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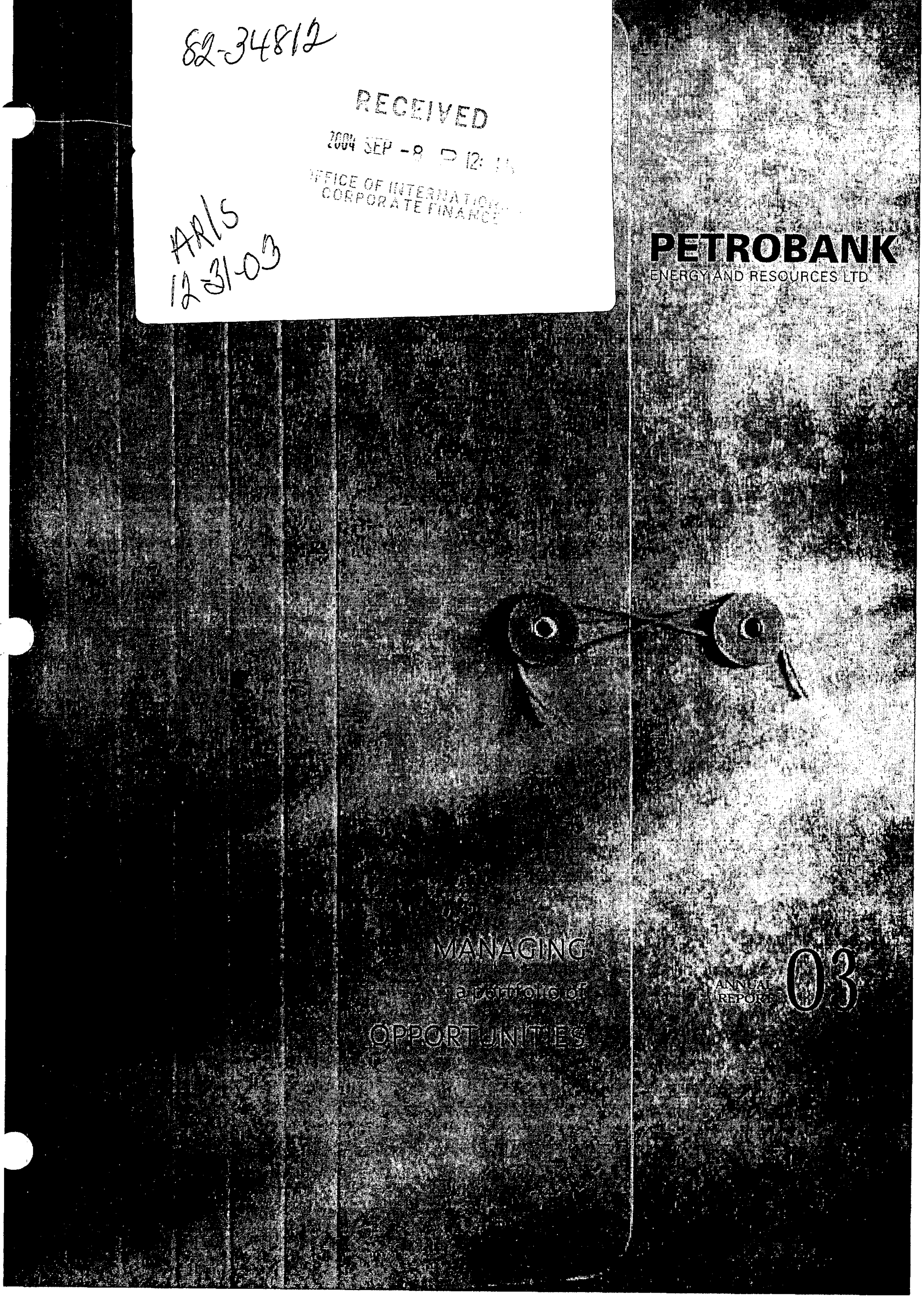

PETROBANK
ENERGY AND RESOURCES LTD.

MANAGING
a portfolio of
OPPORTUNITIES

ANNUAL REPORT 03

S.W., Calgary, Alberta, Canada. All shareholders

forward-looking statements.

Company Profile

Petrobank Energy and Resources Ltd. is a Calgary-based oil and natural gas exploration and production company with operations in western Canada and Colombia. The Company operates high-impact projects through three business units. The Canadian Business Unit combines conventional oil and gas operations with two higher-impact coalbed methane opportunities. The Latin American Business Unit commenced commercial production from our Colombian properties in January 2003. Petrobank's international efforts are focused on high working-interest, operated projects with opportunities to export Canadian exploitation and exploration expertise. The Heavy Oil Business Unit has received approval to proceed with a pilot project to field-demonstrate Petrobank's patented THAI™ oil sands recovery process. Our goal is to maximize after-tax return on equity for shareholders through a portfolio-based investment approach. Petrobank's common shares and subordinated notes trade on the Toronto Stock Exchange under the symbols PBG and PBG.N (PBG.NT.A, effective July 14, 2004).

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Note Regarding "Resource" vs. "Reserves"

Throughout this annual report we have attempted to provide an appreciation of the potential that Petrobank's portfolio of opportunities offers. In doing so, we often use terms such as original oil-in-place, gas-in-place, and bitumen-in-place. These terms refer to the estimated original resource size of a particular prospect and should be distinguished from reserves. Reserves are the amount of hydrocarbons that are estimated to be economically recoverable from a particular resource base. Ultimate recoverable reserves can range widely depending on resource characteristics, available technologies and economic parameters. A more detailed discussion of Petrobank's prospects can be found in the Company's Annual Information Form available at www.sedar.com.

Annual General Meeting

The annual general meeting of shareholders will be held on Thursday, June 17, 2004 at 3:00 p.m. (local time) in the Grand Lecture Theatre of the Metropolitan Conference Centre, 333–4th Avenue S.W., Calgary, Alberta, Canada. All shareholders are cordially invited and encouraged to attend.

This annual 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. 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.

BOE conversions are presented at six mcf = one barrel.

A portfolio
of
OPPORTUNITIES

+

+

Portafolio
de
OPORTUNIDADES

Petrobank's portfolio of assets creates tremendous opportunity. Following divestitures of mature western Canada properties in 2003, Petrobank today has a line-up of high-impact opportunities: leading-edge, patented oil sands technology; two coalbed methane projects; conventional oil and natural gas growth prospects in western Canada and a major oil development program in Latin America.

Highlights

Financial

($000s except where noted)	2003	2002	% change
Oil and natural gas revenue	**66,111**	50,458	31
Cash flow from operations [1]	**29,258**	22,806	28
Per share – basic ($) [2]	**0.45**	0.45	–
Per share – diluted ($) [2]	**0.44**	0.40	10
Net income (loss)	**(14,691)**	6,191	–
Net loss attributable to common shareholders	**(23,111)**	(430)	–
Per share – basic and diluted ($)	**(0.48)**	(0.01)	–
Net capital expenditures	**95,612**	42,894	123
Pro-forma net debt including subordinated notes [3]	**114,955**	62,495	84
Common shares outstanding (000s)			
Basic	**54,503**	45,314	20
Diluted	**59,599**	50,287	19

Operations

Canadian operating netback ($/boe except where noted)			
Oil and NGLs revenue ($/bbl)	**28.48**	31.11	(8)
Natural gas revenue ($/mcf)	**6.08**	3.89	56
Combined oil equivalent revenue	**31.60**	27.39	15
Royalties	**6.56**	5.84	12
Production expenses	**7.48**	6.68	12
Operating netback	**17.56**	14.87	18
Colombian operating netback ($/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	8
Canada – natural gas (mcf)	**10,821**	14,541	(26)
Total Canada (boe)	**4,643**	5,047	(8)
Colombia – oil (bbls)	**1,068**	–	–
Total Company (boe)	**5,711**	5,047	13

Reserves [4]

(Post-Wapella disposition)			
Canada – oil and NGLs (mbbls)	**4,779**	8,982	(47)
Canada – natural gas (bcf)	**39.1**	28.3	38
Colombia – oil (mbbls)	**6,836**	6,475	6
Total Company (mboe)	**18,141**	20,168	(10)
NPV 10% [5]	**200,573**	179,245	12

(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) 2003 proved plus probable reserves are compared to 2002 established reserves where probable reserves were risked at 50 percent.

