operating netback	**12.49**	9.41	13.81	13.99	19.15	12.60	20.04	17.30
Natural gas sales price ($/mcf)	**6.09**	5.89	5.49	6.73	7.71	5.42	3.94	4.23
Royalties	**1.20**	0.88	0.82	1.00	1.61	1.03	0.71	0.88
Production expenses	**1.06**	1.26	1.79	1.51	1.44	1.40	1.16	1.15
Transportation expenses	**0.28**	0.28	0.51	0.39	0.34	0.33	0.31	0.24
Operating netback	**3.55**	3.47	2.37	3.83	4.32	2.66	1.76	1.96
Oil equivalent sales price ($/boe)	**32.18**	30.57	28.75	32.06	38.46	31.79	28.57	28.08
Royalties	**7.15**	5.12	5.35	6.29	9.77	6.78	5.97	6.02
Production expenses	**6.82**	7.55	7.06	8.06	7.24	7.78	6.55	6.24
Transportation expenses	**0.97**	0.85	0.83	0.77	0.82	0.83	0.84	0.76
Operating netback	**17.24**	17.05	15.51	16.94	20.63	16.40	15.21	15.06
Colombian operating netback ($/bbl)								
Oil sales price	**36.63**	31.66	31.37	29.74	38.58	-	-	-
Royalties	**2.93**	2.53	2.44	2.40	3.09	-	-	-
Production expenses	**7.89**	15.62	9.24	7.93	6.09	-	-	-
Operating netback	**25.81**	13.51	19.69	19.41	29.40	-	-	-
Average daily production								
Canada - light/medium oil and NGLs (bbls)	**1,332**	2,147	2,097	2,097	2,225	2,180	2,242	2,216
Canada - heavy oil (bbls)	**703**	784	812	661	532	472	354	325
Canada - natural gas (mcf)	**16,069**	17,702	6,581	8,057	10,920	11,244	13,134	16,546
Total Canada (boe)	**4,713**	5,881	4,005	4,101	4,577	4,526	4,785	5,299
Colombia - oil (bbls)	**1,702**	1,374	1,166	1,028	695	-	-	-
Total Company (boe)	**6,415**	7,255	5,171	5,129	5,272	4,526	4,785	5,299

[1] Sales prices are shown after hedging costs. All hedging costs relating to oil sales are net against the Cdn. light/med oil and NGLs price.

[2] Restated for changes in accounting policies.

·Consolidated Balance Sheets·

(Unaudited, Thousands of Canadian dollars)

As at	March 31, 2004	December 31, 2003 (As restated per Notes 2, 4 & 5)
Assets		
Current assets		
Accounts receivable and other current assets	**$ 21,893**	$ 21,528
Capital assets (Note 3)	**201,312**	235,476
	$ 223,205	$ 257,004
Liabilities and Shareholders' Equity		
Current liabilities		
Accounts payable and accrued liabilities	**$ 26,655**	$ 34,937
Bank debt	**22,628**	30,102
Debenture	**-**	14,014
	49,283	79,053
Obligations under gas sale and transportation contracts	**7,085**	7,287
Asset retirement obligations (Note 5)	**8,270**	9,602
Future income tax liability	**11,618**	12,808
	76,256	108,750
Shareholders' equity		
Subordinated notes	**94,006**	93,430
Common shares (Note 4)	**72,640**	72,355
Contributed surplus (Note 4)	**268**	186
Deficit	**(19,965)**	(17,717)
	146,949	148,254
	$ 223,205	$ 257,004

See accompanying notes to these consolidated financial statements.

Consolidated Statements of Operations and Retained Earnings

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

Three months ended March 31,	2004	2003 (As restated per Notes 2, 4 & 5)
Revenues		
Oil and natural gas	$ 19,474	$ 18,255
Royalties	(3,519)	(4,219)
	15,955	14,036
Expenses		
Production	4,148	3,365
Transportation (Note 2)	416	338
General and administrative	1,699	1,381
Interest on bank debt	478	41
Depletion, depreciation and accretion	9,033	5,186
	15,774	10,311
Income before other items and taxes	181	3,725
Other expense (Note 3)	(531)	(119)
Capital and future income taxes	(14)	(274)
Net income (loss)	(364)	3,332
Interest on subordinated notes, net of future taxes	(1,884)	(1,517)
Net income (loss) attributable to common shareholders	(2,248)	1,815
Retained earnings (deficit), beginning of period	(17,717)	5,628
Retained earnings (deficit), end of period	$ (19,965)	$ 7,443
Basic and diluted earnings (loss) per share (Note 4)	$ (0.04)	$ 0.04

See accompanying notes to these consolidated financial statements.

Consolidated Statements of Cash Flow

(Unaudited, Thousands of Canadian dollars)

Three months ended March 31,	2004	2003 (As restated per Notes 2, 4 & 5)
Operating Activities		
Net income (loss)	$ (364)	$ 3,332
Depletion, depreciation and accretion	9,033	5,186
Non-cash stock compensation	82	12
Future income tax recovery	(249)	-
Loss recorded on disposition of sales contract (Note 3)	375	-
Cash flow from operations	8,877	8,530
Changes in other non-cash items	(3,987)	(1,738)
	4,890	6,792
Financing Activities		
Issuance (repayment) of bank debt	(7,474)	8,204
Issuance of common shares (Note 4)	285	71
Repayment of debenture	(14,014)	-
Interest on subordinated notes	(2,249)	(1,341)
Amortization of obligations under gas sale and transportation contracts	(202)	(200)
	(23,654)	6,734
Investing Activities		
Expenditures on capital assets	(14,713)	(35,961)
Proceeds on disposition of capital assets (Note 3)	38,137	-
Asset retirement obligations settled	-	(27)
Changes in other non-cash items	(4,660)	10,238
	18,764	(25,750)
Net change in cash position	-	(12,224)
Cash and cash equivalents, beginning of period	-	12,224
Cash and cash equivalents, end of period	$ -	$ -

See accompanying notes to these consolidated financial statements.

As at and for the three months ended March 31, 2004
(All tabular amounts are expressed in thousands of Canadian dollars, except share amounts)

Note 1 – Significant Accounting Policies

The interim consolidated financial statements as at and for the three months ended March 31, 2004 should be read in conjunction with the audited consolidated financial statements as at and for the year ended December 31, 2003. The notes to these interim consolidated financial statements do not conform in all respects to the note disclosure requirements of generally accepted accounting policies for annual financial statements. These interim consolidated financial statements are prepared using the same accounting policies and methods of computation as disclosed in the audited consolidated financial statements as at and for the year ended December 31, 2003 except as described in Note 2.

Note 2 – Changes in Accounting Policies

Asset Retirement Obligations

Effective January 1, 2004 the Company retroactively adopted the new standard of the Canadian Institute of Chartered Accountants ("CICA"), "Asset Retirement Obligations". The new standard requires that the recognition of the fair value of obligations associated with the retirement of tangible long-lived assets be recorded in the period the asset is put into use, with a corresponding increase to the carrying amount of the related asset. The obligations recognized are statutory, contractual or legal obligations. The liability is accreted over time for changes in the fair value of the liability through charges to accretion, which is included in depletion, depreciation and accretion expense. The costs capitalized to the related assets are amortized to earnings in a manner consistent with the depletion and depreciation of the underlying asset. The impact of the adoption of this standard on the financial statements is described in Note 5.

Capital Assets – Oil and Gas

Effective January 1, 2004 the Company adopted Accounting Guideline 16, "Oil and Gas Accounting - Full Cost" ("AcG-16"), which replaces Accounting Guideline 5, "Full Cost Accounting in the Oil and Gas Industry". AcG-16 modifies how the ceiling test is performed and is consistent with CICA section 3063, "Impairment of Long-lived Assets". The recoverability of a cost centre is tested by comparing the carrying value of the cost centre to the sum of the undiscounted cash flows expected from the cost centre's use and eventual disposition. If the carrying value is unrecoverable the cost centre is written down to its fair value using the expected present value approach. This approach incorporates risks and uncertainties in the expected future cash flows, which are discounted using a risk free rate. The adoption of AcG-16 had no effect on the Company's financial results.

Hedging Relationships

The CICA published an amended Accounting Guideline 13, "Hedging Relationships", effective January 1, 2004, to clarify circumstances in which hedge accounting is appropriate. All derivative instruments that do not qualify as a hedge under the guideline, or are not properly designated as a hedge, will be recorded on the balance sheet as either an asset or liability with changes in fair value recognized in earnings. The Company adopted the standard January 1, 2004 with no impact on the financial results.

Transportation Costs

Effective January 1, 2004 the Company began classifying certain transportation costs as expenses in the consolidated statements of operations. In prior periods, these costs were netted against revenues and accordingly the prior period financial statements have been reclassified for comparative purposes. The change in accounting policy has no effect on net income but increased natural gas revenues and expenses for the three months ended March 31, 2004 by $416,000 (2003 – $338,000).

Note 3 – Property Dispositions

Petrobank disposed of its Wapella property on January 28, 2004 for net proceeds of $35.5 million. As part of this sale, the purchaser assumed the Company's fixed oil sales price contract on 300 barrels of oil per day at a WTI price of $27.68 per barrel. At the time of sale, this contract had a negative fair value of $0.4 million, which was recorded as other expense.

On March 22, 2004, the Company closed the sale of its Epping property in Western Saskatchewan for net proceeds of $2.6 million.

Note 4 – Share Capital

As at March 31, 2004 the Company had outstanding 54,651,396 common shares, 1,420,300 share purchase warrants, and 3,577,001 stock options.

Common Share Continuity	Number	Amount
Balance at December 31, 2003	54,502,646	$72,355
Exercise of stock options	148,750	285
Balance at March 31, 2004	54,651,396	$72,640

Stock Option Continuity	Number	Weighted - Average Exercise Price
Balance at December 31, 2003	3,676,501	$ 2.42
Granted	147,500	2.74
Exercised	(148,750)	(1.92)
Expired/cancelled	(98,250)	(2.78)
Balance at March 31, 2004	3,577,001	$ 2.44

Earnings Per Share

Basic and diluted earnings (loss) per share have been calculated based on net income (loss) attributable to common shareholders divided by the weighted average number of common shares outstanding for the three month period ended March 31, 2004 of 54,562,599 (2003 – 45,339,439). The diluted calculation for the three month period ended March 31, 2004 includes nil (2003 – 2,223,148) additional shares for the potential impact of share purchase warrants and stock options.

Stock Based Compensation

In 2003, the Company adopted the fair value based method of accounting for its stock-based compensation plan whereby the fair value of stock options granted after January 1, 2003 is recognized as general and administrative expense and as contributed surplus. Stock based compensation costs for the three-month period ended March 31, 2004 totaled $82,000. The three month period ended March 31, 2003 has been restated to record stock-based compensation of $12,000.

Had compensation expense associated with the Company's stock option plan been recognized using the fair value based method for all option grants after January 1, 2002, the Company's net loss attributable to common shareholders for the three months ended March 31, 2004 would have increased by $72,000 and net income attributable to common shareholders for the three months ended March 31, 2003 would have decreased by $107,000. Net income (loss) per share would have approximated reported amounts.

The fair value of stock options granted has been estimated on their respective grant dates using the Black Scholes option-pricing model using the following assumptions:

Three months ended March 31,	2004	2003
Risk free interest rate	4.5%	4%
Dividend rate	0%	0%
Expected life (years)	4	4
Expected volatility	30%	30%

The average value per option granted during the period was $0.84 as at the date of grant.

Note 5 - Asset Retirement Obligations

The total future asset retirement obligation was estimated by management based on the Company's net ownership interest in all wells, gathering lines and facilities, estimated costs to reclaim and abandon the wells and facilities and the estimated timing of the costs to be incurred in future periods. The change was effective January 1, 2004 and the revision was applied retroactively. The impact was as follows:

Consolidated Balance Sheet – as at December 31, 2002

	As Reported	Change	As Restated
Assets			
Net capital assets	126,873	7,726	134,599
Liabilities and shareholders' equity			
Asset retirement obligations	-	10,325	10,325
Site restoration liability	613	(613)	-
Retained earnings	7,614	(1,986)	5,628

Consolidated Balance Sheet – as at December 31, 2003

	As Reported	Change	As Restated
Assets			
Net capital assets	232,007	3,469	235,476
Liabilities and shareholders' equity			
Asset retirement obligations	-	9,602	9,602
Site restoration liability	2,807	(2,807)	-
Future income tax liability	13,920	(1,112)	12,808
Deficit	(15,503)	(2,214)	(17,717)

Consolidated Statement of Operations and Deficit – Three months ended March 31, 2003

	As Reported	Change	As Restated
Depletion, depreciation and accretion	4,993	193	5,186
Net Income [1]	3,537	(193)	3,344

[1] Net income was further reduced by $12,000 to $3,332,000 due to the restatement of stock-based compensation costs (Note 4).

The change in accounting for asset retirement obligations did not have a material impact on net loss reported in the three-month period ended March 31, 2004.

Changes to asset retirement obligations were as follows:

Three months ended March 31,	2004	2003
Asset retirement obligation, beginning of period	9,602	10,325
Obligations incurred	303	132
Obligations settled	-	(27)
Accretion expense	216	232
Obligations related to assets sold and other	(1,851)	347
Asset retirement obligation, end of period	8,270	11,009

The total undiscounted amount of estimated cash flows required to settle the obligation is $25.4 million (2003 - $33.0 million), which has been discounted using a credit-adjusted risk free rate of 9 percent. Most of these obligations are not expected to be paid for several years extending up to 34 years in the future, and will be funded from general company resources at the time of settlement.

Note 6 – Related Party Transactions

In January 2004, the Company paid a $200,000 commitment fee to secure a $10 million credit facility from a company controlled by a director of Petrobank. Any balances outstanding under the facility would bear interest at 12 percent per annum and would be subordinate to Petrobank 's existing secured bank debt. To date, the Company has not drawn on this facility, which expires on December 30, 2004.

Note 7 – Commitments and Contingencies

In Colombia, the Company has US$2.0 million of remaining work commitments on the Neiva Block. Ecopetrol, the state oil company, has agreed to extend the deadline for completion of these work commitments from June 2004 until the end of 2004.

Note 8 – Subsequent Event

In April 2004, the Company entered into an agreement to sells its Edmonton property effective February 1, 2004 for gross proceeds of $4.5 million. The borrowing base under the Company's secured credit facility will decrease from $36.1 million to $33.5 million after closing this transaction, which is scheduled to occur in May 2004.

Note 9 – Segmented Information

Three months ended March 31,

	2004			2003		
	Canada	Colombia	Total	Canada	Colombia	Total
Revenues						
Oil and natural gas	$ 13,801	$ 5,673	$ 19,474	$ 15,842	$ 2,413	$ 18,255
Royalties	(3,065)	(454)	(3,519)	(4,026)	(193)	(4,219)
	10,736	5,219	15,955	11,816	2,220	14,036
Expenses						
Production	2,926	1,222	4,148	2,984	381	3,365
Transportation	416	-	416	338	-	338
General and administrative	1,022	677	1,699	944	437	1,381
Depletion, depreciation and accretion	5,757	3,276	9,033	4,330	856	5,186
Segmented income	$ 615	$ 44	$ 659	$ 3,220	$ 546	$ 3,766
Non-segmented expenses						
Interest on bank debt			(478)			(41)
Other			(531)			(119)
Capital tax and future income taxes			(14)			(274)
Net income (loss)			(364)			3,332
Interest on subordinated notes, net of future taxes			(1,884)			(1,517)
Net income (loss) attributable to common shareholders			$ (2,248)			$ 1,815
Identifiable assets	$144,018	$ 79,187	$223,205	$133,601	$ 46,185	$179,786
Capital expenditures	$ 8,896	$ 5,817	$ 14,713	$ 10,383	$ 25,578	$ 35,961

Certain statements in this report are "forward-looking statements" within the meaning of the United States Private Securities Litigation Reform Act of 1995. Specifically, this press release contains forward-looking statements relating to, prospects for technologies which remain unproven and the expected amount and timing of capital projects. 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: the ability to economically test, develop and utilize the technologies described herein, the feasibility of the technologies, general economic, market and business conditions; fluctuations in oil and gas prices; the results of exploration and development of drilling and related activities; fluctuation in foreign currency exchange rates; the uncertainty of reserve estimates; changes in environmental and other regulations; risks associated with oil and gas operations; and other factors, many of which are beyond the control of the Company. 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 forecast.

PETROBANK
ENERGY AND RESOURCES LTD.

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(403) 266-5794
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Website: www.petrobank.com
TSX: PBG, PBG.N (July 14, 2004 - PBG.NT.A)

FORM 52-109FT2

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CORPORATE FINANCE

CERTIFICATION OF INTERIM FILINGS DURING TRANSITION PERIOD

I, CHRIS J. BLOOMER, Vice-President Heavy Oil and Chief Financial Officer of Petrobank Energy and Resources Ltd., certify that:

1. I have reviewed the interim filings (as this term is defined in Multilateral Instrument 52-109 *Certification of Disclosure in Issuers' Annual and Interim Filings*) of Petrobank Energy and Resources Ltd., (the issuer) for the interim period ending March 31, 2004;

2. Based on my knowledge, the interim filings do not contain any untrue statement of a material fact or omit to state a material fact required to be stated or that is necessary to make a statement not misleading in light of the circumstances under which it was made, with respect to the period covered by the interim filings; and

3. Based on my knowledge, the interim financial statements together with the other financial information included in the interim filings fairly present in all material respects the financial condition, results of operations and cash flows of the issuer, as of the date and for the periods presented in the interim filings.

Date: May 14, 2004

signed "Chris J. Bloomer"
Chris J. Bloomer
Vice-President Heavy Oil and Chief Financial Officer
Petrobank Energy and Resources Ltd.

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CORPORATE FINANCE

FORM 52-109FT2

CERTIFICATION OF INTERIM FILINGS DURING TRANSITION PERIOD

I, JOHN D. WRIGHT, President and Chief Executive Officer of Petrobank Energy and Resources Ltd., certify that:

1. I have reviewed the interim filings (as this term is defined in Multilateral Instrument 52-109 *Certification of Disclosure in Issuers' Annual and Interim Filings*) of Petrobank Energy and Resources Ltd., (the issuer) for the interim period ending March 31, 2004;

2. Based on my knowledge, the interim filings do not contain any untrue statement of a material fact or omit to state a material fact required to be stated or that is necessary to make a statement not misleading in light of the circumstances under which it was made, with respect to the period covered by the interim filings; and

3. Based on my knowledge, the interim financial statements together with the other financial information included in the interim filings fairly present in all material respects the financial condition, results of operations and cash flows of the issuer, as of the date and for the periods presented in the interim filings.

Date: May 14, 2004

signed "John D. Wright"
John D. Wright
President and Chief Executive Officer
Petrobank Energy and Resources Ltd.

Computershare

600, 530 – 8th Ave SW., Calgary, AB T2P 3S8 Tel.: 1 (866) 331-6361 Fax.: (403) 267-6529

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May 18, 2004

Alberta Securities Commission
British Columbia Securities Commission
Saskatchewan Financial Services Commission
The Manitoba Securities Commission
Ontario Securities Commission
L'Autorité des marchés financiers
Nova Scotia Securities Commission
TSX

Dear Sirs:

Subject: Petrobank Energy and Resources Ltd.

We confirm that the following material was sent by pre-paid mail on May 17, 2004 to the registered shareholders of the common shares of the subject Corporation:

1. First Quarter Report 2004 for the three months ended March 31, 2004 and 2003
2. Apology Letter from Globel Direct to Shareholders

In compliance with security regulations, we are providing this material to you in our capacity as agent for the subject Corporation.

We also confirm that a copy of the above was mailed to all non-registered shareholders of the subject Corporation whose names appear on the Corporation's Supplemental Mailing List as defined in the Canadian Securities Administrators' National Instrument 54-102.

Yours truly,

"signed by"

Tracy Williams
Mailing Professional
ClientServicesMailings@Computershare.com

cc: Petrobank Energy and Resources Ltd.
Attention: Corey Ruttan

Tw\43776

FEE RULE

FORM 13-502F1
ANNUAL PARTICIPATION FEE FOR REPORTING ISSUERS

Reporting Issuer Name: Petrobank Energy and Resources Ltd.

Participation Fee for the Financial Year Ending: December 31, 2003

Complete Only One of 1, 2 or 3:

1. Class 1 Reporting Issuers (Canadian Issuers – Listed in Canada and/or the U.S.)

Market value of equity securities:			
Total number of equity securities of a class or series outstanding at the end of the issuer's most recent financial year		54,502,646	
Simple average of the closing price of that class or series as of the last trading day of each of the months of the financial year (under paragraph 2.5(a)(ii)(A) or (B) of the Rule)	X	$2.80	
Market value of class or series	=	152,607,409	
			152,607,409 (A)
(Repeat the above calculation for each class or series of equity securities of the reporting issuer that are listed and posted for trading, or quoted on a marketplace in Canada or the United States of America at the end of the financial year)			(A)
Market value of corporate debt or preferred shares of Reporting Issuer or Subsidiary Entity referred to in Paragraph 2.5(b)(ii): **Average trading price = .907 * Face value = $100,438,000**			91,097,266(B)
(Repeat for each class or series of corporate debt or preferred shares)			(B)
Total Capitalization (add market value of all classes and series of equity securities and market value of debt and preferred shares) (A) + (B) =			243,704,675
Total fee payable in accordance with Appendix A of the Rule			$15,000
Reduced fee for new Reporting Issuers (see section 2.8 of the Rule)			
Total Fee Payable x Number of months remaining in financial year / 12			
Late Fee, if applicable (please include the calculation pursuant to section 2.9 of the Rule)			

2. Class 2 Reporting Issuers (Other Canadian Issuers)

Financial Statement Values (use stated values from the audited financial statements of the reporting issuer as at its most recent audited year end):

Retained earnings or deficit

Contributed surplus

Share capital or owners' equity, options, warrants and preferred shares (whether such shares are

classified as debt or equity for financial reporting purposes) _____
Long term debt (including the current portion) _____

Capital leases (including the current portion) _____

Minority or non-controlling interest _____

Items classified on the balance sheet between current liabilities and shareholders' equity (and not otherwise listed above) _____

Any other item forming part of shareholders' equity and not set out specifically above _____

Total Capitalization _____

Total Fee payable pursuant to Appendix A of the Rule _____

Reduced fee for new Reporting Issuers (see section 2.8 of the Rule)

Total Fee Payable x $\frac{\text{Number of months remaining in financial year year or elapsed since most recent financial year}}{12}$ _____

Late Fee, if applicable (please include the calculation pursuant to section 2.9 of the Rule) _____

3. Class 3 Reporting Issuers (Foreign Issuers)

Market value of securities:
If the issuer has debt or equity securities listed or traded on a marketplace located anywhere in the world (see paragraph 2.7(a) of the Rule):
Total number of the equity or debt securities outstanding at the end of the reporting issuer's most recent financial year _____

Simple average of the published closing market price of that class or series of equity or debt securities as of the last trading day of each of the months of the financial year on the marketplace on which the highest volume of the class or series of securities were traded in that financial year. X _____

Percentage of the class registered in the name of, or held beneficially by, an Ontario person X _____

(Repeat the above calculation for each class or series of equity or debt securities of the reporting issuer) = _____

Capitalization (add market value of all classes and series of securities) _____

Or, if the issuer has no debt or equity securities listed or traded on a marketplace located anywhere in the world (see paragraph 2.7(b) of the Rule):

Financial Statement Values (use stated values from the audited financial statements of the reporting issuer as at its most recent audited year end):

Retained earnings or deficit _____

Contributed surplus _____

Share capital or owners' equity, options, warrants and preferred shares (whether such shares are classified as debt or equity for financial reporting purposes) _____

Long term debt (including the current portion) _____

Capital leases (including the current portion) _____

Minority or non-controlling interest _____

Items classified on the balance sheet between current liabilities and shareholders' equity (and not otherwise listed above) _____
Any other item forming part of shareholders' equity and not set out specifically above _____

Percentage of the outstanding equity securities registered in the name of, or held beneficially by, an Ontario person X _____

Capitalization _____

Total Fee payable pursuant to Appendix A of the Rule _____

Reduced fee for new Reporting Issuers (see section 2.8 of the Rule)

Total Fee Payable x $\frac{\text{Number of months remaining in financial year}}{\text{year or elapsed since most recent financial year}}{12}$ _____

Late Fee, if applicable
(please include the calculation pursuant to section 2.9 of the Rule) _____

Notes and Instructions

1. This participation fee is payable by reporting issuers other than investment funds that do not have an unregistered investment fund manager.

2. The capitalization of income trusts or investment funds that have no investment fund manager, which are listed or posting for trading, or quoted on, a marketplace in either or both of Canada or the U.S. should be determined with reference to the formula for Class 1 Reporting Issuers. The capitalization of any other investment fund that has no investment fund manager should be determined with reference to the formula for Class 2 Reporting Issuers.

3. All monetary figures should be expressed in Canadian dollars and rounded to the nearest thousand. Closing market prices for securities of Class 1 and Class 3 Reporting Issuers should be converted to Canadian dollars at the [daily noon] in effect at the end of the issuer's last financial year, if applicable.

4. A reporting issuer shall pay the appropriate participation fee no later than the date on which it is required to file its annual financial statements.

5. The number of listed securities and published market closing prices of such listed securities of a reporting issuer may be based upon the information made available by a marketplace upon which securities of the reporting issuer trade, unless the issuer has knowledge that such information is inaccurate and the issuer has knowledge of the correct information.

6. Where the securities of a class or series of a Class 1 Reporting Issuer have traded on more than one marketplace in Canada, the published closing market prices shall be those on the marketplace upon which the highest volume of the class or series of securities were traded in that financial year. If none of the class or series of securities were traded on a marketplace in Canada, reference should be made to the marketplace in the United States on which the highest volume of that class or series were traded.

7. Where the securities of a class or series of securities of a Class 3 Reporting Issuer are listed on more than one exchange, the published closing market prices shall be those on the marketplace on which the highest volume of the class or series of securities were traded in the relevant financial year.

Burnet, Duckworth & Palmer LLP
Law Firm

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2004 SEP -8 P 12:
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CORPORATE FINANCE

Reply to: Scott D. Kearl
Direct Phone: (403) 260-0395
Direct Fax: (403) 260-0330
sdk@bdplaw.com

Assistant: Lucie Leblanc
Direct Phone: (403) 260-0365

DELIVERED VIA SEDAR

May 19, 2004

Alberta Securities Commission
British Columbia Securities Commission
Saskatchewan Financial Services Commission
Manitoba Securities Commission
Ontario Securities Commission
Autorité des marches financiers
Nova Scotia Securities Commission

Dear Sirs:

Re: Petrobank Energy and Resources Ltd. – Notice of Filing of Renewal Annual Information Form

Please take notice that Petrobank Energy and Resources Ltd. has filed its Renewal Annual Information Form for the year ended December 31, 2003, under National Instrument 51-102 – Continuous Disclosure Obligations under Project No. 649511. Please note that Petrobank Energy and Resources Ltd. intends to rely on that Annual Information Form for the purposes of National Instrument 44-101 – Short Form Prospectus Distributions.

Yours truly,

BURNET, DUCKWORTH & PALMER LLP

(signed) "*Scott D. Kearl*"

Scott D. Kearl

cc: Petrobank Energy and Resources Ltd.
Attention: Cory Ruttan (via e-mail)

Burnet, Duckworth & Palmer LLP
Attention: Mr. Michael D. Sandrelli

PETROBANK
ENERGY AND RESOURCES LTD.

Notice of Annual and Special Meeting of Shareholders
to be held on June 17, 2004

The annual and special meeting of the shareholders of Petrobank Energy and Resources Ltd. will be held on Thursday, June 17, 2004 at 3:00 p.m. (Calgary time) in the Grand Lecture Theatre of the Metropolitan Conference Centre, 333 – 4th Avenue S.W., Calgary, Alberta to:

1. receive and consider our financial statements for the year ended December 31, 2003, together with the report of the auditors;

2. fix the number of directors to be elected at the meeting at 7 members;

3. elect 7 directors;

4. appoint the auditors and to authorize the directors to fix their remuneration as such;

5. consider, and if thought fit, pass an ordinary resolution of shareholders to approve certain amendments to our stock option plan, all as more particularly set forth in the Information Circular – Proxy Statement accompanying this notice;

6. consider, and if thought fit, pass an ordinary resolution of disinterested shareholders to approve the terms and conditions of a deferred share unit plan;

7. consider, and, if thought fit, pass an ordinary resolution to approve future private placements by the Corporation; and

8. transact such other business as may properly be brought before the meeting or any adjournment thereof.

The specific details of the matters proposed to be put before the meeting are set forth in the information circular - proxy statement accompanying this notice.

If you are unable to attend the meeting in person we request that you date and sign the enclosed form of proxy and mail it to or deposit it with our Secretary, c/o Computershare Trust Company of Canada, Proxy Department, 9th Floor - 100 University Avenue, Toronto, Ontario, M5J 2Y1. In order to be valid and acted upon at the meeting, forms of proxy must be returned to the aforesaid address not less than 48 hours (excluding Saturdays, Sundays and holidays) before the time for holding the meeting or any adjournment thereof.

Only shareholders of record at the close of business on May 14, 2004 will be entitled to vote at the meeting, unless that shareholder has transferred any shares subsequent to that date and the transferee shareholder, not later than 10 days before the meeting, establishes ownership of the shares and demands that the transferee's name be included on the list of shareholders.

DATED at Calgary, Alberta this May 14, 2004.

By order of the board of directors
(signed) *"John D. Wright"*
John D. Wright
President and Chief Executive Officer

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Management's Discussion and Analysis

Summary of Annual Results

(Cdn $000s, except where noted)	2003	2002	2001
Financial			
Oil and natural gas revenue	**66,111**	50,458	46,117
Cash flow from operations [1]	**29,258**	22,806	18,549
Per share - basic ($) [2]	**0.45**	0.45	0.46
Per share - diluted ($) [2]	**0.44**	0.40	0.39
Net income (loss)	**(14,691)**	6,191	5,283
Net income (loss) attributable to common shareholders	**(23,111)**	(430)	431
Per share - basic and diluted ($)	**(0.48)**	(0.01)	0.01
Capital expenditures	**116,060**	46,228	21,859
Total assets	**253,535**	150,618	146,337
Pro-forma net debt including subordinated notes [3]	**114,955**	62,495	31,266
Shares outstanding (000s) [4]			
Basic	**54,503**	45,314	42,166
Diluted	**59,599**	50,287	56,376
Operations			
Canadian operating netback ($/boe except where noted)			
Oil and NGLs revenue ($/bbl)	**28.48**	31.11	28.09
Natural gas revenue ($/mcf)	**6.08**	3.89	5.13
Combined oil equivalent revenue	**31.60**	27.39	29.24
Royalties	**6.56**	5.84	5.00
Production expenses	**7.48**	6.68	6.55
Operating netback	**17.56**	14.87	17.69
Colombian operating netback ($/bbl)			
Oil revenue	**32.22**		
Royalties	**2.56**		
Production expenses	**10.48**		
Operating netback	**19.18**		
Average daily production			
Canada - oil and NGLs (bbls)	**2,840**	2,623	2,480
Canada - natural gas (mcf)	**10,821**	14,541	11,047
Total Canada (boe)	**4,643**	5,047	4,321
Colombia - oil (bbls)	**1,068**		
Total Company (boe)	**5,711**	5,047	4,321

(1) Cash flow from operations before changes in non-cash working capital.

(2) Calculated based on cash flow from operations before changes in non-cash working capital less preferred share dividends and interest paid on subordinated notes.

(3) Includes working capital (deficiency), subordinated notes reflected as equity on the balance sheet and for 2003, is net of proceeds of $36 million received on the January 2004 Wapella property disposition.

(4) Includes common and preferred shares for 2001.

The following management's discussion and analysis ("MD&A") is dated March 12, 2004 and should be read in conjunction with the consolidated financial statements and accompanying notes that begin on page 58 of this annual report. In addition to historical information, the MD&A contains forward-looking statements that reflect management's objectives and expectations as at the date of this report, which involve risks and uncertainties. The Company's actual results may differ materially from those anticipated in these forward-looking statements.

Natural gas volumes have been converted to barrels of oil equivalent ("boe") so that six thousand cubic feet ("mcf") of natural gas equals one barrel based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the well head. Boes may be misleading, particularly if used in isolation. This MD&A contains financial terms that are not considered measures under Canadian Generally Accepted Accounting Principles ("GAAP"), such as cash flow from operations, cash flow per share, net debt, and operating netback. These measures are commonly utilized in the oil and natural gas industry and management considers them to be informative for the Company's shareholders. Cash flow from operations and cash flow per share reflect cash generated from operating activities before changes in other non-cash items. Petrobank considers these measures important as they reflect the Company's ability to generate cash from operations to fund future growth opportunities while servicing future debt obligations. All amounts are in Canadian dollars, unless otherwise stated.

Highlights

- Commenced oil sales from Colombian operations in January 2003.
- Issued additional subordinated notes in May 2003 for net proceeds of $34.4 million.
- Disposed of Zama/Larne property in Northwest Alberta in May 2003, which was producing approximately 700 boe per day (primarily natural gas), for proceeds of $16.6 million.
- Acquired Monolith Oil Corp. ("Monolith") on September 19, 2003 for $39.6 million; production from the acquired properties averaged 2,325 boe per day between the closing date and year-end.
- Issued 2.78 million flow-through common shares for gross proceeds of $10.0 million in September 2003.
- Filed the WHITESANDS (THAI™) experimental pilot project application in October 2003 and received approval in February 2004.
- In January 2004, sold the Company's Wapella property, which produced 1,324 barrels of oil per day in the fourth quarter of 2003, for proceeds of $36.0 million.
- Consolidated production increased by 13 percent to 5,711 boe per day during the year, averaging 7,255 boe per day in the fourth quarter.
- Cash flow from operations increased by 28 percent year-over-year to $29.3 million in 2003.
- Recorded a net loss attributable to common shareholders in 2003 of $23.1 million, including a $16.9 million impairment charge relating to the Company's international properties.
- Capital expenditures net of property dispositions totalled $24.3 million in Canada and $71.3 million in Colombia.

Results of Operations

Significant Transactions

Petrobank disposed of its Zama/Larne properties in Northwest Alberta on May 31, 2003 for $16.6 million and acquired Monolith on September 19, 2003 for $39.6 million. The results of operations for 2003 only reflect results from disposed properties up to the closing date and from the acquired properties subsequent to the closing date. Zama/Larne production contributed 333 boe per day to average 2003 production. The Monolith properties averaged 2,325 boe per day between the closing date and year-end, contributing 663 boe per day to average 2003 production. A portion of the Monolith consideration was a debenture in the amount of $14.0 million, which was repaid in January 2004.

Petrobank issued $10.0 million of flow-through shares in September and renounced related tax benefits to those shareholders in December. The result of this transaction and the Monolith acquisition resulted in a future tax liability being recognized on the consolidated balance sheet as at December 31, 2003.

Petrobank disposed of its Wapella property in January 2004 for cash proceeds of $36.0 million. These proceeds were used to repay the debenture described above and to repay a portion of the Company's outstanding bank debt. Pro-forma this transaction, the Company's net debt as at December 31, 2003 was $115 million. Net debt is defined as debt plus any working capital deficiency and the book value of the Company's subordinated notes. Production at Wapella was approximately 1,400 barrels per day at time of sale.

Revenue

Oil and natural gas revenue before royalties increased by 31 percent to $66.1 million in 2003 from $50.5 million in 2002. Related production increased by 13 percent to 5,711 boe per day while average sales prices increased by 16 percent to $31.72 per boe.

Average Daily Production

	Q4 2003	2003	2002
Canada – oil and NGLs (bbls)	**2,931**	**2,840**	2,623
Canada – natural gas (mcf)	**17,702**	**10,821**	14,541
Total Canada (boe)	**5,881**	**4,643**	5,047
Colombia – oil (bbls)	**1,374**	**1,068**	
Total Company (boe)	**7,255**	**5,711**	5,047

Canadian oil and natural gas liquids (NGLs) production in 2003 increased as a result of drilling activity at Eyehill and Epping in Western Saskatchewan. Fourth-quarter oil and NGLs production averaged 2,931 barrels per day and will decrease in the first quarter of 2004 as a result of the sale of Petrobank's Wapella property in January 2004, which produced 1,324 barrels of oil per day in the fourth quarter of 2003. Natural gas production decreased in 2003 as a result of the sale of the Company's Zama/Larne property in Northwest Alberta in May 2003, but increased again following the Monolith acquisition in September 2003. Canadian drilling activity in 2004 is to be focused at Petrobank's natural gas-prone areas

of Jumpbush, Nevis and Red Willow. Colombian oil production commenced in January 2003 and is expected to be 1,500-1,800 barrels per day in 2004 until drilling resumes, which is not expected earlier than the third quarter of 2004.

Average Benchmark Prices

	Q4 2003	2003	2002
WTI crude oil (US$/bbl)	**31.18**	**31.04**	26.08
WTI crude oil (Cdn$/bbl)	**41.03**	**43.47**	40.95
Bow River heavy oil differential (US$/bbl)	**9.77**	**8.00**	5.90
NYMEX natural gas (US$/mmbtu)	**4.58**	**5.39**	3.22
AECO natural gas (Cdn$/mcf)	**5.76**	**6.71**	4.07
US$/Cdn$ exchange rate	**0.76**	**0.71**	0.64

Increases in U.S. dollar-denominated benchmark commodity prices during 2003 were partially offset by the appreciation of the Canadian dollar. Commodity prices have remained strong in the first quarter of 2004 and are expected to average US$34.08 per barrel WTI and US$5.65 per mmbtu NYMEX natural gas for 2004 including forecast prices in the futures market. The US$/Cdn$ exchange rate is currently forecast to be $0.75 in 2004.

Price Risk Management

At year-end, Petrobank's calendar 2003 oil price swaps on 1,500 barrels per day at an average price of US$23.77 per barrel expired. The Company had a number of new commodity price contracts become effective in 2004, including an oil price swap for 1,000 barrels per day at US$24.00 per barrel WTI, a 300 barrel-per-day fixed price oil sales contract at US$27.74 per barrel WTI; and a natural gas collar on 10,551 GJ/day with AECO prices of $5.00-$5.94 per GJ. In addition to these 2004 commodity price contracts the Company has a long-term physical natural gas sales contract and a natural gas transportation contract, a description of which is included in Note 11 to the Consolidated Financial Statements – "Financial Instruments and Financial Risk Management".

Canadian Operating Netbacks

($/boe except where noted)	Q4 2003	2003	2002
Oil and NGLs revenue ($/bbl)	**25.78**	**28.48**	31.11
Natural gas revenue ($/mcf)	**5.61**	**6.08**	3.89
Combined oil equivalent revenue	**29.72**	**31.60**	27.39
Royalties	**5.12**	**6.56**	5.84
Production expenses	**7.55**	**7.48**	6.68
Operating netback	**17.05**	**17.56**	14.87

The decrease in Canadian crude oil and liquids prices in 2003 was a result of higher financial hedging losses, the appreciation of the Canadian dollar, a widening of the Canadian heavy oil differentials and a decrease in the average quality of barrels produced as production additions during 2003 related primarily to drilling at the western Saskatchewan heavy oil properties.

The average 2003 selling price for the Company's Canadian crude oil and NGLs was $33.82 per barrel (2002 - $32.32 per barrel) before financial hedging losses of $5.34 per barrel (2002 - $1.21 per barrel, representing a US$6.89 per barrel (2002 - $5.49 per barrel) differential to WTI. This compares with a US$7.91 per barrel differential to WTI in the fourth quarter of 2003, as heavy oil differentials typically widen during the winter months.

The average natural gas price received in 2003 was $6.08 per mcf, a 56 percent increase from $3.89 per mcf received in 2002. Natural gas prices reflect the negative impact of the Company's long-term physical natural gas sales and transportation contracts, the impact of which was reduced with the addition of the un-contracted Monolith volumes in September 2003. Assuming an average NYMEX gas price of US$5.50 per mmbtu, the Company would expect to receive an average wellhead natural gas price in 2004 of approximately Cdn$5.80 per mcf.

Colombian Operating Netbacks

($/bbl)	Q4 2003	2003
Oil revenue	31.66	32.22
Royalties	2.53	2.56
Production expenses	15.62	10.48
Operating netback	13.51	19.18

Oil sales commenced from Colombia in January 2003 and prices averaged US$23.01 per barrel in 2003 and US$24.06 per barrel in the fourth quarter, representing discounts to WTI of US$8.03 and US$7.12 per barrel respectively. Oil production in 2003 was sold to the Colombian state oil company, Ecopetrol, during 2003 at contractual discounts to WTI. Petrobank's 2004 oil production from Neiva (approximately 450 barrels per day) is to be exported through an intermediary and sold at prevailing market prices. As a result, the Company expects to increase its wellhead price at Neiva by approximately US$1.00 per barrel. At a WTI price of US$30.00 per barrel Petrobank expects Neiva wellhead prices to be approximately WTI less US$9.00 per barrel. Orito oil production continues to be sold to Ecopetrol; at WTI prices above US$30.00 per barrel the Company receives a wellhead price of WTI less US$6.40 per barrel. Orito oil production would likely have to exceed 3,000 barrels per day before Company exports became feasible.

Royalties

Consolidated royalty expense increased to $12.1 million in 2003 from $10.8 million in 2002. Canadian royalties as a percentage of revenue remained consistent at 21 percent in 2003 and 2002. The decrease in the fourth-quarter 2003 rate to 17 percent reflects a revision of prior period estimates. The Company anticipates Canadian royalty rates to be approximately 21 percent in 2004. Colombian royalties are fixed at 8 percent until Petrobank's net production per contract exceeds 5,000 barrels per day.

Production Expenses

Consolidated production expenses increased from $12.3 million in 2002 to $16.8 million in 2003. Canadian production expenses per unit of production increased from $6.68 per boe to $7.48 per boe over the same period. Petrobank expects 2004 production expenses in Canada to be consistent with 2003 levels.

Production expenses in Colombia averaged $10.48 per barrel in 2003 and $15.62 per barrel in the fourth quarter. Ecopetrol operates both Colombian blocks at a fixed operating fee of $4.40 per barrel at Orito and $2.40 per barrel at Neiva. Production expenses remain high in Colombia for a number of reasons including Ecopetrol's delays in assuming operatorship of new wells, which Petrobank has been operating while also paying Ecopetrol's fee. Costs in the fourth quarter increased as a result of repairs relating to the security incident in November. High well operating costs will continue into April 2004 when Petrobank's new wells are expected to be equipped with permanent surface equipment and operatorship assumed by Ecopetrol.

General and Administrative Expenses

Consolidated general and administrative expenses totalled $5.9 million ($2.85 per boe) in 2003 compared to $3.8 million ($2.05 per boe) in 2002. The increases from 2002 relate to incremental overhead associated with the Company's Colombian operations, which were staffed to facilitate a more aggressive capital program than is currently underway.

Depletion, Depreciation and Site Restoration

Consolidated depletion, depreciation and site restoration expense increased to $27.4 million ($13.13 per boe) in 2003 from $17.3 million ($9.37 per boe) in 2002. The per unit costs increased as a result of cost overruns on the Colombian capital program and the acquisition of the shorter-reserve-life Monolith assets in Canada. On a segmented basis, depletion, depreciation and site restoration expense averaged $11.68 per boe in Canada and $19.44 per boe in Colombia in 2003.

Impairment Expense

A $16.9 million impairment expense related to Petrobank's Colombian ($15.0 million) and other international cost centres ($1.9 million) was recorded in the fourth quarter of 2003 as a result of applying the existing CICA Full Cost Guideline ceiling test rules. The Company will adopt the new CICA Full Cost Guideline in the first quarter of 2004. Application of the ceiling test calculation under the new guideline would not have resulted in an incremental write-down as at December 31, 2003.

Capital and Future Income Taxes

The Company acquired minimal tax pools with the Monolith corporate acquisition and, as a result, recorded a future tax liability of $12.0 million. Petrobank has also reflected an additional liability of $3.5 million associated with the issuance of $10.0 million of flow-through shares and the related renunciation of a similar amount of tax benefits to purchasers. In the fourth quarter the Company recorded a future tax recovery against these balances of $0.5 million in capital and future income taxes and $1.1 million as an offset to interest on subordinated notes. Petrobank does not anticipate a cash income tax liability in either Canada or Colombia for at least the next two years.

Tax Pools

As at December 31, 2003 ($millions)		
Canada		
Canadian development expense (30%)	$	36.0
Canadian exploration expense (100%)		14.0
Undepreciated capital costs (25%)		50.0
Non-capital losses carried forward (100%)		10.0
Other		5.0
Total Canadian tax pools		115.0
Colombia		88.0
Total tax pools	$	203.0

Interest on Subordinated Notes

Interest on subordinated notes of $8.4 million for 2003 was reflected net of a future tax recovery of $1.1 million. This expense increased from $6.1 million in 2002 as a result of the issuance of an additional $40.0 million of notes in May 2003.

Net Loss Attributable to Common Shareholders

A net loss attributable to common shareholders of $23.1 million or $0.48 per share was recorded in 2003, compared to a loss of $0.4 million or $0.01 per share in 2002. Despite improvements in production and operating netbacks, the loss expanded as a result of the $16.9 million impairment charge recorded in the fourth quarter, higher interest and depletion expenses, and increased general and administrative expenses.

Cash Flow from Operations

Cash flow from operations increased to $29.3 million in 2003 from $22.8 million in 2002, primarily due to higher production and operating netbacks offset somewhat by increased interest expense and general and administrative expenses.

Capital Expenditures

Consolidated capital expenditures net of property dispositions were $95.6 million in 2003, comprised of $24.3 million in Canada and $71.3 million in Colombia. Canadian expenditures were incurred primarily on the Company's Jumpbush and Western Saskatchewan properties and included $4.0 million of expenditures on Petrobank's THAI™/CAPRI™ heavy oil recovery technologies and the related WHITESANDS pilot project design. Colombian expenditures were focused on drilling, completions and workovers at Orito and to a lesser extent at Neiva. Capital activity in Colombia in the first quarter of 2004 is being substantially reduced as Petrobank takes a measured approach to assessing its most productive future drilling opportunities. Canadian activity in 2004 will focus on drilling new wells at the natural gas-prone properties of Jumpbush and Nevis/Red Willow.

Summary of Quarterly Results

	2003				2002			
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Financial								
($000s except where noted)								
Oil and natural gas revenue	**20,080**	**13,655**	**14,459**	**17,917**	12,892	12,208	13,173	12,185
Cash flow from operations	**8,701**	**5,842**	**6,185**	**8,530**	5,600	5,806	5,899	5,501
Per share - basic ($)	**0.12**	**0.08**	**0.09**	**0.16**	0.09	0.11	0.13	0.12
- diluted ($)	**0.12**	**0.08**	**0.09**	**0.15**	0.09	0.11	0.10	0.10
Net income (loss)	**(18,563)**	**(600)**	**935**	**3,537**	1,376	1,573	2,223	1,019
Net income (loss) attributable to common shareholders	**(20,343)**	**(3,425)**	**(1,363)**	**2,020**	(171)	(9)	465	(715)
Per share - basic and diluted ($)	**(0.37)**	**(0.07)**	**(0.03)**	**0.04**	-	-	0.01	(0.02)
Capital expenditures	**27,338**	**28,065**	**24,696**	**35,961**	28,620	5,813	4,882	6,913
Operations								
Canadian operating netback ($/boe except where noted)								
Oil and NGLs revenue ($/bbl)	**25.78**	**27.19**	**28.00**	**33.30**	31.27	32.74	30.98	29.48
Natural gas revenue ($/mcf)	**5.61**	**4.98**	**6.34**	**7.37**	5.09	3.63	3.99	3.21
Combined oil equivalent revenue	**29.72**	**27.92**	**31.29**	**37.64**	30.96	27.73	27.32	24.21
Royalties	**5.12**	**5.35**	**6.29**	**9.77**	6.78	5.97	6.02	4.76
Production expenses	**7.55**	**7.06**	**8.06**	**7.24**	7.78	6.55	6.24	6.31
Operating netback	**17.05**	**15.51**	**16.94**	**20.63**	16.40	15.21	15.06	13.14
Colombian operating netback ($/bbl)								
Oil revenue	**31.66**	**31.37**	**29.74**	**38.58**	-	-	-	-
Royalties	**2.53**	**2.44**	**2.40**	**3.09**	-	-	-	-
Production expenses	**15.62**	**9.24**	**7.93**	**6.09**	-	-	-	-
Operating netback	**13.51**	**19.69**	**19.41**	**29.40**	-	-	-	-
Average daily production								
Canada - oil and NGLs (bbls)	**2,931**	**2,909**	**2,758**	**2,757**	2,652	2,596	2,541	2,704
Canada - natural gas (mcf)	**17,702**	**6,581**	**8,057**	**10,920**	11,244	13,134	16,546	17,323
Total Canada (boe)	**5,881**	**4,005**	**4,101**	**4,577**	4,526	4,785	5,299	5,591
Colombia - oil (bbls)	**1,374**	**1,166**	**1,028**	**695**	-	-	-	-
Total Company (boe)	**7,255**	**5,171**	**5,129**	**5,272**	4,526	4,785	5,299	5,591

Major factors impacting quarterly results:

- Commenced oil sales from Colombian operations in January 2003.
- Issued additional subordinated notes in May 2003 for net proceeds of $34.4 million.
- Disposed of Zama/Larne property in Northwest Alberta in May 2003, which was producing approximately 700 boe per day (primarily natural gas), for proceeds of $16.6 million.
- Acquired Monolith on September 19, 2003 for $39.6 million; production from Monolith's properties averaged 2,325 boe per day between the closing date and year-end.
- Incurred a $16.9 million impairment charge relating to the Company's international properties in the fourth quarter of 2003.

Liquidity and Capital Resources

In 2003, Petrobank undertook several significant transactions, including debt and equity financings. The Company acquired Monolith for $39.6 million and incurred net capital expenditures of $95.6 million. These expenditures were financed with positive cash flow of $29.3 million, bank debt of $30.1 million, subordinated note proceeds of $34.4 million, common share proceeds of $27.8 million, and a debenture of $14.0 million.

The Company had the following contractual obligations as at December 31, 2003:

Type of Obligation ($000s)	Total	Less than 1 Year	1-3 Years
Bank debt	30,102	30,102	-
Debenture	14,014	14,014	-
Subordinated notes (face value)	100,438	-	100,438
Colombian work commitments	3,000	3,000	-
Office operating leases	1,280	550	730

The contractual commitments in Colombia reflect work commitments on the Neiva Block and need to be completed by June 2004. These commitments are required to preserve the Company's rights under the contract and will be funded from its credit facility and operating cash flows in Colombia. The debenture was fully repaid and the bank debt was partially repaid with the proceeds from the sale of Wapella in January 2004, leaving the Company with $115 million of net debt. The Company's bank facility currently has a borrowing capacity of $36.1 million.

Petrobank's capital expenditures in 2004 will be dependent on the Company's financial resources. The Company currently plans to allocate up to $40 million to the Canadian Business Unit, $20 million to Colombia and $30 million to the Heavy Oil Business Unit, totalling $90 million in 2004.

In its Colombia program the Company anticipates drilling up to four new wells, initiating a pilot waterflood at Orito and performing various facility modifications. This program can be expanded depending on initial results, which will be reviewed at each stage of the 2004 Colombian program to ensure incremental investments are only made when justifiable and in consideration of available financial resources.

The Canadian Business Unit's capital plan is focused on its core properties and is directed towards drilling wells that can be tied in and brought on production as quickly as possible following completion. Success will enhance the Company's borrowing capacity with its senior secured lender. Normally, Petrobank would anticipate financing approximately 50-60 percent of production-enhancing capital expenditures with increases in the borrowing base. In addition to conventional opportunities, the Canadian Business Unit has coalbed methane (CBM) potential at its Jumpbush and Princeton properties. The Princeton development will require more upfront capital than Jumpbush given its location and the nature of the reservoir. CBM projects will be difficult to finance with conventional debt until they have been proven commercial.

The Heavy Oil Business Unit will be focused on completion of final design and engineering for its THAI™ pilot project, with construction commencing in mid-2004 and first results expected in early 2005. The Company is pursuing a private equity financing in its wholly-owned subsidiary, WHITESANDS INSITU Ltd., to provide the estimated $30 million of funds necessary to complete the pilot. The Company has the ability to defer the initial stages of the pilot without significantly impacting the overall timing of completion, and will expose minimal amounts of capital to this project until financing is complete. Should the pilot be

successful, the Company would expect to start designing a commercial project in late 2005, requiring up to $400 million of capital over three years.

The Company does not have significant working capital requirements, and typically operates with a working capital deficiency by settling its vendor liabilities following collection of oil and gas revenues. This deficiency is considered by Petrobank's lender to be equivalent to debt for purposes of assessing remaining borrowing capacity.

The Company's Canadian credit facility is secured by all of the Company's assets in Canada and is due on demand by the lender. The lender periodically, and at least annually, assesses the amount of the borrowing base, which determines how much the Company can draw. The borrowing base is determined according to a number of factors, primarily the lender's commodity price outlook, the quantity of the Company's proved producing reserves and Petrobank's future production profile. The Company's only other outstanding debt is the subordinated notes, which are unsecured and place no financial covenants on the Company. The Company will need to raise additional capital to finance its currently contemplated 2004 capital program or defer projects as required.

Possible sources of funds available to Petrobank include the following.

- Management has been working on an additional credit facility secured by the Company's Colombian assets. The Company believes such a facility can be completed once Petrobank achieves Colombian production of 4,000 barrels per day net to the Company. Interest expense on such a facility would be 200-300 basis points per annum higher than that under the Canadian credit facility.
- Petrobank has the ability to issue incremental unsecured and subordinate debt. This could be an incremental offer of the subordinated notes currently outstanding, or other similar debt. The Company's ability to complete such an offering will depend on how much appetite exists in the capital markets for such debt. Management is not currently considering issuing incremental debt of this nature until production increases significantly.
- An alternative financing vehicle is pre-export financing or a pre-sale of a portion of future oil production in Colombia. Petrobank's contracts with Ecopetrol on the Orito and Neiva blocks specifically permit the export of oil and there is no requirement for such proceeds to be remitted to Colombia.
- Petrobank may issue common shares, with or without flow-through tax benefits. Flow-through shares allow the issuer to pass through oil and natural gas exploration tax expenditures (100 percent deductible) to the buyer. Typically, these shares attract a premium to existing market prices, but the amount that can be raised is limited to exploration expenditures incurred in Canada within a 12-24-month period following the issue. Following the flow-through share issue in 2003, Petrobank could only issue flow-through shares in 2004 for the amount of estimated exploration expenditures to be incurred in 2005. The maximum amount that could be raised is estimated to be $10 million in 2004.
- Petrobank may sell producing or non-producing assets to raise funds in the short term. Incremental cash resources generated as a result would be reduced by any resulting decreases in future cash flows and the borrowing base under Petrobank's secured credit facility.

Longer-term, a successful Colombian investment program would decrease the relative weighting of Canadian to non-Canadian assets, making it difficult to utilize traditional bank financing for Petrobank's capital programs. Unless Colombian credit becomes more easily accessible, the Company will need to rely more heavily on equity, internally-generated cash flow or other, non-traditional forms of financing.

Petrobank does not anticipate Colombian cash flows to exceed capital expenditures over the next 12-24 months. There are no legal restrictions on repatriating funds to Canada once excess net cash flows are achieved.

Management's plan for the remainder of 2004 is to marshal the Company's resources and invest in cash-generating projects. The intent is not to issue incremental subordinated debt and to live within the boundaries of borrowing base credit facilities for Canada and, possibly, Colombia. The challenge will be to retain and finance the portfolio of upside opportunities (WHITESANDS, Jumpbush and Princeton CBM, and Orito) during their capital-intensive phases while managing the health of the overall balance sheet. Given the Company's wealth of opportunities, it is likely an equity financing will be completed in the next 12-24 months.

Petrobank has completed all but US$2.0 million of its contractual commitments in Colombia, thereby reducing 2004 capital requirements compared to 2003 expenditures. Existing production in Colombia is not subject to significant declines. Canadian production, however, will require significant investment to offset declines in production.

Petrobank will be required to refinance its $100.4 million face value of subordinated notes before July 2006. Petrobank's ability to do so with new debt, and the cost of such debt, will depend on its ability to reduce its debt-to-cash-flow ratio, ideally below 2 to 1. Petrobank has time to increase production rates and cash flows sufficiently in advance of a re-financing period to make this an achievable goal. If Petrobank cannot refinance the subordinated notes with new debt, an incremental equity issue would likely be required.

Risks and Uncertainties

Petrobank is exposed to a variety of risks, including but not limited to competition, operations, political and regulatory changes, environmental liabilities and the ability to raise money to further investment and development of the Company's opportunities.

The oil and natural gas industry is highly competitive, particularly in regard to exploration for and development of new sources of crude oil and natural gas reserves. The competition for land and resources in western Canada is especially intense. Competitors include companies much larger than Petrobank, with greater access to financial resources. The Company's future success is driven in large part by its ability to find and exploit new oil and natural gas reserves at reasonable costs and reinvestment ratios. The process of evaluating prospects and estimating oil and natural gas reserves is complex and subject to significant uncertainty. Actual operating results including production performance will vary from those estimated, possibly materially. The Company manages these risks by maintaining a focused asset base with high working interests and by hiring qualified professionals, including independent reserve engineers, with appropriate industry experience.

Petrobank is exposed to a number of operational risks inherent in the industry including accidents, well blowouts, uncontrolled flows, and environmental risks. Operational risks are managed using prudent field operating procedures. The Company has a detailed emergency response plan to deal with potential incidents and maintains a comprehensive insurance program to reduce the risk of significant economic loss, but not all risks can be eliminated. Losses resulting from the occurrence of these risks could have a material adverse impact on the Company's operations.

Petrobank currently has operations in Canada and Colombia, and is evaluating additional projects internationally. To help mitigate the risks associated with operating in foreign jurisdictions, the Company seeks to operate in regions where the petroleum industry is a key component of the economy. Petrobank believes that management's experience operating both domestically and internationally helps reduce these risks. Some countries in which the Company may operate may be considered politically and economically unstable. However, in Colombia, the government has a long history of democracy and an established legal framework that, in Petrobank's opinion, minimize political risks.

Colombia has a publicized history of security issues associated with certain narco-terrorist groups. The Company and its personnel are subject to these risks but through effective security and social programs, Petrobank believes these risks can be effectively managed. It is difficult to obtain insurance coverage to protect against terrorist incidents and as a result the Company's insurance program excludes this coverage. Consequently, any such future incidents could have a material adverse impact on the Company's operations. The Company felt the impact of such an issue in November 2003 when narco-terrorists attacked Ecopetrol installations near and on Petrobank's block. The impact was a brief shutdown of the Company's production plus costs to make minor repairs and substantially recover previous well productivity. Petrobank's employees were not harmed in this incident.

The Company's WHITESANDS pilot project entails risks incremental to those of conventional oil and natural gas operations. Although other operators have utilized the individual processes involved in the pilot in the past, the pilot project's configuration of wells and processes is a new combination, and thus Petrobank is subject to certain unknown operational risks. Other risks associated with the Pilot include: the THAI™ technology will prove unsuccessful or commercially unviable; the cost of the Pilot will exceed management's initial estimates; and, unknown future regulatory or commodity market factors will make the technology uneconomic. However, management believes that the technology, if successful, would be a step change in heavy oil recovery technology and would address many of the existing risks and economic challenges currently facing the oil sands industry in Canada as well as international heavy oil projects.

The Company is subject to extensive governmental and environmental regulations in its operating jurisdictions. Changes to these regulations could increase the costs of conducting business in these jurisdictions. Environmental risks inherent in the oil and natural gas industry are subject to increasingly stringent legislation and regulation. The Company operates in accordance with all relevant environmental legislation and strives to minimize the environmental impact of its operations by providing for safety and environmental issues in all of its business plans.

Petrobank is exposed to normal financial risks inherent in the oil and natural gas industry including commodity price risk, exchange rate risk, interest rate risk and credit risk. The Company conducts its operations in a manner intended to minimize exposure to these risks, as described in Note 11 to the Consolidated Financial Statements.

Commodity prices are the Company's most significant financial risk. Crude oil prices are influenced by global supply and demand, OPEC policy, and worldwide political events. Natural gas prices in Canada are influenced primarily by North American supply and demand, and to a lesser extent by local market conditions. Fluctuations in commodity prices not only affect the Company's cash flows but may also result in changes to the borrowing capacity under Petrobank's credit facility as assessed by the Company's lender. Management believes it is neither appropriate nor possible to eliminate 100 percent of the Company's exposure to fluctuations in commodity prices. The Company continuously monitors market conditions and selectively utilizes derivative instruments to reduce exposure to commodity price movements.

To the extent revenues and expenditures denominated in or strongly linked to the US dollar are not equivalent, the Company is exposed to exchange rate risk. Revenues in Canada are largely determined by a US dollar reference price. In Colombia, the Company is exposed to the extent US dollar revenues do not equal US dollar expenditures. In addition, a portion of expenditures in Colombia is denominated in Pesos, which are difficult to hedge. The Company is not currently using exchange rate derivatives to manage these risks in Colombia.

Petrobank is exposed to fluctuations in short-term interest rates on amounts drawn under its floating-rate bank facility. The Company has not hedged these rates given the need to remain flexible in borrowing and repaying the balance. The majority of the Company's debt is the subordinated notes which pay a fixed nine percent interest rate and as such minimize Petrobank's exposure to interest rate risk.

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 expected impact on cash flow resulting from the following factors are as follows:

($ millions)		
Change of:		
Crude oil	- US$1.00/bbl WTI reference price	$ 0.6
	- 100 bbls per day in Canadian production @ US$30/bbl WTI	$ 0.7
	- 100 bbls per day in Colombian production @ US$30/bbl WTI	$ 0.8
Natural gas	- US$0.50/mmbtu NYMEX reference price [1]	$ 2.6
	- 1.0 mmcf per day production @ US$5.50/mmbtu	$ 1.6
Currency	- $0.01 in Cdn$/US$ exchange rate	$ 0.7
Interest rates	- 1% with $30 million drawn on credit facility	$ 0.3

(1) Assumes the natural gas price fluctuates between AECO $5.00 and $5.94 per GJ.

Transactions with Related Parties

In July 2003, the Company acquired the THAI™ and CAPRI™ patented heavy oil recovery technologies indirectly from two directors of the Company (John D. Wright and M. Bruce Chernoff) and a third party pursuant to an agreement made by an independent committee of the Board of Directors. Mr. Chernoff recovered his $226,000 investment and Mr. Wright received cash of $189,000 on his $226,000 investment and retained a 7.5 percent net profits interest in any future third-party (non-Petrobank) licensing royalties generated from the technologies. Petrobank is required to take steps to commence a pilot project by the end of November 2004 in order to retain its rights to the THAI™ and CAPRI™ technologies. Petrobank plans to commence this pilot test of the THAI™ technology through Petrobank's subsidiary, WHITESANDS INSITU Ltd.

In January 2004, the Company paid a $200,000 commitment fee to secure a $10 million credit facility from a company controlled by a director of Petrobank (M. Bruce Chernoff). Any balances outstanding under the facility would bear interest at 12 percent per annum and would be subordinate to Petrobank's existing secured bank debt. The Company negotiated this credit facility to increase it financial flexibility and to carry out capital projects and/or acquisitions during 2004. To date, the Company has not drawn on this facility, which expires on December 30, 2004.

Critical Accounting Policies and Estimates

The Company's financial statements have been prepared in accordance with Canadian GAAP, which require management to make judgments, estimates and assumptions, which may have a significant impact on the financial statements. A summary of the Company's significant accounting policies can be found in Note 2 to the Consolidated Financial Statements. The following is a discussion of those accounting policies and estimates that are considered critical in the determination of the Company's financial results.

Full Cost Accounting

Under Canadian GAAP, the Company has two alternatives in accounting for oil and natural gas activities: the full cost and the successful effort methods of accounting. The Company follows the full cost method of accounting for oil and natural gas activities, whereby all costs related to the acquisition of oil and natural gas properties are capitalized. Such costs include land and lease acquisition costs, annual charges on non-producing properties, geological and geophysical costs, and costs of drilling and equipping productive and non-productive wells. Under the successful efforts method of accounting, all costs related to non-productive wells are expensed in the period in which they are incurred.

Under the full cost method of accounting, capitalized costs are subject to a country-by-country cost centre impairment test. Under the successful efforts method of accounting, the costs are aggregated on a property-by-property basis and the carrying value of each property is subject to an impairment test. These policies may result in a different carrying value for capital assets and a different net income.

Reserve estimates can have a significant impact on net income and the carrying value of capital assets. The process of estimating reserves requires significant judgment based on available geological, geophysical, engineering, and economic data, projected rates of production, estimated commodity price forecasts and the timing of future expenditures, all of which are subject to interpretation and uncertainty. Reserve estimates impact net income through depletion expense and the application of impairment tests. Revisions or changes in reserve estimates can have either a positive or a negative impact on net income and can impact the carrying amount of capital assets.

Reserve estimates are also used by Petrobank's lender to assess the borrowing base under its secured bank credit facility. Changes to the reserve estimates can result in borrowing base increases or decreases, which may impact the Company's financial position.

Changes in Accounting and Regulatory Policies

Standards of Disclosure for Oil and Gas Activities

Effective September 30, 2003 the Canadian Securities Administrators implemented National Instrument (NI) 51-101, "Standards of Disclosure for Oil and Gas Activities". NI 51-101 is effective for year-ends beginning December 31, 2003. The instrument imposes more standardized and conservative guidelines for reserve estimates. Definitions for disclosure of reserves, net asset value, netbacks and finding and development costs are also provided in the instrument. Petrobank's Canadian total proved reserves were impacted through a five percent negative revision along with conservative reserve additions being attributed to 2003 drilling activities, particularly where there is a relatively short history of production. Colombian total proved revisions amounted to 30 percent of their opening balance, contributing largely to the 2003 impairment charge. Lower proved reserves estimates resulted in increased depletion expense in 2003 and will similarly impact future periods.

Full Cost Accounting Guideline

The Canadian Institute of Chartered Accountants ("CICA") issued Accounting Guideline 16, "Full Cost Accounting" for years beginning on or after January 1, 2004. The new guideline updates reserve definitions to include the standards of NI 51-101, and has modified how the ceiling test is performed, which requires that cost centres be tested for recoverability using undiscounted future cash flows from proved reserves which are determined by using expected future prices. When the carrying amount of a cost centre is not recoverable, the cost centre would be written down to its estimated fair value, calculated based on the future discounted value of proved plus probable reserves. The guideline also sets standards for presentation and disclosure under full-cost accounting. Petrobank is prospectively adopting this guideline on January 1, 2004. The adoption of the guideline is not expected to impact the Company's reported financial results other than additional required disclosure.

Asset Retirement Obligations

In December 2002 the CICA issued Handbook Section 3110, "Asset Retirement Obligations". This standard requires that the fair value of an asset retirement obligation be recognized in the period in which it is incurred. The estimate of fair value is capitalized and depreciated on the same basis as the related capital assets. The standard is effective for all fiscal years beginning on or after January 1, 2004 and will be retroactively adopted by the Company at that date. Had this standard been adopted in 2003, the impact would have been an increase in long-term liabilities of $5.7 million, in capital assets of $3.5 million in net loss attributable to common shareholders of $0.2 million and a decrease in opening retained earnings of $2.0 million.

Stock-Based Compensation

In September 2003 the CICA amended Handbook section 3870, "Stock-Based Compensation and Other Stock-Based Payments". This standard requires that an option-pricing model be used to determine the fair value of each option granted and that the amount be expensed over the vesting period of the option. Previously, the Company used the intrinsic value method to account for such compensation, which

resulted in no expense being recognized in the Company's financial statements. The Company early-adopted this standard in 2003, the impact of which has been disclosed in Note 8 to the Consolidated Financial Statements.

Hedging Relationships

The CICA published an amended Accounting Guideline 13, "Hedging Relationships", effective January 1, 2004, to clarify circumstances in which hedge accounting is appropriate. All derivative instruments that do not qualify as a hedge under the guideline, or are not properly designated as a hedge, will be recorded on the balance sheet as either an asset or liability with changes in fair value recognized in earnings. Upon adoption on January 1, 2004, the standard is not expected to impact Petrobank's financial results.

Subordinated Notes

The Company's subordinated notes are currently reflected as equity on the balance sheet and the interest thereon is excluded from the determination of net income as the Company has the option to issue common shares to settle both interest and principal payments. The CICA recently issued an Exposure Draft that, when implemented, will require securities such as Petrobank's subordinated notes to be presented as liabilities. This revision will become effective for all fiscal years beginning on or after November 1, 2004.

Continuous Disclosure Obligations

The Canadian Securities Administrators issued NI 51-102, "Continuous Disclosure Obligations", effective for interim MD&A disclosures for the quarter ending March 31, 2004. The instrument outlines enhanced requirements for disclosure in annual and interim financial statements, MD&A and the Annual Information Form ("AIF"). The instrument also proposes shorter reporting deadlines for annual and interim financial statements, MD&A and the AIF. The MD&A disclosures required by NI 51-102 have been adopted by Petrobank for the year ended December 31, 2003.

Outlook

Please see the Letter from the President and the Review of Operations for a discussion of the Company's future business prospects.



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OFFICE OF INTERNATIONAL
CORPORATE FINANCE

Notice of Annual and Special Meeting of Shareholders
to be held on June 17, 2004

The annual and special meeting of the shareholders of Petrobank Energy and Resources Ltd. will be held on Thursday, June 17, 2004 at 3:00 p.m. (Calgary time) in the Grand Lecture Theatre of the Metropolitan Conference Centre, 333 – 4th Avenue S.W., Calgary, Alberta to:

1. receive and consider our financial statements for the year ended December 31, 2003, together with the report of the auditors;

2. fix the number of directors to be elected at the meeting at 7 members;

3. elect 7 directors;

4. appoint the auditors and to authorize the directors to fix their remuneration as such;

5. consider, and if thought fit, pass an ordinary resolution of shareholders to approve certain amendments to our stock option plan, all as more particularly set forth in the Information Circular – Proxy Statement accompanying this notice;

6. consider, and if thought fit, pass an ordinary resolution of disinterested shareholders to approve the terms and conditions of a deferred share unit plan;

7. consider, and, if thought fit, pass an ordinary resolution to approve future private placements by the Corporation; and

8. transact such other business as may properly be brought before the meeting or any adjournment thereof.

The specific details of the matters proposed to be put before the meeting are set forth in the information circular - proxy statement accompanying this notice.

If you are unable to attend the meeting in person we request that you date and sign the enclosed form of proxy and mail it to or deposit it with our Secretary, c/o Computershare Trust Company of Canada, Proxy Department, 9th Floor - 100 University Avenue, Toronto, Ontario, M5J 2Y1. In order to be valid and acted upon at the meeting, forms of proxy must be returned to the aforesaid address not less than 48 hours (excluding Saturdays, Sundays and holidays) before the time for holding the meeting or any adjournment thereof.

Only shareholders of record at the close of business on May 14, 2004 will be entitled to vote at the meeting, unless that shareholder has transferred any shares subsequent to that date and the transferee shareholder, not later than 10 days before the meeting, establishes ownership of the shares and demands that the transferee's name be included on the list of shareholders.

DATED at Calgary, Alberta this May 14, 2004.

By order of the board of directors
(signed) *"John D. Wright"*
John D. Wright
President and Chief Executive Officer

PETROBANK
ENERGY AND RESOURCES LTD.

Information Circular - Proxy Statement
for the Annual and Special Meeting to be held on June 17, 2004

PROXIES

Solicitation of Proxies

This information circular - proxy statement is furnished in connection with the solicitation of proxies for use at our annual and special meeting of the shareholders to be held on Thursday, June 17, 2004 at 3:00 p.m. (Calgary time) in the Grand Lecture Theatre of the Metropolitan Conference Centre, 333 – 4th Avenue S.W., Calgary, Alberta and at any adjournment thereof. Forms of proxy must be addressed to and reach our Secretary, c/o Computershare Trust Company of Canada, Proxy Department, 9th Floor - 100 University Avenue, Toronto, Ontario, M5J 2Y1, not less than 48 hours before the time for holding the meeting or any adjournment thereof. Only shareholders of record at the close of business on May 14, 2004 will be entitled to vote at the meeting, unless that shareholder has transferred any shares subsequent to that date and the transferee shareholder, not later than 10 days before the meeting, establishes ownership of the shares and demands that the transferee's name be included on the list of shareholders.

The instrument appointing a proxy must be in writing and must be executed by you or your attorney authorized in writing or, if you are a corporation, under your corporate seal or by a duly authorized officer or attorney of the corporation.

The persons named in the enclosed form of proxy are our officers. As a shareholder you have the right to appoint a person, who need not be a shareholder, to represent you at the meeting. To exercise this right you should insert the name of the desired representative in the blank space provided on the form of proxy and strike out the other names or submit another appropriate proxy.

Advice to Beneficial Holders of Common Shares

The information set forth in this section is of significant importance to you if you do not hold your common shares in your own name. Only proxies deposited by shareholders whose names appear on our records as the registered holders of common shares can be recognized and acted upon at the meeting. If common shares are listed in your account statement provided by your broker, then in almost all cases those common shares will not be registered in your name on our records. Such common shares will likely be registered under the name of your broker or an agent of that broker. In Canada, the vast majority of such shares are registered under the name of CDS & Co., the registration name for The Canadian Depository for Securities Limited, which acts as nominees for many Canadian brokerage firms. Common shares held by your broker or their nominee can only be voted upon your instructions. Without specific instructions, your broker or their nominee is prohibited from voting your shares.

Applicable regulatory policy requires your broker to seek voting instructions from you in advance of the meeting. Every broker has its own mailing procedures and provides its own return instructions, which you should carefully follow in order to ensure that your shares are voted at the meeting. Often, the form of proxy supplied by your broker is identical to the form of proxy provided to registered shareholders. However, its purpose is limited to instructing the registered shareholder how to vote on your behalf. The majority of brokers now delegate responsibility for obtaining instructions from clients to the ADP Investor Communications. The ADP Investor Communications mails a scannable voting instruction form in lieu of the

form of proxy. You are asked to complete and return the voting instruction form to them by mail or facsimile. Alternately, you can call their toll-free telephone number to vote your shares. They then tabulate the results of all instructions received and provide appropriate instructions respecting the voting of shares to be represented at the meeting. If you receive a voting instruction form from ADP Investor Communications it cannot be used as a proxy to vote shares directly at the meeting as the proxy must be returned to ADP Investor Communications well in advance of the meeting in order to have the shares voted.

Revocability of Proxy

You may revoke your proxy at any time prior to the meeting. If you or the person you give your proxy to attends personally at the meeting you or such person may revoke the proxy and vote in person. In addition to revocation in any other manner permitted by law, a proxy may be revoked by an instrument in writing executed by you or your attorney authorized in writing or, if you are a corporation, under your corporate seal or by a duly authorized officer or attorney of the corporation. To be effective the instrument in writing must be deposited either at our head office at any time up to and including the last business day before the day of the meeting, or any adjournment thereof, at which the proxy is to be used, or with the chairman of the meeting on the day of the meeting, or any adjournment thereof.

Persons Making the Solicitation

This solicitation is made on behalf of our management. We will bear the costs incurred in the preparation and mailing of the form of proxy, notice of annual and special meeting and this information circular - proxy statement. In addition to mailing forms of proxy, proxies may be solicited by personal interviews, or by other means of communication, by our directors, officers and employees who will not be remunerated therefor.

Exercise of Discretion by Proxy

The common shares represented by proxy in favour of management nominees will be voted on any poll at the meeting. Where you specify a choice with respect to any matter to be acted upon the shares will be voted on any poll in accordance with the specification so made. If you do not provide instructions your shares will be voted in favour of the matters to be acted upon as set out herein. The persons appointed under the form of proxy which we have furnished are conferred with discretionary authority with respect to amendments or variations of those matters specified in the form of proxy and notice of annual and special meeting and with respect to any other matters which may properly be brought before the meeting or any adjournment thereof. At the time of printing this information circular - proxy statement, we know of no such amendment, variation or other matter.

VOTING SHARES AND PRINCIPAL HOLDERS THEREOF

We are authorized to issue an unlimited number of common shares without nominal or par value and an unlimited number of preferred shares issuable in series. As at April 30, 2004, there were 54,651,396 common shares and no preferred shares issued and outstanding. Holders of common shares are entitled to one vote for each share held.

To the knowledge of our directors and officers, as at April 30, 2004, no person or company beneficially owns, directly or indirectly, or exercises control or direction over, more than 10% of the voting shares other than Dean's Knight Capital Management Ltd. and Joint Actors who exercise control over 15.6% of the voting shares.

As at April 30, 2004, our directors and officers, as a group, beneficially owned, directly or indirectly, or exercised control over 11,270,204 common shares or 20.6% of the issued and outstanding common shares.

MATTERS TO BE ACTED UPON AT THE MEETING

ANNUAL BUSINESS

Consolidated Financial Statements and Auditors' Report

The audited consolidated financial statements of the Corporation for the year ended December 31, 2003 and the Auditors' Report thereon, as included in the 2003 Annual Report, will be received at the Meeting.

Election of Directors

At the meeting, the shareholders will be asked to fix the number of directors to be elected at the meeting at 7 members and to elect 7 directors. The nominees will hold office until the next annual general meeting or until their successors are elected or appointed.

Management is soliciting proxies, in the accompanying form of proxy, for an ordinary resolution in favour of fixing the board of directors at 7 members, and in favour of the election as directors of the 7 nominees set forth below:

John A. Brussa
M. Bruce Chernoff
Louis L. Frank
Kenneth R. McKinnon
Jerald L. Oaks
James D. Tocher
John D. Wright

In the event that a vacancy among such nominees occurs because of death or for any reason prior to the meeting, the proxy shall not be voted with respect to such vacancy.

The names and municipalities of residence of all of the persons nominated for election as directors, the approximate number of common shares beneficially owned, directly or indirectly, or over which control or direction is exercised, by each of them, the dates on which they became directors, and their principal occupations, as of April 30, 2004, were as follows:

Name of Nominee, Municipality of Residence and Position	Number of Common Shares Beneficially Owned or Controlled	Director Since	Principal Occupation
John A. Brussa [(1)/(3)] Calgary, Alberta Director	226,333	March 14, 2000	Barrister and Solicitor; Partner of Burnet, Duckworth & Palmer LLP.
M. Bruce Chernoff [(1)/(2)/(3)] Calgary, Alberta Director	2,802,041	March 14, 2000	President and Director of Caribou Capital Corp. (a private investment management company).
Louis L. Frank North Woodstock, New Hampshire Director	805,068	September 27, 1993	Independent Consultant, Director and Founder of Loon Mountain Recreation Corp.; President of Recco Inc. (a private oil and gas development and real estate development company).

Kenneth R. McKinnon Calgary, Alberta Corporate Secretary and Director	168,399	March 14, 2000	Vice President Legal Affairs and General Counsel of Critical Mass Inc. (a private marketing company).
Jerald L. Oaks [(1)/(2)] Englewood, Colorado Director	407,000	September 27, 1993	Professional Engineer, President of Oaks Resources Management Inc. (a private petroleum engineering and management company).
James D. Tocher [(2)/(3)] Calgary, Alberta Chairman of the Board	3,259,961	October 8, 1992	Chairman of the Board of the Corporation, and Chairman of the Board of VX Technologies Corp. (a private technology company).
John D. Wright Calgary, Alberta President, Chief Executive Officer and Director	3,502,415	March 14, 2000	President and Chief Executive Officer of the Corporation.

Notes:

(1) Member of the Audit Committee.
(2) Member of the Reserves Committee.
(3) Member of the Compensation Committee.
(4) The Corporation does not have an executive committee of its members.

The information as to voting securities beneficially owned, directly or indirectly, is based upon information furnished to the Corporation by the nominees.

Appointment of Auditors

Management is soliciting proxies, in the accompanying form of proxy, in favour of the appointment of the firm of Deloitte & Touche LLP, Chartered Accountants, as our auditors, to hold office until the next annual meeting of the shareholders and to authorize the directors to fix their remuneration as such.

SPECIAL BUSINESS

Amendments to Stock Option Plan

Shareholders will also be asked at the meeting to consider and, if thought fit, pass an ordinary resolution to approve certain amendments to our stock option plan (the "Plan"). The Plan, in its current form, was last ratified by the shareholders on May 22, 2003.

As at the date hereof, the Plan, as previously adopted by the Board and approved by the shareholders, provides that the aggregate number of common shares issuable under the Plan not exceed 4,552,665 common shares. The approval of shareholders is required to be obtained if the number of common shares which can be issued under the Plan is increased.

As at the date hereof, options to purchase 3,621,001 common shares are presently outstanding under the Plan, representing approximately 6.6% of the common shares outstanding. The Board of Directors is proposing to increase the maximum number of common shares which may, from time to time, be issued under

the Plan from 4,552,665 to 4,960,000 common shares, subject to regulatory and shareholder approval. This amendment will permit the granting of additional options to acquire 1,338,999 common shares in accordance with the Plan. The effect of the increase in the maximum number of common shares issuable pursuant to the Plan as aforesaid is that the number of additional common shares which will be available for the grant of options (1,338,999 options) together with the number of options which have been granted and are outstanding (3,621,001 options) will represent 9.1% of our outstanding common shares.

The Board of Directors has determined that the increase is necessary in order to ensure that a sufficient number of stock options are available under the Plan to provide the Corporation with the ability to attract, retain and reward officers, directors and employees of the Corporation, and its subsidiaries, through the use of a competitive share compensation program.

In accordance with the policies of the TSX, the proposed amendment to the Plan must be approved by a majority of votes cast at the Meeting. Accordingly, at the Meeting, shareholders will be asked to consider and, if thought advisable, to approve an ordinary resolution, substantially in the following form:

"BE IT RESOLVED AS AN ORDINARY RESOLUTION THAT:

1. the amendment of the share option plan of Petrobank Energy and Resources Ltd. (the "Corporation") on the terms described in the information circular – proxy statement dated May 14, 2004, be and the same is hereby ratified, confirmed and approved;

2. any officer or director of the Corporation be and is hereby authorized for and on behalf of the Corporation (whether under its corporate seal or otherwise) to execute and deliver an amendment to the stock option plan and all other documents and instruments and to take all such other actions as such officer or director may deem necessary or desirable to implement this resolution and the matters authorized hereby, such determination to be conclusively evidenced by the execution and delivery of such documents and other instruments or the taking of any of such actions; and

3. notwithstanding that this resolution has been duly passed by the shareholders of the Corporation, the proposed amendment to the stock option plan is conditional upon receipt of final approval from the TSX and the directors of the Corporation are hereby authorized and empowered to revoke this resolution, without any further approval of the shareholders of the Corporation, at any time if such revocation is considered necessary or desirable by the directors."

Unless otherwise directed, the persons named in the enclosed form of proxy intend to vote the proxies in favour of the resolution referred to above.

Adoption of Deferred Compensation Plan

Shareholders will be asked at the Meeting to consider and, if thought fit, ratify and approve a deferred compensation plan (the "Deferred Share Compensation Plan") and the issuance of common shares pursuant to the Deferred Share Compensation Plan.

On March 30, 2004, the Board approved the adoption of the Deferred Share Compensation Plan in order to provide effective incentives for the directors, officers and employees of the Corporation to promote the success and business of the Corporation and to reward such directors, officers and employees in relation to the long term performance and growth of the Corporation by encouraging ownership of common shares of the Corporation.

There are two components to the Deferred Share Compensation Plan: (i) a deferred grant to directors of the Corporation of such number of common shares per calendar year which is approved by the Board from time to time; and (ii) a deferred grant to officers and employees of the Corporation who are

approved by the Board of such number of common shares per calendar year as is approved by the Board. Compensation is payable pursuant to the Deferred Share Compensation Plan in the form of a deferred grant of common shares.

A director, officer or employee of the Corporation will not be entitled to elect to be issued any of the common shares which he or she has been granted until a period of three years has passed since the date of grant of such common shares or until the director, officer or employee ceases to be a director, officer or employee of the Corporation, whichever is earlier. Common shares which a director, officer or employee is entitled to receive pursuant to the Deferred Share Compensation Plan will not be issued until the director, officer or employee has delivered to the Corporation an election in writing that the common shares be issued together with payment to the Corporation in the amount of $0.05 for each Common Share issued. A director, officer or employee shall have no right to receive common shares granted to him or her which have not been issued on the date that is ten years following the date of grant.

The Deferred Share Compensation Plan provides that the number of common shares that are issuable to a director, officer or employee pursuant to the Deferred Share Compensation Plan shall be increased on each date on which a cash dividend is paid to Shareholders by an amount equal to the product of the number of the common shares which remain issuable and the fraction which has as its numerator the cash dividend paid, expressed as an amount per Common Share and which has as its denominator the weighted average trading price of common shares on the Toronto Stock Exchange for the ten trading days preceding the record date for such dividend.

Subject to the receipt of all regulatory approvals, including, without limitation, the approval of the TSX and subject to the receipt of the approval of disinterested Shareholders at this Meeting, the Deferred Share Compensation Plan will be effective January 1, 2004.

The total number of common shares issuable pursuant to the Deferred Share Compensation Plan, subject to adjustment in accordance with the Deferred Share Compensation Plan, including adjustments for cash dividends paid on the common shares, shall not exceed 500,000 common shares. As at the date hereof, there have been no grants made under the Deferred Share Compensation Plan.

A copy of the Deferred Share Compensation Plan is attached hereto as Schedule "A".

At the Meeting, Shareholders will be asked to consider and, if thought fit, to approve the following resolution of disinterested Shareholders to approve the adoption of the Deferred Share Compensation Plan:

> "BE IT RESOLVED as an ordinary resolution of the Shareholders of Petrobank Energy and Resources Ltd. that the Deferred Share Compensation Plan, substantially in the form attached to and as more particularly described in Petrobank Energy and Resources Ltd.'s Information Circular – Proxy Statement dated May 14, 2004, including the issuance of common shares pursuant thereto be and the same is hereby ratified, approved and authorized."

The Board believes that the above resolution is in the best interests of the Corporation and recommends that Shareholders vote in favour of the resolution.

In order for the foregoing resolution to be passed, it must be approved by a simple majority of the votes cast by Shareholders who vote in person or by proxy at the Meeting, excluding votes attaching to common shares beneficially owned by the directors, officers and employees of the Corporation as well as "associates" (as such meaning is defined in the *Securities Act* (Ontario)) of such persons. At the Meeting, the scrutineers will be directed to exclude votes on this resolution by the directors, officers and employees of the

Corporation and their associates, which persons hold, to the Corporation's knowledge, an aggregate of 11,721,058 Common Shares.

The persons named in the instrument of proxy furnished by the Corporation intend, unless otherwise directed, to vote in favour of the resolution approving the Deferred Share Compensation Plan and the issuance of common shares pursuant thereto.

Future Private Placements

The policies of the TSX provide that the aggregate number of shares of a listed corporation which are issued or made subject to issuance by way of one or more private placement transactions during any particular six month period (the "TSX 25% Rule") may not exceed 25% of the number of shares outstanding at the beginning of the aforesaid six month period without first receiving the approval of the shareholders of the listed corporation on such terms and conditions as the TSX may impose in respect of securing such approval.

The TSX will accept advance approval by shareholders in anticipation of private placements that may exceed the TSX 25% Rule provided such private placements are completed within twelve months of the date such advance shareholder approval is given

Equity financing is one of the primary sources of capital presently available and anticipated to be available to the Corporation over the next year. In order to raise funds necessary to carry on current activities and fund future acquisition and development opportunities, we may need to raise additional equity. Management considers that it is in the best interests of Petrobank to obtain advance approval from its shareholders due to the possibility of entering into private placements that may exceed the TSX 25% Rule. Accordingly, the Corporation wishes to present to shareholders a proposal to proceed with additional private placements over the next twelve months in excess of the TSX 25% Rule. Obtaining advance approval should obviate the necessity of securing further shareholder approval for each specific private placement and will thus reduce the time required to obtain regulatory approval therefor. This in turn should decrease Petrobank's administrative costs relating to such private placements and should allow greater flexibility to facilitate the raising of additional capital.

The Corporation's issued and outstanding share capital is 54,651,396 common shares as at May 14, 2004. Accordingly, the Corporation proposes that the maximum number of common shares which either would be issued or made subject to issuance under one or more private placements in the twelve month period commencing June 17, 2004 would not exceed 54,651,396 common shares in the aggregate, or approximately 100% of the Corporation's issued and outstanding common shares.

Any private placement(s) proceeded with by Petrobank in reliance on the advance approval sought at the Meeting will be subject to the following additional restrictions:

(a) it must be substantially with parties who are at arm's length to Petrobank;

(b) it cannot materially affect control of Petrobank;

(c) it must be completed within a twelve month period following the date the shareholder approval is given; and

(d) it must comply with the private placement pricing rules of the TSX, which currently require that the issued price per common share must not be lower than the closing market price of the common shares on the TSX on the trading date prior to the date notice of the private placement is given to the TSX (the "Market Price"), less the applicable discount, as follows:

Market Price	Maximum Discount
$0.50 or less	25%
$0.51 to $2.00	20%
over $2.00	15%

(for these purposes, a private placement of unlisted convertible securities is deemed to be a private placement of the underlying listed securities at an issue price equal to the lowest possible price at which the securities are convertible by holders thereof).

In any event, the TSX retains the discretion to determine whether or not a particular private placement is substantially at arm's length or will materially affect control, in which case, the TSX may require specific shareholder approval for any particular private placement.

In anticipation that Petrobank may wish to enter into one or more private placements to be completed within 12 months of the date of the meeting and such placements may result in the issuance of a number of common shares or securities convertible into common shares equal to 100% of the number of common shares currently outstanding, Petrobank requests that shareholders approve the following ordinary resolution:

> "BE IT RESOLVED that the issuance by the Corporation in one or more private placements during the twelve month period commencing June 17, 2004 of up to 54,651,396 common shares, as more particularly described in and subject to the restrictions described in the Corporation's Information Circular – Proxy Statement dated May 14, 2004, be and is hereby approved."

The directors of Petrobank believe the passing of the foregoing resolution is in the best interests of Petrobank, since it will give Petrobank additional flexibility in accessing capital markets on a timely basis. In order for the foregoing resolution to be passed, it must be approved by a simple majority of the votes cast by shareholders who vote in person or by proxy at the Meeting. The persons named in the enclosed form of proxy, if named as proxy, intend to vote for the approval of the foregoing resolution.

EXECUTIVE COMPENSATION

Summary Compensation Table

The following table sets forth all annual and long-term compensation paid in respect of the individuals who, as at the most recently completed financial year ended December 31, 2003, meet the requirements to be classified as "Named Executive Officers" of the Corporation pursuant to the *Securities Act* (Ontario).

Name and Principal Positions	Year	Annual Compensation			Long-Term Compensation	All Other Compensation ($)
		Salary ($)	Bonus ($)	Other Annual Compensation ($) [1]	Securities Under Options Granted (#)	
JOHN D. WRIGHT	2003	150,000	-	-	-	-
President, Chief	2002	-	-	15,238	350,000[3]	-
Executive Officer and Director [2]	2001	-	-	12,966	-	-
CHRIS J. BLOOMER	2003	156,250	-	-	187,500	-
Vice President Heavy Oil	2002	-	-	-	-	-
and Chief Financial Officer [4]	2001	-	-	-	-	-
GARRY T. HIDES	2003	133,750	-	-	-	-
Vice President Land	2002	130,000	20,000	-	150,000	-
	2001	118,333	9,167	-	-	-
RENE J. LAPRADE	2003	145,625		-	-	-
Vice President Operations	2002	140,000	20,000	-	50,000	-
	2001	149,333 [5]	3,000	-	200,000	-
DAVID J. RAIN	2003	135,000	-	-	-	-
Vice President Finance	2002	115,000	20,000	-	250,000[3]	-
and Chief Financial Officer [6]	2001	105,000	12,500	-	-	-

Notes:

(1) The value of perquisites and other personal benefits received by these Named Executive Officers was not greater than the lesser of $50,000 and 10% of the total annual salary paid to them in the years in question other than for Mr. Wright in 2001 and 2002 when he received no salary. Other Annual Compensation for Mr. Wright includes employee share ownership plan contributions and parking.

(2) Mr. Wright's employment contract provides for a payment of $180,000 in the event his employment contract is terminated by Petrobank or in the event of a change of control of the Corporation. Effective March 1, 2003 Mr. Wright's salary was adjusted from nil to $180,000 per annum.

(3) Neither Mr. Wright nor Mr. Rain had been granted any other stock options by the Corporation in the past. Messrs. Wright and Rain agreed to the cancellation of these stock options in April 2003.

(4) Mr. Bloomer's employment contract provides for a payment equal to 12 months salary in the event his employment contract is terminated by Petrobank or in the event of a change of control of the Corporation.

(5) Includes consulting fees paid to Mr. Laprade. Mr. Laprade was appointed Vice President Operations of Petrobank in October 2001.

(6) Mr. Rain resigned March 31, 2004.

No long-term compensation was paid to the "Named Executive Officers" in the form of restricted share awards or long-term incentive plan payouts during the years ended December 31, 2003, 2002 and 2001.

Long-Term Incentive Plans – Option Grants During the Year Ended December 31, 2003

The following table sets forth, with respect to each of the Named Executive Officers, details regarding stock options granted during the year ended December 31, 2003.

Name	Securities Under Options Granted (#)	% of Total Options Granted to Employees in Financial Year	Exercise or Base Price ($/Security)	Market Value of Securities Underlying Options on the Date of Grant ($/Security)	Expiration Date
John D. Wright	Nil	-	-	-	-
Chris J. Bloomer	187,500	13.7%	$3.40	$3.40	January 3, 2008
Garry T. Hides	Nil	-	-	-	-
Rene J. Laprade	Nil	-	-	-	-
David J. Rain	Nil	-	-	-	-

Aggregated Option Exercises During the Year Ended December 31, 2003 and Year-End Option Values

The following table sets forth, with respect to each of the Named Executive Officers, the number of stock options exercised and the aggregate value realized on exercise during 2003 and the number of unexercised stock options and the value of in-the-money stock options at December 31, 2003.

Name	Securities Acquired on Exercise (#)	Aggregated Value Realized[1] ($)	Unexercised Stock Options at Year-End Exercisable/Unexercisable (#)	Value of Unexercised in-the-Money Stock Options at Year-End [2] Exercisable/Unexercisable ($)
John D. Wright	Nil	Nil	Nil/Nil	Nil/Nil
Chris J. Bloomer	Nil	Nil	Nil/187,500	Nil/Nil
Garry T. Hides	50,000	45,900	87,500/112,500	172,500/33,750
Rene J. Laprade	62,500	111,500	87,500/100,000	99,250/110,000
David J. Rain	Nil	Nil	Nil/Nil	Nil/Nil

Notes:

(1) Based upon market value of the common shares at exercise, less the exercise price.
(2) Based on the closing price of the Corporation's common shares on December 31, 2003 of $2.80, less the exercise price.

COMPENSATION COMMITTEE REPORT ON EXECUTIVE COMPENSATION

Composition of the Compensation Committee

The members of the Compensation Committee are John A. Brussa, M. Bruce Chernoff and James D. Tocher. No member of the Compensation Committee is employed by the Corporation or its affiliates. The Compensation Committee is charged with the establishment and periodic review of our compensation philosophy, the compensation and performance standards for the Chief Executive Officer and the other executive officers and the approval of executive compensation disclosure.

Compensation Committee Report on Compensation

TO: the Shareholders of Petrobank Energy and Resources Ltd.

Executive and Employee Compensation Policy

The Corporation's compensation philosophy is aimed at attracting and retaining quality and experienced people, which is critical to our success. All compensation is based upon the performance of both the Corporation and the individual employee and is comprised of three elements: base salary, short-term incentive compensation (being cash bonuses) and long-term incentive compensation (being stock based compensation). Each element of compensation is determined on an individual basis.

The Corporation may, based upon individual and corporate performance, award cash bonuses to its employees, and executive officers to supplement annual salaries. The award of bonuses is determined, in the case of non-executive employees, by the senior management of the Corporation and approved by the Compensation Committee. The Compensation Committee in consultation with the Chief Executive Officer establishes base salaries and cash bonuses for Vice Presidents and the Compensation Committee establishes the Chief Executive Officer's compensation.