(5) Based on the April 1, 2004 GLJ 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.

Western Canada

Land – 515,000 net acres

Reserves* – 11.3 million boe

Production* – 4,557 boepd (65% gas)

*(Pro-forma Q4 2003)

Colombia

Land – 168,000 net acres

Reserves – 6.8 million bbls

Production – 1,374 bopd (Q4 2003)

Western Canada

Petrobank in 2003 took important steps to re-align its asset portfolio, divesting mature properties with little upside and acquiring growth prospects. Going into 2004 Petrobank has upside opportunity for conventional oil and natural gas drilling at Jumpbush and Nevis/Red Willow, both in Alberta, plus two exciting coalbed methane opportunities at Jumpbush, Alberta and Princeton, B.C.

Colombia

Operations and economics in Colombia proved challenging in 2003, but a major technical reassessment of the Caballos reservoir at the Orito Block, launched late in the year, has enabled Petrobank to formulate a new development plan that will aim to generate up to 50 million gross barrels of incremental crude oil reserves.

Heavy Oil

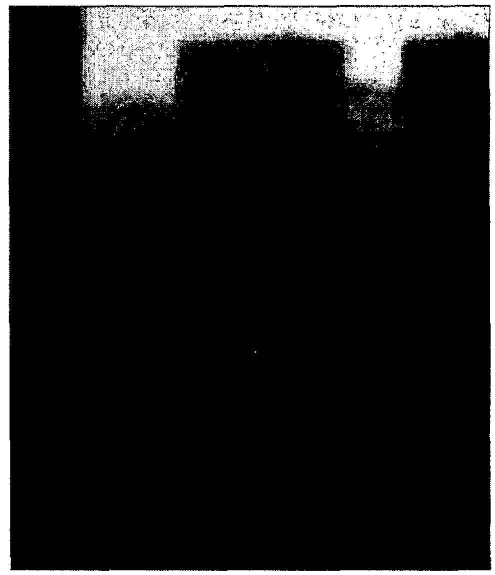
Petrobank made tremendous progress in 2003 and early 2004 on its unique, high-impact WHITESANDS oil sands project. Delineation drilling confirmed 1.3 billion barrels of bitumen-in-place at Petrobank's oil sands leases. Meanwhile, the Company received approvals to proceed with a pilot-scale program to field-demonstrate its patented THAI™ heavy oil recovery process.

2003 Highlights

Although 2003 was a year of significant challenges, including a major asset write-down in Colombia, Petrobank achieved success in re-aligning its asset portfolio. Incremental production was generated in Colombia while Petrobank's development approach was reassessed and significantly reoriented. The Company exited 2003 with significant new volumes of natural gas from recently acquired assets in western Canada and Petrobank's WHITESANDS oil sands project passed several important milestones.

2004 Outlook

Petrobank intends to make significant progress on all projects in 2004. The THAI™ pilot is scheduled to launch at WHITESANDS before year-end. Testing of coalbed methane wells will occur at Jumpbush along with a 50-well, conventional shallow-gas drilling and recompletion program. The Princeton coalbed methane project could be initiated on a pilot-scale by year-end. Conventional development in Canada will be focused on our Jumpbush, Nevis and Red Willow gas properties. Finally, a new Caballos development program at Orito should generate initial results by year-end.



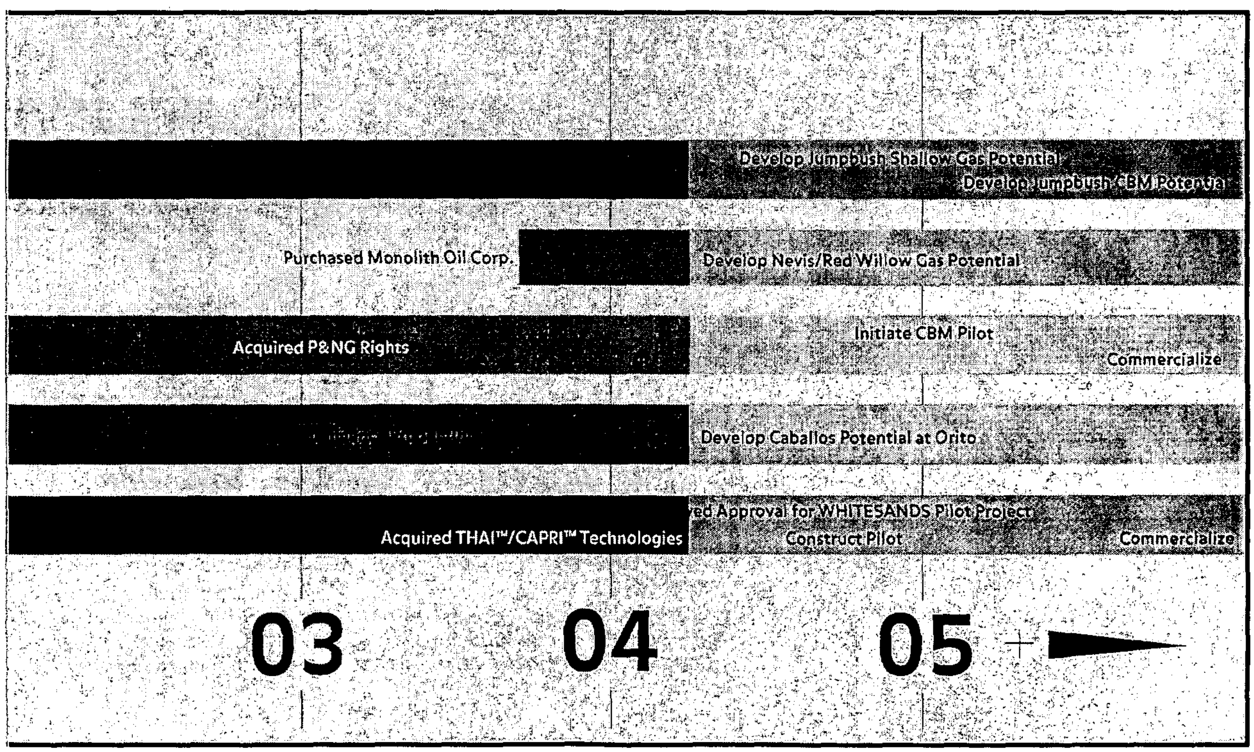
Letter from the President

Since Petrobank's inception as a public company in 1994, the employees, management and directors have worked diligently to create genuine value for all shareholders.