Stock options are normally awarded by the Compensation Committee upon commencement of employment with the Corporation based on the level of responsibility within the Corporation and are intended to align executive and shareholder interests by attempting to create a direct link between compensation and shareholder return as measured through the price of the Corporation's shares. Additional grants are made periodically to recognize the exemplary performance of, or the special contribution by, eligible individuals. An annual grant may be made to eligible individuals based on individual performance and the performance of the Corporation during the most recently completed financial year in relation to performance achieved by industry peer corporations during the comparable period.

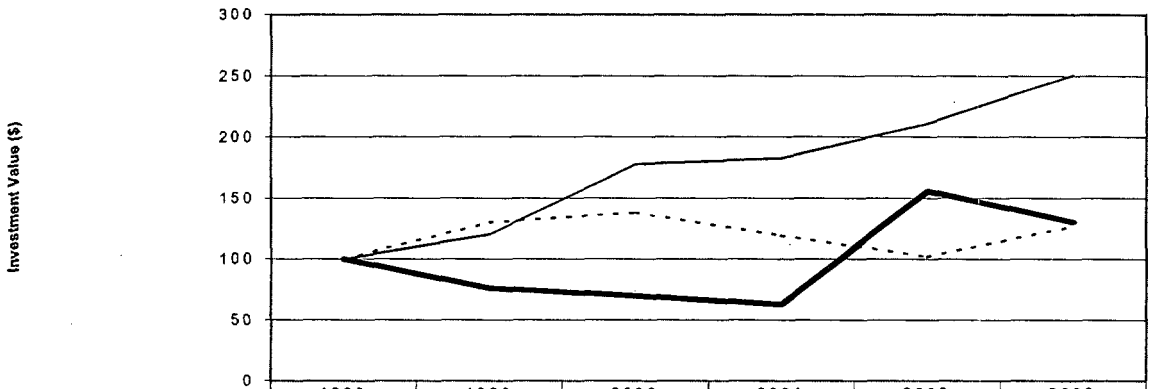
The Corporation's Chief Executive Officer did not receive an annual salary in 2002. Effective March 1, 2003 the Compensation Committee approved an annual salary for Mr. Wright of $180,000. Based on independent surveys, this salary level is considered low compared to the Corporation's peer group. Mr. Wright has significant exposure to the Corporation's share price through his investment in the Corporation's common shares. The Corporation believes it is important for the Chief Executive Officer's compensation to be aligned with the Shareholders' interests and it is intended that bonuses and stock based compensation account for a large component of Mr. Wright's total compensation package.

The Corporation's compensation policies have allowed us to attract and retain a team of motivated professionals and support staff working towards the common goal of enhancing shareholder value. The Compensation Committee reviews compensation policies to ensure that they are competitive within the oil and natural gas industry and consistent with the Corporation's performance.

Report Submitted by:
John A. Brussa
M. Bruce Chernoff
James D. Tocher

Performance Graph

The following graph illustrates the Corporation's five year cumulative shareholder return, as measured by the closing price of the common shares at the end of each financial year, assuming an initial investment of $100, compared to the S&P/TSX Composite Index and the TSX Oil & Gas Producers Index, assuming the reinvestment of dividends where applicable.



	1998	1999	2000	2001	2002	2003
PBG	100	76	70	63	156	130
S&P/TSX Composite Index	100	130	138	119	102	127
TSX O&G Producers Index	100	120	178	183	211	251

Remuneration of Directors

The Corporation does not currently pay its non-management directors any cash compensation except that directors are reimbursed for their out-of-pocket expenses incurred in carrying out their duties as directors. The Corporation pays Mr. McKinnon $12,000 per annum for corporate secretarial services. Non-management directors have historically been entitled to participate in our Stock Option Plan. In April 2003, the Directors, as a group, agreed to cancel or exercise their outstanding stock options which were issued for service periods dating back to 2001. The shareholders are being asked to consider the Deferred Share Compensation Plan as an alternative compensation arrangement, which encourages ownership of common shares of the Corporation. The intention is to make Deferred Share grants for prior years service to those non-management directors who previously agreed to the cancellation of their stock options. For future periods Deferred Share grants are expected to be made in amounts commensurate with time commitments made by each director taking into account membership on committees of the Board.

Indebtedness of Directors and Senior Officers

No director, executive officer or other senior officer, or their associates or affiliates, is or has been at any time since the beginning of the most recently completed financial year of the Corporation, indebted to the Corporation or any of its subsidiaries in respect of any indebtedness that is still outstanding, nor is, or at any time since the beginning of the most recently completed financial year of the Corporation has, any indebtedness of any such person been the subject of a guarantee, support agreement, letter of credit or other similar arrangement or understanding provided by the Corporation or any of its subsidiaries.

CORPORATE GOVERNANCE

The board of directors and management believes in the importance of good corporate governance and its effectiveness in promoting enhanced shareholder value. The TSX has required that listed corporations disclose their approach to corporate governance, making particular reference to the TSX guidelines set out in the report of the TSX Committee on Corporate Governance, which were revised in 1999 (the "Guidelines"). When a corporation's corporate governance system differs from these Guidelines, it is required to give an explanation of the differences. The guidelines contained in the TSX report are not mandatory and the TSX report recognizes that the unique characteristics of individual corporations will result in varying degrees of compliance with such Guidelines. The board of directors and management will continue to monitor the current initiatives of the securities regulatory authorities in Canada with respect to corporate governance in order to ensure that our corporate governance practice complies with all applicable legal requirements. The following summary also addresses each of the Guidelines of the TSX with respect to corporate governance including an explanation of any divergence from the stated Guidelines.

The Ontario Securities Commission has published for comments proposals on corporate governance that are intended to replace the Guidelines when they come into force. Those proposals are subject to public comment and final regulatory approval and the Corporation is not aware whether they will be adopted in the form proposed or whether changes will be made to them prior to adoption, and therefore such proposals have not been reflected in the disclosure on the Guidelines provided herein.

1. *The board of directors should explicitly assume responsibility for the stewardship of the corporation*:

The Board has full plenary powers and the statutory responsibility to oversee the conduct of the business of the Corporation and to supervise management who is responsible for the day-to-day conduct of the business of the Corporation. The Board's fundamental objectives are to enhance and preserve long-term shareholder value and to ensure the Corporation meets its obligations on an ongoing basis. While the Board has delegated the responsibility for day-to-day management of the Corporation to management, the Board has implicitly and explicitly acknowledged its responsibility for the stewardship of the Corporation, including the responsibility for:

(a) approving and monitoring the Corporation's strategic planning through a regular reporting and review process;

(b) the identification of the principal risks of the Corporation's business and ensuring the implementation of appropriate systems to manage these risks;

(c) the appointment of the senior executive officers and for succession planning;

(d) ensuring timely and accurate communications to Shareholders of financial and other matters in accordance with applicable law; and

(e) ensuring the implementation and integrity of the Corporation's internal control and management information systems.

2. *A majority of directors should be "unrelated" (independent):*

The Board is proposed to be comprised of seven members, a majority (six) of whom are considered "unrelated directors", with the President and Chief Executive Officer being considered a "related director" as those terms are defined by the TSX. All the unrelated directors have no business relationships with the Corporation other than the ownership of shares except that Mr. Brussa is a partner in a law firm that provides legal services to the Corporation. It is the Board's opinion that this relationship does not impair Mr. Brussa's ability to act in the best interests of the Shareholders and accordingly Mr. Brussa is considered to be independent.

3. *Analysis of independence determinations:*

Under the TSX guidelines, an "unrelated" director is a director who is independent of management and free from any business or other relationship that could, or could reasonably be perceived to, materially interfere with the director's ability to act with a view to the best interests of the Corporation. These determinations of independence are provided under item 2 above.

4. *Appoint a committee responsible for appointment and assessment of directors composed exclusively of outside directors, a majority of whom are unrelated:*

Historically, the full board of directors has performed the function of a nominating committee of the Corporation with the responsibility for the appointment and assessment of directors. This practice does not comply with the stated guidelines of the TSX. The Board believes that these procedures have proved to be a practical and effective approach to these governance issues in light of the Corporation's particular circumstances, including the size of the Board, and the size of the Corporation.

5. *Implement a process for assessing the effectiveness of the Board as a whole, the committees of the Board and the contribution of individual directors:*

The Board as a whole periodically reviews the effectiveness of the Board, its committees, and the contributions of individual board members. This assessment is often conducted through informal discussion and evaluation of members' contributions.

6. *Provide orientation and education programs for new recruits and continuing education for all directors:*

The Board has historically provided an orientation and education program for directors on an as requested basis and as a result, does not comply with the stated guidelines of the TSX, but the Board believes that these procedures have proved to be a practical and effective approach in light of the Corporation's particular circumstances, including the size of the Board, the size of the Corporation and the nature and scope of the Corporation's business and operations and the experience and expertise of board members.

7. *Examine the size and composition of the Board and undertake, where appropriate, a program to establish a Board comprised of members who facilitate effective decision-making:*

The Board considers that seven members is an appropriate number of directors having regard to the size of the Corporation, the nature of its business and operations and the experience and expertise required to carry out duties effectively while maintaining a diversity of views and experience.

8. *Review the adequacy and form of compensation of the directors reflecting risks and responsibilities:*

The Compensation Committee periodically reviews the compensation of the directors, which is discussed under the heading Remuneration of Directors.

9. *Committees of the Board should generally be composed solely of non-management directors, a majority of whom are unrelated directors:*

The Board has three committees: the Audit Committee, the Reserves Committee, and the Compensation Committee, all of which are comprised solely of non-management unrelated directors. From time to time ad hoc committees of the Board may also be appointed.

10. *Every Board should expressly assume responsibility for, or assign to a committee of directors the general responsibility for, developing the corporation's approach to governance issues:*

The entire Board has retained the responsibility for determining the Corporation's approach to corporate governance.

11. *Define mandates for the Board and for the CEO, involving the definition of the limits to management's responsibilities. In addition, the Board should approve or develop the corporate objectives which the CEO is responsible for meeting and assess the CEO against these objectives:*

The Board and each of its committees have defined mandates. The Board proposes to review all mandates in 2004 in light of the new regulatory guidelines introduced by the securities commissions in 2004.

The Board has the statutory responsibility to oversee the conduct of the business of the Corporation and has delegated the responsibility for the day-to-day conduct of the business to the CEO and other members of management, subject to compliance with plans and objectives approved from time to time by the Board. The CEO is assessed based on corporate objectives established by Petrobank's strategic plan which is regularly reviewed by the Board.

12. *Establish structures and procedures to enable the Board to function independently of management:*

The Chairman of the Board is independent of management and the committees of the Board meet independently of management as required. The Audit Committee regularly meets with the Corporation's external auditors without management present. The Reserves Committee meets with the Corporation's independent engineers without management present.

13. *Establish an audit committee with a specifically defined mandate comprised entirely of unrelated directors:*

The Audit Committee has a defined mandate and is responsible for reviewing the external audit function and the preparation of financial statements and reviewing and recommending for approval to the Board all public financial disclosure information such as financial statements and prospectuses. It also ensures that management has effective internal control systems and meets from time to time with external auditors without management present. The Corporation does not have internal auditors and given the size of the Corporation this is considered practical and appropriate.

The Audit Committee is comprised of Messrs. Brussa (Chairman), Chernoff and Oaks all of whom are unrelated and are considered financially literate.

14. *Implement a system which enables an individual director to engage an external adviser at the expense of the corporation in appropriate circumstances*:

Individual directors may engage outside advisors, at the Corporation's expense.

INTEREST OF INSIDERS IN MATERIAL TRANSACTIONS

In July 2003, the Company acquired the THAI™ and CAPRI™ patented heavy oil recovery technologies indirectly from two directors of the Company (John D. Wright and M. Bruce Chernoff), and a third party, pursuant to an agreement made by an independent committee of the Board of Directors. Mr. Chernoff recovered his $226,000 investment and Mr. Wright received cash of $189,000 on his $226,000 investment and retained a 7.5% net profits interest in any future third party (non-Petrobank) licensing royalties generated from the technologies. Petrobank is required to take steps to commence a pilot by the end of November 2004 in order to retain its rights to the THAI™ and CAPRI™ technologies. Petrobank plans to commence this pilot test of the THAI™ technology through Petrobank's subsidiary, WHITESANDS INSITU Ltd.

In January 2004, the Company paid a $200,000 commitment fee to secure a $10 million credit facility from a company controlled by a director of Petrobank (M. Bruce Chernoff). Any balances outstanding under the facility would bear interest at 12% per annum and would be subordinate to Petrobank's existing secured bank debt. The Company negotiated this credit facility to increase it financial flexibility and to carry out capital projects and/or acquisitions during 2004. To date, the Company has not drawn on this facility, which expires on December 30, 2004.

Except as disclosed herein, there were no material interests, direct or indirect, of the Corporation's insiders, proposed nominees for election as directors, or any associate or affiliate of such insiders or nominees since the beginning of the Corporation's last financial year, or in any proposed transaction, which has affected or would materially affect the Corporation or any of its subsidiaries.

INTEREST OF CERTAIN PERSONS AND COMPANIES IN MATTERS TO BE ACTED UPON

Our management is not aware of any material interest of any director or executive officer or anyone who has held office as such since the beginning of our last financial year or of any associate or affiliate of any of the foregoing in any matter to be acted on at the meeting, save as is disclosed herein.

OTHER MATTERS

Our management knows of no amendment, variation or other matter to come before the meeting other than the matters referred to in the notice of annual and special meeting. However, if any other matter properly comes before the meeting, the accompanying proxy will be voted on such matter in accordance with the best judgment of the person voting the proxy.

The contents and the sending of this information circular - proxy statement have been approved by our directors.

The foregoing contains no untrue statement of a material fact and does not omit to state a material fact that is required to be stated or that is necessary to make a statement not misleading in light of the circumstances in which it was made.

Dated: May 14, 2004

(signed) *"John D. Wright"*
John D. Wright
President and
Chief Executive Officer

(signed) *"Chris J. Bloomer"*
Chris J. Bloomer
Vice-President Heavy Oil and
Chief Financial Officer

SCHEDULE "A"

PETROBANK ENERGY AND RESOURCES LTD.

DEFERRED SHARE COMPENSATION PLAN

1. Purpose of Plan

The deferred share compensation plan (the "Plan") of Petrobank Energy Resources Ltd. (the "Corporation") is intended to provide effective incentives for the directors, officers and employees of the Corporation to promote the success and business of the Corporation and to reward such directors, officers and employees in relation to the long-term performance and growth of the Corporation by encouraging ownership of common shares ("Common Shares") of the Corporation.

2. Components of Plan

The Plan consists of two components as follows:

(a) a deferred grant to each director of the Corporation of such number of Common Shares per calendar year or such other period which is approved by the Board of Directors of the Corporation (the "Board of Directors") from time to time; and

(b) a deferred grant to such officers or employees of the Corporation whom are approved by the Board of Directors of such number of Common Shares per calendar year as is approved by the Board of Directors.

3. Form of Payment

Compensation payable pursuant to the Plan will be payable in the form of a deferred grant of Common Shares.

4. Issue of Common Shares

Common Shares which a director, officer or employee is entitled to receive pursuant to the Plan will not be issued until the director, officer or employee has delivered to the Corporation an exercise election in writing that the Common Shares be issued together with payment to the Corporation in the amount of $0.05 for each Common Share issued together with any statutory withholdings required to be remitted by the Corporation in respect of the subject issuance.

A director, officer or employee will not be entitled to elect to be issued any of the Common Shares which he or she has been granted until a period of three years has passed since the date of grant of such Common Shares or until the director, officer or employee ceases to be a director, officer or employee of the Corporation, whichever is earlier. Upon a director, officer or employee ceasing to be a director, officer or employee of the Corporation, such director, officer or employee shall be required to elect whether he or she will be issued all or any portion of the Common Shares which have been granted to him or her (and to deliver payment for all of such Common Shares to be issued).

A director, officer or employee shall have no right to receive Common Shares granted to him or her which have not been issued on the date that is ten years following the date of grant.

5. Adjustment of Number of Common Shares

The number of Common Shares which are issuable to a director, officer or employee pursuant to a deferred grant of Common Shares shall be increased on the second business day following each date on which cash dividends are paid to holders of Common Shares of the Corporation by an amount equal to the product of the number of the Common Shares which remain issuable and the fraction which has as its numerator the cash distribution paid, expressed as an amount per Common Share and which has as its denominator the weighted average trading price of Common Shares on the Toronto Stock Exchange for the record date for such distribution and the 5 trading days preceding such record date.

6. Grant of Common Shares

Compensation paid to a director, officer or employee pursuant to the Plan in the form of a deferred grant of Common Shares will be evidenced by an agreement between the Corporation and the director, officer or employee in a form which is approved by the Board of Directors from time to time.

7. Common Shares Subject to the Plan and Other Restrictions

The total number of Common Shares issuable pursuant to the Plan shall not exceed 500,000. No Common Shares may be issued to a director, officer or employee under the Plan if such issuance could result, at any time, in (i) the number of Common Shares reserved for issuance pursuant to issuances under the Plan in respect of Common Shares granted to insiders exceeding 10% of the aggregate issued and outstanding Common Shares, (ii) the issuance to insiders of the Corporation pursuant to the Plan and all other established or proposed share compensation arrangements, within a one year period, of a number of Common Shares exceeding 10% of the aggregate issued and outstanding Common Shares, (iii) the issuance pursuant to the Plan and all other established or proposed share compensation arrangements to any one insider of the Corporation, or such insider's associates, within a one year period, of a number of Common Shares exceeding 5% of the aggregate issued and outstanding Common Shares; or (iv) the issuance pursuant to the Plan to any one person of a number of Common Shares exceeding 5% of the aggregate issued and outstanding Common Shares.

8. Eligibility and Determination

The Common Shares issuable under the Plan pursuant to deferred grants of Common Shares are reserved for directors, officers or employees of the Corporation.

In the event that a director qualifies for the payment of compensation under the Plan for services provided as a director for a period of less than twelve months in any calendar year then the entitlement of such director will be calculated on a pro rata basis.

9. No Fractional Shares

No fractional Common Shares may be issued under the Plan and any entitlement hereunder to a fractional Common Share will be rounded down and no amount of money will be payable by the Corporation in respect of such fractional interest.

10. Non-Transferability

The right to receive a deferred grant of Common Shares under the Plan may only be exercised by the director, officer or employee to whom the grant has been made. Except as otherwise provided in this Plan, no assignment, sale, transfer, pledge or charge of a grant, whether voluntary, involuntary, by

operation of law or otherwise, vest any interest or right in such grant whatsoever in any assignee or transferee and, immediately upon any assignment, sale, transfer, pledge or charge or attempt to assign, sell, transfer, pledge or charge, such grant shall terminate and be of no further force or effect.

11. Administration

The Plan shall be administered by the Compensation Committee of the Board of Directors of the Corporation. The Corporation shall effect the deferred grant of Common Shares from time to time under the Plan in accordance with the determinations made as to the number of Common Shares to be granted and the date of grant as provided for under the Plan.

12. Regulation

The Corporation's obligation to issue and deliver Common Shares under the Plan is subject to compliance with all government and stock exchange regulations and requirements.

13. Capital Reorganizations

If and whenever there shall be a capital reorganization of the Corporation such as a share subdivision, consolidation, reclassification, change or exchange of the Common Shares, including as a result of any merger, arrangement, amalgamation or business combination with any other corporation or entity, the entitlement to Common Shares of any director for any applicable year, or portion thereof, shall be adjusted to take into account such capital reorganization.

14. Effective Date

Subject to the receipt of all regulatory approvals including, without limitation, the approval of the Toronto Stock Exchange, the Plan will be effective on January 1, 2004 as provided by a resolution of the Board of Directors of the Corporation passed on March 30, 2004 and shall remain in effect until such time as the Board of Directors amends or cancels the Plan which may occur at any time but not with retroactive effect. Any amendment to the Plan will be subject to the receipt of all regulatory approvals.

PETROBANK ENERGY AND RESOURCES LTD.

Instrument of Proxy
For the Annual and Special Meeting of Shareholders

The undersigned shareholder of Petrobank Energy and Resources Ltd. (the "Corporation") hereby appoints John D. Wright, of the City of Calgary, in the Province of Alberta, President and Chief Executive Officer and a director of the Corporation or, failing him, Chris J. Bloomer, of the City of Calgary, in the Province of Alberta, Chief Financial Officer and Vice President of the Corporation, or instead of either of the foregoing, _____, as proxyholder of the undersigned, with full power of substitution, to attend and act and vote for and on behalf of the undersigned at the annual and special meeting of shareholders of the Corporation (the "Meeting"), to be held on June 17, 2004 and at any adjournment(s) thereof, and on every ballot that may take place in consequence thereof to the same extent and with the same powers as if the undersigned were personally present at the Meeting with authority to vote at the said proxyholder's discretion, except as otherwise specified below.

Without limiting the general powers hereby conferred, the undersigned hereby directs the said proxyholder to vote the shares represented by this Instrument of Proxy in the following manner:

1. **FOR** ☐ or **AGAINST** ☐ fixing the number of directors to be elected at the Meeting at seven (7) as specified in the Information Circular – Proxy Statement of the Corporation dated May 14, 2004 (the "Information Circular");

2. **FOR** ☐ or **WITHHOLD FROM VOTING FOR** ☐ the election of directors as specified in the Information Circular;

3. **FOR** ☐ or **WITHHOLD FROM VOTING FOR** ☐ the appointment of Deloitte & Touche LLP, Chartered Accountants, to serve as auditors of the Corporation for the ensuing year and the authorization of the directors to fix their remuneration as such;

4. **FOR** ☐ or **AGAINST** ☐ the ordinary resolution approving an amendment to the stock option plan (the "Plan") of the Corporation, to provide that the maximum number of common shares ("Common Shares") of the Corporation which may, from time to time, be issuable pursuant to the Plan be increased, all as more particularly described in the Information Circular;

5. **FOR** ☐ or **AGAINST** ☐ the ordinary resolution ratifying and approving the deferred compensation plan of the Corporation and the issuance of Common Shares pursuant thereto, all as more particularly described in the Information Circular; and

6. at the discretion of the said proxyholders, upon any permitted amendment or variation of the above matters or any other matter that may be properly brought before the Meeting or any adjournment(s) thereof in such manner as such proxy, in such proxyholder's sole judgment, may determine.

This Instrument of Proxy is solicited on behalf of the management of the Corporation. The shares represented by this Instrument of Proxy will be voted and, where the shareholder has specified a choice with respect to the above matters, will be voted as directed above or, if no direction is given, will be voted in favour of the above matters.

Each shareholder has the right to appoint a proxyholder, other than the persons designated above, who need not be a shareholder, to attend and to act for such shareholder and on such shareholder's behalf at the Meeting. To exercise such right, the names of the nominees of management should be crossed out and the name of the shareholder's appointee should be legibly printed in the blank space provided.

THE UNDERSIGNED HEREBY REVOKES ANY PROXIES HERETOFORE GIVEN.

Dated this _____ day of _____, 2004.

_____
(signature of shareholder)

_____
(name of shareholder - please print)

_____
(number of common shares being voted)

If you have any questions or need assistance in completing this Instrument of Proxy, please contact Chris J. Bloomer, Chief Financial Officer of the Corporation at: (403) 920-0135 (Calgary)

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NOTES:

1. If the shareholder is a corporation, its corporate seal must be affixed or it must be signed by an officer or attorney thereof duly authorized.

2. This instrument of proxy must be dated and the signature hereon should be exactly the same as the name in which the shares are registered. If the Instrument of Proxy is not dated in the above space, it is deemed to bear the date on which it is mailed by the person making the solicitation.

3. Persons signing as executors, administrators, trustees, etc., should so indicate and give their full title as such.

4. This Instrument of Proxy will not be valid and not be acted upon or voted unless it is completed as outlined herein and delivered to the attention of the Chief Financial Officer of the Corporation c/o Computershare Trust Company of Canada, Proxy Department, 9th Floor, 100 University Avenue, Toronto, Ontario, M5J 2Y1, not less than 48 hours (excluding Saturdays, Sundays and holidays) before the time set for the holding of the Meeting or any adjournment(s) thereof. A proxy is valid only at the meeting in respect of which it is given or any adjournment(s) of that meeting.

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Management's Report

Management is responsible for the integrity and objectivity of the information contained in this annual report and for the consistency between the consolidated financial statements and other financial and operating data contained elsewhere in this report. The accompanying consolidated financial statements have been prepared by management in accordance with accounting principles generally accepted in Canada using estimates and careful judgement, particularly in those circumstances where transactions affecting a current period are dependent upon future events. The accompanying consolidated financial statements have been prepared using policies and procedures established by management and fairly reflect the Company's financial position, results of operations and changes in financial position, within Canadian generally accepted accounting principles. Management has established and maintains a system of internal controls that is designed to provide reasonable assurance that assets are safeguarded from loss or unauthorized use and the financial information is reliable and accurate.

The consolidated financial statements have been examined by the Company's external auditors, Deloitte & Touche LLP. Their examination provides an independent view as to management's discharge of its responsibilities insofar as they relate to the fairness of reported financial results and the financial condition of the Company.

The Audit Committee of the Board of Directors has reviewed in detail the consolidated financial statements with management and the external auditors. The consolidated financial statements have been approved by the Board of Directors on the recommendation of the Audit Committee.

"SIGNED"

John D. Wright
President & Chief Executive Officer
Calgary, Canada
March 12, 2004

"SIGNED"

Chris J. Bloomer
Vice-President Heavy Oil & Chief Financial Officer
Calgary, Canada

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Auditors' Report

TO THE SHAREHOLDERS OF PETROBANK ENERGY AND RESOURCES LTD.:

We have audited the consolidated balance sheets of PETROBANK ENERGY AND RESOURCES LTD. as at December 31, 2003 and 2002 and the consolidated statements of operations and retained earnings and cash flows for the years then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2003 and 2002 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

"SIGNED"

Deloitte & Touche LLP
Chartered Accountants
Calgary, Canada
March 12, 2004

Consolidated Balance Sheets

(Thousands of Canadian dollars) As at December 31,	2003	2002
Assets		
Current assets		
Cash and cash equivalents	$ -	$ 12,224
Accounts receivable and other current assets	21,528	11,521
	21,528	23,745
Capital assets (Note 4)	232,007	126,873
	$ 253,535	$ 150,618
Liabilities and Shareholders' Equity		
Current liabilities		
Accounts payable and accrued liabilities	$ 34,937	$ 28,896
Debenture (Note 3)	14,014	-
Bank debt (Note 5)	30,102	-
	79,053	28,896
Obligations under gas sale and transportation contracts (Note 6)	7,287	8,097
Site restoration liability	2,807	613
Future income tax liability (Notes 3, 7, 8 and 9)	13,920	-
	103,067	37,606
Shareholders' equity		
Subordinated notes (Note 7)	93,430	57,344
Common shares (Note 8)	72,355	48,054
Contributed surplus (Note 8)	186	
Retained earnings (deficit)	(15,503)	7,614
	150,468	113,012
	$ 253,535	$ 150,618

Commitments and contingencies (Note 13)
Subsequent events (Note 14)

See accompanying notes to these consolidated financial statements

Signed on behalf of the Board:

"SIGNED"

James D. Tocher
Chairman

"SIGNED"

John A. Brussa
Chairman of the Audit Committee

Consolidated Statements of Operations and Retained Earnings

(Thousands of Canadian dollars, except per share amounts) Years Ended December 31,	2003	2002
Revenues		
Oil and natural gas	$ 66,111	$ 50,458
Royalties	(12,111)	(10,751)
	54,000	39,707
Expenses		
Production	16,770	12,307
General and administrative	5,940	3,784
Interest	771	-
Depletion, depreciation and site restoration	27,363	17,269
Impairment (Note 4)	16,900	-
	67,744	33,360
Income (loss) before other items and taxes	(13,744)	6,347
Other income (expense)	(48)	284
Gain on sale of temporary investment	-	654
Income (loss) before taxes	(13,792)	7,285
Capital and future income taxes (Note 9)	(899)	(1,094)
Net income (loss)	(14,691)	6,191
Interest on subordinated notes, net of tax (Note 7)	(8,420)	(6,107)
Preferred share dividends and related taxes	-	(514)
Net loss attributable to common shareholders	(23,111)	(430)
Retained earnings, beginning of year	7,614	14,562
Repurchase of securities (Note 8)	(6)	(6,518)
Retained earnings, end of year	$ (15,503)	$ 7,614
Basic and diluted loss per share (Note 8)	$ (0.48)	$ (0.01)

See accompanying notes to these consolidated financial statements

Consolidated Statements of Cash Flows

(Thousands of Canadian dollars) Years Ended December 31,	2003	2002
Operating Activities		
Net income (loss)	$ (14,691)	$ 6,191
Depletion, depreciation and site restoration	27,363	17,269
Impairment	16,900	-
Gain on sale of temporary investment	-	(654)
Future income tax recovery (Note 9)	(500)	-
Stock-based compensation expense (Note 8)	186	-
Cash flow from operations	29,258	22,806
Changes in non-cash items (Note 12)	(8,772)	4,728
	20,486	27,534
Financing Activities		
Increase in bank debt	30,102	-
Issuance of subordinated notes (Note 7)	34,410	-
Issuance of common shares and share purchase warrants (Notes 7 and 8)	12,786	4,450
Interest on subordinated notes	(7,806)	(5,439)
Amortization of obligations under gas sale and transportation contracts (Note 6)	(810)	(419)
Settlement of obligations under gas sale and transportation contracts (Note 6)	-	(894)
Repurchase of securities (Note 8)	(9)	(6,530)
Preferred share dividends and related taxes	-	(514)
Changes in other non-cash items (Note 12)	-	(878)
	68,673	(10,224)
Investing Activities		
Expenditures on capital assets	(116,060)	(46,228)
Proceeds on disposition of capital assets (Note 4)	20,448	3,334
Corporate acquisitions (Note 3)	(8,573)	(42)
Proceeds on disposition of temporary investment	-	1,654
Site restoration expenditures	(32)	(1,129)
Changes in non-cash items (Note 12)	2,834	12,014
	(101,383)	(30,397)
Net change in cash position	(12,224)	(13,087)
Cash and cash equivalents, beginning of year	12,224	25,311
Cash and cash equivalents, end of year	$ -	$ 12,224

See accompanying notes to these consolidated financial statements

Notes to the Consolidated Financial Statements

As at and for the years ended December 31, 2003 and 2002

(All tabular amounts expressed in thousands of Canadian dollars, except share amounts)

1. Description of Business

Petrobank Energy and Resources Ltd. (the "Company" or "Petrobank"), is a public company listed on the Toronto Stock Exchange and incorporated under the Business Corporations Act (Alberta). Petrobank is engaged in the exploration for and development and production of oil and natural gas in the country of Colombia and in the Western Canada Sedimentary Basin and is continuing the evaluation of other international oil and natural gas opportunities. During 2003, Petrobank acquired the intellectual property rights to the THAI™ and CAPRI™ heavy oil recovery technologies and has received regulatory approval to proceed with a pilot project to field test the THAI™ technology.

2. Summary of Significant Accounting Policies

These consolidated financial statements are prepared in accordance with Canadian Generally Accepted Accounting Principles and include the accounts of the Company and its subsidiaries.

Measurement Uncertainty

The preparation of financial statements in conformity with Generally Accepted Accounting Principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities as at the date of the consolidated balance sheets as well as the reported amounts of revenues, expenses, and cash flows during the periods presented. Such estimates relate primarily to unsettled transactions and events as of the date of the consolidated financial statements. Actual results could differ materially from estimated amounts.

Amounts recorded for depreciation, depletion and site restoration costs and amounts used for ceiling test calculations are based on estimates of oil and natural gas reserves and future costs required to develop those reserves that are subject to measurement uncertainty. Changes in these estimates could materially impact the consolidated financial statements of future periods.

Capital Assets

The Company accounts for its oil and natural gas operations in accordance with the Canadian Institute of Chartered Accountants' existing guideline on full cost accounting in the oil and natural gas industry whereby all costs related to the acquisition of oil and natural gas properties are capitalized. Such costs include land and lease acquisition costs, annual charges on non-producing properties, geological and geophysical costs, and costs of drilling and equipping productive and non-productive wells.

Gains and losses are not recognized upon disposition of oil and natural gas properties unless crediting the proceeds against accumulated costs would result in a change in the rate of depletion of more than 20 percent.

Capitalized costs are accumulated in cost centres on a country-by-country basis and are depreciated and depleted using the unit-of-production method based upon estimated proved reserves as determined by independent engineers. Included in costs subject to depletion are estimated costs to develop proved reserves. Reserve and production volumes of oil and natural gas are converted to common units on the basis

of their approximate relative energy content. Costs relating to undeveloped properties may be excluded from the depletion base until it is determined whether or not proved reserves exist or if impairment of such costs has occurred. Depreciation of office equipment is provided at 30 percent using the declining balance method.

The net capitalized costs in each cost centre may not exceed a calculated ceiling. The ceiling is equal to the estimated undiscounted future net revenues, based on year-end prices and costs, derived from proved reserves, less the estimated development and site restoration costs, plus the lower of cost less impairment, and estimated fair value of undeveloped properties. Consolidated net capitalized costs less future income tax liabilities are subject to a second ceiling test whereby the consolidated ceiling is equal to the sum of the cost centre amounts less general and administrative, financing and income tax costs. These ceiling tests are cost recovery tests and are not intended to be estimates of fair value.

The Canadian Institute of Chartered Accountants has issued a new full cost guideline which the Company will prospectively adopt in 2004. The Company does not capitalize general and administrative or interest costs.

Site Restoration

Estimated site restoration costs are provided for in the current period using the unit-of-production method based on estimated proved reserves. The annual charge is accounted for as an expense and the accumulated provision is reflected as a long-term liability. Actual site restoration expenditures are deducted from the liability balance in the year incurred. Future costs are estimated based upon current legislation, technology and industry standards.

Derivative Financial Instruments

The Company may utilize derivative financial instruments in its management of exposures to fluctuations in crude oil and natural gas prices, foreign currency exchange rates and interest rates. The Company does not enter into derivative financial instruments for trading or speculative purposes. The Company formally documents all relationships between hedging instruments and hedged items, as well as its risk management objective and strategy for undertaking various hedge transactions. This process includes linking all derivatives to specific assets and liabilities on the balance sheet or to specific firm commitments or forecasted transactions. The Company also formally assesses, both at inception and on an ongoing basis, whether the derivatives that are used in hedging transactions are highly effective in offsetting changes in fair values or cash flows of hedged items. Gains and losses on contracts that constitute effective hedges are deferred and recognized in income when the related transactions occur.

Joint Operations

The majority of the Company's oil and natural gas operations are conducted jointly with others and accordingly these consolidated financial statements reflect only the Company's proportionate interest in such activities.

Revenue Recognition

Revenues from the sale of crude oil, natural gas and natural gas liquids are recognized when title passes to the customer.

Foreign Currency Translation

The Company translates foreign currency denominated monetary assets and liabilities of its integrated foreign subsidiaries at the exchange rate in effect at the balance sheet date and non-monetary assets and liabilities are translated at historical exchange rates. Revenues and expenses are translated at estimated transaction date exchange rates except depletion and depreciation expense, which is translated at the same historical exchanges rates as the related assets. Exchange gains or losses are included in the determination of net income as other income (expense).

Earnings Per Share

The Company computes diluted earnings per share using the treasury stock method. This method assumes that the proceeds on exercise of in-the-money stock options and share purchase warrants are used to repurchase the Company's common shares at the average market price during the relevant period.

Stock-Based Compensation

During the fourth quarter of 2003, the Company adopted the fair-value method of accounting for stock options granted to employees and directors during 2003. Stock-based compensation expense is recorded and reflected as general and administrative expense for all options granted after January 1, 2003, with a corresponding amount reflected in contributed surplus. Stock-based compensation expense is calculated as the estimated fair value of the related stock option at the time of the grant amortized over the vesting period of the option. For options granted between January 1, 2002 and January 1, 2003, we continue to disclose the pro-forma earnings impact of related stock-based compensation expense as if the fair-value method had been adopted at the beginning of that period (see Note 8). When stock options are exercised, the amounts previously recorded as contributed surplus are reclassified to common share capital.

Income Taxes

The Company accounts for income taxes using the liability method. Under this method, the Company records a future income tax asset or liability to reflect any difference between the accounting and tax bases of assets and liabilities. Future income tax assets are only recognized to the extent it is more likely than not sufficient future taxable income will be available to allow the future income tax asset to be realized.

Flow-Through Common Shares

The Company has financed a portion of its exploration activities in Canada through the issuance of flow-through shares. Under the terms of these shares, the tax attributes of the related expenditures are renounced to subscribers. To recognize the foregone tax benefits, share capital is reduced and a future income tax liability is recorded in the period in which the related tax attributes are effectively renounced.

Subordinated Notes

The subordinated notes are reflected as equity on the balance sheet and the interest thereon is excluded from the determination of net income as the Company has the option to issue common shares to settle both interest and principal payments. The Canadian Institute of Chartered Accountants recently issued an Exposure Draft that, when implemented, will require securities such as Petrobank's subordinated notes to be presented as liabilities. This revision will become effective for all fiscal years beginning on or after November 1, 2004.

Cash and Cash Equivalents

Cash and cash equivalents include securities with a maturity of three months or less when purchased.

3. Corporate Acquisitions

On September 19, 2003, the Company acquired Monolith Oil Corp. ("Monolith"), a privately-owned oil and natural gas company, for the consideration noted below. The debenture was secured by Petrobank's Canadian assets but subordinate to Petrobank's secured credit facility, accrued interest at 9 percent per annum payable monthly, and was due to mature on January 31, 2004. On January 28, 2004, the principal amount of the debenture was reduced from $14.5 million to $14.0 million pursuant to the terms of the related acquisition agreement that allowed Petrobank to offset any increases in assumed working capital deficiency against the principal balance of the debenture. Petrobank settled the adjusted debenture amount with $12.5 million of cash paid to the former Monolith shareholders and $1.5 million deposited into escrow. A recovery of the escrowed amount is being sought by Petrobank to offset estimated incremental liabilities assumed on the acquisition. The acquisition has been accounted for using the purchase method as follows, which is subject to change following the outcome of the recovery process, the results of which are not currently determinable.

Purchase price:	
Net cash paid including transaction costs ($400)	$ 8,573
Debenture issued	14,014
Common shares issued (5,209,551)	15,000
Non-cash working capital deficiency acquired	1,972
	$ 39,559

Allocation of purchase price:	
Capital assets	$ 52,534
Future income tax liability	(12,000)
Future site restoration liability	(975)
	$ 39,559

On January 15, 2002, Petrobank acquired a private company for total consideration of $1.0 million including a cash payment of $42,000, issuance of 250,000 Petrobank common shares and the assumption of a liability of $0.6 million. This liability was payable indirectly to two of the Company's directors and was settled in February 2003.

4. Capital Assets

December 31, 2003	Cost	Accumulated Depletion and Depreciation	Net Book Value
Oil and natural gas properties			
Canada	**$ 212,417**	**$ 46,361**	**$ 166,056**
Colombia	**86,977**	**22,577**	**64,400**
Corporate and other	**4,587**	**3,036**	**1,551**
	$ 303,981	**$ 71,974**	**$ 232,007**

December 31, 2002	Cost	Accumulated Depletion and Depreciation	Net Book Value
Oil and natural gas properties			
Canada	$ 135,340	$ 27,814	$ 107,526
Colombia	15,635	-	15,635
Corporate and other	4,860	1,148	3,712
	$ 155,835	$ 28,962	$ 126,873

At December 31, 2003, oil and natural gas properties included $27.8 million (2002 - $30.5 million) relating to unproved properties in Canada, and $4.4 million (2002 - $2.5 million) related to international unproved properties, primarily in Colombia, that have been excluded from the depletion calculation. Colombian costs incurred through December 31, 2002 totaling $15.6 million were excluded from the depletion calculation in 2002, as oil sales from that country did not commence until 2003.

The 2003 impairment expense relates to the Company's Colombian and other international cost centres, and represents the write-down of the carrying value of the impaired properties to their estimated recoverable amount pursuant to the Company's accounting policy described in Note 2. The Company would not have had any further impairment charges had the new full cost accounting guideline been adopted in 2003.

Dispositions

The Company completed a number of non-core property dispositions during 2003 for total proceeds of $20.4 million, the most significant of which was the second quarter disposition of our Zama/Larne property in Northwest Alberta for proceeds of $16.6 million. On January 28, 2004, the Company closed the sale of its Wapella property in Southeast Saskatchewan for total cash proceeds of $36.0 million (see Note 14).

5. Bank Debt

The Company's borrowing base under its secured bank credit facility at December 31, 2003 was $47.5 million. The facility is a revolving demand loan under which the Company can borrow at bank prime plus 0.125 percent or Bankers' Acceptance fee rates plus 1.625 percent. Advances under the facility are collateralized by a $100 million demand debenture on all present and future Canadian assets of the Company as well as a general assignment of the Company's book debts, a negative pledge to provide fixed charges on major producing petroleum properties in Canada and an assignment of material contracts. Following the sale of the Company's Wapella property in January 2004, the borrowing base under this credit

facility was reduced to $36.1 million. A further re-determination of the borrowing base is expected by May 31, 2004 in connection with the bank's regular annual review.

Interest paid approximated interest expense for the years ended December 31, 2003 and 2002.

6. Obligations Under Gas Sale and Transportation Contracts

The Company assumed certain physical natural gas sales and transportation obligations upon the acquisition of Barrington Petroleum Ltd. in 2001 (see Note 11). The Company recorded a liability for these obligations at that time, which is being amortized to oil and natural gas revenues over the term of the related contracts. This liability was reduced by $0.9 million in 2002 for cash payments made to settle a portion of the outstanding obligations.

7. Subordinated Notes

Petrobank's subordinated notes are unsecured and subordinate to the Company's existing credit facility and any other senior debt that may be outstanding from time-to-time. Interest on the notes is payable quarterly at a rate of 9 percent per annum and the notes mature on July 31, 2006. Interest on subordinated notes in 2003 is reflected net of a future tax recovery of $1.1 million. In certain circumstances, the notes may be repaid at their face value prior to their maturity date and the Company has the option of issuing common shares, at prevailing market prices, to settle quarterly interest payments as well as the principal amount. The notes were recorded at fair value on issuance and the discount to face value is being amortized to interest on subordinated notes over the term of the notes creating an effective interest rate of 12 percent.

On May 5, 2003, the Company closed a subordinated note financing, resulting in the issuance of $40.0 million face value of subordinated notes and 1,420,300 common share purchase warrants for proceeds, net of discount, issuance costs and agents' commissions, of $35.2 million. The net proceeds were allocated between the subordinated notes ($34.4 million) and the common share purchase warrants ($0.8 million). The common share purchase warrants are exercisable for common shares at $4.00 per share and expire on May 6, 2006 (Note 8).

	Carrying Amount	Principal Amount
Balance at December 31, 2001	$ 56,676	$ 60,438
Amortization of discount	668	-
Balance at December 31, 2002	57,344	60,438
Issued	34,410	40,000
Amortization of discount	1,676	-
Balance at December 31, 2003	**$ 93,430**	**$ 100,438**

8. Share Capital

Authorized

Unlimited number of common shares

Unlimited number of preferred shares, issuable in series

Common Shares

	Number	Amount
Balance at December 31, 2001	33,557,140	$ 30,341
Issued pursuant to corporate acquisition	250,000	387
Exercise of stock options	775,249	1,250
Repurchased pursuant to issuer bid [1]	(10,927)	(12)
Exercise of warrants	2,133,333	3,200
Issued pursuant to share capital restructuring	8,609,000	12,888
Balance at December 31, 2002	45,313,795	48,054
Exercise of stock options	547,583	964
Issuance of share purchase warrants (Note 7)	-	768
Exercise of warrants	657,160	1,643
Repurchased pursuant to issuer bid [1]	(3,221)	(3)
Issued pursuant to corporate acquisition (Note 3)	5,209,551	15,000
Issued pursuant to flow through offering (net of costs and future income taxes) [2]	2,777,778	5,929
Balance at December 31, 2003	**54,502,646**	**$ 72,355**

(1) The amount associated with share repurchases reflects the average issuance price of common shares. The excess of the amounts paid for these shares over the average issuance price is reflected as a reduction of retained earnings.

(2) On September 24, 2003, Petrobank issued 2,777,778 flow-through common shares for total gross proceeds of $10.0 million. As at December 31, 2003 the Company made a full renunciation of $10.0 million of tax benefits to those shareholders, and recorded a $3.5 million future income tax liability related to the forgone tax benefits. As at December 31, 2003, the Company had incurred $2.0 million of eligible expenditures related to the renunciation, and the remaining eligible expenditures must be incurred by December 31, 2004.

Share Purchase Warrants

As at December 31, 2003, the Company had 1,420,300 share purchase warrants outstanding that allow the holders to purchase an equivalent number of common shares at $4.00 per share on or before May 6, 2006.

	Number	Weighted Average Exercise Price
Balance at December 31, 2002	777,720	$ 2.50
Issued (Note 7)	1,420,300	4.00
Exercised	(657,160)	(2.50)
Expired	(120,560)	(2.50)
Balance at December 31, 2003	**1,420,300**	**$ 4.00**

Stock Options

The Company has established a stock option plan whereby the Company may grant options to its directors, officers, employees, consultants and underwriters. The Company's shareholders have approved the issuance of up to 4.6 million stock options under this plan. The number of stock options available for grant

under the plan has been reduced to 4.2 million at December 31, 2003 due to the exercise of some stock options. At the next meeting of shareholders, the Company intends to request approval to increase the number of stock options available for grant under the plan to 10 percent of the number of common shares outstanding. The exercise price of each option is no less than the market price of the Company's stock on the date of the grant. Stock option terms are determined by the Company's Board of Directors but typically, options vest evenly over a period of four years from the date of grant and expire five years after the date of grant. The following is a continuity of stock options outstanding:

	2003		2002	
	Stock Options	**Weighted-Average Exercise Price**	Stock Options	Weighted-Average Exercise Price
Opening	**4,195,484**	**$ 2.08**	2,823,334	$ 1.73
Granted	**1,373,550**	**3.07**	3,359,500	2.21
Exercised	**(547,583)**	**1.76**	(775,249)	(1.61)
Cancelled	**(1,344,950)**	**2.28**	(1,212,101)	(1.94)
Closing	**3,676,501**	**$ 2.42**	4,195,484	$ 2.08

The following summarizes information about stock options outstanding as at December 31, 2003:

Range of Exercise Prices $	Number Outstanding at Dec. 31, 2003	Weighted-Average Remaining Contractual Life (Years)	Weighted-Average Exercise Price	Number Exercisable at Dec. 31, 2003	Weighted-Average Exercise Price
1.35 - 1.99	1,148,000	2.4	$ 1.64	633,500	$ 1.65
2.00 - 2.74	1,503,251	4.1	2.45	283,626	2.36
2.75 - 3.40	1,025,250	4.2	3.25	66,250	3.05
	3,676,501	3.6	$ 2.42	983,376	$ 1.95

Loss per Share

Basic and diluted loss per share have been calculated based on net loss attributable to common shareholders divided by the weighted average number of shares outstanding for the year of 48,103,924 (2002 - 37,441,521).

Stock-Based Compensation

In 2003, the Company adopted the fair value based method of accounting for its stock-based compensation plan whereby the fair value of stock options granted after January 1, 2003 is recognized as general and administrative expense and as contributed surplus (2003 - $186,000).

Had compensation expense associated with the Company's stock option plan been recognized using the fair value based method for all option grants after January 1, 2002, the Company's pro-forma net loss attributable to common shareholders for the years ended December 31, 2003 and 2002 would have increased by $394,000 and $224,000, respectively and loss per share would have increased to $0.49 and $0.02 per share, respectively.

The fair value of stock options granted has been estimated on their respective grant dates using the Black Scholes option-pricing model using the following assumptions:

	2003	2002
Risk-free interest rate	4.0%-4.5%	3.5%
Dividend rate	0%	0%
Expected life (years)	4.0	4.0
Expected volatility	30%	30%

The average value per option granted in 2003 was $0.93 as at the date of grant.

Share Capital Restructuring

In August 2002, an independent committee of the Board of Directors reached an agreement to repurchase certain outstanding securities held by certain members of management and the Board. This agreement resulted in the repurchase of the Company's outstanding 8.6 million preferred shares (6 percent dividend rate) and cancellation of an equivalent number of common share purchase warrants in exchange for issuance of 8.6 million common shares. The Company also made a $1.0 million cash payment to settle $1.9 million of future dividend entitlements on preferred shares. In addition, the Company paid $5.5 million to repurchase 8,475,667 outstanding common share purchase warrants from the holders of those warrants who agreed to exercise their remaining 2,133,333 common share purchase warrants for $3.2 million. Payments relating to the repurchase of common share purchase warrants and settlement of future dividend rights totaling $6.5 million were reflected as a reduction of retained earnings in 2002.

9. Income Taxes

The provision for income taxes differs from the amount that would have been expected by applying statutory corporate income tax rates to income (loss) before taxes. The principal reasons for this difference are as follows:

	2003	2002
Income (loss) before taxes	$ (13,792)	$ 7,285
Statutory income tax rate	41.50%	43.20%
Expected tax expense (recovery)	$ (5,724)	$ 3,147
Increase (decrease) in income tax provision resulting from:		
Non-deductible Crown charges, net of royalty credits	2,573	2,797
Resource allowance	(1,892)	(2,538)
Future tax asset not recognized (recognized)	4,214	(3,184)
Non-taxable portion of capital gain	-	(141)
Other	329	(81)
Future income tax recovery	(500)	-
Capital taxes	1,399	1,094
Capital and future income tax provision	$ 899	$ 1,094

The components of the Company's future income tax assets and liabilities arising from temporary differences are as follows:

As at December 31,	2003		2002	
	Future Income Tax Assets	Future Income Tax Liabilities	Future Income Tax Assets	Future Income Tax Liabilities
Non-capital losses	$ 18,194	$ -	$ 15,680	$ -
Obligations under gas sale and transportation contracts	2,523	-	2,623	-
Future site restoration	959	-	199	-
Capital assets	-	26,774	6,847	7,112
Subordinated notes	14	-	-	1,772
Other	250	-	38	-
	21,940	26,774	25,387	8,884
Valuation allowance	(9,086)	-	(16,503)	-
	$ 12,854	$ 26,774	$ 8,884	$ 8,884

The Company has reflected its future income tax liability net of future tax assets on the consolidated balance sheet. Income taxes paid approximate capital tax expense for the years ended December 31, 2003 and 2002.

10. Related Party Transactions

In July 2003, the Company acquired the THAI™ and CAPRI™ patented heavy oil recovery technologies indirectly from two directors of the Company, and a third party, pursuant to an agreement made by an independent committee of the Board of Directors. One of these directors recovered his $226,000 investment and the other received cash of $189,000 on his $226,000 investment and retained a 7.5 percent net profits interest in any future third-party licensing royalties generated from the technologies. Currently, the technologies are unproven, but Petrobank plans to commence a pilot test of the THAI™ technology in Petrobank's WHITESANDS INSITU Ltd. subsidiary in 2004.

In January 2004, the Company paid a $200,000 commitment fee to secure a $10 million credit facility from a company controlled by a director of Petrobank. Any balances outstanding under the facility would bear interest at 12 percent per annum and would be subordinate to Petrobank's existing secured bank debt (Note 5). To date, the Company has not drawn on this facility, which expires on December 30, 2004.

11. Financial Instruments and Financial Risk Management

The nature of oil and natural gas operations and the issuance of debt expose the Company to fluctuations in commodity prices, foreign currency exchange rates and interest rates. The Company manages these risks by operating in a manner that minimizes its exposure to the extent practical, and through the periodic use of derivative instruments. The Board of Directors periodically reviews the results of all derivative activities and all outstanding positions.

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. The majority of the Company's Canadian production is sold to various large creditworthy counterparties. All Colombian oil production during 2003 was sold to the Colombian state oil company, Ecopetrol. The Company's maximum credit exposure to customers is revenue from two month's sales. While counterparties to derivative instruments expose the Company to losses in the event of non-performance, the Company currently only deals with large creditworthy institutions, and does not anticipate non-performance by these counterparties.

Commodity Price Risk Management

Financial Derivative and Physical Oil Sale Contracts

At December 31, 2003, the following financial derivative contracts and fixed price sale contracts were outstanding:

Contract	Daily Volume	Term	Benchmark	Price
Crude oil swap [1]	1,000 bbls	January - December 2004	WTI	US$24.00
Crude oil fixed price sale	300 bbls	January - December 2004	WTI	US$27.74
Crude oil fixed price sale [2]	300 bbls	January - December 2004	WTI	US$27.68
Natural gas collar [1]	10,551 GJ	January - December 2004	AECO	$5.00 - $5.94

(1) The fair value liability of these contracts is supported by US$1.8 million of credit and US$2.0 million of cash deposited with two counterparties. This collateral is adjusted as the fair value of the related liability changes.

(2) In January 2004, the purchaser of the Company's Wapella property assumed this contract.

Long-Term Physical Gas Sale and Transportation Contracts

The Company is committed to deliver 2,225 GJ per day of natural gas under an escalating price contract that expires October 31, 2012. The wellhead price under this contract, at December 31, 2003, was set at $3.26 per GJ. The contract provides for an annual price escalation between 4 percent and 10 percent, based on hydroelectric and natural gas price inflation. Broader price re-determinations are to be made in 2007 and 2012, resulting in a new price that can vary from 65 percent to 135 percent of the previous year's price based on prevailing natural gas prices. The 4 percent minimum annual price escalation was assumed when calculating the fair value of this contract at December 31, 2003.

The Company holds 5,275 GJ per day of firm transportation service on the ANG and PGT pipeline systems through October 31, 2005. The Company may choose to ship gas on these pipelines to the Malin, Oregon delivery point, and receive the related market price less relevant transportation charges. The Company may elect not to ship gas on these pipelines by paying the relevant firm service transportation charges of $0.52 per GJ.

Fair Value of Financial Instruments

The estimated fair values of the following financial instruments at December 31, 2003 are:

	Carrying Value	Fair Value
Liabilities		
Financial derivative and physical oil sale contracts	$ -	$ 5,208
Physical gas sale and transportation contracts	$ 7,287	$ 1,744
Subordinated notes	$ 93,430	$ 93,417

The fair values of the Company's remaining financial instruments at December 31, 2003 approximate their carrying values. Fair values of financial derivative contracts, physical sale contracts and transportation contracts are determined based on the estimated cash payment or receipt necessary to settle the contracts at December 31, 2003. Cash payments are calculated based on discounted cash flow analysis using prevailing market prices at the time. The estimated fair value of the subordinated notes is based on public trading values on January 2, 2004.

12. Changes in Other Non-Cash Items

	2003	2002
Accounts receivable and other current assets	$ (10,007)	$ 9,274
Accounts payable and accrued liabilities	6,041	7,200
Non-cash working capital deficiency acquired	(1,972)	(610)
	$ (5,938)	$ 15,864
Attributable to operating activities	$ (8,772)	$ 4,728
Attributable to financing activities	$ -	$ (878)
Attributable to investing activities	$ 2,834	$ 12,014

13. Commitments and Contingencies

In Colombia, the Company has fulfilled its commitments on the Orito Block and has US$2.0 million of remaining work commitments on the Neiva Block that are required to be completed by June 2004. In October 2003, the Company signed a new exploration contract on a 390,000-acre block ("Bloque Colombia") in the Upper Magdalena Valley, 70 kilometres northeast of our Neiva Block. Petrobank has a one-third, non-operated interest in the block with an estimated US$0.3 million (net) phase-one work commitment that is required to be completed by October 2004. After completion of the phase-one work commitment, the Company and its joint-venture partners have the option to relinquish the block, drill a well at an estimated net cost of US$1.5 million, or shoot 120 kilometres of 2-D seismic.

Petrobank is committed to payments under operating leases for office space, net of sub-lease arrangements, as follows:

2004	$ 550
2005	550
2006	180
	$ 1,280

The Company is party to certain legal actions relating to disputes with industry participants, the outcome of which cannot be reasonably determined. In the opinion of management, the resolution of these matters will not have a material effect on the Company's financial position or results of operations.

The Company has entered into certain types of contracts, particularly those related to divestiture transactions that require us to indemnify parties against possible third-party claims. These obligations are typically limited to the amount of sales proceeds and expire within one year in the case of property dispositions. Management does not expect payments, if any, related to such matters to have a material effect on the Company's financial position or results of operations.

14. Subsequent Events

On January 28, 2004, the Company closed the sale of its Wapella property in Southeast Saskatchewan for total cash proceeds of $36.0 million. The proceeds were used to repay the $14.0 million debenture (Note 3) and to reduce the outstanding balance under the Company's secured bank credit facility (Note 5).

15. Segmented Information

The Company commenced commercial production from its Colombian operations in January 2003 and accordingly segmented results are presented below as at and for the twelve-month period ended December 31, 2003 along with capital expenditure information for the year ended December 31, 2002:

2003	Canada and Other	Colombia	Total
Revenues			
Oil and natural gas	$ 53,551	$ 12,560	**$ 66,111**
Royalties	(11,114)	(997)	**(12,111)**
	42,437	11,563	**54,000**
Expenses			
Production	12,683	4,087	**16,770**
General and administrative	4,012	1,928	**5,940**
Depletion, depreciation and site restoration	19,786	7,577	**27,363**
Impairment	1,900	15,000	**16,900**
Segmented income (loss)	$ 4,056	$ (17,029)	**(12,973)**
Non-segmented items			
Interest			**(771)**
Other expense			**(48)**
Capital and future income tax expense			**(899)**
Net loss			**(14,691)**
Interest on subordinated notes			**(8,420)**
Net loss attributable to common shareholders			**$ (23,111)**
Identifiable assets	$ 187,396	$ 66,139	**$ 253,535**
Net capital expenditures	$ 24,270	$ 71,342	**$ 95,612**
2002			
Net capital expenditures	$ 27,259	$ 15,635	**$ 42,894**

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PETROBANK ENERGY AND RESOURCES LTD.

RENEWAL ANNUAL INFORMATION FORM

FOR THE YEAR ENDED DECEMBER 31, 2003

MAY 19, 2004

TABLE OF CONTENTS

ABBREVIATIONS AND DEFINITIONS....1
SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENT....2
THE COMPANY....3
Incorporation and Organization....3
Three-Year History....3
Trends....4
BUSINESS OF THE COMPANY....5
Production....5
Principal Properties....6
Western Canadian Focus Areas....6
Colombia....9
WHITESANDS Project....12
STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION....13
Disclosure of Reserves Data....13
Notes to Reserve Data Tables....14
Undeveloped Reserves....16
Significant Factors or Uncertainties Affecting Reserves Data....17
Oil and Gas Wells....18
Undeveloped Land Holdings....18
Future Commitments....18
Additional Information Concerning Abandonment and Reclamation Costs....18
Tax Horizon....19
Capital Expenditures....19
Exploration and Development....19
History....20
INDUSTRY CONDITIONS....21
Canada....21
General....21
Environmental....23
Colombia....23
RISK FACTORS....24
SELECTED ANNUAL FINANCIAL INFORMATION....27
DIVIDEND RECORD....27
MANAGEMENT'S DISCUSSION AND ANALYSIS....27
MARKET FOR SECURITIES....27
DIRECTORS AND OFFICERS....28
CONFLICTS OF INTEREST....30
PERSONNEL....30
ADDITIONAL INFORMATION....30
APPENDIX A....A-1
APPENDIX B....B-1
APPENDIX C....C-1

ABBREVIATIONS AND DEFINITIONS

In this Annual Information Form, the abbreviations set forth below have the following meanings:

"M$"	Thousands of Canadian dollars	**"mmcf"**	1,000,000 cubic feet
"MM$"	Millions of Canadian dollars	**"bcf"**	1,000,000,000 cubic feet
"bbl"	Barrel	**"mcf/d"**	One thousand cubic feet per day
"bbl/d"	Barrels per day	**"mcfe"**	1,000 cubic feet of gas equivalent
"mbbl"	1,000 barrels	**"mmcf/d"**	One million cubic feet per day
"mmbbl"	1,000,000 barrels	**"boe"**	Barrel of oil equivalent
"bbl/d"	Barrels per day	**"mboe"**	1,000 barrels of oil equivalent
"stb"	Stock tank barrel	**"boe/d"**	Barrel of oil equivalent per day
"mstb"	1,000 stock tank barrels		
"NGLs"	Natural gas liquids	**"m3"**	Cubic metre
"mcf"	1,000 cubic feet	**"U.S.$"**	United States Dollars

Note: Disclosure provided herein in respect of boes may be misleading, particularly if used in isolation. A boe conversion ratio of 6 mcf:1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

In this Annual Information Form, the capitalized terms set forth below have the following meanings:

"ABCA" means the *Business Corporations Act*, R.S.A. 2000, c. B-9, as amended, together with any amendments thereto and all regulations promulgated thereunder;

"ARTC" means the Alberta royalty tax credit;

"COGE Handbook" means the Canadian Oil and Gas Evaluation Handbook prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy and Petroleum.

"Common Shares" means common shares in the share capital of the Company;

"GAAP" means Canadian generally accepted accounting principles;

"GLJ" means Gilbert Laustsen Jung Associates Ltd., independent oil and gas reservoir engineers of Calgary, Alberta;

"GLJ Report" means the independent engineering evaluation of Petrobank's crude oil and natural gas reserves prepared by GLJ, dated May 7, 2004 and effective January 1, 2004;

"Gross" means:

(a) in relation to the Company's interest in production and reserves, its "Company gross reserves", which are the Company's working interest (operating and non-operating) share before deduction of royalties and without including any royalty interest of the Company;

(b) in relation to wells, the total number of wells in which the Company has an interest; and

(c) in relation to properties, the total area of properties in which the Company has an interest;

"Net" means:

(a) in relation to the Company's interest in production and reserves, its "Company gross reserves", which are the Company's working interest (operating and non-operating) share after deduction of royalties obligations, plus the Company's royalty interest in production or reserves.

(b) in relation to wells, the number of wells obtained by aggregating the Company's working interest in each of its gross wells; and

(c) in relation to the Company's interest in a property, the total area in which the Company has an interest multiplied by the working interest owned by the Company;

"NI 51-101" means National Instrument 51-101 Standards of Disclosure for Oil and Gas Activities;

"Petrobank" or the **"Company"** means Petrobank Energy and Resources Ltd., together with its wholly-owned subsidiaries; and

"TSX" means the Toronto Stock Exchange.

Certain other terms used in this Annual Information Form but not defined herein are defined in NI 51-101 and, unless the context otherwise requires, shall have the same meanings herein as in NI 51-101.

In this Annual Information Form, references to "dollars" and "$" are to the currency of Canada, unless otherwise indicated.

Unless otherwise noted, the Company's average daily production volumes disclosed herein are based on the Company's working interest production before deduction of royalties paid to others and including royalty volumes received.

The estimates of reserves and future net revenue for individual properties may not reflect the same confidence level as estimates of reserves and future net revenue for all properties, due to the effects of aggregation.

SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENT

Petrobank is hereby providing cautionary statements identifying important factors that could cause the Company's actual results to differ materially from those projected in forward-looking statements made in this Annual Information Form. Any statements that express, or involve discussions as to, expectations, beliefs, plans, objectives, assumptions or future events or performance (often, but not always, through the use of words or phrases such as "will likely result," "are expected to," "will continue," "is anticipated," "estimated," "intends," "plans," "projection" and "outlook") 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 the forward looking statements. Accordingly, any such statements are qualified in their entirety by reference to, and are accompanied by, the factors discussed throughout this Annual Information Form. Among the key factors that have a direct bearing on the Company's results of operations are the nature of the Company's involvement in the business of exploration for, and development and production of oil and natural gas reserves, fluctuations in prices received for oil and natural gas, fluctuations in interest rates and the fluctuation of the exchange rate between the Canadian dollar and the United States dollar. These and other factors are discussed herein under "Risk Factors" and under "Management's Discussion and Analysis", incorporated by reference from the Company's 2003 Annual Report, and elsewhere in this Annual Information Form.

Because actual results or outcomes could differ materially from those expressed in any forward-looking statements of the Company made by or on behalf of the Company, investors should not place undue reliance on any such forward-looking statements. 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: the ability to economically test, develop and utilize the technologies described herein, the feasibility of the technologies, general economic, market and business conditions; fluctuations in oil and gas prices; the results of exploration and development of drilling and related activities; fluctuation in foreign currency exchange rates; the uncertainty of reserve estimates; changes in environmental and other regulations; risks associated with oil and gas operations; and other factors, many of which are beyond the control of the Company. Further, any forward-looking statement is made only as of a certain date, and the Company undertakes no obligation to update any forward-looking statement or statements to reflect events or circumstances after the date on which such statement is made or to reflect the occurrence of unanticipated events, except as required by applicable securities laws. New factors emerge from time to time, and it is not possible for management to predict all of these factors and to assess in advance the impact of each such factor on the Company's business or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statement.

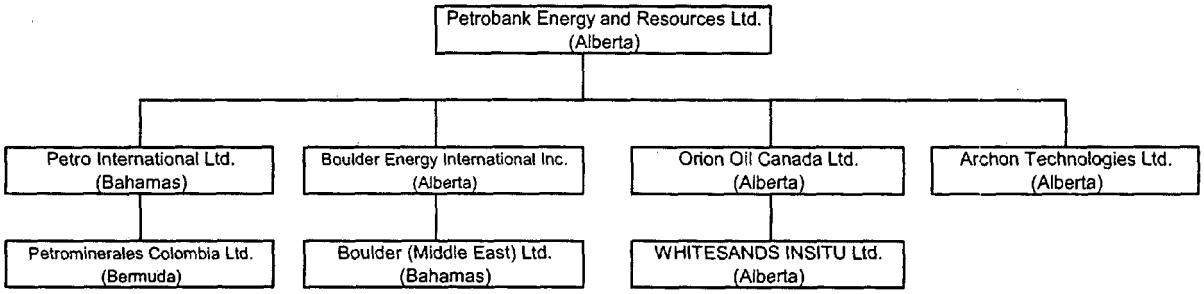
THE COMPANY

Incorporation and Organization

The Company was incorporated under the ABCA on December 1, 1983 as "Petrobank Energy Resources Ltd.". On September 8, 1986, Articles of Amendment were filed to change the Company's name to "Petrobank Energy and Resources Ltd.". On September 8, 1993, the Company filed Articles of Amendment to delete the private company restrictions thereunder. On March 7, 2000, the Company filed Articles of Amendment to create the first series of Preferred Shares designated as Preferred Shares, Series A and on August 22, 2000 to create the second and third series of Preferred Shares designated as Preferred Shares, Series B and Series C. On January 1, 2002, the Company filed Articles of Amalgamation to amalgamate with its wholly owned subsidiary, Barrington Petroleum Ltd. ("Barrington").

The Company's principal office and registered office is located at Suite 2600, 240 - 4th Avenue S.W., Calgary, Alberta, T2P 4H4.

The Company's material operating subsidiaries, each of which is wholly-owned, and their jurisdictions of incorporation are as follows:



Three-Year History

On January 16, 2001, the Company disposed of its properties in the Alder Flats area of Alberta for net proceeds of $85.1 million.

On April 12, 2001, the Company acquired 97.2% of the outstanding common shares of Barrington for consideration of $0.68 per Barrington common share. The total cash purchase price totalled $52 million.

On April 23, 2001, the Company disposed of its properties in the Blood Magrath area of Alberta for net proceeds of $15.9 million.

On July 18, 2001, Petrobank's plan of arrangement with Barrington was made effective whereby Petrobank acquired the remaining 2.8% interest in Barrington for consideration of $0.70 per Barrington common share or $1.3 million. In addition, the former holders of $50 million of Barrington gas linked notes paying interest at 12% per annum, agreed to exchange their notes into $47.5 million of new Petrobank subordinated notes paying 9% per annum interest. Barrington noteholders also subscribed for an additional $13 million of Petrobank subordinated notes.

Through the remainder of 2001, the Company completed a series of non-core area dispositions resulting in proceeds of $60.6 million.

In May 2002, the Company assumed work commitments totalling U.S.$46 million on two incremental production (IP) blocks and three exploration blocks in Colombia. At December 31, 2003, the Company's remaining work commitments on these blocks totalled U.S. $2.0 million.

In November 2002, the Company reorganized its management into three business units; Canada, Latin America and Heavy Oil. The Heavy Oil business unit is operating through Petrobank's wholly owned subsidiary's, Orion Oil Canada Ltd. and WHITESANDS INSITU Ltd., which was created to undertake the world's first field pilot of the THAI™ in situ heavy oil recovery and upgrading technology.

In January 2003 the Company commenced oil sales from its Colombian operations.

In May 2003 the Company issued an additional $40 million of subordinated notes for net proceeds of $34.4 million.

In May 2003 the Company disposed of its Zama/Larne property in Northwest Alberta, which was producing approximately 700 boe per day, for proceeds of $ 16.6 million.

In July 2003, the Company acquired the intellectual property rights to the THAI™ and CAPRI ™ patented heavy oil recovery technologies.

On September 19, 2003 the Company acquired Monolith Oil Corp. ("Monolith") for $39.6 million; production from the acquired properties averaged 2,325 boe per day between the closing date and December 31, 2003.

In September 2003, Petrobank issued 2.78 million flow-through common shares for gross proceeds for $10.0 million.

In the Heavy Oil Business Unit, the Company invested $4 million in 2003 to evaluate its existing reserve base with 3-D seismic and three delineation wells. It also conducted all necessary studies and completed initial engineering design work for the pilot project. The Company filed the WHITESANDS (THAI™) experimental pilot project application with the Alberta Energy and Utilities Board (AEUB) and Alberta Environment (AENV) in October 2003 and received approval on February 22, 2004.

In January 2004 Petrobank sold its Wapella property, which produced 1,324 barrels of oil per day in the fourth quarter of 2003, for proceeds of $36.0 million.

Trends

There are a number of trends that have been developing in the oil and gas industry during the past few years that appear to be shaping the future of the business. The first trend is the increasing consolidation and/or conversion to royalty trusts within the industry. This has affected companies of all sizes from the small emerging companies to the senior integrated companies, increasing competition for assets resulting in higher prices being paid. This trend continued throughout 2003 with numerous companies converting to, or selling to, royalty trusts.

The second trend is the influence of foreign exploration and production companies on the Canadian oil and gas industry. The main influence has been from American companies who have acquired oil and gas companies and assets in Canada in order to build long-term natural gas supplies for shipment to the United States and to develop projects in the oil sands. This trend will continue to influence valuation parameters of Canadian assets and should result in stable values for Canadian companies and assets.

A third trend is the continued volatility of both natural gas and crude oil prices. Natural gas is a commodity influenced by factors primarily in North America. During 2003 we saw record drilling but continental natural gas production did not increase, nor did this drilling result in net reserve additions over production. As we enter 2004, natural gas prices have remained strong. Crude oil is influenced by global demand driven by economic growth and OPEC's ability to adjust its supply to balance demand. Oil prices have been stronger due to higher demand associated with recovering world economies and growing demand from developing countries. This has been supported by the influence of both OPEC production cuts and the political instability in the Middle East. Price volatility is expected to be an ongoing characteristic of the oil and natural gas industry.

The Canadian$/U.S.$ exchange rate also influences commodity prices for Canadian producers. The Canadian dollar strengthened significantly during 2003, which reduced revenues for both crude oil and natural gas.

BUSINESS OF THE COMPANY

The Company operates through three business units. The Canadian Business Unit combines conventional oil and gas operations with two higher-impact coal bed methane ("CBM") opportunities. The Company's conventional western Canadian operations are focused in three main areas, Nevis/Red Willow, Jumpbush and Western Saskatchewan. The Latin American Business Unit commenced commercial production from the Company's Colombian properties in January 2003. Colombian production is derived from two incremental production contracts at Orito and Neiva. The Heavy Oil Business Unit has received approval to proceed with its WHITESANDS pilot project to field-demonstrate Petrobank 's patented THAI™ heavy oil recovery process.

Production

The following table sets forth the Company's average daily production volumes, by major producing region, for the three and twelve month periods ended December 31, 2003.

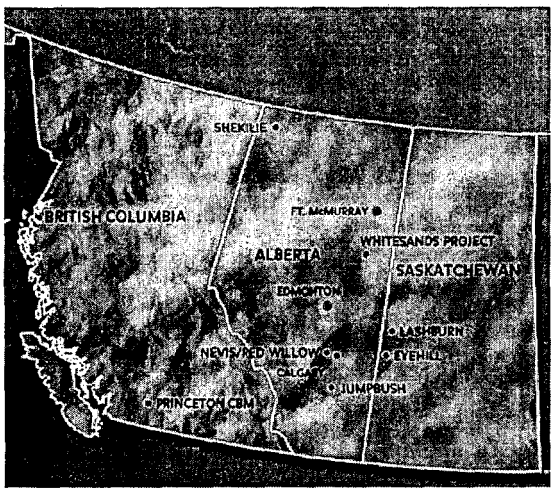
	Light/medium oil and NGLs (bbl) [1]		Heavy oil (bbl)		Gas (mcf)		Total (boe)	
	2003 Average	Q4 2003	2003 Average	Q4 2003	2003 Average	Q4 2003	2003 Average	Q4 2003
Canada								
Southeast Saskatchewan	1,432	1,354	-	-	-	-	1,432	1,354
Northwest Alberta	328	263	-	-	3,499	1,048	911	437
Western Saskatchewan	-	-	635	737	63	87	645	751
Nevis/Red Willow	66	282	-	-	3,465	11,936	643	2,271
Jumpbush	50	58	-	-	1,540	2,201	307	425
Other	265	190	64	47	2,254	2,430	705	642
Total-Canada	2,141	2,147	699	784	10,821	17,702	4,643	5,881
Colombia - Orito	630	908	-	-	-	-	630	908
Colombia - Neiva	438	466	-	-	-	-	438	466
Total-Colombia	1,068	1,374	-	-	-	-	1,068	1,374
Total	3,209	3,521	699	784	10,821	17,702	5,711	7,255

[1] NGLs have been included with light/medium oil as they are not considered to be material. NGLs represent less than 3% of the Company's Canadian total proved plus probable reserves.

Included in the above, is production from the Company's Wapella property in Southeast Saskatchewan, which was disposed of in January 2004 that produced an average of 1,402 barrels of oil per day in 2003 and 1,324 barrels of oil per day in the fourth quarter of 2003.

Principal Properties

Western Canadian Focus Areas



Nevis/Red Willow Alberta

The Nevis and Red Willow properties were the most significant assets acquired in the September 2003 Monolith purchase and cover a total of 43,800 gross acres (40,700 net acres). Production from these properties averaged 2,271 boe/d in the fourth quarter of 2003 from 31 gross wells (27 net). The primary drilling targets at these properties are the Glauconite and Ellerslie zones within the Mannville Group. Regionally, these sandstone reservoirs are characterized by high-deliverability natural gas, although high-deliverability oil production is not uncommon. Secondary targets in the area are the Edmonton, Belly River, Stettler and Nisku zones. The Edmonton and Belly River are sandstone reservoirs that tend to be long-term, low-deliverability natural gas. Although typically not our specific target, they frequently provide additional up-hole potential while drilling for deeper, more prolific zones. The deepest zones targeted by Petrobank in these areas are the Stettler and Nisku horizons, which are typically drilled only when they can be stacked with potential from the Glauconite or Ellerslie zones in order to mitigate drilling risk. The Stettler is a carbonate reservoir that offers long-term, low-productivity natural gas production. Currently the Company has no Stettler production but is in the process of tying in several wells that have tested commercial natural gas rates from this zone. The Nevis property is also situated on a narrow fairway that can offer prolific Nisku oil potential.

The Nevis and Red Willow properties were attractive to Petrobank because of the high working interest (mostly 100 percent), the high-netback production, the large number of drilling opportunities and the excellent infrastructure position. Production maintenance in these areas is operationally intensive, making it critical to have control over infrastructure. Petrobank's Nevis natural gas production is processed at Duke Energy's Nevis plant, which operates well below its capacity and could currently manage any additional gas produced by Petrobank in the area. Petrobank operates its own pipelines and compression in the area, providing the flexibility to optimize production. At Red Willow, Petrobank operates pipelines, a sour gas facility, satellite compression and a recently completed oil battery. Currently the facilities can manage all of the Company's production and can be expanded as required.

In 2003, Petrobank drilled one well at Nevis and two at Red Willow. The 2004 capital plan anticipates drilling 14 wells at Nevis and seven at Red Willow. At Nevis, five of the 2004 wells have already been drilled and all are cased for either oil or natural gas potential. The newest development to date has been the extent to which oil production is being added from the Glauconite zone at both properties. Petrobank's 2004 capital plan is dedicated to new wells, pipelines and facilities with a view to bringing on new production quickly. The Company anticipates spending approximately 40 percent of its 2004 Canadian capital plan in the Nevis and Red Willow areas.

Western Saskatchewan

Petrobank has three properties in the West Central Saskatchewan areas of Eyehill, Lashburn and Macklin. The most significant of which is the 100% working interest Eyehill property (11,500 acres) that produced an average of 423 bbl/day of heavy oil from the Sparky formation in the fourth quarter of 2003 from 18 gross/net wells. The Company produced an average of 136 boe/day in the fourth quarter of 2003 (mostly heavy oil with some associated natural gas) from its 60% working interest Lashburn property. The Macklin property (100% working interest) is comprised of seven sections of undeveloped acreage purchased for both Sparky and Cummings potential.

Petrobank developed the Eyehill pool during 2003 and 2003, with 18 wells and received regulatory approval for waterflood and well down spacing. The plans to implement the waterflood were delayed to allow both further technical evaluation of the waterflood's implementation and for the primary Sparky oil production to mature. In 2004, Petrobank plans to drill a step-out well to evaluate an extension to the Sparky oil potential.

In 2003 Petrobank drilled a horizontal well within the Lashburn pool. Petrobank has identified another six horizontal locations from its 3-D seismic interpretation. Petrobank plans to drill one of these horizontal locations in 2004 to employ what was learned from the completion and production of the first horizontal.

The Macklin property will require further seismic work to evaluate its full potential. However, utilizing the information from available 2-D seismic and an existing well capable of Cummings heavy oil production, Petrobank plans to drill a horizontal well in 2004 targeting a thick Cummings oil channel. Further drilling for both Sparky and Cummings potential would likely occur in 2005 following the acquisition of additional seismic.

Jumpbush Alberta

Petrobank's Jumpbush property is located on the Siksika First Nation, one hour's drive east of Calgary, where we are operator and 70-percent working-interest partner with Siksika Energy Resources Corporation ("SERC"). Our land base at Jumpbush grew considerably in 2003 through two transactions that added 35,000 gross acres to complement Petrobank's existing land and infrastructure position. All expiring prospective permit lands were drilled in 2003 to validate the Company's land base and establish a large, commercial shallow-gas project. At Jumpbush, Petrobank now holds 55,100 gross acres (38,500 net acres) of under-exploited lands. Jumpbush is a unique opportunity as it represents a large island of undeveloped acreage surrounded by non-reserve lands that have been intensely developed over the years. Petrobank has 56 gross wells (38 net) at Jumpbush and during the fourth quarter of 2003 the Company's production averaged 425 boe per day, 86 percent of which was natural gas with all production moving through our centrally-located facilities.

The focus for 2004 is to exploit the opportunities identified by the 2003 drilling and acquisition program. The Company plans to devote approximately one-third of its 2004 Canadian capital program to Jumpbush, where we expect to drill 30 shallow-gas wells and recomplete 20 wells targeting the Belly River and Medicine Hat formations. This production can provide superior economics for an operator that can maintain tight capital-cost control while continuously managing operations to minimize costs. To this end, the 2004 drilling program is focused on specific areas of our land base that will allow new production to be tied-in quickly to existing infrastructure or build the critical mass necessary to justify pipeline construction to our underutilized facilities. Our natural gas plant has 12 mmcf per day of total capacity (8.4 mmcf per day working interest), creating ample room to grow production from the Company's fourth-quarter 2003 rate of 2.2 mmcf per day.

Coalbed Methane (CBM) Projects

Industry recognition of the commercial potential of CBM, a vast resource in western Canada, has been growing rapidly. Since 2002, Petrobank has been establishing a CBM position in both the Western Canada Sedimentary Basin at Jumpbush, and also through a unique niche position in an isolated Tertiary Age basin around Princeton, B.C. Typically, viable CBM opportunities require a relatively large land position to justify the necessary field infrastructure to produce, process and manage the natural gas and any associated water production. The Jumpbush CBM project is attractive because Petrobank has a large land position at 70 percent working interest, the prospect is nearby existing infrastructure and because the coals have demonstrated the ability to flow gas in a

relatively short period of time with little or no water production. At Princeton, Petrobank (60 percent working interest) and its partners have secured the natural gas rights over an entire basin, which is relatively small in area but which contains very thick gas-bearing coals.

Jumpbush Alberta - CBM

In partnership with SERC, Petrobank has been developing a CBM project to complement the shallow gas program at Jumpbush. This area has potential for CBM in both the Belly River and Horseshoe Canyon coals and other operators are actively developing CBM projects in the vicinity. EnCana Corporation's ("EnCana") CBM projects at Entice and Rockyford are about 75 kilometers away from Petrobank's Jumpbush land position. Initially, the focus has been on the Lethbridge, Taber and McKay coals of the Belly River Formation, as these coals are expected to be at depths optimal for combining resource potential and permeability. The depths of the Belly River coals can be mapped from older wells drilled for deeper targets and are generally between 400 to 600 meters. Petrobank anticipates the costs to drill and complete a CBM well at these depths to be approximately $170,000.

In 2003, while drilling wells for conventional Belly River, Medicine Hat and Mannville natural gas targets, Petrobank cored and evaluated coals from four wells in the Jumpbush area to assess the CBM resource potential. Natural gas was tested at 100 mcf per day from a single coal zone in a well with multiple coal intervals present. Importantly, this production was free of water and in close proximity to our natural gas plant. In July of 2004 this well and at least four other existing nearby wells are to be perforated and stimulated in all three of the Belly River coal zones and, with successful flow rates, will be produced through a dedicated pipeline and compression infrastructure tied to Petrobank's nearby facility. Drilling for CBM alone would likely begin in May of 2005, and all gas from these wells can be brought on production relatively quickly because of Petrobank's local infrastructure. The Horseshoe Canyon coals are yet to be evaluated, but Petrobank plans to test a shallow Edmonton sand play in 2004 where the coals of the Horseshoe Canyon can be cored for evaluation.

The core analysis and production test on one of the coals has addressed many of the potential technical risks with this play. Petrobank can now estimate the potential resource size, permeability and lack of water saturation for this play. The main risk for Jumpbush CBM potential is the ability for the wells to deliver commercial quantities of production once additional wells are completed and stimulated. For these reasons Petrobank estimates the chance of commercial success to be approximately 50 percent.

Princeton British Columbia - CBM

Princeton is an attractive CBM opportunity because Petrobank (60% working interest) and its partners control the entire Princeton or Tulameen basin and the Tertiary age, gas-bearing coals are very thick. There are a number of other tertiary-aged coal-bearing basins present in South West British Columbia. The most well known is the Hat Creek basin which contains one of the thickest coal accumulations in the world at 1,750 feet of coal in a 3,850 foot section. The closest known commercial CBM project in Canada is EnCana's Rockyford / Entice CBM production in Southern Alberta approximately 580 kilometers to the East. The coals at Princeton appear to have an average thickness of 137 feet, approximately five to ten times the typical Alberta thickness. These coals can vary in economic depth from 300 meters to 1800 meters. Princeton is a longer-term project where the coal characteristics are less well-known, requiring more initial evaluation. Also, the government approval and the First Nation and community consultation processes are more time-intensive in areas like Princeton that are new to oil and natural gas activity.

Initially, Petrobank and its partners secured coal-mining rights in the area and drilled three mining test wells to evaluate the coal characteristics. The wells confirmed the quality of the basin's coal resource. In November of 2002 Petrobank acquired the petroleum and natural gas rights to the basin, which, without validation through drilling, will expire in November of 2007. In November of 2004 Petrobank acquired a 121-kilometre 2-D seismic program to map the basin and design a drilling strategy. Seismic interpretation confirmed the basin's geometry and our ability to map the underlying thick coal sequences. Petrobank has selected a drilling location in the southern portion of the Princeton basin for an initial test to further delineate the quality of the coal resource and to assess the permeability and gas saturation of the coals. The drilling location is considered representative of the basin and is suitable for a potential pilot project. This initial well will determine the viability of a pilot project on this site. The

pilot project could be drilled in late 2004 or early 2005, followed by a 6-12 month production-testing period. Plans for developing the resource could be completed and development could commence as early as 2006.

Drilling in this area is costly as equipment needs to be moved from Alberta. The first completion program will be expensive because of the extensive testing program required to assess potential. The drilling and completion of the first well is expected to be $600,000 and $700,000, respectively. Drilling a development program will allow Petrobank to distribute the costs of moving equipment over more wells and reduce the drilling and completion costs downwards to approximately $400,000 and $200,000, respectively.

CBM projects normally require a dewatering phase prior to commercial natural gas production. Typical ultimate production is 50-250 mcf per day per successful well although higher rates are encountered in other basins. Petrobank is maintaining a measured approach to investment of capital because of the risks that are not fully understood with this CBM project at this time. The first well is designed to address our most significant risks of permeability and water saturation. Petrobank feels that without further knowledge on these factors, the chance of commercial success is 20%. Drilling costs, dewatering time and individual well productivity will determine the commercial viability of this project. Petrobank is excited about the Princeton CBM project because of the large resource potential and the ease with which any successful natural gas production could be connected to market via the existing gas pipeline that runs through the Princeton property, facilitating the low-cost tie-in of future production.

Colombia

Colombia is an oil-rich country with major potential for value-creation through the application of current technologies and exploitation strategies to under-capitalized producing fields. Petrobank has Incremental Production Contracts ("IPCs") in two such fields in southwestern Colombia. Petrobank's strategy is to realize near-term cash flow from these exploitation opportunities by applying state-of-the-art-North American technical and business models, followed by opportunity-driven exploration as the region's additional geological potential unfolds. The Colombian government has encouraged foreign participation by making contracts available with generally attractive fiscal terms. Each IPC provides that Petrobank will share in a portion (initially 79 percent in the case of the Orito block and 69 percent in the case of Neiva) of the incremental production, above an established baseline production curve, generated by its development activities. Each IPC's established baseline of production, corresponds to the decline curve predicted by production from the field's production history. Petrobank's working interest production is subject to an initial 8 percent royalty paid to the government. See also "Industry Conditions–Colombia".



Orito

The Orito Field is the largest in southern Colombia's Putumayo Basin. The area has extensive field infrastructure, good seismic control and connection to an underutilized export pipeline with deep water loading facilities, enabling immediate fiscalization of any incremental oil production. Historically Ecopetrol, Colombia's state oil company, has managed the field without the capital resources needed for a comprehensive program of late-primary exploitation and secondary recovery. Pursuant to the IPC, Petrobank gains access to all existing infrastructure and data, while Ecopetrol participates in any incremental upside Petrobank generates over the life of the contract, which terminates in 2023. Petrobank holds 42,492 gross acres of land at Orito.

Orito offers numerous opportunities to create value through in-fill drilling, field extension, facilities upgrades, secondary recovery and other techniques proven in Canada and elsewhere in the world. Including baseline production, the Orito field produced an average of 4,187 barrels per day from 45 gross wells in 2003. Current baseline production is 3,170 barrels per day, while incremental production is approximately 1,700 bbls per day (1,350 barrels per day working interest to Petrobank before deduction of an eight percent royalty). The most significant of three reservoirs at Orito is the Cretaceous Caballos zone, which is estimated by the Company to have originally contained between 725 and 1,050 million barrels of original oil-in-place ("OOIP") resource. To date, the Orito field has produced a total of approximately 227 million barrels of oil, including approximately 187 million barrels from the Caballos zone. Consequently, the current Caballos recovery factor is in the range of 18 to 26 percent. The majority of expenditures to date have targeted this Caballos zone, as will be the case in 2004.

In 2003, all of Petrobank's wells were successful to varying degrees. The Orito-112, 113 and 115 wells are producing a total of approximately 1,000 bbl/d combined (790 bbl/d working interest). The structurally lower Orito-114 well produced water from the lower Caballos and has been shut in. Petrobank may re-enter this well, to plug back and isolate the shallower Caballos zones that produced oil during early testing.

Petrobank also performed seven workovers in 2003, which met with varying success. In the Orito-35, 72 and 90 wells, Petrobank re-perforated selected Caballos intervals and installed high-volume electric submersible pumps. This more than doubled average oil production from these wells. Workover activities did not increase production at the Orito-13, 14, 33 and 80 wells, due to well-bore and casing integrity problems.

The Caballos formation is a reservoir containing four major sand packages. As we now interpret the field, it has a strongly tilted oil-water contact that varies from a depth of 5,200 feet in the northern part of the field to 6,200 feet in the south. This aquifer provides pressure support to the Caballos reservoir as evidenced by relatively unchanged pressures since 1980. In addition, we now understand that the Caballos reservoir fluid is compositionally graded: ranging, at original conditions, from a conventional black ±30° API oil at structural low positions, increasing to a volatile ±50° API oil with decreasing depth, and culminating in a gas-condensate region at the very top of the reservoir. The complex fluid combined with the tilted contact and structural nature of the reservoir results in a system that has several drive processes occurring simultaneously. "Combination drive" reservoirs (water drive, solution gas drive, and gas cap expansion) tend to exhibit high recovery efficiencies that can be 30 to 40 percent of the original-oil-in-place. Cumulative total production from the Caballos zone of approximately 187 million barrels is considerably below average for a field of this type. To enhance current production, Petrobank is employing a combination of late-stage primary recovery techniques, such as drilling in-fill wells, changing from gas lift to electrical submersible pumps, and re-completing wells to enhance oil inflow.

Petrobank's 2004 plan for Orito will begin with completion of our revised Caballos compositional reservoir model that incorporates our new understanding of the reservoir's complex architecture and distribution of hydrocarbons. This work is expected to be followed by a two to three well drilling program in 2004, (U.S.$3.0 to U.S.$3.5 million dollars per well) focused on the high-potential areas of the field. Currently these potential areas may include drilling the oil rim surrounding the "gas cap" area of the Southern Dome, the liquids rich Southern Dome "gas cap", and continued pool extensions on the down dip edge of the Southern and Northern Domes afforded by the tilted oil-water contact. If these wells confirm our revised understanding of the Caballos reservoir, we would anticipate proceeding with a full-scale delineation program extending through 2005 and beyond. Petrobank will also launch a pilot-scale waterflood in the Caballos in 2004 at an estimated cost of U.S.$2.0 million dollars. A successful pilot could lead to a full-field waterflood, which could also generate additional reserves and production.

GLJ estimates in the GLJ Report that, at January 1, 2004, Petrobank had gross proved plus probable reserves at Orito (working interest 79%) of 5.8 million barrels (7.4 million barrels – gross lease). These are reserves in excess of the remaining reserves associated with Orito's defined baseline production of 14.5 million barrels representing a combined range in incremental recovery factors of 2-3 percent if it is sourced solely from the Caballos reservoir. Given that the Pepino and Villeta zones are currently contributing approximately 35% of the defined baseline production, the incremental recovery required solely from the Caballos zone is lower than that noted above. Major risks inherent in realization of these targets relate to the current distribution of water, oil and potentially gas in the Caballos reservoir. This should be mitigated with the new reservoir simulation model and by selecting structurally higher prospects or those focused more toward to southern portion of the field where the benefits of the tilted oil/water contact can be realized. Wellbore and mechanical integrity is also a risk especially when working with older baseline wells (pre-existing to the IPC contract).

Based on our initial reservoir model and geological and geophysical activities, we have identified four in-field and near-field areas that provide the majority of the potential we see in the Caballos reservoir. The "West" lead is a structural anomaly located immediately west of the main field and will require additional seismic data to identify a suitable drilling location. To the south of the field we have identified a second lead, which will be evaluated in 2005 or 2006 and requires additional 2D seismic.

Within the main Orito field, two areas have been highlighted for 2004 activity. In the structurally highest part of the field, where the Caballos reservoir was originally thought to contain only gas, we believe that the potential to encounter high gas-oil-ratio oil and condensate production is excellent. We foresee the potential of drilling an additional 7 wells in this area. After the completion of the new reservoir model, one of our 2004 wells will be drilled in this area to confirm this interpretation. Another area of immediate interest lies along the southwest flank of the field. In this area it is thought that significant amounts of reserves lie in undeveloped and bypassed parts of the Caballos reservoir and could accommodate an additional 10 drilling locations. Another of our 2004 wells is expected to target this area.

The probability of success for each area of the field varies related to its location within the field. We view the probability of success for the gas cap region as higher than the rest of the field due to its structurally higher position to all currently producing wells and the numerous historical production tests in the area. The primary risk in this area is the quantity of gas relative to liquid hydrocarbons produced.

Along the southwest extension to the field, the probability of success is also high, although we believe it will vary from well to well depending on position above the original oil/water contact and relative to other conduits (faults, etc.). In this area, completion of the reservoir simulation will be imperative to prioritize the locations we have identified.

The west extension and south extension have lower probabilities of success due to their position separate from the field proper and the current lack of conclusive data regarding the structural interpretation for these leads.

Neiva

The Neiva Field in the upper Magdalena Basin lies approximately 300 kilometres northeast of Orito. Neiva has shallow multi-zone reservoirs facilitating low-risk exploitation drilling. Petrobank holds 2,395 gross acres (1,653 net acres) of land at Neiva. Total Neiva production including baseline production averaged 3,438 barrels per day in 2003 from 62 gross wells. Neiva's reservoir consists of sand-shale sequences totalling up to 1,500 feet of gross pay. Efforts to date have been focused on the shallower Honda and Doima/Chicoral zones. The deeper Tenay/Caballos zone has been returned to Ecopetrol due to the technical risks and economics of drilling to this reservoir. Petrobank incurred no investment commitment in evaluating this reservoir.

In 2003 Petrobank completed its initial investment of more than U.S.$11 million but has committed to further development estimated to cost U.S.$2 million. In June 2004 the IPC will enter a 19-year phase during which Petrobank will evaluate and develop the field's remaining potential. Petrobank will continue to receive 69 percent of incremental production above estimated baseline production. Current baseline production is near 2,700 bbl/d while incremental production is approximately 650 barrels per day (450 barrels per day working interest to Petrobank

before deduction of an 8 percent royalty). To date Petrobank has drilled five Honda zone wells, one Doima-Chicoral well and performed 13 workovers.

Success will be determined by Petrobank's ability to reduce capital costs. Unfortunately, the current IPC terms and cost structure are not attractive relative to the opportunity and make further drilling marginally economic. Petrobank has begun discussions with Ecopetrol regarding improving field economics to enable continued development.

Central Colombia Block

This 400,000 acres (133,000 net) exploration block, located in the Upper Magdalena Basin, lies northeast of the Neiva field. Sipetrol, the Chilean national oil company, is the operator of this block with Petrobank holding a one-third interest.

As at Orito, the target oil reservoir on this prospect is the Lower Cretaceous Caballos, with the primary risk in this prospect being the timing of hydrocarbon migration relative to the timing of formation of the trap. Petrobank and partners have identified a significant target based on 2-D seismic. Oil quality on this block is expected to be approximately 36 degrees API and production would be exported at Coveñas, the Caribbean port. Expected prices given expected crude quality and location would be WTI less approximately U.S.$5.00 per barrel.

Petrobank and partners plan to finalize interpretation of the prospect during the first half of 2004, at which time we expect to make the decision of whether to proceed to the next phase of the exploration contract, with the option of drilling an initial exploratory well at an estimated cost of U.S.$5 million dollars (U.S.$1.7 million net to Petrobank) or acquiring 3-D seismic at an estimated cost of U.S.$3.9 million (U.S.$1.3 million net to Petrobank) beginning as early as the fourth quarter of this year. The contract has three phases of varying commitment with termination in 2031.

WHITESANDS Project

Petrobank, through WHITESANDS Insitu Ltd. ("WHITESANDS"), a wholly owned subsidiary, has a 100% working interest in 45 sections of oil sands leases located at Township 77-78 Range 8&9 W4M (28,800 gross acres) near the Hamlet of Conklin, Alberta (the "Lands"). A third party holds a 2% net profits interest in 20 sections of the 45 sections comprising the Lands. The oil sands bitumen deposit is contained within the cretaceous a McMurray filled valley sandstone at a depth of 350 to 400 meters. The Lands are Crown leased with a primary term to the year 2015. With commercial development the Lands can be held indefinitely. The nearest commercial production to the Lands is at the EnCana Christina Lake SAGD (Steam Assisted Gravity Drainage) project approximately 24 km east of the Lands.