Four years ago, we were essentially a two-asset company with mature properties offering little prospect for growth. We have spent the ensuing period evolving and refining Petrobank's asset portfolio, focusing on niche opportunities in Canada and high-impact projects internationally, primarily in Latin America. We added a further dimension in 2002 when we created our Heavy Oil Business Unit to capture value in Alberta's vast bitumen resource and to refine and implement our proprietary "step-change" THAI™ technology.

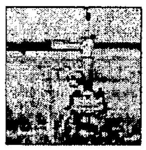
John D. Wright
President and Chief Executive Officer

Our portfolio management approach is a proactive process, which involves the continuous assessment of candidate projects while we focus on enhancing our existing strong assets and liquidating those that have reached their full value or have under-performed. The evolution of this portfolio has come a long way, particularly during 2003, and today Petrobank has multiple opportunities for significant growth embedded in this group of assets.



This year's annual report presents the Company as we see it: a robust portfolio of opportunities poised for significant growth. Each of our Business Units has the potential to be a "company-maker" and therefore could significantly impact the value of Petrobank. To help visualize the asset evolution process within each Business Unit, we have included a timeline of our major activities, showing successes, failures and the current state of the Company's portfolio. There is also a Question-and-Answer format in the Operations Review to provide specific answers to common shareholder questions. The following is a summary of the Company's assets and prospects as we move into 2004, and a brief outline of the potential for future growth.

Petrobank's Portfolio

 +  +  + 

Canadian Business Unit

Our Canadian assets are composed of a solid reserves and production base focused in the Nevis/Red Willow, Jumpbush and Eyehill areas. These are conventional, shallow, multi-zone properties predominantly targeting natural gas, plus certain light and heavy oil development prospects. During 2003 we executed transactions to dispose of mature production at Zama/Larne and Wapella, acquire production and future drilling opportunities at Jumpbush, and to acquire Monolith Oil Corp. The large majority of our 2004 capital expenditures will be focused in these new growth areas, where we have an extensive prospect inventory.

Complementing the short-term growth potential of these conventional producing assets are our two coalbed methane (CBM) projects at Princeton, B.C. and at Jumpbush, Alberta (which was encountered concurrently with our conventional activities). While CBM projects require a resource-specific exploitation program and commerciality must first be verified through testing and piloting, the ultimate potential of our CBM projects could be tremendous. Either could be capable of generating incremental reserves of more than 100 bcf net to the Company. Through the end of 2004 and into 2005 we will intensify our efforts to assess their commerciality.

Latin American Business Unit

In 2003 we commenced commercial production from our two Incremental Production Sharing Contracts (IPCs) in Colombia, and returned three exploration blocks to Ecopetrol, the state oil company, thereby reducing our capital exposure to low-potential exploration acreage. Considerable shareholders' capital has been invested in our two producing fields, Orito and Neiva, with very mixed results. The hard news for 2003 is that much of our preliminary investment did not generate economic returns. This has led to a full re-assessment of the reservoir and of our drilling, completion and operation strategy in the Orito Block, and a reduction of capital plans for the Neiva Block.

The positive news is that the lessons learned from this experience have been integrated into our revised development plans for Orito and the size of the reserves potential remains intact. We intend to substantiate our new reservoir interpretation with a drilling program to commence in the second half of 2004. In our judgment, Orito remains a very large prize, with an estimated potential of 50 million gross barrels (35-40 million barrels net to Petrobank) incrementally recoverable in the Caballos zone. This would be achieved through the combined application of an infill and step-out drilling program, field-wide installation of high-volume lift and implementation of a secondary recovery waterflood.

Heavy Oil Business Unit

We have made outstanding progress from conceptual plan to project reality over the past year. The WHITESANDS Experimental Pilot Project has received final regulatory and environmental approval and we expect to commence construction in 2004. We have integrated our recent 3-D seismic evaluation and delineation drilling on a portion of our 45-section oil sands lease into an independent resource assessment, increasing the estimated bitumen resource-in-place to 1.3 billion barrels. While this resource base would be sufficient to support a large-scale SAGD development, we are confident that the implementation and testing of our patented THAI™ process can create a "step change" beyond SAGD, potentially revolutionizing the heavy oil extraction business. Petrobank shareholders stand to benefit enormously from the commercial opportunity at WHITESANDS, combined with the future possibility of licensing the technologies and capturing additional resources domestically and internationally.

In sum, in addition to our conventional western Canadian oil and natural gas production and reserve base, Petrobank's portfolio contains: two major CBM opportunities; the potential in Colombia to add 50 million barrels of gross incremental reserves; and a patented technology, coupled with a massive resource base and an approved pilot project, that could potentially revolutionize the heavy oil industry. These are not simply play concepts or theories; these are real assets in the form of lands, leases, contracts, patents, a fully approved experimental project and proprietary intellectual property rights. While at present none of these upside opportunities has booked reserves or recognized net asset value, all of them are well-defined, active projects and we are working industriously to realize their inherent value.

2003 in Review

In 2003 we made capital investments considerably in excess of our available cash flow and added further equity, notes and bank debt to our balance sheet. Net capital expenditures were 3.3 times the year's cash flow. Although such an investment rate would be unsustainable over the long term, our 2003 investments were crucial steps in the evolution of Petrobank, enabling us to add growth opportunities as we divested of mature properties with little or no upside. I believe these investments will have a major, positive impact on Petrobank beginning in 2004.

In the Heavy Oil Business Unit, we invested $4 million to delineate our existing reserve base with 3-D seismic and three delineation wells. We also conducted all necessary studies and completed initial engineering design work for our pilot project. Finally we completed and filed our pilot application, receiving regulatory and government approvals in February 2004. We expect to realize initial pilot production as early as 2005. A large-scale commercial development could follow by about 2008. Commercial SAGD projects near WHITESANDS, with analogous resource, are sized at 30,000-70,000 barrels per day.

In our Canadian Business Unit, expenditures were focused on drilling and production operations at Jumpbush and Eyehill and the acquisition of Monolith. We invested approximately $3 million to expand and consolidate our land holdings at Jumpbush. Petrobank also tested new exploration concepts outside our core areas, without commercial success, at a cost of approximately $5 million. Further such expenditures in these areas have been terminated.

During 2003 the Canadian Business Unit evolved into a focused operation centered primarily on Jumpbush and Nevis/Red Willow. These areas offer a combination of long-life shallow-gas zones mixed with high-deliverability, shorter-life natural gas projects. We are also pursuing certain conventional light and heavy oil opportunities. Exiting 2003 the Canadian Business Unit has become a source of growth, with an inventory of more than 200 drilling locations and a capacity to generate new reserves and net asset value.

In our Latin American Business Unit we added production and validated our two Colombian IPCs. We also relinquished remaining commitment obligations on the three exploration blocks initially acquired in 2002, substantially reducing future risks. We were, however, disappointed with the results of our drilling and production investments.

Our operations in the Neiva field generated new production and reserves, but a combination of the high cost of services, low productivity wells, and the contractual fiscal regime made these investments marginal, even amid today's high oil prices. We will strictly limit any further investments in Neiva pending the renegotiation the contractual fiscal terms.

In Orito, we entered the year with high hopes and an aggressive development plan based on our initial technical assessment and the prevailing reservoir interpretation. Difficulties associated with field services and equipment caused delays and increased costs. Concurrently it became apparent that our drilling and completion methodology, although state-of-the-art, was not suitable for the reservoir. This led to a complete re-engineering of our drilling and completion techniques. Finally, certain well results contradicted our initial reservoir interpretation leading us to question the validity of our original model. These difficult lessons resulted in a $15 million write-off of our Colombian investment, severely impacting our 2003 profitability.