In 2003, Petrobank conducted a 20-square kilometre seismic survey and completed three stratigraphic cored wells on the Lands in the area of a proposed pilot project. In 2004, Fekete Associates Inc. ("Fekete") completed a resource evaluation of the Lands incorporating existing well data regionally and over the Lands, along with the seismic and drilling work carried out by Petrobank in 2003. In a report dated April 8, 2004, Fekete estimates original in-place bitumen resources in the order of 1 billion barrels, plus or minus 20%. This translates to an in-place bitumen resource estimate of 831million barrels in the Middle McMurray sands and 484 million barrels in the Upper McMurray sands. Reserves have yet to be assigned to these Lands.

Petrobank, through WHITESANDS, intends to undertake an experimental pilot project to demonstrate the patented THAI™ *in-situ* heavy oil recovery process in the oil sands resource on the Lands. To this end, Petrobank filed an application to conduct a THAI™ pilot project on the lands in October 2003. In February 2004, the WHITESANDS Pilot Project received approval from the Alberta Energy and Utilities Board (AEUB) and Alberta Environment (AENV). The approval was the culmination of rigorous technical and environmental scrutiny by the regulatory authorities.

The pilot project will consist of three horizontal wells (500 meters long and 100 meters apart), three vertical air injection wells, and 19 vertical observation wells (17 for temperature and 2 for pressure observations).

The Company has designed the pilot for peak production of 600 barrels of oil per day for each well. The total capital cost of the project is estimated to be $30 million with first results expected in early-2005. The timing of the pilot project is however contingent upon obtaining project financing. To that end, on January 15, 2004, Petrobank retained TD Securities Inc. and Tristone Capital Inc., on behalf of WHITESANDS to arrange equity financing for the estimated capital cost of the pilot project. It is currently proposed that the financing will be effected by the issuance of up to a 40% equity interest in WHITESANDS. The financing has not closed and discussions are currently being held with potential investors.

While the Lands would support a large-scale Steam Assisted Gravity Drainage ("SAGD") development, a successful demonstration the THAI™ in-situ combustion process would create a "step change" beyond SAGD.

The potential benefits of the THAI™ process include a higher recovery rate of the oil in place, negligible use of natural gas and water, lower greenhouse gas emissions and lower capital and operating costs. Pilot project risks include technical (related to the THAI™ process), geological, project execution, operating and financing.

The THAI™ process was initially discovered, developed and tested using scaled physical reactor models and further evaluated using field scale numerical reservoir computer simulation models. The laboratory work demonstrated the key physical and process elements of the technology and the numerical simulation work confirmed the process efficacy at a field scale and under actual reservoir conditions. The next step in the technology's development is to demonstrate it under actual field conditions which is the purpose of the WHITESANDS pilot project. Despite the significant amount of research and development which has demonstrated the efficacy of the process as well as its economic and environmental benefits there is still a significant risk associated with the performance of the technology under actual field conditions.

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

The statement of reserves data and other oil and gas information set forth herein and in Appendix A (the "Statement") is dated May 19, 2004. The effective date of the Statement is January 1, 2004 and the preparation date of the Statement is February 10, 2004 (Canada) and February 15, 2004 (Colombia).

Disclosure of Reserves Data

The reserves data set forth below and in Appendix A is based upon an evaluation by GLJ with an effective date of January 1, 2004 contained in the GLJ Report dated May 7, 2004. The reserves data summarizes the oil, liquids and natural gas reserves of the Company and the net present values of future net revenue for these reserves using constant prices and costs and forecast prices and costs. The Reserves Data conforms with the requirements of NI 51-101. Additional information not required by NI 51-101 has been presented to provide continuity and additional information which we believe is important to the readers of this information. Petrobank engaged GLJ to provide an evaluation of proved and proved plus probable reserves and no attempt was made to evaluate possible reserves.

All of the Company's reserves are in Colombia and Canada (specifically, in the provinces of Alberta and Saskatchewan).

In preparing the GLJ Report, GLJ obtained basic information from Petrobank, which included land data, well information, geological information, reservoir studies, estimates of on-stream dates, contract information, current hydrocarbon product prices, operating cost data, capital budget forecasts, financial data and future operating plans. Other engineering, geological or economic data required to conduct the evaluation and upon which the GLJ Report is based, was obtained from public records, other operators and from GLJ's non-confidential files. The extent and character of ownership and the accuracy of all factual data supplied for the independent evaluation, from all sources, was accepted by GLJ as represented.

The tables contained in Appendix A attached hereto, based on the GLJ Report, show the estimated share of Petrobank's crude oil, natural gas and NGLs reserves in its properties and the present value of estimated future net revenue for these reserves, after provision for ARTC (as applicable) and Alberta gas cost allowance, using forecast and constant prices and costs as indicated. Canadian reserves are presented both including and excluding the

Company's Wapella property which was sold effective December 31, 2003 but did not close until January 28, 2004. Colombian estimated future net revenue is presented in U.S. dollars and in presenting Company totals has been converted into Canadian dollars using an exchange rate of Cdn.$/U.S.$0.75 for the forecast price case and Cdn.$/U.S.$0.7738 for the constant price case. **All evaluations and reviews of future net cash flow are stated prior to any provision for interest costs or general and administrative costs and after the deduction of estimated future capital expenditures for wells to which reserves have been assigned and future site restoration and reclamation costs for all the Company's wells. It should not be assumed that the estimated future net cash flow shown below is representative of the fair market value of the Company's properties. There is no assurance that such price and cost assumptions will be attained and variances could be material. The recovery and reserve estimates of crude oil, NGLs and natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual crude oil, NGLs and natural gas reserves may be greater than or less than the estimates provided herein.**

The reserves data contained in Appendix A is based on GLJ's price forecast published in January. Reserve disclosures contained in the Company's news release dated March 31, 2004 and the 2003 annual report were based on GLJ's April 2004 price forecast.

Notes to Reserve Data Tables

In the tables set forth in Appendix A and elsewhere in this Annual Information Form the following definitions and other notes are applicable:

1. Crude oil, natural gas liquids and natural gas reserves estimates presented in the GLJ Report are based on the definitions and guidelines contained in the COGE Handbook. A summary of those definitions are set forth below:

   Reserve Categories

   Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, from a given date forward, based on:

   - analysis of drilling, geological, geophysical and engineering data;
   - the use of established technology; and
   - specified economic conditions.

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

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

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

   Other criteria that must also be met for the categorization of reserves are provided in the COGE Handbook.

   Each of the reserve categories (proved and probable) may be divided into developed and undeveloped categories:

   (c) **Developed reserves** are those reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (for

example, when compared to the cost of drilling a well) to put the reserves on production. The developed category may be subdivided into producing and non-producing.

(i) **Developed producing reserves** are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut-in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.

(ii) **Developed non-producing reserves** are those reserves that either have not been on production, or have previously been on production, but are shut-in, and the date of resumption of production is unknown.

(d) **Undeveloped reserves** are those reserves expected to be recovered from known accumulations where a significant expenditure (for example, when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves classification (proved, probable) to which they are assigned.

In multi-well pools it may be appropriate to allocate total pool reserves between the developed and undeveloped categories or to subdivide the developed reserves for the pool between developed producing and developed non-producing. This allocation should be based on the estimator's assessment as to the reserves that will be recovered from specific wells, facilities and completion intervals in the pool and their respective development and production status.

Levels of Certainty for Reported Reserves

The qualitative certainty levels referred to in the definitions above are applicable to individual reserve entities (which refers to the lowest level at which reserves calculations are performed) and to reported reserves (which refers to the highest level sum of individual entity estimates for which reserves are presented). Reported reserves should target the following levels of certainty under a specific set of economic conditions:

(a) at least a 90 percent probability that the quantities actually recovered will equal or exceed the estimated proved reserves; and

(b) at least a 50 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable reserves.

A qualitative measure of the certainty levels pertaining to estimates prepared for the various reserves categories is desirable to provide a clearer understanding of the associated risks and uncertainties. However, the majority of reserves estimates will be prepared using deterministic methods that do not provide a mathematically derived quantitative measure of probability. In principle, there should be no difference between estimates prepared using probabilistic or deterministic methods.

Additional clarification of certainty levels associated with reserve estimates and the effect of aggregation is provided in the COGE Handbook.

2. Forecast prices and costs

Future prices and costs that are:

(a) generally acceptable as being a reasonable outlook of the future; and

(b) if and only to the extent that, there are fixed or presently determinable future prices or costs to which the Company is legally bound by a contractual or other obligation to supply a physical product,

including those for an extension period of a contract that is likely to be extended, those prices or costs rather than the prices and costs referred to in paragraph (a).

The forecast summary table contained on page A-9 of Appendix A identifies benchmark reference pricing utilized in the GLJ Report.

3. Constant prices and costs

Prices and costs used in an estimate that are:

(a) the Company's prices and costs as at the effective date of the estimation, held constant throughout the estimated lives of the properties to which the estimate applies; and

(b) if, and only to the extent that, there are fixed or presently determinable future prices or costs to which the Company is legally bound by a contractual or other obligation to supply a physical product, including those for an extension period of a contract that is likely to be extended, those prices or costs rather than the prices and costs referred to in paragraph (a).

For the purposes of paragraph (a), the Company's prices are the posted prices for oil and the spot price for gas, after historical adjustments for transportation, gravity and other factors.

The constant crude oil, natural gas and natural gas liquids benchmark reference pricing and the exchange rate utilized in the GLJ Report were as set forth on page A-9 of Appendix A.

4. ARTC is included in the cumulative cash flow amounts. ARTC is based on the program announced November 1989 by the Alberta government with modifications effective January 1, 1995. The Company qualifies for the maximum ARTC.

5. Estimated future abandonment and reclamation costs related to a property have been taken into account by GLJ in determining reserves that should be attributed to a property and in determining the aggregate future net revenue therefrom, there was deducted the reasonable estimated future well abandonment costs.

6. Columns may not add due to rounding.

7. Both the constant and forecast price and cost assumptions assumed the continuance of current laws and regulations.

8. The extended character of all factual data supplied to GLJ were accepted by GLJ as represented. No field inspection was conducted.

Undeveloped Reserves

Subject to the success of operations, within the next two years, the Company has the following plans regarding the development of proved and probable undeveloped reserves:

1) The Company's undeveloped medium to light oil reserves in the GLJ Report are located in Colombia within the Orito, Caballos reservoir. The Company's proven undeveloped reserves in this reservoir are planned to be developed through the drilling of three new locations and probable undeveloped reserves are planned to be developed through the drilling of two new locations.

2) The Company's undeveloped heavy crude oil reserves are planned to be developed from two projects:

   (a) At Lashburn, one additional horizontal well is planned to be drilled to develop proved undeveloped reserves and four horizontal wells are planned to be drilled to develop

probable undeveloped reserves. These wells are planned in the next two years contingent on optimizing the current horizontal well drilled in 2003.

(b) A waterflood at Eyehill is expected to be implemented within the next two years where seven new wells are planned to be drilled to develop proved undeveloped reserves and two new wells are planned to be drilled to develop probable undeveloped reserves.

3) The undeveloped natural gas reserves are mainly planned to be developed through the Company's 2004 (28 well) drilling program at Jumpbush where 14 wells are planned to develop proved undeveloped reserves and 14 wells are planned to develop probable undeveloped reserves.

Undeveloped reserves, like all projects, are subject to competition for capital and consequently may be delayed or accelerated from time to time.

Significant Factors or Uncertainties Affecting Reserves Data

There are numerous uncertainties inherent in estimating quantities of proved reserves, including many factors beyond the control of the Company. The reserve data included herein represents estimates only. In general, estimates of economically recoverable oil and natural gas reserves and the future net cash flows therefrom are based upon a number of variable factors and assumptions, such as historical production from the properties, the assumed effects of regulation by governmental agencies and future operating costs, all of which may vary considerably from actual results. All such estimates are to some degree speculative, and classifications of reserves are only attempts to define the degree of speculation involved. For those reasons, estimates of the economically recoverable oil and natural gas reserves attributable to any particular group of properties, classification of such reserves based on risk of recovery and estimates of future net revenues expected therefrom, prepared by different engineers or by the same engineers at different times, may vary substantially. The actual production, revenues, taxes and development and operating expenditures of the Company with respect to these reserves will vary from such estimates, and such variances could be material.

Estimates with respect to proved reserves that may be developed and produced in the future are often based upon volumetric calculations and upon analogy to similar types of reserves rather than actual production history. Estimates based on these methods are generally less reliable than those based on actual production history. Subsequent evaluation of the same reserves based upon production history will result in variations, which may be substantial, in the estimated reserves.

Consistent with the securities disclosure legislation and policies of Canada, the Company has used forecast prices and costs in calculating reserve quantities included herein. Actual future net cash flows also will be affected by other factors such as actual production levels, supply and demand for oil and natural gas, curtailments or increases in consumption by oil and natural gas purchasers, changes in governmental regulation or taxation and the impact of inflation on costs.

Oil and Gas Wells

The following table summarizes Petrobank's interests as at December 31, 2003 in oil and natural gas wells which are producing or which are considered capable of production. All significant non-producing oil and natural gas wells are within economic distance of transportation facilities.

	Producing Wells				Non-Producing Wells			
	Oil		Natural Gas		Oil		Natural Gas	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta	90	33	184	63	13	8	31	19
Saskatchewan	136	108	-	-	2	2	-	-
Canada	226	141	184	63	15	10	31	19
Orito	48	38	-	-	-	-	-	-
Neiva	63	43	-	-	-	-	-	-
Colombia	111	81	-	-	-	-	-	-
Total	337	222	184	63	15	10	31	19

Undeveloped Land Holdings

The undeveloped land holdings of the Company as at December 31, 2003, are set forth in the following table:

	Undeveloped Acres (000's)	
	Gross	Net
Canada		
Alberta	237	189
Saskatchewan	227	218
Other	78	59
Total Canada	542	466
Colombia	400	133
Total Company	942	599

The Company expects that rights to explore, develop and exploit 57,000 net acres of its undeveloped land in Canada will expire by December 31, 2004. The Colombian undeveloped acreage will expire by December 31, 2004 if the Company does not elect to advance to the next phase of its exploration contract, see "Principal Properties-Colombia-Central Colombia Block".

Future Commitments

See Notes 11, "Financial Instruments and Financial Risk Management", and 13, "Commitments and Contingencies", to the Consolidated Financial Statements on pages 71 and 73 of the Company's 2003 Annual Report which information is incorporated herein by reference. The Company's obligations under gas sale and transportation contracts have been reflected in future net revenue in the tables in Appendix A.

Additional Information Concerning Abandonment and Reclamation Costs

Abandonment and reclamation costs were estimated for all legal obligations associated with the retirement of long-lived tangible assets such as wells, facilities and plants based on market prices or on the best information available where no market price was available. As at December 31, 2003, the Company expected to incur abandonment and reclamation costs in respect of 368 net wells, however 96 of these net wells were sold in connection with property dispositions in the first quarter of 2004. The total abandonment and reclamation costs net of salvage values of all the Company's 368 net wells are estimated to be $12.3 million (without discount) and $2.7

million discounted at 10%. In the next three financial years $0.3 million of these costs are expected to be incurred. Future net revenue in the tables in Appendix A has been reduced by the entire amount of these estimated abandonment and reclamation costs.

Tax Horizon

In Canada and Colombia, Petrobank's tax pools shelter it from paying current cash income taxes. The Company is subject to Federal Large Corporations Tax and Saskatchewan Capital Tax in Canada, and presumptive income tax and remittance tax in Colombia (see "Industry Conditions-Colombia"). Based on the Company's current exploration and development plans, Petrobank does not expect to pay income tax within the next three years.

Capital Expenditures

The following table summarizes capital expenditures related to the Corporation's activities for the year ended December 31, 2003:

	Canada	Colombia	Total
Drilling and completions - development	$16,250	$62,949	$79,199
Drilling and completions - exploration	10,829	-	10,829
Facilities and equipment	5,418	3,391	8,809
Land	3,553	-	3,553
Seismic (net of sales)	(474)	-	(474)
Property acquisitions - proved	2,225	-	2,225
Property acquisitions - unproved	3,248	-	3,248
Other	2,480	5,002	7,482
Pilot design, technology acquisition and engineering	1,189	-	1,189
Total	$44,718	$71,342	$116,060

Exploration and Development

The following table summarizes the gross and net exploratory and development wells in which the Company participated during the year ended December 31, 2003.

	Exploratory		Development	
	Gross	Net	Gross	Net
Oil				
Canada	4	1.8	19	18.4
Colombia	-	-	10	7.3
Natural Gas - Canada	16	12.1	16	10.4
Dry - Canada	9	8.4	5	4.7
Total	29	22.3	50	40.8

The Company's exploration and development plans are discussed under the heading "Business of the Company".

History

Production

The following table shows the Company's average working interest production volumes before deduction of royalties payable to others, average netbacks received and oil and gas capital expenditures incurred for each of the last four fiscal quarters. See "Principal Properties" for production volumes by major area :

	Three Months Ended			
	Mar 31, 2003	June 30, 2003	Sept 30, 2003	Dec 31, 2003
Average daily production [1]				
Canada - light / medium oil and NGLs (bbl/d)	2,225	2,097	2,097	2,147
Canada - heavy oil (bbl/d)	532	661	812	784
Canada – natural gas (mcf/d)	10,920	8,057	6,581	17,702
Total Canada (boe/d)	4,577	4,101	4,005	5,881
Colombia – oil (bbl/d)	695	1,028	1,166	1,374
Total Company (boe/d)	5,272	5,129	5,171	7,255

(1) NGLs have been included with light/medium oil as they are not considered to be material. NGLs represent less than 3% of the Company's Canadian total proved plus probable reserves.

Canadian Netback by Product

Light/Medium Crude Oil and NGLs Netback ($ per bbl)

	Three Months Ended			
	Mar 31, 2003	June 30, 2003	Sept 30, 2003	Dec 31, 2003
Average price received [1]	33.28	28.28	28.09	26.81
Royalties [2]	10.79	7.28	6.01	5.89
Operating costs [3]	5.84	6.99	5.24	6.22
Netback	16.65	14.01	16.84	14.70

Heavy Crude Oil Netback ($ per bbl)

	Three Months Ended			
	Mar 31, 2003	June 30, 2003	Sept 30, 2003	Dec 31, 2003
Average price received	33.37	27.14	24.86	22.95
Royalties [2]	5.89	3.75	4.22	2.36
Operating costs [3]	8.33	9.40	6.83	11.18
Netback	19.15	13.99	13.81	9.41

Natural Gas Netbacks ($ per mcf)

	Three Months Ended			
	Mar 31, 2003	June 30, 2003	Sept 30, 2003	Dec 31, 2003
Average price received [1]	7.37	6.34	4.98	5.61
Royalties [2]	1.61	1.00	0.82	0.88
Operating costs [3]	1.44	1.51	1.79	1.26
Netback	4.32	3.83	2.37	3.47

Notes:

(1) After reduction for hedging costs. All hedging costs relating to oil sales are included with light/medium crude oil.

(2) After inclusion of ARTC.

(3) Operating costs are expenses incurred in the operation of producing properties and include items such as field staff salaries, power, fuel, chemicals, repairs and maintenance, property taxes, processing and treating fees, overhead fees and other costs.

Colombian Netback

Light and Medium Crude Oil Netback ($ per bbl)

	Three Months Ended			
	Mar 31, 2003	June 30, 2003	Sept 30, 2003	Dec 31, 2003
Average price received	38.58	29.74	31.37	31.66
Royalties	3.09	2.40	2.44	2.53
Operating costs [1]	6.09	7.93	9.24	15.62
Netback	29.40	19.41	19.69	13.51

Notes:

(1) Operating costs are expenses incurred in the operation of producing properties and include items such as Ecopetrol operating fees, field staff salaries, repairs and maintenance, overhead fees and other costs.

INDUSTRY CONDITIONS

Canada

General

The oil and natural gas industry in Canada is subject to extensive controls and regulations imposed by various levels of government. Petrobank does not expect that any of these controls or regulations will affect its operations in a manner materially different than they would affect other oil and gas companies of similar size.

Crude oil and natural gas located in Alberta, Saskatchewan and British Columbia are owned predominantly by the respective provincial governments, generally termed the "Crown". Provincial governments grant rights to explore for and produce oil and natural gas under leases, licenses and permits with terms generally varying from two years to five years and on conditions contained in provincial legislation. Leases, licenses and permits may be continued indefinitely by producing under the lease, license or permit. Some of the oil and natural gas located in these provinces is privately owned and rights to explore for and produce oil and natural gas are granted by the mineral owners on negotiated terms and conditions.

Oil produced from oil sands is produced under Crown Oil Sands Leases granted by the Province of Alberta. Such Crown Oil Sands Leases have an initial term of 15 years, and may be continued thereafter under the Oil Sands Tenure Regulation (Alberta) to the extent that the lessee has attained the required minimum level of evaluation of the oil sands in the leases, or the leases are producing.

In addition to federal regulations, each province has legislation and regulations, which govern land tenure, royalties, production rates, environmental protection and other matters. The royalty regime is a significant factor in the profitability of oil and natural gas production. Royalties payable on production from lands other than government lands are determined by negotiations between the mineral owner and the lessee. Royalties on government land are determined by government regulation and are generally calculated as a percentage of the value of gross production, and the rate of royalties payable generally depends upon prescribed reference prices, well productivity, geographical location, field discovery date and the type or quality of the petroleum product produced.

An initial oil sands royalty of 1% of the gross revenue on the bitumen produced is paid until the owners have recovered 100% of the capital costs associated with the mine and extraction plant, including a return on capital. Such return is based on the monthly Canadian federal long-term bond rate. Subsequent thereto, the royalty will be the greater of 1% of the gross revenue on the bitumen produced and 25% of net bitumen revenue. Gross revenue is calculated based on the fair market value of the bitumen prior to upgrading. Net revenue is determined by deducting from gross revenue the aggregate of all allowable operating costs, interest expense and amortization of capital costs and any loss carryforwards.

From time to time the governments of Canada, Alberta, British Columbia and Saskatchewan have established incentive programs, which have included royalty rate deduction and tax credits for the purpose of encouraging oil and natural gas exploration or enhanced recovery projects.

In Alberta, a producer of oil or natural gas is entitled to a credit against the royalties payable to the government by virtue of the ARTC program. The ARTC program is based on a price sensitive formula, and ranges between 75%, for prices for oil at or below $100 per cubic meter ($15.90 per barrel), to 25%, for prices above $210 per cubic meter ($33.39 per barrel). In general, the ARTC rate is applied to a maximum of $2,000,000 of government royalties payable for each producer or associated group of producers. Government royalties on production from producing properties acquired from companies claiming maximum entitlement to ARTC will generally not be eligible for ARTC. The rate is established quarterly based on the average "par price", as determined by the Alberta Department of Energy for the previous quarterly period.

In Canada, producers of oil negotiate sales contracts directly with oil purchasers, with the result that the market determines the price of oil. The price depends in part on oil quality, prices of competing fuels, distance to market and the value of refined products. Oil exports may be made under export contracts having terms not exceeding one year in the case of oil other than heavy oil, and not exceeding two years in the case of heavy oil, so long as an order approving any such export has been obtained from the National Energy Board. Any oil export to be made pursuant to a contract of longer duration requires an exporter to obtain an export license from the National Energy Board and the issue of a license requires the approval of the Canadian federal government. The term of the license may not exceed 25 years.

In Canada, the price of natural gas sold in interprovincial and international trade is determined by negotiation between buyers and sellers. Natural gas exported from Canada is subject to regulation by the Government of Canada through the National Energy Board. Producers and exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts must continue to meet criteria prescribed by the National Energy Board. Natural gas exports for a term of two years or less, or for 2 to 20 years in quantities not more than 1.1 million cubic feet per day may be made under a National Energy Board order, or, in the case of exports for a longer duration or larger volumes, under a National Energy Board license and Canadian federal government approval.

The provincial governments of Alberta, British Columbia and Saskatchewan also regulate the removal of natural gas from those provinces for consumption elsewhere. They do so based on such factors as reserve availability, transportation arrangements and market considerations.

The North American Free Trade Agreement ("NAFTA") among the governments of Canada, the United States and Mexico became effective on January 1, 1994. NAFTA carries forward most of the material energy terms that are contained in the Canada-US Free Trade Agreement. Subject to the General Agreement on Tariffs and Trade, Canada continues to remain free to determine whether exports of energy resources to the United States or Mexico will be allowed, so long as any export restrictions do not:

- reduce the proportion of energy resources exported relative to total supply (based upon the proportion prevailing in the most recent 36 month period or another representative period agreed upon by the parties);
- impose an export price higher than the domestic price (subject to an exception that applies to some measures that only restrict the value of exports); or
- disrupt normal channels of supply.

All three countries are prohibited from imposing minimum or maximum export or import price requirements, with some limited exceptions.

Environmental

The oil and natural gas industry is governed by environmental regulation under Canadian federal and provincial laws, rules and regulations, which restrict and prohibit the release or emission and regulate the storage and transportation of various substances produced or utilized in association with oil and gas industry operations. In addition, applicable environmental laws require that well and facility sites be abandoned and reclaimed, to the satisfaction of provincial authorities, in order to prevent pollution from former operations. Also, environmental laws may impose upon "responsible persons" remediation obligations on property designated as a contaminated site. Responsible persons include persons responsible for the substance causing the contamination, persons who caused the release of the substance and any present or past owner, tenant or other person in possession of the site. A breach of environmental laws may result in the imposition of fines and penalties, in addition to the costs of abandonment and reclamation.

Petrobank is committed to meeting its responsibilities to protect the environment wherever it operates and anticipates making increased, although not material, expenditures of both a capital and expense nature as a result of the increasingly stringent laws relating to the protection of the environment. Petrobank believes that it is in material compliance with environmental laws and regulations applicable as at the date hereof.

In December 2002 the Government of Canada ratified the Kyoto Protocol. This protocol calls for Canada to reduce its greenhouse gas emissions to 6 percent below 1990 levels during the period between 2008 and 2012. The protocol will only become legally binding when it is ratified by at least 55 countries, covering at least 55 percent of the emissions addressed by the protocol. If the protocol becomes legally binding, it is expected to affect the operation of all industries in Canada, including the oil and gas industry. As details of the implementation of this protocol have yet to be announced, the effect on Petrobank cannot be determined at this time.

Colombia

The regulatory regime in Colombia underwent a significant change effective January 1, 2004 with the formation of the Agencia Nacional de Hidrocarburos (ANH) which has taken over the role of regulating and significantly increasing the amount of exploration and production in the country. The state oil company, Ecopetrol, will maintain its exploration and production activities across the country, but will become a more direct competitor in future projects.

In conjunction with this change, the ANH has developed a new exploration risk contract that will take effect when it is finalized (expected in May 2004). This contract will be a significant change in the way the industry views Colombia. In place of the earlier association contracts in which the government (Ecopetrol) had an immediate back-in to production, the new agreement will provide full risk/reward benefits for the contractor. Under the terms of the contract the successful operator will retain the rights to all production subject to existing royalty and income tax regulations.

The Company is the owner of interests in, and is engaged in the exploration for, and development and production of oil from two incremental production contracts (Orito and Neiva) and one exploration contract granted by Empresa Colombiana de Petroleos ("Ecopetrol"), the Colombian national oil company. Each concession is governed by a separate contract with Ecopetrol. Generally, the contracts cover a specific period and require certain expenditures in the early years of the contract in order to advance to subsequent development phases. The Company's current activities are focused on its incremental production contracts, which provide that the Company is permitted to carry out development activities on the blocks and share in incremental production generated above a pre-defined baseline. The Company's participation levels at Orito and Neiva are 79% and 69%, respectively. These participation levels decline on a contract by contract basis once the ratio of cumulative total revenues to total costs (R factor) exceeds 1.5 times. At R factors above 2.5 times the participation levels at Orito and Neiva are fixed at 39.5% and 34.5%, respectively.

Royalties are calculated on a field-by-field basis using a sliding scale that ranges from 8% (for incremental production up to 5,000 barrels per day) up to a maximum of 25% (for incremental production above 600,000 barrels per day).

The Company's Orito oil production is currently being sold pursuant to a sales contract with Ecopetrol whereby the price paid, adjusted for quality differences, for each barrel of oil sold is determined based on the monthly average of WTI less a variable differential as follows:

Average WTI (U.S.$/bbl)	Differential (U.S.$/bbl)
$15 or less	$3.60
$15.01 to $20.00	$4.10
$20.01 to $25.00	$4.60
$25.01 to $30.00	$5.60
Over $30	$6.60

The Company or Ecopetrol may cancel this sales contract on one month's notice after which, the Company may elect to export its oil production directly.

The Company's Neiva oil production is currently being sold pursuant to a sales contract with a third party whereby the price paid, adjusted for quality differences, for each barrel of oil sold is determined based on a five day average (relative to the time of lifting) and, including transportation, is generally WTI multiplied by approximately 80% less U.S.$2.70.

Development plans are submitted to Ecopetrol for approval for all exploration and development activities conducted on the Company's Colombian properties. In addition, the Company files an environmental management plan (PMA) covering the contemplated activities with the Ministry of Environment. PMA's are submitted to demonstrate compliance with applicable Colombian law but advance approval is not required to commence activities within existing development areas (Orito and Neiva). In exploration areas such as the Central Colombia Block, an approved PMA is required before work commences.

The Company's pretax income from Colombian sources, as defined under Colombian law, is subject to Colombian income taxes at a statutory rate of 38.5%, although a "presumptive" minimum income tax based on net assets, may apply in years of little or no net income which may be recovered against future cash taxes otherwise payable. The Company's income after Colombian income taxes is subject to a Colombian remittance tax that accrues at a rate of 7%, which may be eliminated under certain circumstances if the Company reinvests such income in Colombia.

RISK FACTORS

An investment in Petrobank may be considered speculative due to the nature of the Company's involvement in the exploration for, and the acquisition, development, production and marketing of, oil and natural gas and its current stage of development. Oil and gas operations involve many risks which even a combination of experience and knowledge and careful evaluation may not be able to overcome. There is no assurance that further commercial quantities of oil and natural gas will be discovered or acquired by the Company.

The oil and natural gas industry is intensely competitive. Competition is particularly intense in the acquisition of prospective oil and natural gas properties and oil and gas reserves. Petrobank's competitive position depends on its geological, geophysical and engineering expertise, its financial resources, its ability to develop its properties and its ability to select, acquire and develop proved reserves. Petrobank competes with a substantial number of other companies having larger technical staffs and greater financial and operational resources. Many such companies not only engage in the acquisition, exploration, development and production of oil and natural gas reserves, but also carry on refining operations and market refined products. Petrobank also competes with major and independent oil and natural gas companies and other industries supplying energy and fuel in the marketing and sale of oil and natural gas to transporters, distributors and end users, including industrial, commercial and individual consumers. Petrobank also competes with other oil and natural gas companies in attempting to secure drilling rigs and other equipment necessary for drilling and completion of wells. Such equipment may be in short supply from time to time. In addition, equipment and other materials necessary to construct production and transmission facilities may be in short supply from time to time. Finally, companies not previously investing in oil and natural gas may choose to acquire reserves to establish a firm supply or simply as an investment. Such companies will also provide competition for Petrobank.

The marketability and ultimate commerciality of oil and natural gas acquired or discovered is affected by numerous factors beyond the control of Petrobank. These factors include reservoir characteristics, market fluctuations, the proximity and capacity of oil and natural gas pipelines and processing equipment and government regulation. Oil and natural gas operations (exploration, production, pricing, marketing and transportation) are subject to extensive controls and regulations imposed by various levels of government, which may be amended from time to time. See "Industry Conditions". Petrobank's oil and natural gas operations may also be subject to compliance with federal, provincial and local laws and regulations controlling the discharge of materials into the environment or otherwise relating to the protection of the environment. Although the Company believes that it is in material compliance with current applicable environmental regulations, changes to such regulations may have a material adverse effect on the Company. See "Industry Conditions – Canada - Environmental Regulation".

Both oil and natural gas prices are unstable and are subject to fluctuation. Any material decline in prices could result in a reduction of Petrobank's net production revenue and overall value and could result in ceiling test write-downs. The economics of producing from some wells may change as a result of lower prices, which could result in a reduction in the volumes of Petrobank's reserves. Petrobank might also elect not to produce from certain wells at lower prices. All of these factors could result in a material decrease in Petrobank's net production revenue causing a reduction in its oil and gas acquisition and development activities. A substantial material decline in prices from historical average prices could reduce the Company's borrowing base, therefore reducing the bank credit available to the Company and possibly require that a portion of the Company's bank debt be repaid.

GAAP requires that management apply certain accounting policies and make certain estimates and assumptions, which affect reported amounts in the consolidated financial statements of the Company. The accounting policies may result in non-cash charges to net income and write-down of net assets in the financial statements. Such non-cash charges and write-downs may be viewed unfavourably by the market and result in an inability to borrow funds and/or may result in a decline in the trading price of the Company's shares.

Under GAAP, the net amounts at which petroleum and natural gas costs on a property or project basis are carried are subject to a test, which is based in part upon estimated future net cash flow from reserves. The carrying value is assessed to be recoverable when the sum of the undiscounted cash flows expected from the production of proved reserves, the lower of cost and market of unproved properties and the cost of major development projects exceeds the carrying value. When the carrying value is not assessed to be recoverable, an impairment loss is recognized to the extent that the carrying value of assets exceeds the sum of the discounted cash flows expected from the production of proved and probable reserves, the lower of cost and market of unproved properties and the cost of major development projects. A decline in the net value of oil and natural gas properties could cause capitalized costs to exceed the cost ceiling, resulting in a charge against earnings.

Emerging GAAP surrounding hedge accounting may result in non-cash charges against net income as a result of changes in the fair market value of hedging instruments. A decrease in the fair market value of the hedging instruments as a result of fluctuations in commodity prices and foreign exchange rates may result in a write-down of net assets and a non-cash charge against net income. Such write-downs and non-cash charges may be temporary in nature if the fair market value subsequently increases.

From time to time the Company may enter into agreements to receive fixed prices on its oil and natural gas production to offset the risk of revenue losses if commodity prices decline; however, if commodity prices increase beyond the levels set in such agreements, the Company will not benefit from such increases.

From time to time the Company may enter into agreements to fix the exchange rate of Canadian to United States dollars in order to offset the risk of revenue losses if the Canadian dollar increases in value compared to the United States dollar; however, if the Canadian dollar declines in value compared to the United States dollar, the Company will not benefit from the fluctuating exchange rate and the Company may nevertheless be obligated to pay royalties on such higher prices, even though not received by it, after giving effect to such agreements.

Oil and natural gas exploration, development and production operations are subject to all the risks and hazards typically associated with such operations, including hazards such as fire, explosion, blowouts, and oil spills, each of which could result in substantial damage to oil and natural gas wells, production facilities, other property and the environment or in personal injury. In accordance with industry practice, the Company is not fully insured

against all of these risks, nor are all such risks insurable. Although Petrobank maintains liability insurance in an amount that it considers adequate and consistent with industry practice, the nature of these risks is such that liabilities could exceed policy limits, in which event Petrobank could incur significant costs that could have a materially adverse effect upon its financial condition. Oil and natural gas production operations are also subject to all the risks typically associated with such operations, including premature decline of reservoirs and the invasion of water into producing formations.

Oil and natural gas exploration and development activities are dependent on the availability of drilling and related equipment in the particular areas where such activities will be conducted. Demand for such limited equipment or access restrictions may affect the availability of such equipment to the Company and may delay exploration and development activities. To the extent Petrobank is not the operator of its oil and gas properties, Petrobank will be dependent on such operators for the timing of activities related to such properties and will be largely unable to direct or control the activities of the operators.

Although title reviews are done according to industry standards prior to the purchase of most oil and natural gas producing properties or the commencement of drilling wells, such reviews do not guarantee or certify that an unforeseen defect in the chain of title will not arise to defeat the claim of Petrobank which could result in a reduction of the revenue received by Petrobank.

There are numerous uncertainties inherent in estimating quantities of reserves and cash flows to be derived therefrom, including many factors that are beyond the control of the Company. The reserve and cash flow information set forth in this Annual Information Form represent estimates only. The reserves and estimated future net cash flow from the Company's properties have been independently evaluated by GLJ in the GLJ Report. These evaluations include a number of assumptions relating to factors such as initial production rates, production decline rates, ultimate recovery of reserves, timing and amount of capital expenditures, marketability of production, future prices of oil and natural gas, operating costs and royalties and other government levies that may be imposed over the producing life of the reserves. These assumptions were based on price forecasts in use at the date the relevant evaluations were prepared and many of these assumptions are subject to change and are beyond the control of the Company. Actual production and cash flows derived therefrom will vary from these evaluations, and such variations could be material. The foregoing evaluations are based in part on the assumed success of exploitation activities intended to be undertaken in future years. The reserves and estimated cash flows to be derived therefrom contained in such evaluations will be reduced to the extent that such exploitation activities do not achieve the level of success assumed in the evaluations.

From time to time the Company may enter into transactions to acquire assets or the shares of other companies. These transactions may be financed partially or wholly with debt, which may increase the Company's debt levels above industry standards. Depending on future exploration and development plans, the Company may require additional financing, which may not be available or, if available, may not be available on favourable terms.

In addition to the risks faced by Canadian oil and gas companies, the Company is subject to risks related to its foreign operations in Colombia as a portion of the Company's business regulated by the laws and regulations of Colombia, including those related to the development, production, marketing, transportation of crude oil and natural gas, taxation and environmental and safety matters. The Company may be adversely affected by changes in governmental policies or social instability or other political or economic developments in Colombia that are outside the Company's control including among other things, expropriation, risks of war and terrorism, foreign exchange and repatriation restrictions, changing political conditions and monetary fluctuations and changing governmental policies including taxation policies.

Please also see the information under the heading "Risks and Uncertainties" beginning on page 51 of the Annual Report which information is incorporated herein by reference.

SELECTED ANNUAL FINANCIAL INFORMATION

The following table sets forth selected financial information of the Company for each the three years ended December 31, 2003. Amounts are expressed in thousands of dollars, except for share amounts.

	Year Ended December 31		
	2003	2002	2001
Oil and natural gas revenue before royalties	66,111	50,458	46,117
Cash flow from operations [1]	29,258	22,806	18,549
Per share – basic $ [2]	0.45	0.45	0.46
Per share – diluted $	0.44	0.40	0.39
Net income	(14,691)	6,191	5,283
Net income (loss) attributable to common shareholders	(23,111)	(430)	431
Per share – basic $	(0.48)	(0.01)	0.01
Per share – diluted $	(0.48)	(0.01)	0.01
Capital expenditures	116,060	46,228	21,859
Pro-forma net debt including subordinated notes [3]	114,955	62,495	31,266
Total assets	253,535	150,618	146,337

Notes:

(1) Calculated based on cash flow from operations before changes in other non-cash items.

(2) Calculated based on cash flow from operations before changes in other non-cash items less preferred share dividends and interest paid on subordinated notes and adding back $1.5 million of non-recurring well control costs in 2001.

(3) None of the Company's financial liabilities are considered long-term as bank debt is classified as a current liability and the Company's subordinated notes are reflected as equity on the balance sheet. Pro-forma net debt includes working capital (deficiency), subordinated notes and for 2003, is net of proceeds of $36 million received on the January 2004 Wapella property disposition.

DIVIDEND RECORD

Petrobank has not declared or paid any dividends on its Common Shares since its incorporation. Any decision to pay dividends on the Common Shares will be made by the board of directors on the basis of Petrobank's earnings, financial requirements and other conditions existing at such future time. Pursuant to the terms of the loan agreement with its current banker, the Company cannot declare or pay dividends on its Common Shares without obtaining the bank's consent.

MANAGEMENT'S DISCUSSION AND ANALYSIS

Reference is made to the information under the headings "Management's Discussion and Analysis" contained on pages 41 through 56 of Petrobank's Annual Report for the year ended December 31, 2003, which information is incorporated herein by reference.

MARKET FOR SECURITIES

The Company's outstanding Common Shares and Subordinated Notes are listed and posted for trading on the TSX under the trading symbols "PBG" and "PBG.N" ("PBG.NT.A" starting on July 14, 2004), respectively.

DIRECTORS AND OFFICERS

The name, municipality of residence, position and principal occupation of each of the directors and senior officers of Petrobank are as follows:

Name and Municipality of Residence	Positions Held	Principal Occupation During Last Five Years
Steven J. Benedetti Bogotá, Colombia	Vice President Latin America	Vice President Latin America since January 2004; consultant and President - Southern Cone Energy Consultants, Santiago, Chile July 2002 to December 2003; Vice President for International Samson International April 2000 through June 2002; Country Manager - Argentina for Unocal Patagonia, Buenos Aires, Argentina April 1997 through April 2000.
Chris J. Bloomer Calgary, Alberta, Canada	Vice President Heavy Oil and Chief Financial Officer	Chief Financial Officer since April 2003, Vice President Heavy Oil since January 2003, Managing Director of Korn/Ferry International (Calgary) from May 1999 to December 2002, President and Chief Operating Officer of Canadian TALON Resources, Ltd. from August 1997 to May 1999.
John A. Brussa [(1)/(3)] Calgary, Alberta, Canada	Director	Director of the Company since March 2000; Partner of Burnet, Duckworth & Palmer LLP (barristers and solicitors) since 1987. Director of several public companies.
M. Bruce Chernoff [(1)/(2)/(3)] Calgary, Alberta, Canada	Director	Director of the Company since March 2000; President and Director of Caribou Capital Corp. ("Caribou"), a private investment company, since June 1999; Chairman of Harvest Energy Corp. since July 2002; Executive Vice-President and Chief Financial Officer of the Company from March 2000 to October 2001; Executive Vice-President and Chief Financial Officer of Pacalta Resources Ltd. from February 1999 to May 1999; Executive Vice-President of Pacalta from March 1997 to January 1999. Director of several public companies.
Louis L. Frank North Woodstock, New Hampshire, U.S.A.	Director	Director of the Company since September 1993; Independent Consultant; Director and founder of Loon Mountain Recreation Corp.; President of Recco Inc., a private oil and gas development and real estate development company.
Garry Hides Calgary, Alberta, Canada	Vice President Land	Vice President Land of Petrobank since October 2001; Manager Land of the Company from November 1997 to September 2001.

Name and Municipality of Residence	Positions Held	Principal Occupation During Last Five Years
Rene Laprade Calgary, Alberta, Canada	Vice President Operations	Vice President Operations of the Company since October 2001; Manager Operations of Barrington from May 2001 to September 2001; Independent Consultant from May 2000 to May 2001, Vice President Operations of Petrorep Resources Ltd. from June 1995 to May 2000.
Kenneth R. McKinnon Calgary, Alberta, Canada	Corporate Secretary and Director	Director of the Company since March 2000 and Corporate Secretary of the Company since November 1997; Vice President Legal Affairs and General Counsel of Critical Mass Inc. since September 2000; Vice President, Finance and Chief Financial Officer of the Company from November 1997 to March 2000.
Jerald L. Oaks [(1)/(2)] Englewood, Colorado, U.S.A.	Director	Director of the Company since September 1993; Professional Engineer, President of Oaks Resources Management Inc. since June 1986.
Doreen Scheidt Calgary, Alberta, Canada	Corporate Controller	Corporate Controller of the Company since December 2001; Manager, Operations Accounting of Northstar Energy Company, formerly Morrison Petroleums Ltd., from November 1994 to November 2001.
R. Gregg Smith Calgary, Alberta, Canada	Vice President Canada	Vice President Canada of the Company since March 2003; various positions at Hunt Oil Company of Canada Ltd. including Exploration Manager, Senior Geophysicist and Exploration Team Leader from July 2000 to August 2002, Senior Geophysicist of Newport Petroleum Ltd. from July 1998 to July 2000, Senior Geophysicist of Pinnacle Resources Ltd. from August 1997 to July 1998.
James D. Tocher [(2)/(3)] Calgary, Alberta, Canada	Chairman of the Board	Chairman of the Board of the Company since September 1993; Chief Executive Officer from September 1993 to March 2000; Chairman of the Board of VX Technologies Corp., (a private technology company) since March 1989.
John D. Wright Calgary, Alberta, Canada	President, Chief Executive Officer and Director	President, Chief Executive Officer and Director of the Company since March 2000; General Manager of Ecuadorian Operations of Alberta Energy Company from May 1999 to December 1999; President and CEO of Pacalta Resources Ltd. from May 1996 to May 1999. Director of two other public companies.

Notes:

(1) Member of the Audit Committee

(2) Member of the Reserves Committee

(3) Member of the Compensation Committee

The term of office of each director expires at the next annual meeting of shareholders.

As at April 30, 2003, the directors and senior officers of Petrobank, as a group, beneficially owned, directly or indirectly, 11,270,204 Common Shares constituting approximately 20.6% of the issued and outstanding Common Shares.

CONFLICTS OF INTEREST

Certain officers and directors of Petrobank are also officers and/or directors of other companies engaged in the oil and gas business generally. As a result, situations arise where the interest of such directors and officers conflict with their interests as directors and officers of other companies. The resolution of such conflicts is governed by applicable corporate laws, which require that directors act honestly, in good faith and with a view to the best interests of Petrobank. In addition, the ABCA, Petrobank's governing statute, requires that any director or officer of a corporation who is party to, or is a director and officer of, or has a material interest in any person who is a party to, a material contract or proposed material contract with the Corporation must disclose his or her interest and, in the case of directors, refrain from voting on any matter in respect of such contract, unless otherwise permitted under the ABCA.

PERSONNEL

As at December 31, 2003, Petrobank had 43 employees in Canada and 36 in Colombia.

ADDITIONAL INFORMATION

Additional information, including information as to directors' and officers' remuneration and indebtedness, principal holders of the Company's securities, options to purchase securities and interests of insiders in material transactions, is contained in the Management Proxy Circular of the Company dated May 14, 2004 provided for the annual and special meeting of the shareholders of the Company to be held on June 17, 2004. Additional financial information is also provided in the Company's consolidated financial statements for the year ended December 31, 2003 which are contained in the Annual Report of the Company for the year ended December 31, 2003.

Upon request the Company will provide to any person:

1. One copy of this Annual Information Form together with one copy of any document, or the pertinent pages of any document incorporated by reference in the Annual Information Form;

2. One copy of the Company's consolidated financial statements contained in the Annual Report for the year ended December 31, 2003, together with the report of the auditors thereon, and one copy of any of the Company's interim financial statements subsequent to such audited consolidated financial statements;

3. One copy of the information circular of the Company in respect of its most recent annual meeting of shareholders involving the election of directors or one copy of any annual filing prepared instead of that information circular, as appropriate; and

4. When the Company's securities are in the course of a distribution pursuant to a short form prospectus or when a preliminary short form prospectus has been filed in respect of a distribution of the Company's securities, also upon request to the Company, one copy of any other document that is incorporated by reference in the preliminary or final short form prospectus, as the case may be.

Copies of these documents may be obtained (in some cases upon payment of a reasonable charge if the request is made by a person or company that is not a securityholder of the Company) upon request to:

Petrobank Energy and Resources Ltd.
Suite 2600, 240 - 4th Avenue S.W.
Calgary, Alberta
T2P 4H4
Phone: (403) 750-4400
Fax: (403) 266-5794

APPENDIX A

SUMMARY OF OIL AND GAS RESERVES
as of December 31, 2003
CONSTANT PRICES AND COSTS

	RESERVES							
	LIGHT AND MEDIUM OIL		HEAVY OIL		NATURAL GAS		NATURAL GAS LIQUIDS	
RESERVES CATEGORY	Gross (mbbl)	Net (mbbl)	Gross (mbbl)	Net (mbbl)	Gross (mmcf)	Net (mmcf)	Gross (mbbl)	Net (mbbl)
Canada								
PROVED								
Developed Producing	3,975	3,570	696	646	18,340	16,016	255	198
Developed Non-Producing	26	36	-	-	6,782	5,252	95	70
Undeveloped	725	565	460	429	1,800	1,644	-	-
TOTAL PROVED including Wapella	4,726	4,171	1,156	1,075	26,922	22,912	350	268
Wapella	3,537	2,971	-	-	-	-	-	-
TOTAL PROVED excluding Wapella	1,189	1,200	1,156	1,075	26,922	22,912	350	268
PROBABLE	2,039	1,709	1,239	1,137	11,008	9,291	97	71
TOTAL PROVED PLUS PROBABLE								
Including Wapella	6,765	5,880	2,395	2,212	37,930	32,203	447	339
Wapella	4,940	4,144	-	-	-	-	-	-
Excluding Wapella	1,825	1,736	2,395	2,212	37,930	32,203	447	339
Colombia								
PROVED								
Developed Producing	2,101	1,933	-	-	-	-	-	-
Developed Non-Producing	-	-	-	-	-	-	-	-
Undeveloped	1,913	1,759	-	-	-	-	-	-
TOTAL PROVED	4,014	3,692	-	-	-	-	-	-
PROBABLE	2,793	2,567	-	-	-	-	-	-
TOTAL PROVED PLUS PROBABLE	6,807	6,259	-	-	-	-	-	-
Canada & Colombia								
PROVED								
Developed Producing	6,076	5,503	696	646	18,340	16,016	255	198
Developed Non-Producing	26	36	-	-	6,782	5,252	95	70
Undeveloped	2,638	2,324	460	429	1,800	1,644	-	-
TOTAL PROVED including Wapella	8,740	7,863	1,156	1,075	26,922	22,912	350	268
Wapella	3,537	2,971	-	-	-	-	-	-
TOTAL PROVED excluding Wapella	5,203	4,892	1,156	1,075	26,922	22,912	350	268
PROBABLE	4,832	4,276	1,239	1,137	11,008	9,291	97	71
TOTAL PROVED PLUS PROBABLE								
Including Wapella	13,572	12,139	2,395	2,212	37,930	32,203	447	339
Wapella	4,940	4,144	-	-	-	-	-	-
Excluding Wapella	8,632	7,995	2,395	2,212	37,930	32,203	447	339

CONSTANT PRICES AND COSTS
NET PRESENT VALUES OF FUTURE NET REVENUE
as of December 31, 2003

RESERVES CATEGORY	BEFORE INCOME TAXES DISCOUNTED AT (%/year) 0	5	10	15	20	AFTER INCOME TAXES DISCOUNTED AT (%/year) 0	5	10	15	20
	(CDN M$)	(CDN M$)	(CDN M$)	(CDN M$)	(CDN M$)	(CDN M$)	(CDN M$)	(CDN M$)	(CDN M$)	(CDN M$)
Canada										
PROVED										
Developed Producing	149,392	127,863	111,983	99,992	90,678	137,102	118,873	105,157	94,665	86,427
Developed Non-Producing	25,288	20,392	16,934	14,389	12,457					
Undeveloped	19,478	14,077	10,356	7,680	5,684					
TOTAL PROVED including Wapella	194,158	162,332	139,273	122,061	108,819	166,038	140,837	122,279	108,278	97,409
Wapella	48,858	40,698	34,299	29,447	25,717	41,346	35,149	30,032	26,064	22,971
TOTAL PROVED excluding Wapella	145,300	121,634	104,974	92,614	83,102	124,692	105,688	92,247	82,214	74,438
PROBABLE	92,064	65,563	49,916	39,752	32,702					
TOTAL PROVED PLUS PROBABLE										
Including Wapella	286,222	227,895	189,189	161,813	141,521	223,216	181,090	152,634	132,252	116,989
Wapella	72,708	57,636	47,272	39,891	34,422	55,562	45,174	37,676	32,197	27,069
Excluding Wapella	213,514	170,259	141,917	121,922	107,099	167,654	135,916	114,958	100,055	89,920
Colombia	(US M$)	(US M$)	(US M$)	(US M$)	(US M$)	(US M$)	(US M$)	(US M$)	(US M$)	(US M$)
PROVED										
Developed Producing	37,064	32,310	28,803	26,098	23,939	37,064	32,310	28,803	26,098	23,939
Developed Non-Producing	-	-	-	-	-					
Undeveloped	25,999	21,017	17,202	14,223	11,856					
TOTAL PROVED	63,063	53,327	46,005	40,321	35,795	62,122	52,622	45,470	39,909	35,474
PROBABLE	45,651	34,181	26,406	20,918	16,911					
TOTAL PROVED PLUS PROBABLE	108,714	87,508	72,411	61,239	52,706	93,162	75,536	62,977	53,657	46,507
Canada & Colombia [1]	(CDN M$)	(CDN M$)	(CDN M$)	(CDN M$)	(CDN M$)	(CDN M$)	(CDN M$)	(CDN M$)	(CDN M$)	(CDN M$)
PROVED										
Developed Producing	197,291	169,618	149,206	133,719	121,615	185,001	160,628	142,380	128,392	117,364
Developed Non-Producing	25,288	20,392	16,934	14,389	12,457					
Undeveloped	53,077	41,238	32,587	26,061	21,006					
TOTAL PROVED including Wapella	275,656	231,248	198,726	174,169	155,078	246,320	208,842	181,041	159,853	143,253
Wapella	48,858	40,698	34,299	29,447	25,717	41,346	35,149	30,032	26,064	22,971
TOTAL PROVED excluding Wapella	226,798	190,550	164,427	144,722	129,361	204,974	173,693	151,009	133,789	120,282
PROBABLE	151,060	109,736	84,041	66,785	54,556					
TOTAL PROVED PLUS PROBABLE										
Including Wapella	426,716	340,984	282,767	240,954	209,634	343,611	278,707	234,021	201,594	177,091
Wapella	72,708	57,636	47,272	39,891	34,422	55,562	45,174	37,676	32,197	27,069
Excluding Wapella	354,008	283,348	235,495	201,063	175,212	288,049	233,533	196,345	169,397	150,022

Notes:
[1] U.S. dollars are converted into Canadian dollars using an exchange rate of Cdn.$/U.S.$0.7738.

(UNDISCOUNTED)
as of December 31, 2003
CONSTANT PRICES AND COSTS

RESERVES CATEGORY	REVENUE (CDN M$)	ROYALTIES (CDN M$)	OPERATING COSTS (CDN M$)	DEVELOPMENT COSTS (CDN M$)	WELL ABANDONMENT COSTS (CDN M$)	FUTURE NET REVENUE BEFORE INCOME TAXES (CDN M$)	INCOME TAXES (CDN M$)	FUTURE NET REVENUE AFTER INCOME TAXES (CDN M$)
Canada								
TOTAL PROVED								
Including Wapella	392,754	80,135	94,264	14,991	9,206	194,158	28,120	166,038
Wapella	124,343	35,465	31,905	5,280	2,835	48,858	12,887	41,346
Excluding Wapella	268,411	44,670	62,359	9,711	6,371	145,300	15,233	124,692
TOTAL PROVED PLUS PROBABLE								
Including Wapella	569,784	113,417	136,390	24,474	9,281	286,222	63,006	223,216
Wapella	173,527	49,025	42,889	6,070	2,835	72,708	17,146	55,562
Excluding Wapella	396,257	64,392	93,501	18,404	6,446	213,514	45,860	167,654
	(US M$)	(US M$)	(US M$)	(US M$)	(US M$)	(US M$)	(US M$)	(US M$)
Colombia								
PROVED RESERVES	104,863	8,409	22,591	10,800	-	63,063	941	62,122
PROVED PLUS PROBABLE RESERVES	178,226	14,353	36,858	18,300	-	108,715	15,553	93,162
	(CDN M$)	(CDN M$)	(CDN M$)	(CDN M$)	(CDN M$)	(CDN M$)	(CDN M$)	(CDN M$)
Canada & Colombia [1]								
TOTAL PROVED								
Including Wapella	528,271	91,002	123,459	28,948	9,206	275,656	29,336	246,320
Wapella	124,343	35,465	31,905	5,280	2,835	48,858	12,887	41,346
Excluding Wapella	403,928	55,537	91,554	23,668	6,371	226,798	16,449	204,974
TOTAL PROVED PLUS PROBABLE								
Including Wapella	800,110	131,966	184,022	48,124	9,281	426,717	83,106	343,611
Wapella	173,527	49,025	42,889	6,070	2,835	72,708	17,146	55,562
Excluding Wapella	626,583	82,941	141,133	42,054	6,446	354,009	65,960	288,049

Notes:

[1] U.S. dollars are converted into Canadian dollars using an exchange rate of Cdn.$/U.S.$0.7738.

FUTURE NET REVENUE
BY PRODUCTION GROUP
as of December 31, 2003
CONSTANT PRICES AND COSTS

RESERVES CATEGORY	PRODUCTION GROUP	FUTURE NET REVENUE BEFORE INCOME TAXES (discounted at 10%/year) Including Wapella	Excluding Wapella
Canada		(CDN M$)	(CDN M$)
PROVED RESERVES	Light and Medium Crude Oil (1)	56,540	21,903
	Heavy Oil (1)	9,245	9,245
	Natural Gas (2)	75,562	75,562
PROVED PLUS PROBABLE RESERVES	Light and Medium Crude Oil (1)	77,255	29,644
	Heavy Oil (1)	15,617	15,617
	Natural Gas (2)	97,742	97,742
Colombia		(US M$)	(US M$)
PROVED RESERVES	Light and Medium Crude Oil (1)	46,005	46,005
PROVED PLUS PROBABLE RESERVES	Light and Medium Crude Oil (1)	72,411	72,411
Canada & Colombia [3]		(CDN M$)	(CDN M$)
PROVED RESERVES	Light and Medium Crude Oil (1)	115,993	81,356
	Heavy Oil (1)	9,245	9,245
	Natural Gas (2)	75,562	75,562
PROVED PLUS PROBABLE RESERVES	Light and Medium Crude Oil (1)	170,833	123,222
	Heavy Oil (1)	15,617	15,617
	Natural Gas (2)	97,742	97,742

Notes:
(1) Including solution gas and other by-products.
(2) Including by-products but excluding solution gas from oil wells.
(3) U.S. dollars are converted into Canadian dollars using an exchange rate of Cdn.$/U.S.$0.7738.

SUMMARY OF OIL AND GAS RESERVES
as of December 31, 2003
FORECAST PRICES AND COSTS

	RESERVES							
	LIGHT AND MEDIUM OIL		HEAVY OIL		NATURAL GAS		NATURAL GAS LIQUIDS	
RESERVES CATEGORY	Gross (mbbl)	Net (mbbl)	Gross (mbbl)	Net (mbbl)	Gross (mmcf)	Net (mmcf)	Gross (mbbl)	Net (mbbl)
Canada								
PROVED								
Developed Producing	3,580	3,236	653	611	18,140	15,832	253	196
Developed Non-Producing	25	34	-	-	6,731	5,198	95	70
Undeveloped	725	578	464	438	1,799	1,645	-	-
TOTAL PROVED including Wapella	4,330	3,848	1,117	1,049	26,670	22,675	348	266
Wapella	3,262	2,749	-	-	-	-	-	-
TOTAL PROVED excluding Wapella	1,068	1,099	1,117	1,049	26,670	22,675	348	266
PROBABLE	1,850	1,568	1,202	1,111	10,873	9,169	97	71
TOTAL PROVED PLUS PROBABLE								
Including Wapella	6,180	5,416	2,319	2,160	37,543	31,844	445	337
Wapella	4,539	3,821	-	-	-	-	-	-
Excluding Wapella	1,641	1,595	2,319	2,160	37,543	31,844	445	337
Colombia								
PROVED								
Developed Producing	2,155	1,983	-	-	-	-	-	-
Developed Non-Producing	-	-	-	-	-	-	-	-
Undeveloped	1,914	1,759	-	-	-	-	-	-
TOTAL PROVED	4,069	3,742	-	-	-	-	-	-
PROBABLE	2,804	2,577	-	-	-	-	-	-
TOTAL PROVED PLUS PROBABLE	6,873	6,319	-	-	-	-	-	-
Canada & Colombia								
PROVED								
Developed Producing	5,735	5,219	653	611	18,140	15,832	253	196
Developed Non-Producing	25	34	-	-	6,731	5,198	95	70
Undeveloped	2,639	2,337	464	438	1,799	1,645	-	-
TOTAL PROVED including Wapella	8,399	7,590	1,117	1,049	26,670	22,675	348	266
Wapella	3,262	2,749	-	-	-	-	-	-
TOTAL PROVED excluding Wapella	5,137	4,841	1,117	1,049	26,670	22,675	348	266
PROBABLE	4,654	4,145	1,202	1,111	10,873	9,169	97	71
TOTAL PROVED PLUS PROBABLE								
Including Wapella	13,053	11,735	2,319	2,160	37,543	31,844	445	337
Wapella	4,539	3,821	-	-	-	-	-	-
Excluding Wapella	8,514	7,914	2,319	2,160	37,543	31,844	445	337

FORECAST PRICES AND COSTS
NET PRESENT VALUES OF FUTURE NET REVENUE
as of December 31, 2003

RESERVES CATEGORY	BEFORE INCOME TAXES DISCOUNTED AT (%/year)					AFTER INCOME TAXES DISCOUNTED AT (%/year)				
	0	5	10	15	20	0	5	10	15	20
	(CDN M$)	(CDN M$)	(CDN M$)	(CDN M$)	(CDN M$)	(CDN M$)	(CDN M$)	(CDN M$)	(CDN M$)	(CDN M$)
Canada										
PROVED										
Developed Producing	100,925	90,917	81,919	74,541	68,547	100,527	90,716	81,799	74,466	68,498
Developed Non-Producing	18,273	14,942	12,539	10,744	9,365					
Undeveloped	12,088	8,260	5,598	3,673	2,238					
TOTAL PROVED including Wapella	131,286	114,119	100,056	88,958	80,150	125,024	109,558	96,596	86,270	78,021
Wapella	27,162	24,554	21,370	18,634	16,410	27,308	24,814	21,682	18,966	16,744
TOTAL PROVED excluding Wapella	104,124	89,565	78,686	70,324	63,740	97,716	84,744	74,914	67,304	61,277
PROBABLE	61,800	44,969	34,737	27,914	23,082					
TOTAL PROVED PLUS PROBABLE										
Including Wapella	193,086	159,088	134,793	116,872	103,232	164,590	138,058	118,566	103,967	92,728
Wapella	42,683	36,176	30,539	26,144	22,734	37,016	32,171	27,575	23,875	20,953
Excluding Wapella	150,403	122,912	104,254	90,728	80,498	127,574	105,887	90,991	80,092	71,775
Colombia	(US M$)	(US M$)	(US M$)	(US M$)	(US M$)	(US M$)	(US M$)	(US M$)	(US M$)	(US M$)
PROVED										
Developed Producing	25,797	22,790	20,566	18,843	17,459	25,797	22,790	20,566	18,843	17,459
Developed Non-Producing	-	-	-	-	-					
Undeveloped	15,064	11,954	9,545	7,645	6,124					
TOTAL PROVED	40,861	34,744	30,111	26,488	23,583	40,861	34,744	30,111	26,488	23,583
PROBABLE	29,099	21,693	16,615	12,995	10,330					
TOTAL PROVED PLUS PROBABLE	69,960	56,437	46,726	39,483	33,913	67,557	54,733	45,493	38,576	33,234
Canada & Colombia [1]	(CDN M$)	(CDN M$)	(CDN M$)	(CDN M$)	(CDN M$)	(CDN M$)	(CDN M$)	(CDN M$)	(CDN M$)	(CDN M$)
PROVED										
Developed Producing	135,321	121,304	109,340	99,665	91,826	134,923	121,103	109,220	99,590	91,777
Developed Non-Producing	18,273	14,942	12,539	10,744	9,365					
Undeveloped	32,173	24,199	18,325	13,866	10,403					
TOTAL PROVED including Wapella	185,767	160,444	140,204	124,275	111,594	179,505	155,883	136,744	121,587	109,465
Wapella	27,162	24,554	21,370	18,634	16,410	27,308	24,814	21,682	18,966	16,744
TOTAL PROVED excluding Wapella	158,605	135,890	118,834	105,641	95,184	152,197	131,069	115,062	102,621	92,721
PROBABLE	100,599	73,893	56,890	45,241	36,855					
TOTAL PROVED PLUS PROBABLE										
Including Wapella	286,366	234,337	197,094	169,516	148,449	254,666	211,035	179,223	155,402	137,040
Wapella	42,683	36,176	30,539	26,144	22,734	37,016	32,171	27,575	23,875	20,953
Excluding Wapella	243,683	198,161	166,555	143,372	125,715	217,650	178,864	151,648	131,527	116,087

Notes:

[1] U.S. dollars are converted into Canadian dollars using an exchange rate of Cdn.$/U.S.$0.75 .

TOTAL FUTURE NET REVENUE
(UNDISCOUNTED)
as of December 31, 2003
FORECAST PRICES AND COSTS

RESERVES CATEGORY	REVENUE	ROYALTIES	OPERATING COSTS	DEVELOPMENT COSTS	WELL ABANDONMENT COSTS	FUTURE NET REVENUE BEFORE INCOME TAXES	INCOME TAXES	FUTURE NET REVENUE AFTER INCOME TAXES
Canada	(CDN M$)	(CDN M$)	(CDN M$)	(CDN M$)	(CDN M$)	(CDN M$)	(CDN M$)	(CDN M$)
TOTAL PROVED								
Including Wapella	307,534	60,713	88,178	15,144	12,213	131,286	6,262	125,024
Wapella	88,690	24,841	27,296	5,280	4,111	27,162	(146)	27,308
Excluding Wapella	218,844	35,872	60,882	9,864	8,102	104,124	6,408	97,716
TOTAL PROVED PLUS PROBABLE								
Including Wapella	445,317	85,084	130,031	24,814	12,302	193,086	28,496	164,590
Wapella	123,953	34,242	36,845	6,070	4,112	42,683	5,667	37,016
Excluding Wapella	321,364	50,842	93,186	18,744	8,190	150,403	22,829	127,574
	(US M$)	(US M$)	(US M$)	(US M$)	(US M$)	(US M$)	(US M$)	(US M$)
Colombia								
PROVED RESERVES	82,438	6,612	24,166	10,800	-	40,861	-	40,861
PROVED PLUS PROBABLE RESERVES	138,479	11,155	39,063	18,300	-	69,960	2,403	67,557
	(CDN M$)	(CDN M$)	(CDN M$)	(CDN M$)	(CDN M$)	(CDN M$)	(CDN M$)	(CDN M$)
Canada & Colombia [1]								
TOTAL PROVED								
Including Wapella	417,451	69,528	120,399	29,544	12,213	185,767	6,262	179,505
Wapella	88,690	24,841	27,296	5,280	4,111	27,162	(146)	27,308
Excluding Wapella	328,761	44,687	93,103	24,264	8,102	158,605	6,408	152,197
TOTAL PROVED PLUS PROBABLE								
Including Wapella	629,956	99,958	182,116	49,214	12,302	286,366	31,700	254,666
Wapella	123,953	34,242	36,845	6,070	4,112	42,683	5,667	37,016
Excluding Wapella	506,003	65,715	145,271	43,144	8,190	243,683	26,033	217,650

Notes:

[1] U.S. dollars are converted into Canadian dollars using an exchange rate of Cdn.$/U.S.$0.75

FUTURE NET REVENUE
BY PRODUCTION GROUP
as of December 31, 2003
FORECAST PRICES AND COSTS

RESERVES CATEGORY	PRODUCTION GROUP	FUTURE NET REVENUE BEFORE INCOME TAXES (discounted at 10%/year) Including Wapella	Excluding Wapella
Canada		(CDN M$)	(CDN M$)
PROVED RESERVES	Light and Medium Crude Oil (1)	37,431	15,611
	Heavy Oil (1)	6,141	6,141
	Natural Gas (2)	58,750	58,750
PROVED PLUS PROBABLE RESERVES	Light and Medium Crude Oil (1)	52,188	21,199
	Heavy Oil (1)	10,161	10,161
	Natural Gas (2)	74,106	74,106
Colombia		(US M$)	(US M$)
PROVED RESERVES	Light and Medium Crude Oil (1)	30,111	30,111
PROVED PLUS PROBABLE RESERVES	Light and Medium Crude Oil (1)	46,726	46,726
Canada & Colombia [3]		(CDN M$)	(CDN M$)
PROVED RESERVES	Light and Medium Crude Oil (1)	77,579	55,759
	Heavy Oil (1)	6,141	6,141
	Natural Gas (2)	58,750	58,750
PROVED PLUS PROBABLE RESERVES	Light and Medium Crude Oil (1)	114,489	83,500
	Heavy Oil (1)	10,161	10,161
	Natural Gas (2)	74,106	74,106

Notes:

(1) Including solution gas and other by-products.

(2) Including by-products but excluding solution gas from oil wells.

(3) U.S. dollars are converted into Canadian dollars using an exchange rate of Cdn.$/U.S.$0.75.

Pricing Assumptions

The following sets for the benchmark reference prices, reflected in the reserves data and utilized in the GLJ Report. These price assumptions were provided to the Corporation by GLJ, the Corporation's independent qualified reserve evaluator.

SUMMARY OF PRICING ASSUMPTIONS
CONSTANT PRICES AND COSTS

Year	West Texas Intermediate Crude Oil at Cushing $US/bbl	Light, Sweet Crude Oil 40 API at Edmonton $Cdn/bbl	Heavy Crude Oil 12 API at Hardisty $Cdn/bbl	Medium Crude Oil 29 API At Cromer $Cdn/bbl	Natural Gas AECO Gas Price $Cdn/mmbtu	Alberta Natural Gas Liquids: Edmonton Propane $Cdn/bbl	Alberta Natural Gas Liquids: Edmonton Butane $Cdn/bbl	Alberta Natural Gas Liquids: Edmonton Pentanes Plus $Cdn/bbl	Inflation Rates %/Year	Exchange Rate $US/$Cdn
2003 [1]	$ 32.52	$ 40.81	$ 23.31	$ 34.81	$ 6.09	$ 29.81	$ 31.81	$ 41.31	-	$ 0.7738

[1] As at December 31, 2003.

SUMMARY OF PRICING ASSUMPTIONS
FORECAST PRICES AND COSTS

Year	West Texas Intermediate Crude Oil at Cushing $US/bbl	Light, Sweet Crude Oil 40 API at Edmonton $Cdn/bbl	Heavy Crude Oil 12 API at Hardisty $Cdn/bbl	Medium Crude Oil 29 API At Cromer $Cdn/bbl	Natural Gas AECO Gas Price $Cdn/mmbtu	Alberta Natural Gas Liquids: Edmonton Propane $Cdn/bbl	Alberta Natural Gas Liquids: Edmonton Butane $Cdn/bbl	Alberta Natural Gas Liquids: Edmonton Pentanes Plus $Cdn/bbl	Inflation Rates %/Year	Exchange Rate $US/$Cdn
2004	$ 29.00	$ 37.75	$ 20.25	$ 31.75	$ 5.85	$ 26.75	$ 28.75	$ 38.25	$ 1.50	$ 0.7500
2005	$ 26.00	$ 33.75	$ 20.25	$ 28.75	$ 5.15	$ 21.75	$ 23.75	$ 34.25	$ 1.50	$ 0.7500
2006	$ 25.00	$ 32.50	$ 21.00	$ 28.50	$ 5.00	$ 20.50	$ 22.50	$ 33.00	$ 1.50	$ 0.7500
2007	$ 25.00	$ 32.50	$ 21.00	$ 28.50	$ 5.00	$ 20.50	$ 22.50	$ 33.00	$ 1.50	$ 0.7500
2008	$ 25.00	$ 32.50	$ 21.00	$ 28.50	$ 5.00	$ 20.50	$ 22.50	$ 33.00	$ 1.50	$ 0.7500
2009	$ 25.00	$ 32.50	$ 21.00	$ 28.50	$ 5.00	$ 20.50	$ 22.50	$ 33.00	$ 1.50	$ 0.7500
2010	$ 25.00	$ 32.50	$ 21.00	$ 28.50	$ 5.00	$ 20.50	$ 22.50	$ 33.00	$ 1.50	$ 0.7500
2011	$ 25.00	$ 32.50	$ 21.00	$ 28.50	$ 5.00	$ 20.50	$ 22.50	$ 33.00	$ 1.50	$ 0.7500
2012	$ 25.00	$ 32.50	$ 21.00	$ 28.50	$ 5.00	$ 20.50	$ 22.50	$ 33.00	$ 1.50	$ 0.7500
2013	$ 25.00	$ 32.50	$ 21.00	$ 28.50	$ 5.00	$ 20.50	$ 22.50	$ 33.00	$ 1.50	$ 0.7500
2014	$ 25.00	$ 32.50	$ 21.00	$ 28.50	$ 5.00	$ 20.50	$ 22.50	$ 33.00	$ 1.50	$ 0.7500
2015+	+1.5%/yr	+1.5%/yr	+1.5%/yr	+1.5%/yr	+1.5%/yr	+1.5%/yr	+1.5%/yr	+1.5%/yr	$ 1.50	$ 0.7500

Weighted average historical prices realized by the Corporation for the year ended December 31, 2003 in Canada, were $6.08 /mcf for natural gas (includes negative impact of physical gas sale and transportation contracts), $29.14 /bbl for light/medium crude oil and natural gas liquids (includes impact of financial hedging contracts), and $26.46/bbl for heavy oil. In Colombia, light/medium crude oil prices averaged $32.22/bbl.

RECONCILIATION OF COMPANY NET RESERVES BY PRINCIPAL PRODUCT TYPE

FORECAST PRICES AND COSTS

	Light and Medium Oil			Heavy Oil			Natural Gas			Natural Gas Liquids		
FACTORS	Net Proved (mbbl)	Net Probable (mbbl)	Net Proved Plus Probable (mbbl)	Net Proved (mbbl)	Net Probable (mbbl)	Net Proved Plus Probable (mbbl)	Net Proved (mmcf)	Net Probable (mmcf)	Net Proved Plus Probable (mmcf)	Net Proved (mbbl)	Net Probable (mbbl)	Net Proved Plus Probable (mbbl)
Canada												
December 31 2002[1]	4,438	1,283	5,721	1,008	870	1,878	16,280	5,820	22,100	142	30	172
Extensions	6	8	14	389	295	684	3,740	20	3,760	17	24	41
Improved Recovery	171	681	852	-	-	-	260	(50)	210	2	1	3
Technical Revisions	(250)	(425)	(676)	(111)	(54)	(164)	(1,505)	1,819	314	87	8	96
Discoveries	-	-	-	-	-	-	1,970	1,150	3,120	-	-	-
Acquisitions	192	52	245	-	-	-	11,150	3,130	14,280	102	25	127
Dispositions	(86)	(30)	(116)	-	-	-	(6,070)	(2,720)	(8,790)	(41)	(17)	(58)
Economic Factors	-	-	-	-	-	-	-	-	-	-	-	-
Production	(624)	-	(624)	(238)	-	(238)	(3,150)	-	(3,150)	(43)	-	(43)
Dec. 31 2003 including Wapella	3,848	1,568	5,416	1,049	1,111	2,160	22,675	9,169	31,844	266	71	337
Wapella	2,748	1,073	3,821	-	-	-	-	-	-	-	-	-
Dec. 31 2003 excluding Wapella	1,100	495	1,595	1,049	1,111	2,160	22,675	9,169	31,844	266	71	337
Colombia												
December 31 2002[1]	4,385	1,761	6,146	-	-	-	-	-	-	-	-	-
Extensions	1,117	185	1,302	-	-	-	-	-	-	-	-	-
Improved Recovery	-	-	-	-	-	-	-	-	-	-	-	-
Technical Revisions	(1,401)	631	(770)	-	-	-	-	-	-	-	-	-
Discoveries	-	-	-	-	-	-	-	-	-	-	-	-
Acquisitions	-	-	-	-	-	-	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-	-	-	-	-	-	-
Economic Factors	-	-	-	-	-	-	-	-	-	-	-	-
Production	(359)	-	(359)	-	-	-	-	-	-	-	-	-
December 31 2003	3,742	2,577	6,319	-	-	-	-	-	-	-	-	-
Canada & Colombia												
December 31 2002[1]	8,823	3,044	11,867	1,008	870	1,878	16,280	5,820	22,100	142	30	172
Extensions	1,123	193	1,315	389	295	684	3,740	20	3,760	17	24	41
Improved Recovery	171	681	852	-	-	-	260	(50)	210	2	1	3
Technical Revisions	(1,651)	206	(1,446)	(111)	(54)	(164)	(1,505)	1,819	314	87	8	96
Discoveries	-	-	-	-	-	-	1,970	1,150	3,120	-	-	-
Acquisitions	192	52	245	-	-	-	11,150	3,130	14,280	102	25	127
Dispositions	(86)	(30)	(116)	-	-	-	(6,070)	(2,720)	(8,790)	(41)	(17)	(58)
Economic Factors	-	-	-	-	-	-	-	-	-	-	-	-
Production	(982)	-	(982)	(238)	-	(238)	(3,150)	-	(3,150)	(43)	-	(43)
Dec. 31 2003 including Wapella	7,590	4,145	11,735	1,049	1,111	2,160	22,675	9,169	31,844	266	71	337
Wapella	2,748	1,073	3,821	-	-	-	-	-	-	-	-	-
Dec. 31 2003 excluding Wapella	4,842	3,072	7,914	1,049	1,111	2,160	22,675	9,169	31,844	266	71	337

Note:

[1] The previous evaluation was prepared using Canadian National Policy 2-B reserves definitions. Under those definitions, probable reserves were adjusted by a factor to account for the risk associated with their recovery. The Company previously applied a risk factor of 50 percent in reporting its probable reserves. Under current NI 51-101 reserves definitions, estimates are prepared such that the full proved plus probable reserves are estimated to be recoverable. The above reconciliation reflects current probable reserves versus previous risk adjusted (50 percent) probable reserves reported by the Company.

**RECONCILIATION OF CHANGES IN
NET PRESENT VALUES OF FUTURE NET REVENUE
DISCOUNTED AT 10% PER YEAR
PROVED RESERVES
CONSTANT PRICES AND COSTS**

PERIOD AND FACTOR	2003
Canada	**(CDN M$)**
Estimated Future Net Revenue at December 31, 2002 (without abandonment costs)	**129,655**
Oil and Gas Sales During the Period Net of Production Costs and Royalties (1)	29,754
Changes due to Prices and Royalties Related to Forecast Production (2)	(32,663)
Development Costs During the Period (3)	5,335
Changes In Forecast Development Costs	(3,935)
Changes Resulting from Extensions and Improved Recovery	17,024
Changes Resulting from Discoveries	4,608
Changes Resulting from Acquisitions of Reserves	47,882
Changes Resulting from Dispositions of Reserves	(23,311)
Accretion of Discount (4)	14,749
Net Change in Income Taxes (5)	838
Changes Resulting from Technical Reserves Revisions	(5,719)
All Other Changes (6)	(61,938)
Estimated Future Net Revenue at at December 31, 2003 including Wapella	122,279
Wapella	30,032
Estimated Future Net Revenue at at December 31, 2003 excluding Wapella	**92,247**
Colombia	**(US M$)**
Estimated Future Net Revenue at December 31, 2002 (without abandonment costs)	**36,085**
Oil and Gas Sales During the Period Net of Production Costs and Royalties (1)	5,340
Changes due to Prices and Royalties Related to Forecast Production (2)	4,128
Development Costs During the Period (3)	44,396
Changes In Forecast Development Costs	(35,905)
Changes Resulting from Extensions and Improved Recovery	13,912
Changes Resulting from Discoveries	-
Changes Resulting from Acquisitions of Reserves	-
Changes Resulting from Dispositions of Reserves	-
Accretion of Discount (4)	5,333
Net Change in Income Taxes (5)	16,713
Changes Resulting from Technical Reserves Revisions	(15,815)
Other (6)	(28,718)
Estimated Future Net Revenue at at December 31, 2003	**45,470**
Canada & Colombia (7)	**(CDN M$)**
Estimated Future Net Revenue at December 31, 2002 (without abandonment costs)	**177,768**
Oil and Gas Sales During the Period (1)	36,874
Changes due to Prices and Royalties (2)	(27,159)
Development Costs During the Period (3)	64,530
Changes In Forecast Development Costs	(51,808)
Changes Resulting from Extensions and Improved Recovery	35,574
Changes Resulting from Discoveries	4,608
Changes Resulting from Acquisitions of Reserves	47,882
Changes Resulting from Dispositions of Reserves	(23,311)
Accretion of Discount (4)	21,860
Net Change in Income Taxes (5)	23,122
Changes from Technical Reserves Revisions	(26,805)
Other (6)	(100,228)
Estimated Future Net Revenue at at December 31, 2003 including Wapella	182,906
Wapella	30,032
Estimated Future Net Revenue at at December 31, 2003 excluding Wapella	**152,874**

Notes:
(1) Company actual before income taxes, excluding general and administrative expenses.
(2) The impact of changes in prices and other economic factors on future net revenue.
(3) Actual 2004 capital expenditures relating to the exploration, development and production of oil and gas reserves within the 2003 total proved reserves.
(4) Estimated as 10% of the beginning of period net present value.
(5) The difference between forecast income taxes at beginning of period and the actual taxes for the period plus forecast income taxes at the end of period.
(6) Includes changes due to revised production profiles, development timing, operating costs, royalty rates, actual price received in 2003 versus forecast, etc. Abandonment costs not included in previous evaluation.
(7) U.S. dollars are converted into Canadian dollars using an exchange rate of Cdn.$/U.S.$0.7738

FUTURE DEVELOPMENT COSTS [1][2]

YEAR		FORECAST PRICES AND COSTS PROVED RESERVES 0%	FORECAST PRICES AND COSTS PROVED PLUS PROBABLE RESERVES 0%	CONSTANT PRICES AND COSTS PROVED RESERVES 0%
Canada		(CDN M$)	(CDN M$)	(CDN M$)
Including Wapella				
	2004	10,778	13,431	10,778
	2005	3,088	9,913	3,042
	2006	96	97	94
	2007	297	52	285
	2008	-	249	-
Thereafter		885	1,071	792
Total		15,144	24,813	14,991
Total discounted at 10%		13,672	22,030	13,579
Excluding Wapella				
	2004	5,498	7,361	5,498
	2005	3,088	9,913	3,042
	2006	96	97	94
	2007	297	52	285
	2008	-	249	-
Thereafter		885	1,072	792
Total		9,864	18,744	9,711
Total discounted at 10%		8,637	16,242	8,545
Colombia		(US M$)	(US M$)	(US M$)
	2004	10,800	18,300	10,800
	2005	-	-	-
	2006	-	-	-
	2007	-	-	-
	2008	-	-	-
Thereafter		-	-	-
Total		10,800	18,300	10,800
Total discounted at 10%		10,297	17,448	10,297
Canada & Colombia				
Including Wapella		(CDN M$) (3)	(CDN M$) (3)	(CDN M$) (4)
	2004	25,178	37,831	25,178
	2005	3,088	9,913	3,042
	2006	96	97	94
	2007	297	52	285
	2008	-	249	-
Thereafter		885	1,071	792
Total		29,544	49,213	29,391
Total discounted at 10%		27,401	45,294	26,886
Excluding Wapella				
	2004	19,898	31,761	19,898
	2005	3,088	9,913	3,042
	2006	96	97	94
	2007	297	52	285
	2008	-	249	-
Thereafter		885	1,072	792
Total		24,264	43,144	24,111
Total discounted at 10%		22,366	39,506	21,852

Notes:

[1] The above table sets forth development costs deducted in the estimation of the Corporation's future net revenue attributable to the reserve categories noted above.

[2] Future development costs are expected to be funded by, internally generated cash flow, and from a combination of equity financing and debt, the costs of which are not expected to have an effect on the reserves or future net revenue.

[3] U.S. dollars are converted into Canadian dollars using an exchange rate of Cdn.$/U.S.$0.75

[4] U.S. dollars are converted into Canadian dollars using an exchange rate of Cdn.$/U.S.$0.7738

2004 PRODUCTION ESTIMATES

The following table sets out the volume of the Corporation's production estimated for the year ended December 31, 2004 which is reflected in the estimate of future net revenue disclosed in the tables contained in this Appendix A. Gross production excludes the Company's interest in royalty volumes received.

	LIGHT AND MEDIUM OIL		HEAVY OIL		NATURAL GAS		NATURAL GAS LIQUIDS		OIL EQUIVALENT	
RESERVES CATEGORY	Gross (bbl/d)	Net (bbl/d)	Gross (bbl/d)	Net (bbl/d)	Gross (mcf/d)	Net (mcf/d)	Gross (bbl/d)	Net (bbl/d)	Gross (boe/d)	Net (boe/d)
Canada										
PROVED PRODUCING										
Nevis & Red Willow	111	99	-	-	10,011	7,759	215	165	1,995	1,557
Others	1,740	1,514	532	493	5,044	4,535	41	32	3,153	2,794
Total Proved Producing	1,851	1,612	532	493	15,055	12,294	256	197	5,148	4,351
TOTAL PROVED										
Nevis & Red Willow	111	99	-	-	11,219	8,643	232	176	2,212	1,715
Others	1,882	1,626	597	552	6,030	5,241	41	32	3,525	3,083
Total Proved	1,993	1,724	597	552	17,249	13,884	273	208	5,737	4,799
TOTAL PROVED PLUS PROBABLE										
Nevis & Red Willow	115	102	-	-	12,230	9,427	245	187	2,398	1,860
Others	2,079	1,785	698	645	6,633	5,724	49	37	3,932	3,422
Total Proved Plus Probable	2,195	1,888	698	645	18,863	15,150	294	224	6,330	5,282
Colombia										
PROVED PRODUCING										
Orito	1,138	1,047	-	-	-	-	-	-	1,138	1,047
Nevia	354	325	-	-	-	-	-	-	354	325
Total Proved Producing	1,492	1,372	-	-	-	-	-	-	1,492	1,372
TOTAL PROVED										
Orito	1,738	1,599	-	-	-	-	-	-	1,738	1,599
Nevia	353	324	-	-	-	-	-	-	353	324
Total Proved	2,091	1,924	-	-	-	-	-	-	2,091	1,924
TOTAL PROVED PLUS PROBABLE										
Orito	2,133	1,961	-	-	-	-	-	-	2,133	1,961
Nevia	360	331	-	-	-	-	-	-	360	331
Total Proved Plus Probable	2,493	2,292	-	-	-	-	-	-	2,493	2,292
Canada & Colombia										
PROVED PRODUCING	3,343	2,985	532	493	15,055	12,294	256	197	6,640	5,724
TOTAL PROVED	4,084	3,648	597	552	17,249	13,884	273	208	7,828	6,722
TOTAL PROVED PLUS PROBABLE	4,688	4,180	698	645	18,863	15,150	294	224	8,823	7,574

APPENDIX B

REPORT OF MANAGEMENT AND DIRECTORS ON OIL AND GAS DISCLOSURE

Management of Petrobank Energy and Resources Ltd. (the "Company") are responsible for the preparation and disclosure of information with respect to the Company's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data, which consist of the following:

(a) (i) proved and proved plus probable oil and gas reserves estimated as at January 1, 2004 using forecast prices and costs; and

(ii) the related estimated future net revenue; and

(b) (i) proved oil and gas reserves estimated as at January 1, 2004 using constant prices and costs; and

(ii) the related estimated future net revenue.

An independent qualified reserves evaluator has evaluated the Company's reserves data. The report of the independent qualified reserves evaluator will be filed with securities regulatory authorities concurrently with this report.

The Reserves Committee of the board of directors of the Company has:

(c) reviewed the Company's procedures for providing information to the independent qualified reserves evaluator;

(d) met with the independent qualified reserves evaluator to determine whether any restrictions affected the ability of the independent qualified reserves evaluator to report without reservation; and

(e) reviewed the reserves data with management and the independent qualified reserves evaluator.

The Reserves Committee of the board of directors has reviewed the Company's procedures for assembling and reporting other information associated with oil and gas activities and has reviewed that information with management. The board of directors has approved:

(f) the content and filing with securities regulatory authorities of the reserves data and other oil and gas information;

(g) the filing of the report of the independent qualified reserves evaluator on the reserves data; and

(h) the content and filing of this report.

Because the reserves data are based on judgments regarding future events, actual results will vary and the variations may be material.

(signed) "John D. Wright"

John D. Wright

President and Chief Executive Officer

(signed) "R. Gregg Smith"

R. Gregg Smith

Vice President Canada

(signed) "M. Bruce Chernoff "

M. Bruce Chernoff

Director and Chairman of the Reserves Committee

(signed) " James D. Tocher "

James D. Tocher

Director and Member of the Reserves Committee

May 19, 2004

APPENDIX C

REPORT ON RESERVES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATOR

To the board of directors of Petrobank Energy and Resources Ltd. (the "Company"):

1. We have prepared an evaluation of the Company's reserves data as at January 1, 2004. The reserves data consist of the following:

   (a) (i) proved and proved plus probable oil and gas reserves estimated as at January 1, 2004 using forecast prices and costs; and

   (ii) the related estimated future net revenue; and

   (b) (i) proved oil and gas reserves estimated as at January 1, 2004 using constant prices and costs; and

   (ii) the related estimated future net revenue.

2. The reserves data are the responsibility of the Company's management. Our responsibility is to express an opinion on the reserves data based on our evaluation.

   We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook (the "COGE Handbook") prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society).

3. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation also includes assessing whether the reserves data are in accordance with principles and definitions presented in the COGE Handbook.

4. The following table sets forth the estimated future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated by us for the year ended December 31, 2003, and identifies the respective portions thereof that we have audited, evaluated and reviewed and reported on to the Company's board of directors:

Description and Preparation Date of Evaluation Report	Location of Reserves (County or Foreign Geographic Area)	Net Present Value of Future Net Revenue (before income taxes, 10% discount rate)			
		Audited	Evaluated	Reviewed	Total
February 10, 2004	Canada	$nil	$134.8MM	$nil	$134.8MM
February 15, 2004	Colombia	$nil	U.S.$46.7MM	$nil	U.S.$46.7MM

5. In our opinion, the reserves data respectively evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook.

6. We have no responsibility to update our reports referred to in paragraph 4 for events and circumstances occurring after their respective preparation dates.

7. Because the reserves data are based on judgements regarding future events, actual results will vary and the variations may be material.

Executed as to our report referred to above:

Gilbert Laustsen Jung Associates Ltd., Calgary, Alberta, Canada

(signed) "Dana B. Laustsen"

Dana B. Laustsen, P. Eng.

Calgary, Alberta

May 7, 2004

Computershare

600, 530 – 8th Ave SW., Calgary, AB T2P 3S8 Tel.: 1 (866) 331-6361 Fax.: (403) 267-6529

May 19, 2004

Alberta Securities Commission
British Columbia Securities Commission
Saskatchewan Financial Services Commission
The Manitoba Securities Commission
Ontario Securities Commission
L'Autorité des marchés financiers
Nova Scotia Securities Commission
TSX

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CORPORATE FINANCE

Dear Sirs:

Subject: Petrobank Energy and Resources Ltd.

We confirm that the following material was sent by pre-paid mail on May 18, 2004 to the registered shareholders of the common shares of the subject Corporation:

1. Annual Report 2003
2. Notice of Meeting / Information Circular
3. Proxy
4. Proxy Return Envelope

We further confirm that copies of the above mentioned material together with the NI 54-102 Cards were sent by courier, on May 18, 2004 to each intermediary holding shares of the Corporation who responded to the search procedures pursuant to Canadian Securities Administrators' National Instrument 54-101 regarding shareholder communications.

In compliance with security regulations, we are providing this material to you in our capacity as agent for the subject Corporation.

Yours truly,

"signed by"

Tracy Williams
Mailing Professional
ClientServicesMailings@Computershare.com

cc: Petrobank Energy and Resources Ltd.
Attention: Corey Rhuttan

PETROBANK
ENERGY AND RESOURCES LTD.

NEWS RELEASE

PETROBANK ANNOUNCES FILING OF ITS 2003 YEAR END DISCLOSURE DOCUMENTS

Calgary, Alberta – May 19, 2004 - Petrobank Energy and Resources Ltd. ("Petrobank") today filed its Renewal Annual Information Form, which includes Petrobank's reserves data and other oil and gas information for the period ended December 31, 2003 as mandated by National Instrument 51-101 Standards of Disclosure for Oil and Gas Activities of the Canadian Securities Administrators. Petrobank has also filed its audited consolidated financial statements and accompanying notes for the period ended December 31, 2003 and related Management Discussion and Analysis with Canadian securities regulatory authorities. Copies of Petrobank's 2003 disclosure documents may be obtained at www.sedar.com or by emailing Petrobank at ir@petrobank.com.

For more information please contact:

John D. Wright, President and CEO, or
Corey C. Ruttan, Director Corporate Finance and Investor Relations
Telephone: (403) 750-4400

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

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PETROBANK ENERGY AND RESOURCES LTD.

Instrument of Proxy
For the Annual and Special Meeting of Shareholders

The undersigned shareholder of Petrobank Energy and Resources Ltd. (the "Corporation") hereby appoints John D. Wright, of the City of Calgary, in the Province of Alberta, President and Chief Executive Officer and a director of the Corporation or, failing him, Chris J. Bloomer, of the City of Calgary, in the Province of Alberta, Chief Financial Officer and Vice President of the Corporation, or instead of either of the foregoing, _____, as proxyholder of the undersigned, with full power of substitution, to attend and act and vote for and on behalf of the undersigned at the annual and special meeting of shareholders of the Corporation (the "Meeting"), to be held on June 17, 2004 and at any adjournment(s) thereof, and on every ballot that may take place in consequence thereof to the same extent and with the same powers as if the undersigned were personally present at the Meeting with authority to vote at the said proxyholder's discretion, except as otherwise specified below.

Without limiting the general powers hereby conferred, the undersigned hereby directs the said proxyholder to vote the shares represented by this Instrument of Proxy in the following manner:

1. **FOR** ☐ or **AGAINST** ☐ fixing the number of directors to be elected at the Meeting at seven (7) as specified in the Information Circular – Proxy Statement of the Corporation dated May 14, 2004 (the "Information Circular");

2. **FOR** ☐ or **WITHHOLD FROM VOTING FOR** ☐ the election of directors as specified in the Information Circular;

3. **FOR** ☐ or **WITHHOLD FROM VOTING FOR** ☐ the appointment of Deloitte & Touche LLP, Chartered Accountants, to serve as auditors of the Corporation for the ensuing year and the authorization of the directors to fix their remuneration as such;

4. **FOR** ☐ or **AGAINST** ☐ the ordinary resolution approving an amendment to the stock option plan (the "Plan") of the Corporation, to provide that the maximum number of common shares ("Common Shares") of the Corporation which may, from time to time, be issuable pursuant to the Plan be increased, all as more particularly described in the Information Circular;

5. **FOR** ☐ or **AGAINST** ☐ the ordinary resolution ratifying and approving the deferred compensation plan of the Corporation and the issuance of Common Shares pursuant thereto, all as more particularly described in the Information Circular;

6. **FOR** ☐ or **AGAINST** ☐ the ordinary resolution approving the issuance by the Corporation in one or more private placements during the twelve month period commencing June 17, 2004 of up to 54,651,396 Common Shares, all as more particularly described in and subject to the restrictions described in the Information Circular; and

7. at the discretion of the said proxyholders, upon any permitted amendment or variation of the above matters or any other matter that may be properly brought before the Meeting or any adjournment(s) thereof in such manner as such proxy, in such proxyholder's sole judgment, may determine.

This Instrument of Proxy is solicited on behalf of the management of the Corporation. The shares represented by this Instrument of Proxy will be voted and, where the shareholder has specified a choice with respect to the above matters, will be voted as directed above or, if no direction is given, will be voted in favour of the above matters.

Each shareholder has the right to appoint a proxyholder, other than the persons designated above, who need not be a shareholder, to attend and to act for such shareholder and on such shareholder's behalf at the Meeting. To exercise such right, the names of the nominees of management should be crossed out and the name of the shareholder's appointee should be legibly printed in the blank space provided.

THE UNDERSIGNED HEREBY REVOKES ANY PROXIES HERETOFORE GIVEN.

Dated this _____ day of _____, 2004.

_____
(signature of shareholder)

_____
(name of shareholder - please print)

_____
(number of common shares being voted)

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If you have any questions or need assistance in completing this Instrument of Proxy, please contact Chris J. Bloomer, Chief Financial Officer of the Corporation at: (403) 920-0135 (Calgary)

NOTES:

1. If the shareholder is a corporation, its corporate seal must be affixed or it must be signed by an officer or attorney thereof duly authorized.