Petrobank's accumulating experience at Orito has generated a radically different interpretation of the reservoir system. We believe the Caballos interval had approximately 800 million barrels of original oil-in-place with a cumulative recovery to date of only 23 percent. Working with independent experts, we have concluded that the reservoir was initially dominated by a tilted oil-water contact and contains a compositional gradient, so that the oil within the pool varies from medium-gravity to very light-gravity. We also believe any gas cap in the field may be radically different from earlier interpretations. Consequently, we have re-assessed our reservoir model and are preparing a new drilling program to reflect this new reservoir interpretation. Following this hard-won knowledge, we are optimistic that our new interpretation could enable Petrobank to unlock a 50-million-barrel (35-40 million net to Petrobank) prize from this single zone.

Reserves

National Instrument (NI) 51-101 "Standards of Disclosure for Oil and Gas Activities" has impacted a number of producers upon implementation this year. Petrobank recorded negative revisions in 2003 on Canadian total proved reserves of five percent and proved plus probable reserves of three percent when compared to 2002's established reserves. The larger impact in Canada was related to conservative reserve additions being attributed to our 2003 drilling activities, particularly where there is a relatively short history of production. We expect this to translate into positive revisions in the future, particularly in areas like Jumpbush. Due primarily to our poor operating results in 2003, Colombian total proved revisions amounted to 30 percent of their opening balance, and 10 percent on a proved plus probable basis. The Colombian evaluation excluded our latest reservoir simulation work at Orito which is expected to be incorporated into future reserve assessments.

2004 Outlook

Although we are coming out of a challenging year with a more leveraged balance sheet than we would prefer, we truly believe this is a good time to be a Petrobank shareholder. We have a small-company market capitalization and big-company upside, a combination that could potentially generate outstanding returns for shareholders. Our principal challenge is that we don't currently have sufficient capital to move all our high-impact projects forward at full speed simultaneously. With success, our combined capital requirements could total $1 billion over the next five to 10 years. We have a responsibility to be fiscally prudent and to carefully plot our course to achieve our planned growth. Finally, we need to re-establish and maintain the confidence of our shareholders by consistently delivering positive results.

Petrobank today has a portfolio of growth-oriented, high-impact assets, some of which could prove world-class. This year we will prudently govern the pace of our investment program and attempt to create more financial flexibility. In 2004 our goals include initiating tests on our two CBM projects, kicking off the WHITESANDS pilot project, and in Colombia, substantiating our Orito-Caballos reservoir model. We expect to begin realizing concrete results from these projects in 2005 and beyond. Underpinning this plan is our Canadian production base and inventory of conventional drilling opportunities at Jumpbush and Nevis/Red Willow. We will also continue our program of divesting of fully valued assets.

The employees, management and directors of Petrobank are committed to and fully aligned with our shareholders. I express my thanks and appreciation to all of them for their continuing hard work and dedication. I would also like to thank Mr. David Rain, who resigned March 31, 2004 as Chief Financial Officer, for his valuable contributions over the past four years. Everyone at Petrobank wishes him the best in all his future endeavours. Mr. Chris Bloomer has assumed the position of Chief Financial Officer, and we also welcomed Mr. Steven Benedetti as our new Vice-President, Latin America. Finally, we thank all shareholders for your ongoing patience and support. We are striving to see your patience rewarded.

Respectfully submitted on behalf of the Board of Directors,

"SIGNED"

John D. Wright

President, Chief Executive Officer and Director

April 15, 2004

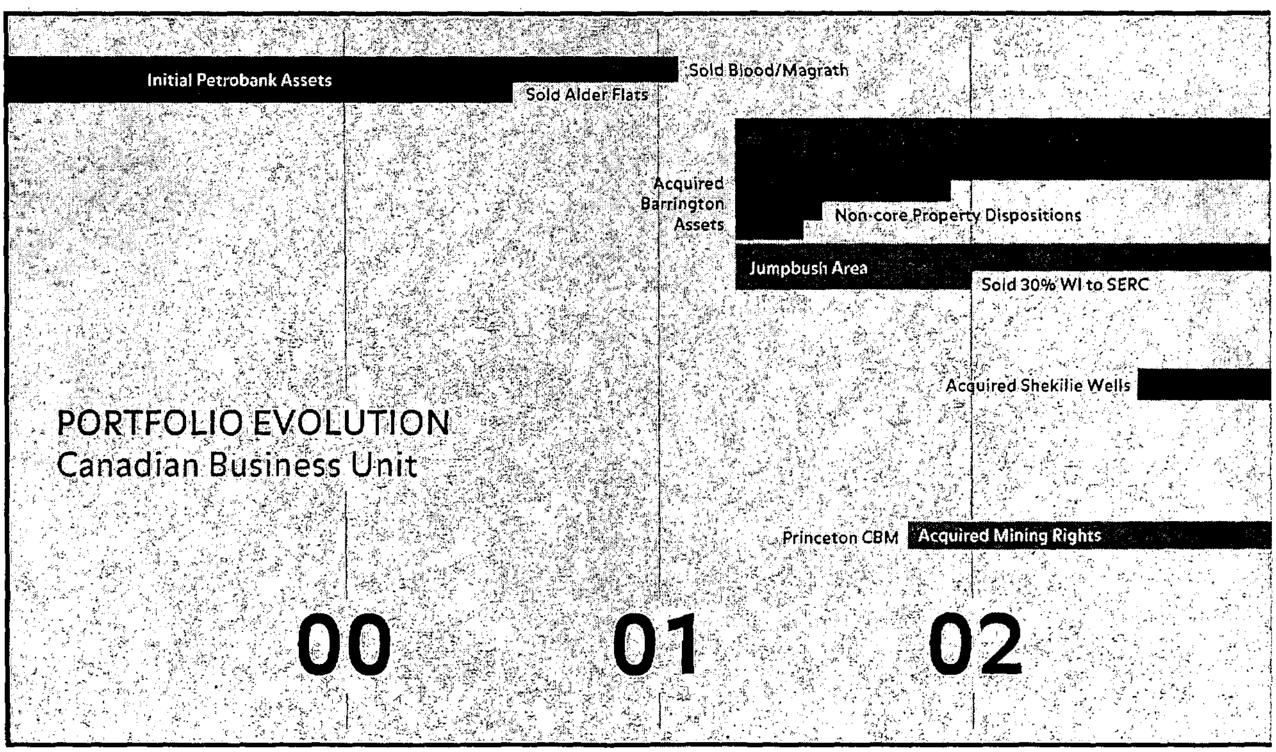
Review of Operations

Western Canada

What is the strategic role of the Canadian assets?

Petrobank's conventional western Canadian asset base is a "flywheel" for corporate value creation. The flywheel's main purposes are to provide steady returns and create balance sheet stability, which improve our ability to fund higher-impact opportunities, both domestically and internationally. It also serves to reduce the average perceived risk of the Company's asset portfolio and consequently our cost of new capital.