2. This instrument of proxy must be dated and the signature hereon should be exactly the same as the name in which the shares are registered. If the Instrument of Proxy is not dated in the above space, it is deemed to bear the date on which it is mailed by the person making the solicitation.

3. Persons signing as executors, administrators, trustees, etc., should so indicate and give their full title as such.

4. This Instrument of Proxy will not be valid and not be acted upon or voted unless it is completed as outlined herein and delivered to the attention of the Chief Financial Officer of the Corporation c/o Computershare Trust Company of Canada, Proxy Department, 9th Floor, 100 University Avenue, Toronto, Ontario, M5J 2Y1, not less than 48 hours (excluding Saturdays, Sundays and holidays) before the time set for the holding of the Meeting or any adjournment(s) thereof. A proxy is valid only at the meeting in respect of which it is given or any adjournment(s) of that meeting.

REPORT IN RESPECT OF VOTING RESULTS PURSUANT TO SECTION 11.3 OF NATIONAL INSTRUMENT 51-102 – CONTINUOUS DISCLOSURE OBLIGATIONS

In respect of the Annual and Special Meeting of holders of common shares of Petrobank Energy and Resources Ltd. ("**Petrobank**" or the "**Company**") held June 17, 2004 (the "**Meeting**"), the following sets forth a brief description of each matter which was voted upon at such Meeting and the outcome of the vote:

	Description of Matter	Outcome of Vote
1.	Ordinary resolution to approve fixing the number of members of the Board of Directors of Petrobank to be elected at the Meeting at seven members	Resolution approved
2.	Ordinary resolution to approve the election of the seven nominees to serve as directors of Petrobank for the ensuing year, or until their successors are duly elected or appointed, as described in the information circular of Petrobank dated May 14, 2004 (the "**Information Circular**")	Resolution approved
3.	Ordinary resolution to approve the appointment of Deloitte & Touche LLP, Chartered Accountants, as auditors of Petrobank for the ensuing year and to authorize the directors of Petrobank to fix their remuneration as such	Resolution approved
4.	Ordinary resolution to amend the Corporation's stock option plan to increase the maximum number of common shares which may be issued thereunder, as described in the Information Circular	Resolution approved
5.	Ordinary resolution of disinterested shareholders to ratify and approve Petrobank's deferred compensation plan and the issuance of common shares pursuant thereto, as described in the Information Circular	Resolution approved
6.	Ordinary resolution to approve in advance one or more private placements by the Corporation in the next twelve months up to 100% of the Corporation's currently outstanding share capital, as described in the Information Circular	Resolution approved

The resolutions to approve items 4 and 5 noted above were conducted by way of ballot. Attached to this report is a report of Computershare Trust Company of Canada, the Scrutineers of the Meeting, in respect of these ballots.

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Dated at Calgary, Alberta this 17th day of June, 2004.

PETROBANK ENERGY AND RESOURCES LTD.

Per: (signed) *"Chris J. Bloomer"*
Chris J. Bloomer
Chief Financial Officer

PETROBANK ENERGY AND RESOURCES LTD.
ANNUAL AND SPECIAL (NON-ROUTINE)
MEETING OF SHAREHOLDERS
JUNE 17, 2004

SCRUTINEERS REPORT ON BALLOT RESOLUTION 4

THE SCRUTINEERS REPORT THE RESULTS OF THE BALLOT ON THE ORDINARY RESOLUTION APPROVING AN AMENDMENT TO THE STOCK OPTION PLAN (THE "PLAN") OF THE CORPORATION, TO PROVIDE THAT THE MAXIMUM NUMBER OF COMMON SHARES ("COMMON SHARES") OF THE CORPORATION WHICH MAY, FROM TIME TO TIME, BE ISSUABLE PURSUANT TO THE PLAN BE INCREASED, ALL AS MORE PARTICULARLY DESCRIBED IN THE INFORMATION CIRCULAR.

VOTES FOR	20,702,310
VOTES AGAINST	1,071,967
TOTAL VOTES CAST	21,774,277
PERCENTAGE OF VOTES IN FAVOUR OF RESOLUTION	95 %
PERCENTAGE OF VOTES AGAINST RESOLUTION	5 %

DATED THIS 17TH DAY OF JUNE , 2004
COMPUTERSHARE TRUST COMPANY OF CANADA

(signed) *"Carol Kinmond"*
CAROL KINMOND SCRUTINEER

(signed) *"Betty Muller"*
BETTY MULLER SCRUTINEER

PETROBANK ENERGY AND RESOURCES LTD.
ANNUAL AND SPECIAL (NON-ROUTINE)
MEETING OF SHAREHOLDERS
JUNE 17, 2004

SCRUTINEERS REPORT ON BALLOT RESOLUTION 5

THE SCRUTINEERS REPORT THE RESULTS OF THE BALLOT ON THE ORDINARY RESOLUTION RATIFYING AND APPROVING THE DEFERRED COMPENSATION PLAN OF THE CORPORATION AND THE ISSUANCE OF COMMON SHARES PURSUANT THERETO, ALL AS MORE PARTICULARLY DESCRIBED IN THE INFORMATION CIRCULAR;

VOTES FOR	9,915,606
VOTES AGAINST	1,096,467
TOTAL VOTES CAST	11,012,073
EXCLUDES VOTES OF INSIDERS	
PERCENTAGE OF VOTES IN FAVOUR OF RESOLUTION	90 %
PERCENTAGE OF VOTES AGAINST RESOLUTION	10 %

DATED THIS 17TH DAY OF JUNE, 2004
COMPUTERSHARE TRUST COMPANY OF CANADA

(signed) *"Carol Kinmond"*
CAROL KINMOND SCRUTINEER

(signed) *"Betty Muller"*
BETTY MULLER SCRUTINEER

·Management's Discussion and Analysis·

The following Management's Discussion and Analysis ("MD&A") is dated August 12, 2004 and should be read in conjunction with the unaudited consolidated financial statements of the Company for the three and six month periods ended June 30, 2004, MD&A for the year ended December 31, 2003, and the audited consolidated financial statements for the year ended December 31, 2003. Additional information for the Company can be found at www.sedar.com. In addition to historical information, the MD&A contains forward-looking statements that reflect management's objectives and expectations as at the date of this report, which involve risks and uncertainties. The Company's actual results may differ materially from those anticipated in these forward-looking statements.

Natural gas volumes have been converted to barrels of oil equivalent ("boe") so that six thousand cubic feet ("mcf") of natural gas equals one barrel based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the well head. Boes may be misleading, particularly if used in isolation. This report contains financial terms that are considered non-GAAP measures such as cash flow from operations, cash flow per share, net debt, and operating netback. These measures are commonly utilized in the oil and gas industry and are considered informative for our shareholders. Specifically, cash flow from operations and cash flow per share reflect cash generated from operating activities before changes in non-cash working capital. We consider these measures important as they demonstrate our ability to generate sufficient cash to fund future growth opportunities and repay debt. All amounts are in Canadian dollars, unless otherwise stated.

Property Dispositions

Petrobank closed two property dispositions in May for net proceeds of $4.2 million. The results of operations for 2004 only include results from disposed properties up to the closing date of the transaction.

Production

Oil and NGL production in Canada during the second quarter averaged 1,850 barrels per day (bpd), a decrease from the 2,035 bpd produced in the first quarter of 2004 and the 2,758 bpd produced in the second quarter of 2003. These decreases are due to the disposition of the Wapella and Epping properties in the first quarter of 2004 that produced 1,456 bpd in the second quarter of 2003 and an average of 635 bpd in the first quarter of 2004. Excluding production from these disposed properties, oil and NGL production increased by 42 percent over the 2003 period and 32 percent over the prior quarter. The increase over the prior quarter relates to increased production from our Nevis, Red Willow, and Shekilie properties. Second quarter natural gas production of 14.6 million cubic feet per day (mmcfpd) increased 81 percent from 8.1 mmcfpd in the second quarter of 2003. The increase was a result of the acquisition of the Nevis and Red Willow properties in September 2003 partially offset by the disposition of the Company's Zama/Larne property in May 2003 and the Edmonton property in May 2004. Total Canadian production for the second quarter was 4,282 boepd, a 4 percent increase from the same period last year.

Colombian oil production averaged 1,354 bpd in the second quarter of 2004 compared to 1,028 bpd in the second quarter of 2003. Production declined from 1,702 bpd in the first quarter of 2004 due to field maintenance delays, problems with Ecopetrol's gas lift system and an increase in the water cut in our Orito-115 well.

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Average Benchmark Prices

For the three months ended June 30,	2004	2003	% change
WTI crude oil (U.S.$/bbl)	38.32	28.91	33
WTI crude oil (C$/bbl)	52.11	40.39	29
Bow River heavy oil differential (U.S.$/bbl)	11.02	6.54	69
NYMEX natural gas (U.S.$/mmbtu)	6.17	5.72	8
AECO (daily) natural gas (C$/mcf)	6.99	6.82	2
C$/U.S.$ exchange rate	0.74	0.72	3

Realized Prices

The average Canadian oil and NGL price received in the second quarter was $27.35 per barrel, a 2 percent decrease from the $28.00 per barrel received in the comparable 2003 period. Canadian oil and NGL prices averaged $40.18 per barrel, before hedging losses of $12.83 per barrel, representing a U.S.$8.76 discount to average WTI prices in the quarter compared to a U.S.$6.18 discount to WTI in the second quarter of 2003. The average discount increased as a result of a widening of Canadian heavy crude oil differentials offset by an increase in the average quality of barrels produced. In 2004, 1,000 barrels per day of new swaps at U.S.$24.00 became effective, along with a fixed price oil sales contract for 300 bpd at an average price of U.S.$27.74 per barrel.

The average natural gas price received in the second quarter was $5.99 per mcf, an 11 percent decrease from the $6.73 per mcf received in the second quarter of 2003. Natural gas prices reflect the negative impact of the Company's long-term physical gas sales contracts, and in the current period includes the effect of the Company's natural gas price collar for 2004 on 10,551 GJ/day with AECO prices between $5.00 and $5.94 per GJ.

Oil sales prices in Colombia averaged U.S.$33.56 per barrel in the second quarter, representing a U.S.$4.76 discount to WTI compared to a discount of U.S.$7.64 per barrel in the comparable 2003 period. The average discount to WTI decreased as our higher quality Orito oil comprised a larger portion of Colombian production, and as a result of our new marketing arrangement for our Neiva oil.

Royalties

Royalties increased from $2.6 million in the second quarter of 2003 to $3.1 million in the current period. Canadian royalties as a percentage of revenue increased slightly from 20 percent in the second quarter of 2003 to 21 percent in the current period. We anticipate Canadian royalty rates to average approximately 21 percent throughout the remainder of 2004. Colombian royalties are included in the current quarter at a rate of 8 percent.

Production Expenses

Production expenses in Canada decreased 16 percent from $8.06 per boe in the second quarter of 2003 to $6.77 per boe in the current period. The decrease was primarily a result of the acquisition of lower cost Nevis and Red Willow production in September of 2003. Production expenses in Colombia averaged $8.53 per barrel during the quarter, an 8 percent increase from the second quarter 2003 average of $7.93 per barrel and an 8 percent increase from the first quarter 2004 average of $7.89 per barrel. The increase is a result of well workover costs incurred in the current period.

General and Administrative Expenses

General and administrative expenses increased by 18 percent to $2.1 million in the second quarter of 2004 compared to $1.8 million in the second quarter of 2003. The increase is primarily due to higher incremental overhead associated with higher staff levels in Colombia.

Interest on Bank Debt

The Company's credit facility was drawn $8.2 million at March 31, 2003 and increased to $24.8 million drawn at June 30, 2004. As a result, interest on bank debt increased from $98,000 in the second quarter of 2003 to $251,000 in the second quarter of 2004.

Depletion, Depreciation and Accretion

Depletion, depreciation and accretion expense for the second quarter of $8.4 million ($16.32 per boe) compared to $5.4 million ($11.46 per boe) in the comparable 2003 period. The increased rate was primarily due to the acquisition of Monolith Oil Corp. in September of 2003, and the results of the 2003 Colombian drilling program.

Interest on Subordinated Notes

Interest on subordinated notes totaled $2.8 million during the second quarter ($1.9 million net of future taxes), compared to $2.3 million in the same period last year. The increase relates to the issuance of an additional $40.0 million of notes in May of 2003.

Income Taxes

At the end of the first quarter of 2004, Petrobank had a future income tax liability of $11.6 million primarily due to the Monolith corporate acquisition and the issuance and renouncement of flow through shares in 2003. In the second quarter of 2004, future tax recoveries were recorded against these balances of $0.1 million included in capital and future income taxes, and a $0.9 million recovery that was offset against interest on subordinated notes. Current tax of $274,000 in the second quarter of 2004 relates to Large Corporations Tax in Canada and presumptive income taxes in Colombia that are based on debt and equity levels. Colombian presumptive income taxes can be recovered against income taxes payable in future periods and can be carried forward for eight years.

Capital Expenditures

Consolidated capital expenditures during the quarter were $10.0 million, comprised of $7.6 million in Canada and $2.4 million in Colombia. In Canada, the majority of expenditures were spent at our Nevis/Red Willow properties, while our Colombian expenditures were focused on the Orito Block.

Liquidity and Capital Resources

At June 30, 2004 net debt totaled $121.8 million, including the book value of outstanding subordinated notes ($94.6 million). The subordinated notes are not callable and mature in July 2006. Petrobank's borrowing base under its senior secured credit facility was increased from $33.5 million to $37.0 million in July 2004. Working capital deficit at June 30, 2004, including the $24.8 million balance drawn under the secured credit facility, totaled $27.2 million leaving $9.8 million of available borrowing capacity under the increased borrowing base.

Changes in Accounting Policies

Asset Retirement Obligations

Effective January 1, 2004 the Company retroactively adopted the new standard of the Canadian Institute of Chartered Accountants ("CICA"), "Asset Retirement Obligations". The new standard requires that the recognition of the fair value of obligations associated with the retirement of tangible long-lived assets be

recorded in the period the asset is put into use, with a corresponding increase to the carrying amount of the related asset. The obligations recognized are statutory, contractual or legal obligations. The liability is accreted over time for changes in the fair value of the liability through charges to accretion, which is included in depletion, depreciation and accretion expense. The costs capitalized to the related assets are amortized to earnings in a manner consistent with the depletion and depreciation of the underlying asset. The impact of the adoption of this standard on the financial statements is described in Note 5 to the consolidated financial statements for the three and six month periods ended June 30, 2004.

Transportation Costs

Effective January 1, 2004 the Company began classifying certain transportation costs as expenses in the consolidated statements of operations. In prior periods, these costs were netted against revenues and accordingly the prior period financial statements have been reclassified for comparative purposes. The change in accounting policy has no effect on net income but increased natural gas revenues and expenses for the three and six month periods ended June 30, 2004 by $395,000 and $811,000, respectively (2003 – $288,000 and $626,000). The reclassification translates into a $0.30 per mcf increase in natural gas prices in the second quarter of 2004 (2003 - $0.39 per mcf). Also as a result, Canadian transportation expenses of $1.02 per boe were recognized in the current quarter (2003 - $0.77 per boe).

MANAGING a portfolio of OPPORTUNITIES

PETROBANK
ENERGY AND RESOURCES LTD.

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CORPORATE FINANCE

Q2 2004

· Highlights ·

	Three months ended June 30, 2004	2003	% change	Six months ended June 30, 2004	2003	% change
Financial						
($000s, except where noted)						
Oil and natural gas revenue	**18,175**	14,747	**23**	**37,649**	33,002	**14**
Cash flow from operations [1]	**8,461**	6,185	**37**	**17,338**	14,715	**18**
Per share – basic ($) [2]	**0.11**	0.09	**22**	**0.23**	0.25	**(8)**
Per share – diluted ($) [2]	**0.11**	0.09	**22**	**0.23**	0.24	**(4)**
Net income	**80**	790	**(90)**	**(284)**	4,122	
Net income (loss) attributable to common shareholders	**(1,822)**	(1,508)	**(21)**	**(4,070)**	307	
Per share – basic and diluted ($)	**(0.03)**	(0.03)	**-**	**(0.07)**	0.01	
Capital expenditures	**9,995**	24,696	**(60)**	**24,708**	60,657	**(59)**
Net debt [3]	**121,803**	94,801	**(28)**	**121,803**	94,801	**(28)**
Common shares outstanding (000s)						
Basic	**54,732**	45,594	**20**	**54,732**	45,594	**20**
Diluted	**59,582**	51,587	**15**	**59,582**	51,587	**15**
Operations [4]						
Canadian operating netback ($/boe except where noted)						
Oil and NGLs revenue ($/bbl)	**27.35**	28.00	**(2)**	**26.89**	30.64	**(12)**
Natural gas revenue ($/mcf)	**5.99**	6.73	**(11)**	**6.04**	7.29	**(17)**
Oil and natural gas revenue	**32.22**	32.06	**-**	**32.19**	35.42	**(9)**
Royalties	**6.79**	6.29	**8**	**6.98**	8.12	**(14)**
Production expenses	**6.77**	8.06	**(16)**	**6.80**	7.63	**(11)**
Transportation expenses	**1.02**	0.77	**32**	**0.99**	0.80	**24**
Operating netback	**17.64**	16.94	**4**	**17.42**	18.87	**(8)**
Colombian operating netback ($/bbl)						
Oil revenue	**45.62**	29.74	**53**	**40.61**	33.27	**22**
Royalties	**3.62**	2.40	**51**	**3.24**	2.67	**21**
Production expenses	**8.53**	7.93	**8**	**8.13**	7.18	**13**
Operating netback	**33.47**	19.41	**72**	**29.24**	23.42	**25**
Average daily production						
Canada - oil and NGLs (bbls)	**1,850**	2,758	**(33)**	**1,942**	2,758	**(30)**
Canada - natural gas (mcf)	**14,592**	8,057	**81**	**15,331**	9,480	**62**
Total Canada (boe)	**4,282**	4,101	**4**	**4,497**	4,338	**4**
Colombia - oil (bbls)	**1,354**	1,028	**32**	**1,528**	862	**77**
Total Company (boe)	**5,636**	5,129	**10**	**6,025**	5,200	**16**

(1) Cash flow from operations before changes in other non-cash items.
(2) Calculated based on cash flow from operations before changes in other non-cash items less preferred share dividends and interest paid on subordinated notes.
(3) Includes working capital (deficiency) and subordinated notes reflected as equity on the balance sheet.
(4) 6 Mcf of natural gas is equivalent to 1 barrel of oil equivalent (BOE).

Petrobank Energy and Resources Ltd. ("Petrobank") is pleased to provide this operational update of our Canadian, Latin American and Heavy Oil Business Units as well as our second quarter financial results.

OPERATIONAL UPDATE

Canadian Business Unit

Second quarter Canadian production averaged 4,282 barrels of oil equivalent per day ("boepd") consisting of 1,850 barrels per day of liquids and 14,592 mcf per day of natural gas. In the first quarter we disposed of our Wapella and Epping properties and in the second quarter we completed additional minor property dispositions. Excluding production from disposed properties Canadian production increased 316 boepd or 8 percent from the first to second quarters of 2004. Most of our activity in the second quarter related to drilling, completions and recompletions. However, planned pipeline construction and tie-ins have run behind schedule due to surface access problems, regulatory approval delays and wet field conditions. During the second quarter, we drilled 6 wells (5.7 net), completed 6 wells (5.7 net), and recompleted a further 18 (14.6 net) locations. The drilling resulted in 3 gas wells (2.7 net), 2 oil wells (2.0 net) and 1 suspended well (1.0 net). Production additions have been behind forecast as a result of pipelining delays, but recently significant progress has been made.

Petrobank's most active areas during the second quarter were Nevis and Red Willow where we drilled and completed 5 new wells (5.0 net), resulting in 2 oil wells, 2 gas wells and 1 suspended well. In addition, we recompleted a further 8 wells (8.0 net) in these areas. During the third quarter we have drilled 3 locations (3.0 net) to-date, resulting in 2 gas wells and 1 oil well. Due to wet field conditions, minimal pipelining activity occurred during the second quarter and as a result, production is expected to continue to improve through the third quarter as these new wells are brought on-line.

In West Central Saskatchewan, 4 recompletions (2.4 net) were performed at Lashburn during the second quarter, and early in the third quarter, we made a significant Colony gas discovery at Eyehill.

During the second quarter at Jumpbush we drilled and completed 1 well (0.7 net), and recompleted an additional 6 wells (4.2 net). Recently, the Siksika First Nation's Chief and Council approved the pipeline tie-ins to 13 wells (9.1 net) and this construction will commence shortly. Jumpbush production will increase over the near term upon completion of these tie-ins and installation of additional field compression. A further 30-well (21.0 net) drilling and tie-in program has been submitted for approvals.

At Jumpbush, we are currently evaluating completion results on our first two coalbed methane ("CBM") test wells and plan to tie-in at least one of these wells into nearby facilities for long-term evaluation. At Princeton, the approval process for drilling our initial CBM test well is ongoing.

Latin American Business Unit

In Colombia, we produced an average of 1,354 barrels of oil per day from our Orito and Neiva blocks in the second quarter, down from 1,702 barrels per day in first quarter. During the second quarter we completed the transfer of the majority of our field operations to the Colombian state oil company, Ecopetrol, who have assumed responsibility for well operations and field maintenance as part of their contractual operating fee. While this will result in long-term operating cost savings to Petrobank, certain transitional issues have impacted the pace and priority of ongoing field maintenance and optimization. Increased water cuts in our Orito-115 well and problems with Ecopetrol's gas lift system have also impacted production. We are proactively addressing these issues.

After completing our initial work commitments on both the Neiva and Orito blocks, the term of our contracts were validated through June 2023, adding flexibility to our future development plans. We have submitted our annual work plans to Ecopetrol, which entail the evaluation of potential waterfloods at

Neiva and at Orito, as well as drilling a minimum of one development well in both blocks. For the remainder of 2004, we have planned a number of rig-less interventions and are planning to workover the Orito-114 and 115 wells. We are also engaged in discussions with Ecopetrol to improve the participation terms at Neiva to facilitate a broader development program.

Our ongoing reservoir simulation work of the main producing zone at Orito indicates significant additional potential remains in several regions of the field. We are using this model to prioritize future development activities. Our next development well will target Orito's southwest extension, offsetting 4 of the field's most productive wells, which have averaged more than 7 mmbbls of cumulative oil production each.

Evaluation of the Central Colombia Block by Petrobank and our partners is ongoing and a proposal has been submitted to Ecopetrol to include their participation. A final decision to continue into the second phase of exploration or relinquish the block is required in September 2004.

Significant efforts to optimize our operating and administrative costs have been recently implemented, and the full impact of these cost reductions will be realized over the remainder of the year.

Heavy Oil Business Unit

Detailed project engineering of the WHITESANDS project is finalized, including AFE quality cost estimates, procurement planning, and civil design for the access road and plant site. WHITESANDS is now positioned to commence at our discretion with minimal risk of seasonal delay. Critical path civil and utilities work is anticipated to commence in the third quarter.

Research and development work over the past year has yielded significant results generating a "patent pipeline" of enhancements to the THAI™ process. In June, our first new patent, "Oilfield Enhanced In-situ Combustion Process – U.S. Registration #33,105", was filed as a world patent. The principal benefit of this enhancement to the THAI™ technology is that it will allow us to generate higher average well-bore temperatures, resulting in increased production rates and the flexibility to inject air at higher rates. Our ongoing research activity is creating significant intellectual capital and know-how that will serve to further build and protect the value of the THAI™ and CAPRI™ technologies.

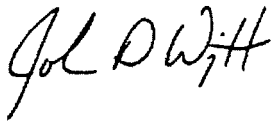
International activities have resulted in the joint execution of confidentiality agreements by Petrobank and the Colombian state oil company, Ecopetrol, to facilitate the evaluation of the THAI™ process by Ecopetrol and for Petrobank to evaluate suitable Colombian reservoirs. The object of this process is to evaluate the feasibility of undertaking a THAI™ pilot project and to ultimately commercialize the THAI™ technology in Colombia. Petrobank is actively discussing similar arrangements with other state and international oil companies. Financing options for the WHITESANDS project in Canada are being evaluated to enable the earliest commencement of the project while preserving maximum value for Petrobank shareholders.

OUTLOOK

Although 2004 has been a year of consolidation where we have disposed of approximately 1,800 boepd of production, we are extremely encouraged by our 2004 drilling and completion results. While production additions planned for the second quarter have not come on stream in as timely a manner as planned we have added significant behind pipe reserves that are being brought on line in the third quarter.

Our work on our Colombian properties has resulted in a follow-up drilling plan in Orito that, if successful, will yield a new inventory of drilling opportunities for 2005 and beyond. In Canada, between Nevis, Red Willow and Jumpbush we have a suite of drilling locations for at least the next two years on our existing lands. The initial assessment of our CBM properties should give us an indication of their commerciality by late 2005. The WHITESANDS project is ready to go, pending an appropriate financing arrangement.

Our unique inventory of opportunities is unprecedented for a company Petrobank's size, and the pace of execution of these projects is naturally being constrained by our available capital resources. To maximize flexibility, we continue to evaluate strategic dispositions of mature or fully valued assets. In addition, our lender recently completed their annual review resulting in an increase in our borrowing base from $33.5 million to $37.0 million, further increasing our financial flexibility. We see a managed investment approach over the near term as being the most appropriate way to unlock the unrealized value of this outstanding portfolio of high-impact opportunities, to the benefit of our shareholders.



John D. Wright
President and Chief Executive Officer
August 12, 2004

The following Management's Discussion and Analysis ("MD&A") is dated August 12, 2004 and should be read in conjunction with the unaudited consolidated financial statements of the Company for the three and six month periods ended June 30, 2004, MD&A for the year ended December 31, 2003, and the audited consolidated financial statements for the year ended December 31, 2003. Additional information for the Company can be found at www.sedar.com. In addition to historical information, the MD&A contains forward-looking statements that reflect management's objectives and expectations as at the date of this report, which involve risks and uncertainties. The Company's actual results may differ materially from those anticipated in these forward-looking statements.

Natural gas volumes have been converted to barrels of oil equivalent ("boe") so that six thousand cubic feet ("mcf") of natural gas equals one barrel based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the well head. Boes may be misleading, particularly if used in isolation. This report contains financial terms that are considered non-GAAP measures such as cash flow from operations, cash flow per share, net debt, and operating netback. These measures are commonly utilized in the oil and gas industry and are considered informative for our shareholders. Specifically, cash flow from operations and cash flow per share reflect cash generated from operating activities before changes in non-cash working capital. We consider these measures important as they demonstrate our ability to generate sufficient cash to fund future growth opportunities and repay debt. All amounts are in Canadian dollars, unless otherwise stated.

Property Dispositions

Petrobank closed two property dispositions in May for net proceeds of $4.2 million. The results of operations for 2004 only include results from disposed properties up to the closing date of the transaction.

Production

Oil and NGL production in Canada during the second quarter averaged 1,850 barrels per day (bpd), a decrease from the 2,035 bpd produced in the first quarter of 2004 and the 2,758 bpd produced in the second quarter of 2003. These decreases are due to the disposition of the Wapella and Epping properties in the first quarter of 2004 that produced 1,456 bpd in the second quarter of 2003 and an average of 635 bpd in the first quarter of 2004. Excluding production from these disposed properties, oil and NGL production increased by 42 percent over the 2003 period and 32 percent over the prior quarter. The increase over the prior quarter relates to increased production from our Nevis, Red Willow, and Shekilie properties. Second quarter natural gas production of 14.6 million cubic feet per day (mmcfpd) increased 81 percent from 8.1 mmcfpd in the second quarter of 2003. The increase was a result of the acquisition of the Nevis and Red Willow properties in September 2003 partially offset by the disposition of the Company's Zama/Larne property in May 2003 and the Edmonton property in May 2004. Total Canadian production for the second quarter was 4,282 boepd, a 4 percent increase from the same period last year.

Colombian oil production averaged 1,354 bpd in the second quarter of 2004 compared to 1,028 bpd in the second quarter of 2003. Production declined from 1,702 bpd in the first quarter of 2004 due to field maintenance delays, problems with Ecopetrol's gas lift system and an increase in the water cut in our Orito-115 well.

Average Benchmark Prices

For the three months ended June 30,	2004	2003	% change
WTI crude oil (U.S.$/bbl)	38.32	28.91	33
WTI crude oil (C$/bbl)	52.11	40.39	29
Bow River heavy oil differential (U.S.$/bbl)	11.02	6.54	69
NYMEX natural gas (U.S.$/mmbtu)	6.17	5.72	8
AECO (daily) natural gas (C$/mcf)	6.99	6.82	2
C$/U.S.$ exchange rate	0.74	0.72	3

Realized Prices

The average Canadian oil and NGL price received in the second quarter was $27.35 per barrel, a 2 percent decrease from the $28.00 per barrel received in the comparable 2003 period. Canadian oil and NGL prices averaged $40.18 per barrel, before hedging losses of $12.83 per barrel, representing a U.S.$8.76 discount to average WTI prices in the quarter compared to a U.S.$6.18 discount to WTI in the second quarter of 2003. The average discount increased as a result of a widening of Canadian heavy crude oil differentials offset by an increase in the average quality of barrels produced. In 2004, 1,000 barrels per day of new swaps at U.S.$24.00 became effective, along with a fixed price oil sales contract for 300 bpd at an average price of U.S.$27.74 per barrel.

The average natural gas price received in the second quarter was $5.99 per mcf, an 11 percent decrease from the $6.73 per mcf received in the second quarter of 2003. Natural gas prices reflect the negative impact of the Company's long-term physical gas sales contracts, and in the current period includes the effect of the Company's natural gas price collar for 2004 on 10,551 GJ/day with AECO prices between $5.00 and $5.94 per GJ.

Oil sales prices in Colombia averaged U.S.$33.56 per barrel in the second quarter, representing a U.S.$4.76 discount to WTI compared to a discount of U.S.$7.64 per barrel in the comparable 2003 period. The average discount to WTI decreased as our higher quality Orito oil comprised a larger portion of Colombian production, and as a result of our new marketing arrangement for our Neiva oil.

Royalties

Royalties increased from $2.6 million in the second quarter of 2003 to $3.1 million in the current period. Canadian royalties as a percentage of revenue increased slightly from 20 percent in the second quarter of 2003 to 21 percent in the current period. We anticipate Canadian royalty rates to average approximately 21 percent throughout the remainder of 2004. Colombian royalties are included in the current quarter at a rate of 8 percent.

Production Expenses

Production expenses in Canada decreased 16 percent from $8.06 per boe in the second quarter of 2003 to $6.77 per boe in the current period. The decrease was primarily a result of the acquisition of lower cost Nevis and Red Willow production in September of 2003. Production expenses in Colombia averaged $8.53 per barrel during the quarter, an 8 percent increase from the second quarter 2003 average of $7.93 per barrel and an 8 percent increase from the first quarter 2004 average of $7.89 per barrel. The increase is a result of well workover costs incurred in the current period.

General and Administrative Expenses

General and administrative expenses increased by 18 percent to $2.1 million in the second quarter of 2004 compared to $1.8 million in the second quarter of 2003. The increase is primarily due to higher incremental overhead associated with higher staff levels in Colombia.

Interest on Bank Debt

The Company's credit facility was drawn $8.2 million at March 31, 2003 and increased to $24.8 million drawn at June 30, 2004. As a result, interest on bank debt increased from $98,000 in the second quarter of 2003 to $251,000 in the second quarter of 2004.

Depletion, Depreciation and Accretion

Depletion, depreciation and accretion expense for the second quarter of $8.4 million ($16.32 per boe) compared to $5.4 million ($11.46 per boe) in the comparable 2003 period. The increased rate was primarily due to the acquisition of Monolith Oil Corp. in September of 2003, and the results of the 2003 Colombian drilling program.

Interest on Subordinated Notes

Interest on subordinated notes totaled $2.8 million during the second quarter ($1.9 million net of future taxes), compared to $2.3 million in the same period last year. The increase relates to the issuance of an additional $40.0 million of notes in May of 2003.

Income Taxes

At the end of the first quarter of 2004, Petrobank had a future income tax liability of $11.6 million primarily due to the Monolith corporate acquisition and the issuance and renouncement of flow through shares in 2003. In the second quarter of 2004, future tax recoveries were recorded against these balances of $0.1 million included in capital and future income taxes, and a $0.9 million recovery that was offset against interest on subordinated notes. Current tax of $274,000 in the second quarter of 2004 relates to Large Corporations Tax in Canada and presumptive income taxes in Colombia that are based on debt and equity levels. Colombian presumptive income taxes can be recovered against income taxes payable in future periods and can be carried forward for eight years.

Capital Expenditures

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SUMMARY OF QUARTERLY RESULTS

	2004		2003 [2]				2002 [2]	
	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3
Financial ($000s except where noted)								
Oil and natural gas revenue	**18,175**	19,474	20,540	13,963	14,747	18,255	13,238	12,579
Cash flow from operations	**8,461**	8,877	8,701	5,842	6,185	8,530	5,600	5,806
Per share - basic ($)	**0.11**	0.12	0.12	0.08	0.09	0.16	0.09	0.11
- diluted ($)	**0.11**	0.12	0.12	0.08	0.09	0.15	0.09	0.11
Net income (loss)	**80**	(364)	(18,654)	(573)	790	3,332	1,010	1,207
Net income (loss) attributable to common shareholders	**(1,822)**	(2,248)	(20,434)	(3,398)	(1,508)	1,815	(537)	(375)
Per share - basic and diluted ($)	**(0.03)**	(0.04)	(0.38)	(0.07)	(0.03)	0.04	(0.01)	(0.01)
Capital expenditures	**9,995**	14,713	27,338	28,065	24,696	35,961	28,620	5,813
Operations								
Canadian operating netbacks by product [1]								
Light/medium oil and NGLs sales price ($/bbl)	**29.54**	27.50	26.81	28.09	28.28	33.28	32.44	33.16
Royalties	**8.93**	8.97	5.89	6.01	7.28	10.79	7.76	7.93
Production expenses	**7.14**	6.81	6.22	5.24	6.99	5.84	7.04	6.32
Operating netback	**13.47**	11.72	14.70	16.84	14.02	16.65	17.65	18.92
Heavy oil sales price ($/bbl)	**22.36**	24.46	22.95	24.86	27.14	33.37	25.90	30.09
Royalties	**3.29**	3.45	2.36	4.22	3.75	5.89	4.62	4.13
Production expenses	**10.69**	8.52	11.18	6.83	9.40	8.33	8.68	5.92
Operating netback	**8.38**	12.49	9.41	13.81	13.99	19.15	12.60	20.04
Natural gas sales price ($/mcf)	**5.99**	6.09	5.89	5.49	6.73	7.71	5.42	3.94
Royalties	**1.08**	1.20	0.88	0.82	1.00	1.61	1.03	0.71
Production expenses	**0.94**	1.06	1.26	1.79	1.51	1.44	1.40	1.16
Transportation expenses	**0.30**	0.28	0.28	0.51	0.39	0.34	0.33	0.31
Operating netback	**3.67**	3.55	3.47	2.37	3.83	4.32	2.66	1.76
Oil equivalent sales price ($/boe)	**32.22**	32.18	30.57	28.75	32.06	38.46	31.79	28.57
Royalties	**6.79**	7.15	5.12	5.35	6.29	9.77	6.78	5.97
Production expenses	**6.77**	6.82	7.55	7.06	8.06	7.24	7.78	6.55
Transportation expenses	**1.02**	0.97	0.85	0.83	0.77	0.82	0.83	0.84
Operating netback	**17.64**	17.24	17.05	15.51	16.94	20.63	16.40	15.21
Colombian operating netback ($/bbl)								
Oil sales price	**45.62**	36.63	31.66	31.37	29.74	38.58	-	-
Royalties	**3.62**	2.93	2.53	2.44	2.40	3.09	-	-
Production expenses	**8.53**	7.89	15.62	9.24	7.93	6.09	-	-
Operating netback	**33.47**	25.81	13.51	19.69	19.41	29.40	-	-
Average daily production								
Canada - light/medium oil and NGLs (bbls)	**1,288**	1,332	2,147	2,097	2,097	2,225	2,180	2,242
Canada - heavy oil (bbls)	**562**	703	784	812	661	532	472	354
Canada - natural gas (mcf)	**14,592**	16,069	17,702	6,581	8,057	10,920	11,244	13,134
Total Canada (boe)	**4,282**	4,713	5,881	4,005	4,101	4,577	4,526	4,785
Colombia - oil (bbls)	**1,354**	1,702	1,374	1,166	1,028	695	-	-
Total Company (boe)	**5,636**	6,415	7,255	5,171	5,129	5,272	4,526	4,785

(1) Sales prices are shown after hedging costs. All hedging costs relating to oil sales are net against Canadian light/medium oil and NGLs price, except for the Company's 300 bopd fixed price contract (WTI – U.S.$27.74) that is net against the heavy oil sales price in the first and second quarters of 2004.

(2) Restated for changes in accounting policies.

Consolidated Balance Sheets

(Unaudited, Thousands of Canadian dollars)

As at	June 30, 2004	December 31, 2003 (As restated per Notes 2, 4 & 5)
Assets		
Current assets		
Accounts receivable and other current assets	**$ 21,582**	$ 21,528
Capital assets	**198,531**	235,476
	$ 220,113	$ 257,004
Liabilities and Shareholders' Equity		
Current liabilities		
Accounts payable and accrued liabilities	**$ 23,939**	$ 34,937
Bank debt (Note 3)	**24,843**	30,102
Debenture	**-**	14,014
	48,782	79,053
Obligations under gas sale and transportation contracts	**6,883**	7,287
Asset retirement obligations (Note 5)	**7,909**	9,602
Future income tax liability	**10,606**	12,808
	74,180	108,750
Shareholders' equity		
Subordinated notes	**94,603**	93,430
Common shares (Note 4)	**72,765**	72,355
Contributed surplus (Note 4)	**352**	186
Deficit	**(21,787)**	(17,717)
	145,933	148,254
	$ 220,113	$ 257,004

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,	
	2004	2003 (As restated per Notes 2, 4 & 5)	2004	2003 (As restated per Notes 2, 4 & 5)
Revenues				
Oil and natural gas	$ 18,175	$ 14,747	$ 37,649	$ 33,002
Royalties	(3,093)	(2,571)	(6,612)	(6,790)
	15,082	12,176	31,037	26,212
Expenses				
Production	3,676	3,748	7,824	7,113
Transportation (Note 2)	395	288	811	626
General and administrative	2,087	1,763	3,786	3,144
Interest on bank debt	251	98	729	139
Depletion, depreciation and accretion	8,368	5,350	17,401	10,536
	14,777	11,247	30,551	21,558
Income before other items and taxes	305	929	486	4,654
Other income (expense)	(22)	149	(553)	30
Capital and future income taxes	(203)	(288)	(217)	(562)
Net income (loss)	80	790	(284)	4,122
Interest on subordinated notes, net of future taxes	(1,902)	(2,298)	(3,786)	(3,815)
Net income (loss) attributable to common shareholders	(1,822)	(1,508)	(4,070)	307
Retained earnings (deficit), beginning of period	(19,965)	7,443	(17,717)	5,628
Retained earnings (deficit), end of period	$ (21,787)	$ 5,935	$ (21,787)	$ 5,935
Basic and diluted earnings (loss) per share (Note 4)	$ (0.03)	$ (0.03)	$ (0.07)	$ 0.01

See accompanying notes to these consolidated financial statements.

Consolidated Statements of Cash Flow

(Unaudited, Thousands of Canadian dollars)

	Three months ended June 30,		Six months ended June 30,	
	2004	2003 (As restated per Notes 2, 4 & 5)	**2004**	2003 (As restated per Notes 2, 4 & 5)
Operating Activities				
Net income (loss)	**$ 80**	$ 790	**$ (284)**	$ 4,122
Depletion, depreciation and accretion	**8,368**	5,350	**17,401**	10,536
Non-cash stock compensation	**84**	45	**166**	57
Future income tax recovery	**(71)**	-	**(320)**	-
Loss recorded on disposition of sales contract	**-**	-	**375**	-
Cash flow from operations	**8,461**	6,185	**17,338**	14,715
Changes in other non-cash items	**(1,005)**	(5,440)	**(4,992)**	(7,178)
	7,456	745	**12,346**	7,537
Financing Activities				
Issuance (repayment) of bank debt	**2,215**	(8,204)	**(5,259)**	-
Issuance of common shares and share purchase warrants (Note 4)	**125**	1,183	**410**	1,254
Repayment of debenture	**-**	-	**(14,014)**	-
Issuance of subordinated notes	**-**	34,410	**-**	34,410
Interest on subordinated notes	**(2,246)**	(1,908)	**(4,495)**	(3,249)
Amortization of obligations under gas hedging contracts	**(202)**	(202)	**(404)**	(402)
	(108)	25,279	**(23,762)**	32,013
Investing Activities				
Expenditures on capital assets	**(9,995)**	(24,696)	**(24,708)**	(60,657)
Proceeds on disposition of capital assets	**4,174**	16,626	**42,311**	16,626
Asset retirement obligations settled	**(127)**	-	**(127)**	(27)
Changes in other non-cash items	**(1,400)**	(8,839)	**(6,060)**	1,399
	(7,348)	(16,909)	**11,416**	(42,659)
Net change in cash position	**-**	9,115	**-**	(3,109)
Cash and cash equivalents, beginning of period	**-**	-	**-**	12,224
Cash and cash equivalents, end of period	**$ -**	$ 9,115	**$ -**	$ 9,115

See accompanying notes to these consolidated financial statements.

As at and for the three and six month periods ended June 30, 2004
(All tabular amounts are expressed in thousands of Canadian dollars, except share amounts)

Note 1 – Significant Accounting Policies

The interim consolidated financial statements as at and for the three and six month periods ended June 30, 2004 should be read in conjunction with the audited consolidated financial statements as at and for the year ended December 31, 2003. The notes to these interim consolidated financial statements do not conform in all respects to the note disclosure requirements of generally accepted accounting policies for annual financial statements. These interim consolidated financial statements are prepared using the same accounting policies and methods of computation as disclosed in the audited consolidated financial statements as at and for the year ended December 31, 2003 except as described in Note 2.

Note 2 – Changes in Accounting Policies

Asset Retirement Obligations

Effective January 1, 2004 the Company retroactively adopted the new standard of the Canadian Institute of Chartered Accountants ("CICA"), "Asset Retirement Obligations". The new standard requires that the recognition of the fair value of obligations associated with the retirement of tangible long-lived assets be recorded in the period the asset is put into use, with a corresponding increase to the carrying amount of the related asset. The obligations recognized are statutory, contractual or legal obligations. The liability is accreted over time for changes in the fair value of the liability through charges to accretion, which is included in depletion, depreciation and accretion expense. The costs capitalized to the related assets are amortized to earnings in a manner consistent with the depletion and depreciation of the underlying asset. The impact of the adoption of this standard on the financial statements is described in Note 5.

Capital Assets – Oil and Gas

Effective January 1, 2004 the Company adopted Accounting Guideline 16, "Oil and Gas Accounting - Full Cost" ("AcG-16"), which replaces Accounting Guideline 5, "Full Cost Accounting in the Oil and Gas Industry". AcG-16 modifies how the ceiling test is performed and is consistent with CICA section 3063, "Impairment of Long-lived Assets". The recoverability of a cost centre is tested by comparing the carrying value of the cost centre to the sum of the undiscounted cash flows expected from the cost centre's use and eventual disposition. If the carrying value is unrecoverable the cost centre is written down to its fair value using the expected present value approach. This approach incorporates risks and uncertainties in the expected future cash flows, which are discounted using a risk free rate. The adoption of AcG-16 had no effect on the Company's financial results.

Hedging Relationships

The CICA published an amended Accounting Guideline 13, "Hedging Relationships", effective January 1, 2004, to clarify circumstances in which hedge accounting is appropriate. All derivative instruments that do not qualify as a hedge under the guideline, or are not properly designated as a hedge, will be recorded on the balance sheet as either an asset or liability with changes in fair value recognized in earnings. The Company adopted the standard January 1, 2004 with no impact on the financial results.

Transportation Costs

Effective January 1, 2004 the Company began classifying certain transportation costs as expenses in the consolidated statements of operations. In prior periods, these costs were netted against revenues and accordingly the prior period financial statements have been reclassified for comparative purposes. The change in accounting policy has no effect on net income but increased natural gas revenues and expenses for the three and six month periods ended June 30, 2004 by $395,000 and $811,000, respectively (2003 – $288,000 and $626,000).

Note 3 – Bank debt

Petrobank's borrowing base under its senior secured credit facility was increased from $33.5 million to $37.0 million in July of 2004.

Note 4 – Share Capital

As at June 30, 2004 the Company had outstanding 54,732,396 common shares, 3,429,501 stock options, and 1,420,300 share purchase warrants. The share purchase warrants allow holders to purchase an equivalent number of common shares at $4.00 per share on or before May 6, 2006.

Common Share Continuity	Number	Amount
Balance at December 31, 2003	54,502,646	$72,355
Exercise of stock options	148,750	285
Balance at March 31, 2004	54,651,396	72,640
Exercise of stock options	81,000	125
Balance at June 30, 2004	54,732,396	$72,765

Stock Option Continuity	Number	Weighted - Average Exercise Price
Balance at December 31, 2003	3,676,501	$ 2.42
Granted	147,500	2.74
Exercised	(148,750)	(1.92)
Expired/cancelled	(98,250)	(2.78)
Balance at March 31, 2004	3,577,001	$ 2.44
Granted	172,500	1.95
Exercised	(81,000)	(1.55)
Expired/cancelled	(239,000)	(2.36)
Balance at June 30, 2004	3,429,501	$ 2.44

Earnings Per Share

Basic and diluted earnings (loss) per share have been calculated based on net income (loss) attributable to common shareholders divided by the weighted average number of common shares outstanding for the three month period ended June 30, 2004 of 54,683,858 (2003 – 45,534,147) and for the six month period ended June 30, 2004 of 54,623,228 (2003 – 45,437,331). The diluted calculations for the three and six month periods ended June 30, 2004 include nil (2003 – nil and 1,105,433 respectively) additional shares for the potential impact of share purchase warrants and stock options.

Stock Based Compensation

In 2003, the Company adopted the fair value based method of accounting for its stock-based compensation plan whereby the fair value of stock options granted after January 1, 2003 is recognized as general and administrative expense and as contributed surplus. Stock based compensation costs for the three and six month periods ended June 30, 2004 totaled $84,000 and $166,000, respectively. The corresponding three and six month periods ended June 30, 2003 have been restated to record stock-based compensation of $45,000 and $57,000, respectively.

Had compensation expense associated with the Company's stock option plan been recognized using the fair value based method for all option grants after January 1, 2002, the Company's net loss attributable to common shareholders for the three and six month periods ended June 30, 2004 would have increased by $61,000 and $133,000, respectively (2003 - $108,000 and $215,000). Net income (loss) per share would have changed by less than $0.01 per share for each period presented.

The fair value of stock options granted has been estimated on their respective grant dates using the Black Scholes option-pricing model using the following assumptions:

Three months ended June 30,	2004	2003
Risk free interest rate	4.5%	4.5%
Dividend rate	0%	0%
Expected life (years)	4	4
Expected volatility	30%	30%

The average value per option granted during the three and six month periods ended June 30, 2004 were $0.60 and $0.71 as at the date of grant.

Note 5 - Asset Retirement Obligations

The total future asset retirement obligation was estimated by management based on the Company's net ownership interest in all wells, gathering lines and facilities, estimated costs to reclaim and abandon the wells and facilities and the estimated timing of the costs to be incurred in future periods. The change was effective January 1, 2004 and the revision was applied retroactively. The impact was as follows:

Consolidated Balance Sheet – as at December 31, 2003

	As Reported	Change	As Restated
Assets			
Net capital assets	232,007	3,469	235,476
Liabilities and shareholders' equity			
Asset retirement obligations	-	9,602	9,602
Site restoration liability	2,807	(2,807)	-
Future income tax liability	13,920	(1,112)	12,808
Deficit	(15,503)	(2,214)	(17,717)

Consolidated Statement of Operations and Deficit – Three months ended June 30, 2003

	As Reported	Change	As Restated
Depletion, depreciation and accretion	5,250	100	5,350
Net Income [1]	935	(100)	835

Consolidated Statement of Operations and Deficit – Six months ended June 30, 2003

	As Reported	Change	As Restated
Depletion, depreciation and accretion	10,243	293	10,536
Net Income [1]	4,472	(293)	4,179

[1] Net income was further reduced for the three and six month periods by $45,000 and $57,000 to $790,000 and $4,122,000, respectively due to the restatement of stock-based compensation costs (Note 4).

The change in accounting for asset retirement obligations did not have a material impact on net loss reported in the three and six month periods ended June 30, 2004.

Changes to asset retirement obligations were as follows:

	Three months ended June 30,		Six months ended June 30,	
	2004	2003	2004	2003
Asset retirement obligation, beginning of period	8,270	11,009	9,602	10,325
Obligations incurred	100	130	403	262
Obligations settled	(127)	-	(127)	(27)
Accretion expense	186	248	402	480
Obligations related to assets sold and other	(520)	(4,260)	(2,371)	(3,913)
Asset retirement obligation, end of period	7,909	7,127	7,909	7,127

The total undiscounted amount of estimated cash flows required to settle the obligation at June 30, 2004 is $24.5 million (2003 - $28.7 million), which has been discounted using a credit-adjusted risk free rate of 9 percent. Most of these obligations are not expected to be paid for several years extending up to 34 years in the future, and are expected to be funded from general company resources at the time of settlement.

Note 6 – Commitments and Contingencies

In Colombia, the Company has U.S.$2.0 million of remaining work commitments on the Neiva Block that are required to be completed by December 31, 2004. The Company's work program for the Orito Block includes drilling one well and implementing a pilot waterflood before June 2005 at an estimated cost of U.S.$5.0 million.

Note 7 – Segmented Information

Three months ended June 30,

	2004			2003		
	Canada	Colombia	Total	Canada	Colombia	Total
Revenues						
Oil and natural gas	$ 12,554	$ 5,621	$ 18,175	$ 11,965	$ 2,782	$ 14,747
Royalties	(2,647)	(446)	(3,093)	(2,347)	(224)	(2,571)
	9,907	5,175	15,082	9,618	2,558	12,176
Expenses						
Production	2,625	1,051	3,676	3,007	741	3,748
Transportation	395	-	395	288	-	288
General and administrative	1,330	757	2,087	1,274	489	1,763
Depletion, depreciation and accretion	5,697	2,671	8,368	3,741	1,609	5,350
Segmented income	$ (140)	$ 696	$ 556	$ 1,308	$ (281)	$ 1,027
Non-segmented expenses						
Interest on bank debt			(251)			(98)
Other			(22)			149
Capital tax and future income taxes			(203)			(288)
Net income (loss)			80			790
Interest on subordinated notes, net of future taxes			(1,902)			(2,298)
Net income (loss) attributable to common shareholders			$ (1,822)			$ (1,508)
Identifiable assets	$146,652	$ 73,461	$220,113	$130,616	$ 60,192	$190,808
Capital expenditures	$ 7,577	$ 2,418	$ 9,995	$ 8,735	$ 15,961	$ 24,696

Six months ended June 30,

	2004			2003		
	Canada	Colombia	Total	Canada	Colombia	Total
Revenues						
Oil and natural gas	$ 26,355	$ 11,294	$ 37,649	$ 27,807	$ 5,195	$ 33,002
Royalties	(5,712)	(900)	(6,612)	(6,373)	(417)	(6,790)
	20,643	10,394	31,037	21,434	4,778	26,212
Expenses						
Production	5,551	2,273	7,824	5,991	1,122	7,113
Transportation	811	-	811	626	-	626
General and administrative	2,352	1,434	3,786	2,218	926	3,144
Depletion, depreciation and accretion	11,454	5,947	17,401	8,071	2,465	10,536
Segmented income	$ 475	$ 740	$ 1,215	$ 4,528	$ 265	$ 4,793
Non-segmented expenses						
Interest on bank debt			(729)			(139)
Other			(553)			30
Capital tax and future income taxes			(217)			(562)
Net income (loss)			(284)			4,122
Interest on subordinated notes, net of future taxes			(3,786)			(3,815)
Net income (loss) attributable to common shareholders			$ (4,070)			$ 307
Identifiable assets	$146,652	$ 73,461	$220,113	$130,616	$ 60,192	$190,808
Capital expenditures	$ 16,473	$ 8,235	$ 24,708	$ 19,118	$ 41,539	$ 60,657

Certain statements in this report are "forward-looking statements" within the meaning of the United States Private Securities Litigation Reform Act of 1995. Specifically, this press release contains forward-looking statements relating to, prospects for technologies which remain unproven and the expected amount and timing of capital projects. 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: the ability to economically test, develop and utilize the technologies described herein, the feasibility of the technologies, general economic, market and business conditions; fluctuations in oil and gas prices; the results of exploration and development of drilling and related activities; fluctuation in foreign currency exchange rates; the uncertainty of reserve estimates; changes in environmental and other regulations; risks associated with oil and gas operations; and other factors, many of which are beyond the control of the Company. 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 forecast.



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FORM 52-109FT2

CERTIFICATION OF INTERIM FILINGS DURING TRANSITION PERIOD

I, CHRIS J. BLOOMER, Vice-President Heavy Oil and Chief Financial Officer of Petrobank Energy and Resources Ltd., certify that:

1. I have reviewed the interim filings (as this term is defined in Multilateral Instrument 52-109 *Certification of Disclosure in Issuers' Annual and Interim Filings*) of Petrobank Energy and Resources Ltd., (the issuer) for the interim period ending June 30, 2004;

2. Based on my knowledge, the interim filings do not contain any untrue statement of a material fact or omit to state a material fact required to be stated or that is necessary to make a statement not misleading in light of the circumstances under which it was made, with respect to the period covered by the interim filings; and

3. Based on my knowledge, the interim financial statements together with the other financial information included in the interim filings fairly present in all material respects the financial condition, results of operations and cash flows of the issuer, as of the date and for the periods presented in the interim filings.

Date: August 12, 2004

signed "Chris J. Bloomer"

Chris J. Bloomer
Vice-President Heavy Oil and Chief Financial Officer
Petrobank Energy and Resources Ltd.

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FORM 52-109FT2

CERTIFICATION OF INTERIM FILINGS DURING TRANSITION PERIOD

I, JOHN D. WRIGHT, President and Chief Executive Officer of Petrobank Energy and Resources Ltd., certify that:

1. I have reviewed the interim filings (as this term is defined in Multilateral Instrument 52-109 *Certification of Disclosure in Issuers' Annual and Interim Filings*) of Petrobank Energy and Resources Ltd., (the issuer) for the interim period ending June 30, 2004;

2. Based on my knowledge, the interim filings do not contain any untrue statement of a material fact or omit to state a material fact required to be stated or that is necessary to make a statement not misleading in light of the circumstances under which it was made, with respect to the period covered by the interim filings; and

3. Based on my knowledge, the interim financial statements together with the other financial information included in the interim filings fairly present in all material respects the financial condition, results of operations and cash flows of the issuer, as of the date and for the periods presented in the interim filings.

Date: August 12, 2004

signed "John D. Wright"
John D. Wright
President and Chief Executive Officer
Petrobank Energy and Resources Ltd.

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PETROBANK
ENERGY AND RESOURCES LTD.

NEWS RELEASE

PETROBANK ANNOUNCES SECOND QUARTER RESULTS AND FIRST PATENTED ENHANCEMENT TO THE REVOLUTIONARY THAI™ TECHNOLOGY

Calgary, Alberta – August 12, 2004 - Petrobank Energy and Resources Ltd. ("Petrobank") is pleased to provide this operational update of our Canadian, Latin American and Heavy Oil Business Units as well as our second quarter financial results.

OPERATIONAL UPDATE

Canadian Business Unit

Second quarter Canadian production averaged 4,282 barrels of oil equivalent per day ("boepd") consisting of 1,850 barrels per day of liquids and 14,592 mcf per day of natural gas. In the first quarter we disposed of our Wapella and Epping properties and in the second quarter we completed additional minor property dispositions. Excluding production from disposed properties Canadian production increased 316 boepd or 8 percent from the first to second quarters of 2004. Most of our activity in the second quarter related to drilling, completions and recompletions. However, planned pipeline construction and tie-ins have run behind schedule due to surface access problems, regulatory approval delays and wet field conditions. During the second quarter, we drilled 6 wells (5.7 net), completed 6 wells (5.7 net), and recompleted a further 18 (14.6 net) locations. The drilling resulted in 3 gas wells (2.7 net), 2 oil wells (2.0 net) and 1 suspended well (1.0 net). Production additions have been behind forecast as a result of pipelining delays, but recently significant progress has been made.

Petrobank's most active areas during the second quarter were Nevis and Red Willow where we drilled and completed 5 new wells (5.0 net), resulting in 2 oil wells, 2 gas wells and 1 suspended well. In addition, we recompleted a further 8 wells (8.0 net) in these areas. During the third quarter we have drilled 3 locations (3.0 net) to-date, resulting in 2 gas wells and 1 oil well. Due to wet field conditions, minimal pipelining activity occurred during the second quarter and as a result, production is expected to continue to improve through the third quarter as these new wells are brought on-line.

In West Central Saskatchewan, 4 recompletions (2.4 net) were performed at Lashburn during the second quarter, and early in the third quarter, we made a significant Colony gas discovery at Eyehill.

During the second quarter at Jumpbush we drilled and completed 1 well (0.7 net), and recompleted an additional 6 wells (4.2 net). Recently, the Siksika First Nation's Chief and Council approved the pipeline tie-ins to 13 wells (9.1 net) and this construction will commence shortly. Jumpbush production will increase over the near term upon completion of these tie-ins and installation of additional field compression. A further 30-well (21.0 net) drilling and tie-in program has been submitted for approvals.

At Jumpbush, we are currently evaluating completion results on our first two coalbed methane ("CBM") test wells and plan to tie-in at least one of these wells into nearby facilities for long-term evaluation. At Princeton, the approval process for drilling our initial CBM test well is ongoing.

Latin American Business Unit

In Colombia, we produced an average of 1,354 barrels of oil per day from our Orito and Neiva blocks in the second quarter, down from 1,702 barrels per day in first quarter. During the second quarter we completed the transfer of the majority of our field operations to the Colombian state oil company, Ecopetrol, who have assumed responsibility for well operations and field maintenance as part of their contractual operating fee. While this will result in long-term operating cost savings to Petrobank, certain transitional issues have impacted the pace and priority of ongoing field maintenance and optimization.

Increased water cuts in our Orito-115 well and problems with Ecopetrol's gas lift system have also impacted production. We are proactively addressing these issues.

After completing our initial work commitments on both the Neiva and Orito blocks, the term of our contracts were validated through June 2023, adding flexibility to our future development plans. We have submitted our annual work plans to Ecopetrol, which entail the evaluation of potential waterfloods at Neiva and at Orito, as well as drilling a minimum of one development well in both blocks. For the remainder of 2004, we have planned a number of rig-less interventions and are planning to workover the Orito-114 and 115 wells. We are also engaged in discussions with Ecopetrol to improve the participation terms at Neiva to facilitate a broader development program.

Our ongoing reservoir simulation work of the main producing zone at Orito indicates significant additional potential remains in several regions of the field. We are using this model to prioritize future development activities. Our next development well will target Orito's southwest extension, offsetting 4 of the field's most productive wells, which have averaged more than 7 mmbbls of cumulative oil production each.

Evaluation of the Central Colombia Block by Petrobank and our partners is ongoing and a proposal has been submitted to Ecopetrol to include their participation. A final decision to continue into the second phase of exploration or relinquish the block is required in September 2004.

Significant efforts to optimize our operating and administrative costs have been recently implemented, and the full impact of these cost reductions will be realized over the remainder of the year.

Heavy Oil Business Unit

Detailed project engineering of the WHITESANDS project is finalized, including AFE quality cost estimates, procurement planning, and civil design for the access road and plant site. WHITESANDS is now positioned to commence at our discretion with minimal risk of seasonal delay. Critical path civil and utilities work is anticipated to commence in the third quarter.

Research and development work over the past year has yielded significant results generating a "patent pipeline" of enhancements to the THAI™ process. In June, our first new patent, "Oilfield Enhanced In-situ Combustion Process – U.S. Registration #33,105", was filed as a world patent. The principal benefit of this enhancement to the THAI™ technology is that it will allow us to generate higher average well-bore temperatures, resulting in increased production rates and the flexibility to inject air at higher rates. Our ongoing research activity is creating significant intellectual capital and know-how that will serve to further build and protect the value of the THAI™ and CAPRI™ technologies.

International activities have resulted in the joint execution of confidentiality agreements by Petrobank and the Colombian state oil company, Ecopetrol, to facilitate the evaluation of the THAI™ process by Ecopetrol and for Petrobank to evaluate suitable Colombian reservoirs. The object of this process is to evaluate the feasibility of undertaking a THAI™ pilot project and to ultimately commercialize the THAI™ technology in Colombia. Petrobank is actively discussing similar arrangements with other state and international oil companies. Financing options for the WHITESANDS project in Canada are being evaluated to enable the earliest commencement of the project while preserving maximum value for Petrobank shareholders.

OUTLOOK

Although 2004 has been a year of consolidation where we have disposed of approximately 1,800 boepd of production, we are extremely encouraged by our 2004 drilling and completion results. While production additions planned for the second quarter have not come on stream in as timely a manner as planned we have added significant behind pipe reserves that are being brought on line in the third quarter.

Our work on our Colombian properties has resulted in a follow-up drilling plan in Orito that, if successful, will yield a new inventory of drilling opportunities for 2005 and beyond. In Canada, between Nevis, Red Willow and Jumpbush we have a suite of drilling locations for at least the next two years on our existing lands. The initial assessment of our CBM properties should give us an indication of their commerciality by late 2005. The WHITESANDS project is ready to go, pending an appropriate financing arrangement.

Our unique inventory of opportunities is unprecedented for a company Petrobank's size, and the pace of execution of these projects is naturally being constrained by our available capital resources. To maximize flexibility, we continue to evaluate strategic dispositions of mature or fully valued assets. In addition, our lender recently completed their annual review resulting in an increase in our borrowing base from $33.5 million to $37.0 million, further increasing our financial flexibility. We see a managed investment approach over the near term as being the most appropriate way to unlock the unrealized value of this outstanding portfolio of high-impact opportunities, to the benefit of our shareholders.

Management's Discussion and Analysis

The following Management's Discussion and Analysis ("MD&A") is dated August 12, 2004 and should be read in conjunction with the unaudited consolidated financial statements of the Company for the three and six month periods ended June 30, 2004, MD&A for the year ended December 31, 2003, and the audited consolidated financial statements for the year ended December 31, 2003. Additional information for the Company can be found at www.sedar.com. In addition to historical information, the MD&A contains forward-looking statements that reflect management's objectives and expectations as at the date of this report, which involve risks and uncertainties. The Company's actual results may differ materially from those anticipated in these forward-looking statements.

Natural gas volumes have been converted to barrels of oil equivalent ("boe") so that six thousand cubic feet ("mcf") of natural gas equals one barrel based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the well head. Boes may be misleading, particularly if used in isolation. This report contains financial terms that are considered non-GAAP measures such as cash flow from operations, cash flow per share, net debt, and operating netback. These measures are commonly utilized in the oil and gas industry and are considered informative for our shareholders. Specifically, cash flow from operations and cash flow per share reflect cash generated from operating activities before changes in non-cash working capital. We consider these measures important as they demonstrate our ability to generate sufficient cash to fund future growth opportunities and repay debt. All amounts are in Canadian dollars, unless otherwise stated.

Property Dispositions

Petrobank closed two property dispositions in May for net proceeds of $4.2 million. The results of operations for 2004 only include results from disposed properties up to the closing date of the transaction.

Production

Oil and NGL production in Canada during the second quarter averaged 1,850 barrels per day (bpd), a decrease from the 2,035 bpd produced in the first quarter of 2004 and the 2,758 bpd produced in the second quarter of 2003. These decreases are due to the disposition of the Wapella and Epping properties in the first quarter of 2004 that produced 1,456 bpd in the second quarter of 2003 and an average of 635 bpd in the first quarter of 2004. Excluding production from these disposed properties, oil and NGL production increased by 42 percent over the 2003 period and 32 percent over the prior quarter. The increase over the prior quarter relates to increased production from our Nevis, Red Willow, and Shekilie properties. Second quarter natural gas production of 14.6 million cubic feet per day (mmcfpd) increased 81 percent from 8.1 mmcfpd in the second quarter of 2003. The increase was a result of the acquisition of the Nevis and Red Willow properties in September 2003 partially offset by the disposition of the

Company's Zama/Larne property in May 2003 and the Edmonton property in May 2004. Total Canadian production for the second quarter was 4,282 boepd, a 4 percent increase from the same period last year.

Colombian oil production averaged 1,354 bpd in the second quarter of 2004 compared to 1,028 bpd in the second quarter of 2003. Production declined from 1,702 bpd in the first quarter of 2004 due to field maintenance delays, problems with Ecopetrol's gas lift system and an increase in the water cut in our Orito-115 well.

Average Benchmark Prices

For the three months ended June 30,	2004	2003	% change
WTI crude oil (U.S.$/bbl)	38.32	28.91	33
WTI crude oil (C$/bbl)	52.11	40.39	29
Bow River heavy oil differential (U.S.$/bbl)	11.02	6.54	69
NYMEX natural gas (U.S.$/mmbtu)	6.17	5.72	8
AECO (daily) natural gas (C$/mcf)	6.99	6.82	2
C$/U.S.$ exchange rate	0.74	0.72	3

Realized Prices

The average Canadian oil and NGL price received in the second quarter was $27.35 per barrel, a 2 percent decrease from the $28.00 per barrel received in the comparable 2003 period. Canadian oil and NGL prices averaged $40.18 per barrel, before hedging losses of $12.83 per barrel, representing a U.S.$8.76 discount to average WTI prices in the quarter compared to a U.S.$6.18 discount to WTI in the second quarter of 2003. The average discount increased as a result of a widening of Canadian heavy crude oil differentials offset by an increase in the average quality of barrels produced. In 2004, 1,000 barrels per day of new swaps at U.S.$24.00 became effective, along with a fixed price oil sales contract for 300 bpd at an average price of U.S.$27.74 per barrel.

The average natural gas price received in the second quarter was $5.99 per mcf, an 11 percent decrease from the $6.73 per mcf received in the second quarter of 2003. Natural gas prices reflect the negative impact of the Company's long-term physical gas sales contracts, and in the current period includes the effect of the Company's natural gas price collar for 2004 on 10,551 GJ/day with AECO prices between $5.00 and $5.94 per GJ.

Oil sales prices in Colombia averaged U.S.$33.56 per barrel in the second quarter, representing a U.S.$4.76 discount to WTI compared to a discount of U.S.$7.64 per barrel in the comparable 2003 period. The average discount to WTI decreased as our higher quality Orito oil comprised a larger portion of Colombian production, and as a result of our new marketing arrangement for our Neiva oil.

Royalties

Royalties increased from $2.6 million in the second quarter of 2003 to $3.1 million in the current period. Canadian royalties as a percentage of revenue increased slightly from 20 percent in the second quarter of 2003 to 21 percent in the current period. We anticipate Canadian royalty rates to average approximately 21 percent throughout the remainder of 2004. Colombian royalties are included in the current quarter at a rate of 8 percent.

Production Expenses

Production expenses in Canada decreased 16 percent from $8.06 per boe in the second quarter of 2003 to $6.77 per boe in the current period. The decrease was primarily a result of the acquisition of lower cost Nevis and Red Willow production in September of 2003. Production expenses in Colombia averaged $8.53 per barrel during the quarter, an 8 percent increase from the second quarter 2003 average of $7.93

per barrel and an 8 percent increase from the first quarter 2004 average of $7.89 per barrel. The increase is a result of well workover costs incurred in the current period.

General and Administrative Expenses

General and administrative expenses increased by 18 percent to $2.1 million in the second quarter of 2004 compared to $1.8 million in the second quarter of 2003. The increase is primarily due to higher incremental overhead associated with higher staff levels in Colombia.

Interest on Bank Debt

The Company's credit facility was drawn $8.2 million at March 31, 2003 and increased to $24.8 million drawn at June 30, 2004. As a result, interest on bank debt increased from $98,000 in the second quarter of 2003 to $251,000 in the second quarter of 2004.

Depletion, Depreciation and Accretion

Depletion, depreciation and accretion expense for the second quarter of $8.4 million ($16.32 per boe) compared to $5.4 million ($11.46 per boe) in the comparable 2003 period. The increased rate was primarily due to the acquisition of Monolith Oil Corp. in September of 2003, and the results of the 2003 Colombian drilling program.

Interest on Subordinated Notes

Interest on subordinated notes totaled $2.8 million during the second quarter ($1.9 million net of future taxes), compared to $2.3 million in the same period last year. The increase relates to the issuance of an additional $40.0 million of notes in May of 2003.

Income Taxes

At the end of the first quarter of 2004, Petrobank had a future income tax liability of $11.6 million primarily due to the Monolith corporate acquisition and the issuance and renouncement of flow through shares in 2003. In the second quarter of 2004, future tax recoveries were recorded against these balances of $0.1 million included in capital and future income taxes, and a $0.9 million recovery that was offset against interest on subordinated notes. Current tax of $274,000 in the second quarter of 2004 relates to Large Corporations Tax in Canada and presumptive income taxes in Colombia that are based on debt and equity levels. Colombian presumptive income taxes can be recovered against income taxes payable in future periods and can be carried forward for eight years.

Capital Expenditures

Consolidated capital expenditures during the quarter were $10.0 million, comprised of $7.6 million in Canada and $2.4 million in Colombia. In Canada, the majority of expenditures were spent at our Nevis/Red Willow properties, while our Colombian expenditures were focused on the Orito Block.

Liquidity and Capital Resources

At June 30, 2004 net debt totaled $121.8 million, including the book value of outstanding subordinated notes ($94.6 million). The subordinated notes are not callable and mature in July 2006. Petrobank's borrowing base under its senior secured credit facility was increased from $33.5 million to $37.0 million in July 2004. Working capital deficit at June 30, 2004, including the $24.8 million balance drawn under the secured credit facility, totaled $27.2 million leaving $9.8 million of available borrowing capacity under the increased borrowing base.

Changes in Accounting Policies

Asset Retirement Obligations

Effective January 1, 2004 the Company retroactively adopted the new standard of the Canadian Institute of Chartered Accountants ("CICA"), "Asset Retirement Obligations". The new standard requires that the recognition of the fair value of obligations associated with the retirement of tangible long-lived assets be recorded in the period the asset is put into use, with a corresponding increase to the carrying amount of the related asset. The obligations recognized are statutory, contractual or legal obligations. The liability is accreted over time for changes in the fair value of the liability through charges to accretion, which is included in depletion, depreciation and accretion expense. The costs capitalized to the related assets are amortized to earnings in a manner consistent with the depletion and depreciation of the underlying asset. The impact of the adoption of this standard on the financial statements is described in Note 5 to the consolidated financial statements for the three and six month periods ended June 30, 2004.

Transportation Costs

Effective January 1, 2004 the Company began classifying certain transportation costs as expenses in the consolidated statements of operations. In prior periods, these costs were netted against revenues and accordingly the prior period financial statements have been reclassified for comparative purposes. The change in accounting policy has no effect on net income but increased natural gas revenues and expenses for the three and six month periods ended June 30, 2004 by $395,000 and $811,000, respectively (2003 – $288,000 and $626,000). The reclassification translates into a $0.30 per mcf increase in natural gas prices in the second quarter of 2004 (2003 - $0.39 per mcf). Also as a result, Canadian transportation expenses of $1.02 per boe were recognized in the current quarter (2003 - $0.77 per boe).

SUMMARY OF QUARTERLY RESULTS

	2004		2003 [2]				2002 [2]	
	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3
Financial ($000s except where noted)								
Oil and natural gas revenue	**18,175**	19,474	20,540	13,963	14,747	18,255	13,238	12,579
Cash flow from operations	**8,461**	8,877	8,701	5,842	6,185	8,530	5,600	5,806
Per share - basic ($)	**0.11**	0.12	0.12	0.08	0.09	0.16	0.09	0.11
- diluted ($)	**0.11**	0.12	0.12	0.08	0.09	0.15	0.09	0.11
Net income (loss)	**80**	(364)	(18,654)	(573)	790	3,332	1,010	1,207
Net income (loss) attributable to common shareholders	**(1,822)**	(2,248)	(20,434)	(3,398)	(1,508)	1,815	(537)	(375)
Per share - basic and diluted ($)	**(0.03)**	(0.04)	(0.38)	(0.07)	(0.03)	0.04	(0.01)	(0.01)
Capital expenditures	**9,995**	14,713	27,338	28,065	24,696	35,961	28,620	5,813
Operations								
Canadian operating netbacks by product [1]								
Light/medium oil and NGLs sales price ($/bbl)	**29.54**	27.50	26.81	28.09	28.28	33.28	32.44	33.16
Royalties	**8.93**	8.97	5.89	6.01	7.28	10.79	7.76	7.93
Production expenses	**7.14**	6.81	6.22	5.24	6.99	5.84	7.04	6.32
Operating netback	**13.47**	11.72	14.70	16.84	14.02	16.65	17.65	18.92
Heavy oil sales price ($/bbl)	**22.36**	24.46	22.95	24.86	27.14	33.37	25.90	30.09
Royalties	**3.29**	3.45	2.36	4.22	3.75	5.89	4.62	4.13
Production expenses	**10.69**	8.52	11.18	6.83	9.40	8.33	8.68	5.92
Operating netback	**8.38**	12.49	9.41	13.81	13.99	19.15	12.60	20.04
Natural gas sales price ($/mcf)	**5.99**	6.09	5.89	5.49	6.73	7.71	5.42	3.94
Royalties	**1.08**	1.20	0.88	0.82	1.00	1.61	1.03	0.71
Production expenses	**0.94**	1.06	1.26	1.79	1.51	1.44	1.40	1.16
Transportation expenses	**0.30**	0.28	0.28	0.51	0.39	0.34	0.33	0.31
Operating netback	**3.67**	3.55	3.47	2.37	3.83	4.32	2.66	1.76
Oil equivalent sales price ($/boe)	**32.22**	32.18	30.57	28.75	32.06	38.46	31.79	28.57
Royalties	**6.79**	7.15	5.12	5.35	6.29	9.77	6.78	5.97
Production expenses	**6.77**	6.82	7.55	7.06	8.06	7.24	7.78	6.55
Transportation expenses	**1.02**	0.97	0.85	0.83	0.77	0.82	0.83	0.84
Operating netback	**17.64**	17.24	17.05	15.51	16.94	20.63	16.40	15.21
Colombian operating netback ($/bbl)								
Oil sales price	**45.62**	36.63	31.66	31.37	29.74	38.58	-	-
Royalties	**3.62**	2.93	2.53	2.44	2.40	3.09	-	-
Production expenses	**8.53**	7.89	15.62	9.24	7.93	6.09	-	-
Operating netback	**33.47**	25.81	13.51	19.69	19.41	29.40	-	-
Average daily production								
Canada - light/medium oil and NGLs (bbls)	**1,288**	1,332	2,147	2,097	2,097	2,225	2,180	2,242
Canada - heavy oil (bbls)	**562**	703	784	812	661	532	472	354
Canada - natural gas (mcf)	**14,592**	16,069	17,702	6,581	8,057	10,920	11,244	13,134
Total Canada (boe)	**4,282**	4,713	5,881	4,005	4,101	4,577	4,526	4,785
Colombia - oil (bbls)	**1,354**	1,702	1,374	1,166	1,028	695	-	-
Total Company (boe)	**5,636**	6,415	7,255	5,171	5,129	5,272	4,526	4,785

(1) Sales prices are shown after hedging costs. All hedging costs relating to oil sales are net against Canadian light/medium oil and NGLs price, except for the Company's 300 bopd fixed price contract (WTI – U.S.$27.74) that is net against the heavy oil sales price in the first and second quarters of 2004.

(2) Restated for changes in accounting policies.

· Highlights ·

	Three months ended June 30, 2004	2003	% change	Six months ended June 30, 2004	2003	% change
Financial						
($000s, except where noted)						
Oil and natural gas revenue	**18,175**	14,747	**23**	**37,649**	33,002	**14**
Cash flow from operations [1]	**8,461**	6,185	**37**	**17,338**	14,715	**18**
Per share – basic ($) [2]	**0.11**	0.09	**22**	**0.23**	0.25	**(8)**
Per share – diluted ($) [2]	**0.11**	0.09	**22**	**0.23**	0.24	**(4)**
Net income	**80**	790	**(90)**	**(284)**	4,122	
Net income (loss) attributable to common shareholders	**(1,822)**	(1,508)	**(21)**	**(4,070)**	307	
Per share – basic and diluted ($)	**(0.03)**	(0.03)	**-**	**(0.07)**	0.01	
Capital expenditures	**9,995**	24,696	**(60)**	**24,708**	60,657	**(59)**
Net debt [3]	**121,803**	94,801	**(28)**	**121,803**	94,801	**(28)**
Common shares outstanding (000s)						
Basic	**54,732**	45,594	**20**	**54,732**	45,594	**20**
Diluted	**59,582**	51,587	**15**	**59,582**	51,587	**15**
Operations [4]						
Canadian operating netback ($/boe except where noted)						
Oil and NGLs revenue ($/bbl)	**27.35**	28.00	**(2)**	**26.89**	30.64	**(12)**
Natural gas revenue ($/mcf)	**5.99**	6.73	**(11)**	**6.04**	7.29	**(17)**
Oil and natural gas revenue	**32.22**	32.06	**-**	**32.19**	35.42	**(9)**
Royalties	**6.79**	6.29	**8**	**6.98**	8.12	**(14)**
Production expenses	**6.77**	8.06	**(16)**	**6.80**	7.63	**(11)**
Transportation expenses	**1.02**	0.77	**32**	**0.99**	0.80	**24**
Operating netback	**17.64**	16.94	**4**	**17.42**	18.87	**(8)**
Colombian operating netback ($/bbl)						
Oil revenue	**45.62**	29.74	**53**	**40.61**	33.27	**22**
Royalties	**3.62**	2.40	**51**	**3.24**	2.67	**21**
Production expenses	**8.53**	7.93	**8**	**8.13**	7.18	**13**
Operating netback	**33.47**	19.41	**72**	**29.24**	23.42	**25**
Average daily production						
Canada - oil and NGLs (bbls)	**1,850**	2,758	**(33)**	**1,942**	2,758	**(30)**
Canada - natural gas (mcf)	**14,592**	8,057	**81**	**15,331**	9,480	**62**
Total Canada (boe)	**4,282**	4,101	**4**	**4,497**	4,338	**4**
Colombia - oil (bbls)	**1,354**	1,028	**32**	**1,528**	862	**77**
Total Company (boe)	**5,636**	5,129	**10**	**6,025**	5,200	**16**

(1) Cash flow from operations before changes in other non-cash items.
(2) Calculated based on cash flow from operations before changes in other non-cash items less preferred share dividends and interest paid on subordinated notes.
(3) Includes working capital (deficiency) and subordinated notes reflected as equity on the balance sheet.
(4) 6 Mcf of natural gas is equivalent to 1 barrel of oil equivalent (BOE).

Consolidated Balance Sheets

(Unaudited, Thousands of Canadian dollars)

As at	June 30, 2004	December 31, 2003 (As restated per Notes 2, 4 & 5)
Assets		
Current assets		
Accounts receivable and other current assets	**$ 21,582**	$ 21,528
Capital assets	**198,531**	235,476
	$ 220,113	$ 257,004
Liabilities and Shareholders' Equity		
Current liabilities		
Accounts payable and accrued liabilities	**$ 23,939**	$ 34,937
Bank debt (Note 3)	**24,843**	30,102
Debenture	**-**	14,014
	48,782	79,053
Obligations under gas sale and transportation contracts	**6,883**	7,287
Asset retirement obligations (Note 5)	**7,909**	9,602
Future income tax liability	**10,606**	12,808
	74,180	108,750
Shareholders' equity		
Subordinated notes	**94,603**	93,430
Common shares (Note 4)	**72,765**	72,355
Contributed surplus (Note 4)	**352**	186
Deficit	**(21,787)**	(17,717)
	145,933	148,254
	$ 220,113	$ 257,004

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,	
	2004	2003 (As restated per Notes 2, 4 & 5)	2004	2003 (As restated per Notes 2, 4 & 5)
Revenues				
Oil and natural gas	**$ 18,175**	$ 14,747	**$ 37,649**	$ 33,002
Royalties	**(3,093)**	(2,571)	**(6,612)**	(6,790)
	15,082	12,176	**31,037**	26,212
Expenses				
Production	**3,676**	3,748	**7,824**	7,113
Transportation (Note 2)	**395**	288	**811**	626
General and administrative	**2,087**	1,763	**3,786**	3,144
Interest on bank debt	**251**	98	**729**	139
Depletion, depreciation and accretion	**8,368**	5,350	**17,401**	10,536
	14,777	11,247	**30,551**	21,558
Income before other items and taxes	**305**	929	**486**	4,654
Other income (expense)	**(22)**	149	**(553)**	30
Capital and future income taxes	**(203)**	(288)	**(217)**	(562)
Net income (loss)	**80**	790	**(284)**	4,122
Interest on subordinated notes, net of future taxes	**(1,902)**	(2,298)	**(3,786)**	(3,815)
Net income (loss) attributable to common shareholders	**(1,822)**	(1,508)	**(4,070)**	307
Retained earnings (deficit), beginning of period	**(19,965)**	7,443	**(17,717)**	5,628
Retained earnings (deficit), end of period	**$ (21,787)**	$ 5,935	**$ (21,787)**	$ 5,935
Basic and diluted earnings (loss) per share (Note 4)	**$ (0.03)**	$ (0.03)	**$ (0.07)**	$ 0.01

See accompanying notes to these consolidated financial statements.

Consolidated Statements of Cash Flow

(Unaudited, Thousands of Canadian dollars)

	Three months ended June 30,		Six months ended June 30,	
	2004	2003 (As restated per Notes 2, 4 & 5)	**2004**	2003 (As restated per Notes 2, 4 & 5)
Operating Activities				
Net income (loss)	**$ 80**	$ 790	**$ (284)**	$ 4,122
Depletion, depreciation and accretion	**8,368**	5,350	**17,401**	10,536
Non-cash stock compensation	**84**	45	**166**	57
Future income tax recovery	**(71)**	-	**(320)**	-
Loss recorded on disposition of sales contract	**-**	-	**375**	-
Cash flow from operations	**8,461**	6,185	**17,338**	14,715
Changes in other non-cash items	**(1,005)**	(5,440)	**(4,992)**	(7,178)
	7,456	745	**12,346**	7,537
Financing Activities				
Issuance (repayment) of bank debt	**2,215**	(8,204)	**(5,259)**	-
Issuance of common shares and share purchase warrants (Note 4)	**125**	1,183	**410**	1,254
Repayment of debenture	**-**	-	**(14,014)**	-
Issuance of subordinated notes	**-**	34,410	**-**	34,410
Interest on subordinated notes	**(2,246)**	(1,908)	**(4,495)**	(3,249)
Amortization of obligations under gas hedging contracts	**(202)**	(202)	**(404)**	(402)
	(108)	25,279	**(23,762)**	32,013
Investing Activities				
Expenditures on capital assets	**(9,995)**	(24,696)	**(24,708)**	(60,657)
Proceeds on disposition of capital assets	**4,174**	16,626	**42,311**	16,626
Asset retirement obligations settled	**(127)**	-	**(127)**	(27)
Changes in other non-cash items	**(1,400)**	(8,839)	**(6,060)**	1,399
	(7,348)	(16,909)	**11,416**	(42,659)
Net change in cash position	**-**	9,115	**-**	(3,109)
Cash and cash equivalents, beginning of period	**-**	-	**-**	12,224
Cash and cash equivalents, end of period	**$ -**	$ 9,115	**$ -**	$ 9,115

See accompanying notes to these consolidated financial statements.

As at and for the three and six month periods ended June 30, 2004
(All tabular amounts are expressed in thousands of Canadian dollars, except share amounts)

Note 1 – Significant Accounting Policies

The interim consolidated financial statements as at and for the three and six month periods ended June 30, 2004 should be read in conjunction with the audited consolidated financial statements as at and for the year ended December 31, 2003. The notes to these interim consolidated financial statements do not conform in all respects to the note disclosure requirements of generally accepted accounting policies for annual financial statements. These interim consolidated financial statements are prepared using the same accounting policies and methods of computation as disclosed in the audited consolidated financial statements as at and for the year ended December 31, 2003 except as described in Note 2.

Note 2 – Changes in Accounting Policies

Asset Retirement Obligations

Effective January 1, 2004 the Company retroactively adopted the new standard of the Canadian Institute of Chartered Accountants ("CICA"), "Asset Retirement Obligations". The new standard requires that the recognition of the fair value of obligations associated with the retirement of tangible long-lived assets be recorded in the period the asset is put into use, with a corresponding increase to the carrying amount of the related asset. The obligations recognized are statutory, contractual or legal obligations. The liability is accreted over time for changes in the fair value of the liability through charges to accretion, which is included in depletion, depreciation and accretion expense. The costs capitalized to the related assets are amortized to earnings in a manner consistent with the depletion and depreciation of the underlying asset. The impact of the adoption of this standard on the financial statements is described in Note 5.

Capital Assets – Oil and Gas

Effective January 1, 2004 the Company adopted Accounting Guideline 16, "Oil and Gas Accounting - Full Cost" ("AcG-16"), which replaces Accounting Guideline 5, "Full Cost Accounting in the Oil and Gas Industry". AcG-16 modifies how the ceiling test is performed and is consistent with CICA section 3063, "Impairment of Long-lived Assets". The recoverability of a cost centre is tested by comparing the carrying value of the cost centre to the sum of the undiscounted cash flows expected from the cost centre's use and eventual disposition. If the carrying value is unrecoverable the cost centre is written down to its fair value using the expected present value approach. This approach incorporates risks and uncertainties in the expected future cash flows, which are discounted using a risk free rate. The adoption of AcG-16 had no effect on the Company's financial results.

Hedging Relationships

The CICA published an amended Accounting Guideline 13, "Hedging Relationships", effective January 1, 2004, to clarify circumstances in which hedge accounting is appropriate. All derivative instruments that do not qualify as a hedge under the guideline, or are not properly designated as a hedge, will be recorded on the balance sheet as either an asset or liability with changes in fair value recognized in earnings. The Company adopted the standard January 1, 2004 with no impact on the financial results.

Transportation Costs

Effective January 1, 2004 the Company began classifying certain transportation costs as expenses in the consolidated statements of operations. In prior periods, these costs were netted against revenues and accordingly the prior period financial statements have been reclassified for comparative purposes. The change in accounting policy has no effect on net income but increased natural gas revenues and expenses for the three and six month periods ended June 30, 2004 by $395,000 and $811,000, respectively (2003 – $288,000 and $626,000).

Note 3 – Bank debt

Petrobank's borrowing base under its senior secured credit facility was increased from $33.5 million to $37.0 million in July of 2004.

Note 4 – Share Capital

As at June 30, 2004 the Company had outstanding 54,732,396 common shares, 3,429,501 stock options, and 1,420,300 share purchase warrants. The share purchase warrants allow holders to purchase an equivalent number of common shares at $4.00 per share on or before May 6, 2006.

Common Share Continuity	Number	Amount
Balance at December 31, 2003	54,502,646	$72,355
Exercise of stock options	148,750	285
Balance at March 31, 2004	54,651,396	72,640
Exercise of stock options	81,000	125
Balance at June 30, 2004	54,732,396	$72,765

Stock Option Continuity	Number	Weighted - Average Exercise Price
Balance at December 31, 2003	3,676,501	$ 2.42
Granted	147,500	2.74
Exercised	(148,750)	(1.92)
Expired/cancelled	(98,250)	(2.78)
Balance at March 31, 2004	3,577,001	$ 2.44
Granted	172,500	1.95
Exercised	(81,000)	(1.55)
Expired/cancelled	(239,000)	(2.36)
Balance at June 30, 2004	3,429,501	$ 2.44

Earnings Per Share

Basic and diluted earnings (loss) per share have been calculated based on net income (loss) attributable to common shareholders divided by the weighted average number of common shares outstanding for the three month period ended June 30, 2004 of 54,683,858 (2003 – 45,534,147) and for the six month period ended June 30, 2004 of 54,623,228 (2003 – 45,437,331). The diluted calculations for the three and six month periods ended June 30, 2004 include nil (2003 – nil and 1,105,433 respectively) additional shares for the potential impact of share purchase warrants and stock options.

Stock Based Compensation

In 2003, the Company adopted the fair value based method of accounting for its stock-based compensation plan whereby the fair value of stock options granted after January 1, 2003 is recognized as general and administrative expense and as contributed surplus. Stock based compensation costs for the three and six month periods ended June 30, 2004 totaled $84,000 and $166,000, respectively. The corresponding three and six month periods ended June 30, 2003 have been restated to record stock-based compensation of $45,000 and $57,000, respectively.

Had compensation expense associated with the Company's stock option plan been recognized using the fair value based method for all option grants after January 1, 2002, the Company's net loss attributable to common shareholders for the three and six month periods ended June 30, 2004 would have increased by $61,000 and $133,000, respectively (2003 - $108,000 and $215,000). Net income (loss) per share would have changed by less than $0.01 per share for each period presented.

The fair value of stock options granted has been estimated on their respective grant dates using the Black Scholes option-pricing model using the following assumptions:

Three months ended June 30,	2004	2003
Risk free interest rate	4.5%	4.5%
Dividend rate	0%	0%
Expected life (years)	4	4
Expected volatility	30%	30%

The average value per option granted during the three and six month periods ended June 30, 2004 were $0.60 and $0.71 as at the date of grant.

Note 5 - Asset Retirement Obligations

The total future asset retirement obligation was estimated by management based on the Company's net ownership interest in all wells, gathering lines and facilities, estimated costs to reclaim and abandon the wells and facilities and the estimated timing of the costs to be incurred in future periods. The change was effective January 1, 2004 and the revision was applied retroactively. The impact was as follows:

Consolidated Balance Sheet – as at December 31, 2003

	As Reported	Change	As Restated
Assets			
Net capital assets	232,007	3,469	235,476
Liabilities and shareholders' equity			
Asset retirement obligations	-	9,602	9,602
Site restoration liability	2,807	(2,807)	-
Future income tax liability	13,920	(1,112)	12,808
Deficit	(15,503)	(2,214)	(17,717)

Consolidated Statement of Operations and Deficit – Three months ended June 30, 2003

	As Reported	Change	As Restated
Depletion, depreciation and accretion	5,250	100	5,350
Net Income [1]	935	(100)	835

Consolidated Statement of Operations and Deficit – Six months ended June 30, 2003

	As Reported	Change	As Restated
Depletion, depreciation and accretion	10,243	293	10,536
Net Income [1]	4,472	(293)	4,179

[1] Net income was further reduced for the three and six month periods by $45,000 and $57,000 to $790,000 and $4,122,000, respectively due to the restatement of stock-based compensation costs (Note 4).

The change in accounting for asset retirement obligations did not have a material impact on net loss reported in the three and six month periods ended June 30, 2004.

Changes to asset retirement obligations were as follows:

	Three months ended June 30,		Six months ended June 30,	
	2004	2003	2004	2003
Asset retirement obligation, beginning of period	8,270	11,009	9,602	10,325
Obligations incurred	100	130	403	262
Obligations settled	(127)	-	(127)	(27)
Accretion expense	186	248	402	480
Obligations related to assets sold and other	(520)	(4,260)	(2,371)	(3,913)
Asset retirement obligation, end of period	7,909	7,127	7,909	7,127

The total undiscounted amount of estimated cash flows required to settle the obligation at June 30, 2004 is $24.5 million (2003 - $28.7 million), which has been discounted using a credit-adjusted risk free rate of 9 percent. Most of these obligations are not expected to be paid for several years extending up to 34 years in the future, and are expected to be funded from general company resources at the time of settlement.

Note 6 – Commitments and Contingencies

In Colombia, the Company has U.S.$2.0 million of remaining work commitments on the Neiva Block that are required to be completed by December 31, 2004. The Company's work program for the Orito Block includes drilling one well and implementing a pilot waterflood before June 2005 at an estimated cost of U.S.$5.0 million.

Note 7 – Segmented Information

Three months ended June 30,

	2004			2003		
	Canada	Colombia	Total	Canada	Colombia	Total
Revenues						
Oil and natural gas	$ 12,554	$ 5,621	$ 18,175	$ 11,965	$ 2,782	$ 14,747
Royalties	(2,647)	(446)	(3,093)	(2,347)	(224)	(2,571)
	9,907	5,175	15,082	9,618	2,558	12,176
Expenses						
Production	2,625	1,051	3,676	3,007	741	3,748
Transportation	395	-	395	288	-	288
General and administrative	1,330	757	2,087	1,274	489	1,763
Depletion, depreciation and accretion	5,697	2,671	8,368	3,741	1,609	5,350
Segmented income	$ (140)	$ 696	$ 556	$ 1,308	$ (281)	$ 1,027
Non-segmented expenses						
Interest on bank debt			(251)			(98)
Other			(22)			149
Capital tax and future income taxes			(203)			(288)
Net income (loss)			80			790
Interest on subordinated notes, net of future taxes			(1,902)			(2,298)
Net income (loss) attributable to common shareholders			$ (1,822)			$ (1,508)
Identifiable assets	$146,652	$ 73,461	$220,113	$130,616	$ 60,192	$190,808
Capital expenditures	$ 7,577	$ 2,418	$ 9,995	$ 8,735	$ 15,961	$ 24,696

Six months ended June 30,

	2004			2003		
	Canada	Colombia	Total	Canada	Colombia	Total
Revenues						
Oil and natural gas	$ 26,355	$ 11,294	$ 37,649	$ 27,807	$ 5,195	$ 33,002
Royalties	(5,712)	(900)	(6,612)	(6,373)	(417)	(6,790)
	20,643	10,394	31,037	21,434	4,778	26,212
Expenses						
Production	5,551	2,273	7,824	5,991	1,122	7,113
Transportation	811	-	811	626	-	626
General and administrative	2,352	1,434	3,786	2,218	926	3,144
Depletion, depreciation and accretion	11,454	5,947	17,401	8,071	2,465	10,536
Segmented income	$ 475	$ 740	$ 1,215	$ 4,528	$ 265	$ 4,793
Non-segmented expenses						
Interest on bank debt			(729)			(139)
Other			(553)			30
Capital tax and future income taxes			(217)			(562)
Net income (loss)			(284)			4,122
Interest on subordinated notes, net of future taxes			(3,786)			(3,815)
Net income (loss) attributable to common shareholders			$ (4,070)			$ 307
Identifiable assets	$146,652	$ 73,461	$220,113	$130,616	$ 60,192	$190,808
Capital expenditures	$ 16,473	$ 8,235	$ 24,708	$ 19,118	$ 41,539	$ 60,657

Certain statements in this report are "forward-looking statements" within the meaning of the United States Private Securities Litigation Reform Act of 1995. Specifically, this press release contains forward-looking statements relating to, prospects for technologies which remain unproven and the expected amount and timing of capital projects. 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: the ability to economically test, develop and utilize the technologies described herein, the feasibility of the technologies, general economic, market and business conditions; fluctuations in oil and gas prices; the results of exploration and development of drilling and related activities; fluctuation in foreign currency exchange rates; the uncertainty of reserve estimates; changes in environmental and other regulations; risks associated with oil and gas operations; and other factors, many of which are beyond the control of the Company. 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 forecast.

For more information please contact:

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August 13, 2004

Alberta Securities Commission
British Columbia Securities Commission
Saskatchewan Financial Services Commission
The Manitoba Securities Commission
Ontario Securities Commission
L'Autorité des marchés financiers
Nova Scotia Securities Commission
TSX

Dear Sirs:

Subject: Petrobank Energy and Resources Ltd.

We confirm that the following material was sent by pre-paid mail on August 13, 2004 to the registered shareholders of the common shares of the subject Corporation:

1. Q2 2004

In compliance with security regulations, we are providing this material to you in our capacity as agent for the subject Corporation.

We also confirm that a copy of the above was mailed to all non-registered shareholders of the subject Corporation whose names appear on the Corporation's Supplemental Mailing List as defined in the Canadian Securities Administrators' National Instrument 54-102.

Yours truly,

"signed by"

Robyn Hall
Mailing Professional
ClientServicesMailings@Computershare.com

cc: Petrobank Energy and Resources Ltd.
Attention: Corey Ruttan

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