Our portfolio approach in Canada remains opportunistic and focused on a few core areas and certain niche projects. We are not focused strictly on volume growth with our conventional western Canadian assets; in fact we have consistently sold assets when they have reached maturity, opting to reinvest the capital in earlier-life-cycle assets with larger growth opportunities. To that end we sold our Zama/Larne property in May, acquired Monolith (Nevis/Red Willow) in September and sold our Wapella property in January 2004. The result is a redeployment of capital to our greatly expanded drilling inventory, particularly at Jumpbush, Nevis and Red Willow. Our conventional asset base is complemented by two high-impact coalbed methane (CBM) prospects that provide an opportunity to create significant value.

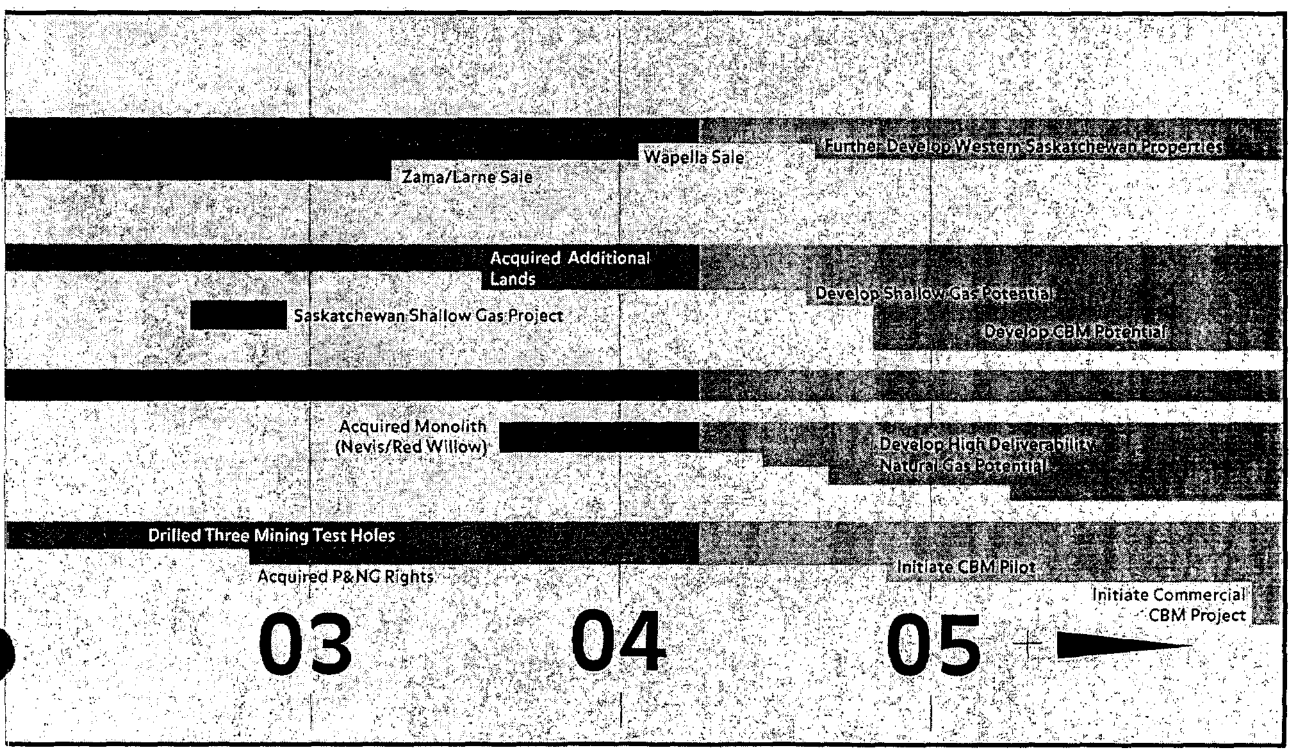


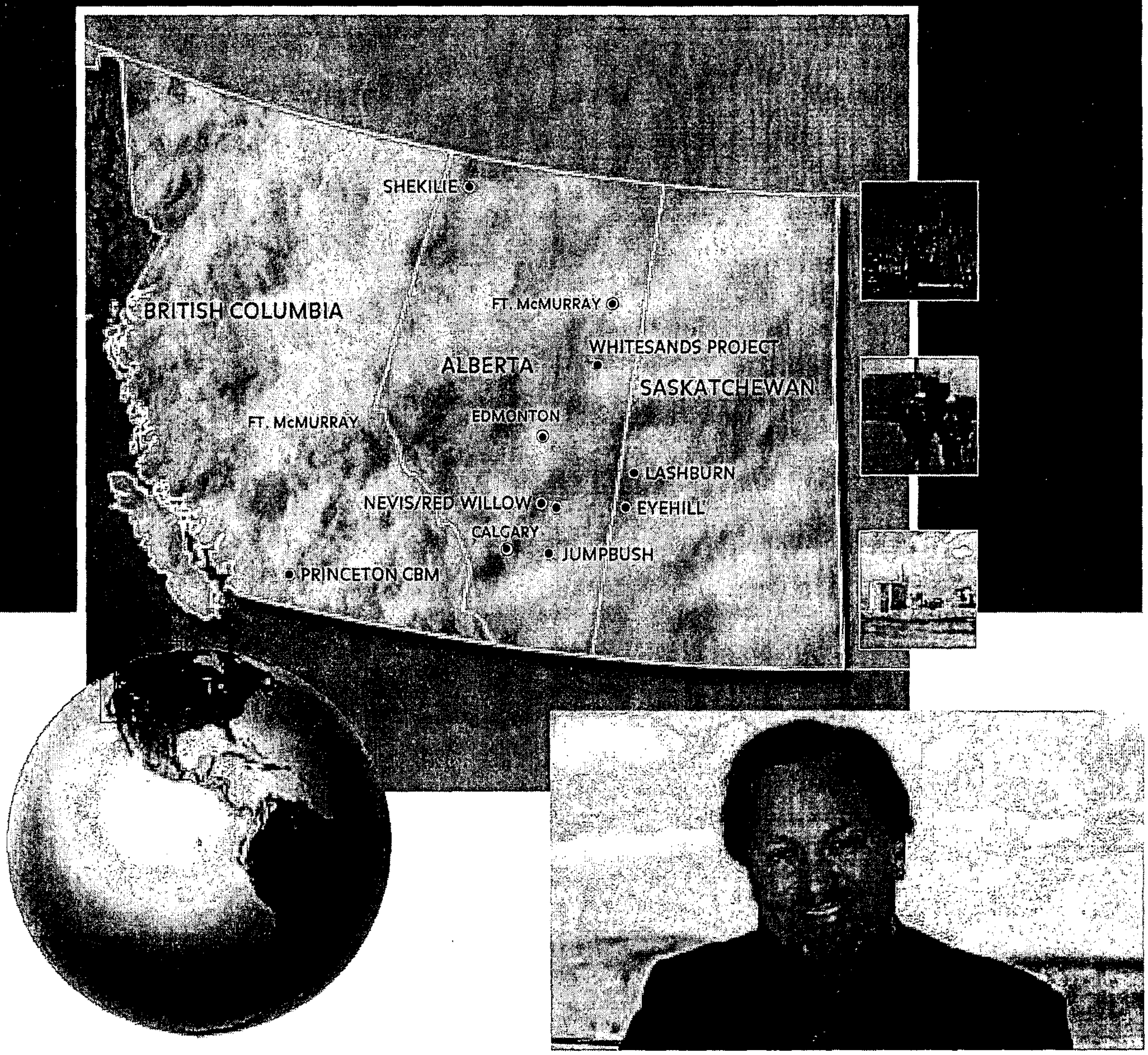
What did you accomplish in 2003?

Our efforts in 2003 established the platform for our growth potential in 2004 and beyond. Our CBM play at Princeton, B.C., was advanced toward the pilot stage with the acquisition of 121 kilometres of 2-D seismic in 2003. With the purchase of Monolith in September, we acquired the Nevis and Red Willow areas, which offer numerous opportunities to invest in high-deliverability, high-netback Mannville natural gas targets. A great deal of effort and capital in 2003 were dedicated to acquiring additional lands and several large exploration permits on the Siksika First Nation (Jumpbush). These permits were close to expiry and as a result, a portion of the 2003-drilling program was dedicated to earning these lands prior to expiry. Our Jumpbush drilling program added reserves and production in 2003, but more importantly we preserved and solidified our large land base (now at 55,000 gross acres), establishing large-scale shallow-gas and CBM projects. This land base will continue to provide an inventory of drilling opportunities and stable production for years to come.

Where will the 2004 capital program focus?

Our 2004 capital program in Canada is dedicated to drilling, completing and tying-in many of the locations and opportunities that were developed during the rebuilding of our inventory in 2003. Petrobank is currently in the enviable position in Canada of having more opportunity than available capital to fund it. For that reason Petrobank has been very selective, focusing the majority of our





R. Gregg Smith
Vice-President Canada

capital in the particular project areas that can provide the greatest increase in asset value per dollar invested. In 2004, for the purposes of maintaining our production and increasing our opportunity base, the Shekilie, Eyehill, Macklin and Lashburn properties will also see some modest funding. Our CBM project at Princeton is a high-impact, long-term project that will see moderate funding as we advance towards launching a pilot project by year-end. Petrobank recognizes the need to strengthen the Canadian production base and the majority of our 2004 capital will be dedicated to drilling opportunities identified at Nevis, Red Willow and Jumpbush.

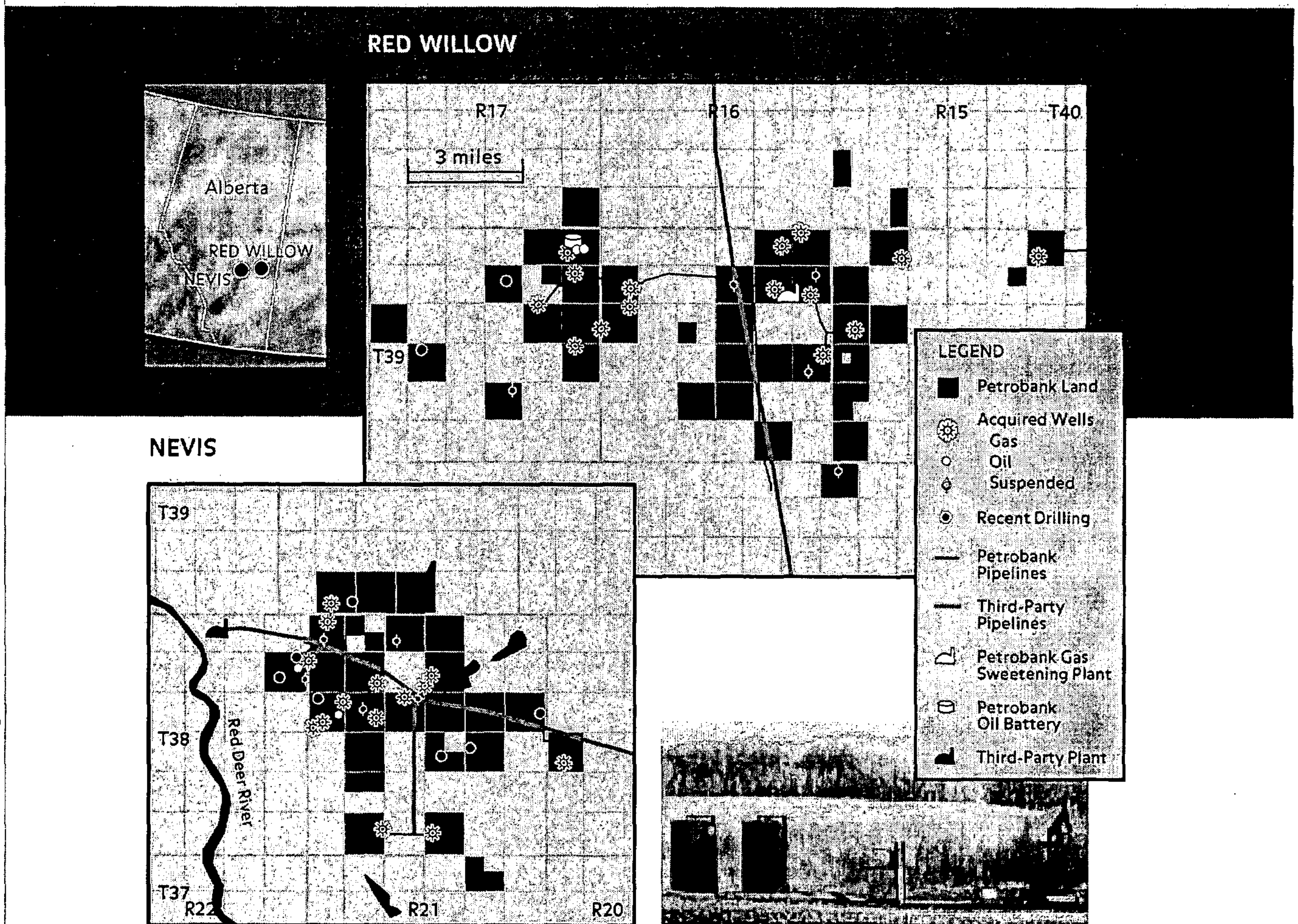
A planned 60 percent of the 2004 capital program will be spent on drilling, completions and recompletions. To support the planned new production and the optimization of existing production, 27 percent of the capital plan will be invested in pipelines and facilities. As this year is very focused on drilling our existing inventory, only 13 percent of our domestic capital is planned for seismic and land acquisitions.

Further drilling in the Nevis and Red Willow areas is expected to add higher-deliverability/decline natural gas. Our drilling program at Jumpbush will provide balance to this more volatile production base with its stable, longer-life, lower-deliverability, shallow natural gas production. Our CBM projects at Princeton and Jumpbush will provide the upside and longer-term potential to complement our conventional projects. The Princeton project will see two phases of drilling in 2004, with the objective of commencing a pilot towards year-end. At Jumpbush we have successfully tested 100 mcf per day from a single coal zone in a well with multiple coal zones. Petrobank plans to execute a CBM pilot project at Jumpbush by completing and producing all the coal zones in this well and in four other nearby wells.

Nevis/Red Willow

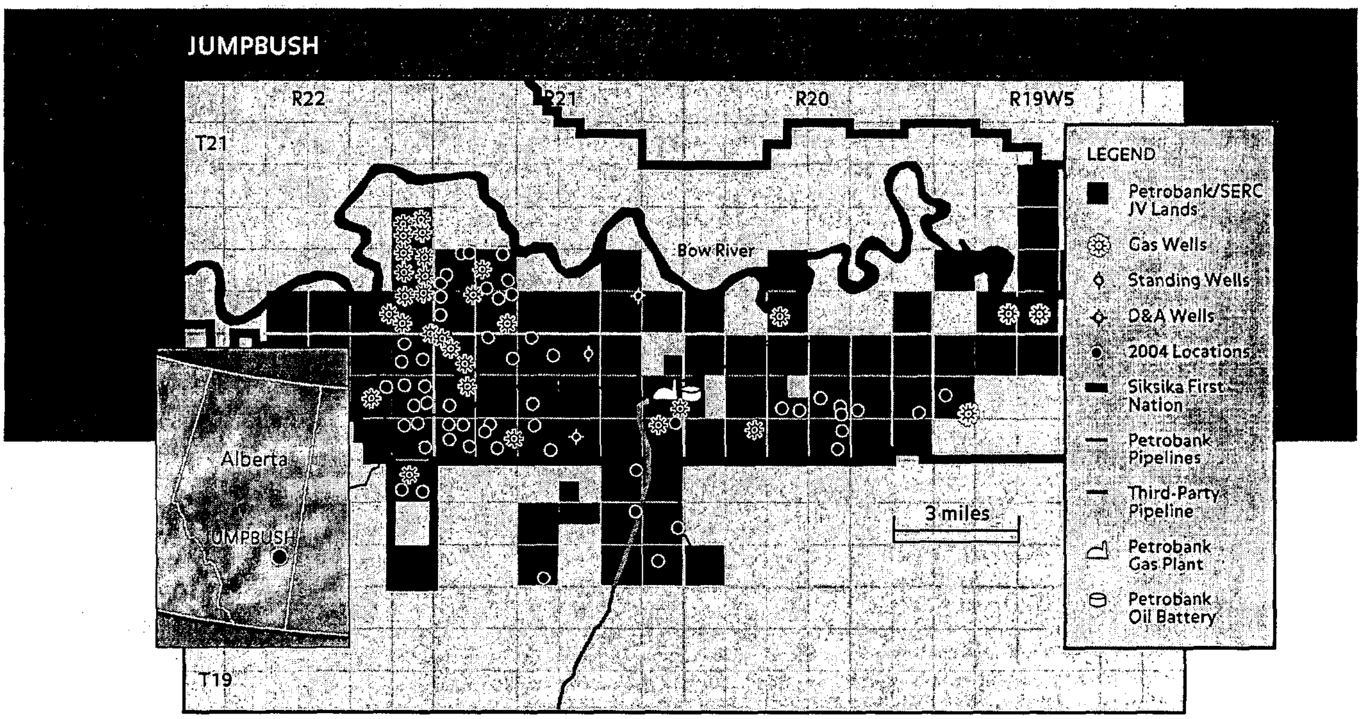
The Nevis and Red Willow properties were the most significant assets acquired in the September 2003 Monolith purchase. The primary drilling targets at these properties are the Glauconite and Ellerslie zones within the Mannville Group. Regionally, these sandstone reservoirs are characterized by high-deliverability 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 we can stack these horizons 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 we have no Stettler production but are 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. Our Nevis natural gas production is processed at Duke's Nevis plant, which operates well below its capacity and could manage any additional gas produced by Petrobank in the area. We operate our own pipelines and



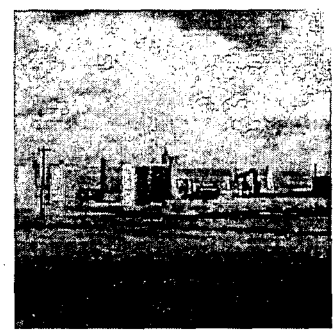
compression in the area, providing the flexibility to optimize production. At Red Willow, we operate our pipelines, a sour gas facility, satellite compression and a recently completed oil battery. Currently our facilities can manage all of our production and can easily be expanded as required.

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 greatest surprise to date has been the extent to which oil production is being added from the Glauconite at both properties. We plan to further pursue the upside in this newly identified oil play. Over 50 drilling locations were identified at the time of the Monolith acquisition, forming an inventory that continues to be drilled, refined and expanded. Our 2004 capital plan is dedicated to new wells, pipelines and facilities with a view to bringing on new production quickly. We anticipate spending approximately 40 percent of our 2004 capital plan in the Nevis and Red Willow areas.



"Siksika Energy Resources Corporation's joint-venture relationships, such as the one with Petrobank, have played a key role in our growth and development. The joint-development program is key to our continued growth as a company."
- Alfred Many Heads

Alfred Many Heads
Director, Siksika Energy
Resources Corporation



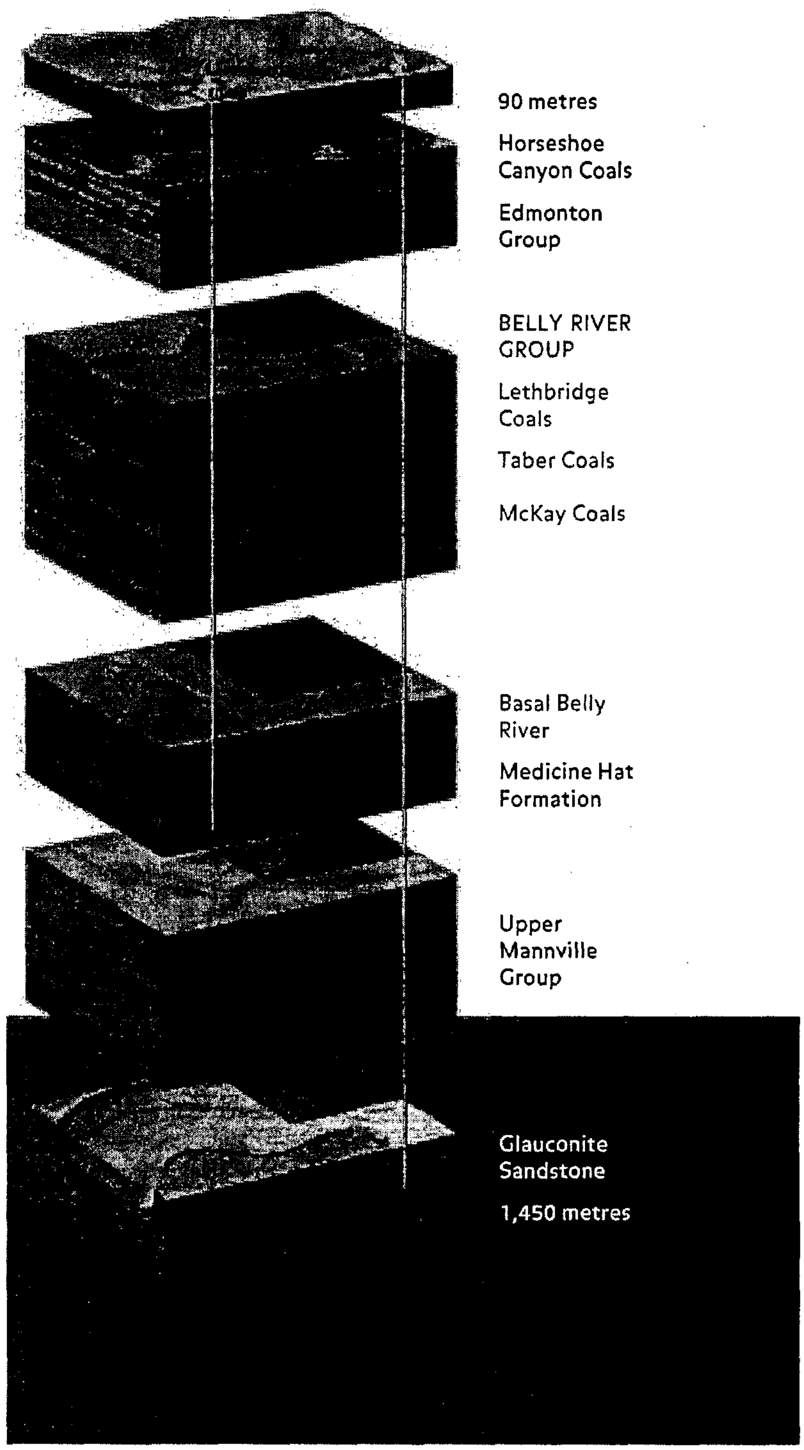
Jumpbush

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 highly prospective acres to complement our existing land and infrastructure position. All expiring prospective permit lands were drilled in 2003 to validate our land base and establish a large, commercial shallow-gas project. At Jumpbush, we now hold more than 55,000 gross acres of under-exploited lands. Jumpbush is a unique opportunity as it represents a large island of undeveloped acreage surrounded by Crown lands that have been intensely developed over the years.

Our drilling program utilizes existing 3-D seismic data to identify some of the more prolific Belly River trends, and our interpretation was confirmed by our late 2003 drilling program. Petrobank's net production at Jumpbush during the fourth quarter of 2003 was 425 boe per day, 86 percent of which was natural gas. All production moves through our centrally-located facilities.

The focus for 2004 is to exploit the opportunities identified by the 2003 drilling and acquisition program. We plan to devote approximately one-third of our 2004 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 us to tie-in new production 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 gross capacity (8.4 mmcf per day net), creating ample room to grow production from our fourth-quarter 2003 net rate of 2.2 mmcf per day.

JUMPBUSH CROSS-SECTION



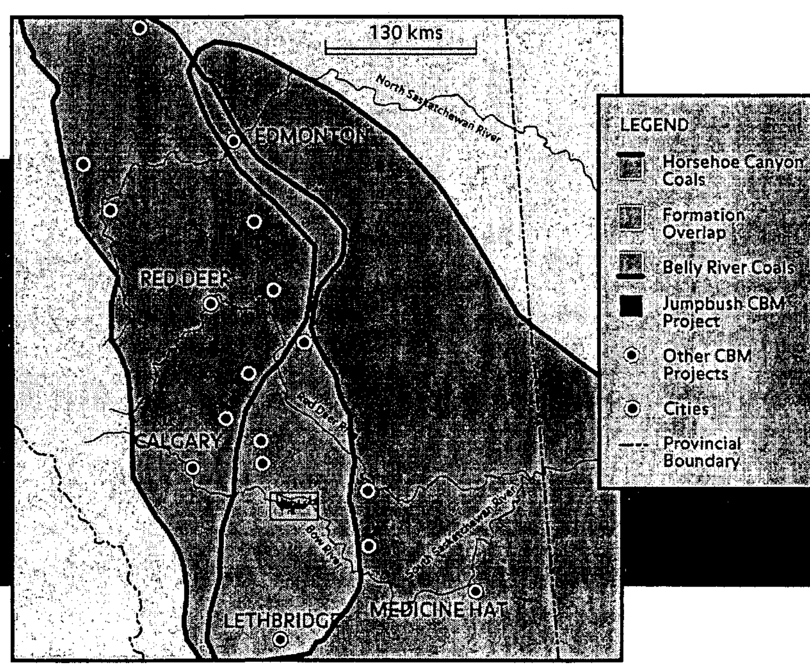
Coalbed Methane (CBM) Projects

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 Eocene 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 underlies our 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 taken the aggressive approach of securing the natural gas rights over an entire basin, which is relatively small in area but which contains very thick gas-bearing coals.

Jumpbush CBM

In partnership with SERC, we have been developing a CBM project to complement our 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. Initially, we have focused on the Lethbridge, Taber and McKay coals of the Belly River Formation, as these coals are at depths optimal for combining resource potential and permeability.

HORSESHOE CANYON AND BELLY RIVER COAL FORMATIONS



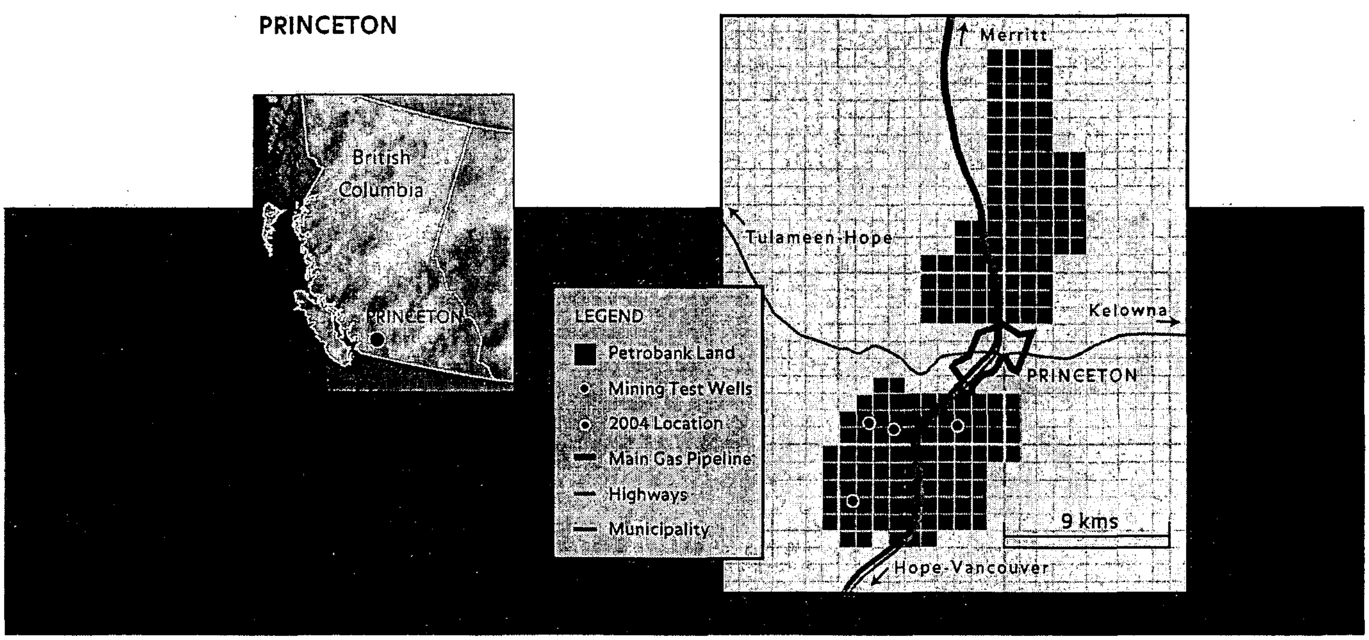
In 2003, while drilling wells for conventional Belly River, Medicine Hat and Mannville natural gas targets, Petrobank cored and evaluated coals from four well-bores in the Jumpbush area to assess the CBM resource potential. In-house assessment suggests that the gas-in-place resource could be up to 300 bcf for the Belly River coals alone. 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 2004 this well and at least four other existing nearby wells will 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. 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.

Princeton

Princeton is an attractive CBM opportunity because Petrobank and its partners control the entire basin and the gas-bearing coals are very thick. The coals appear to have an average thickness of 137 feet, approximately five to ten times the typical Alberta thickness. To be clear, Princeton is a longer-term project and its 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.

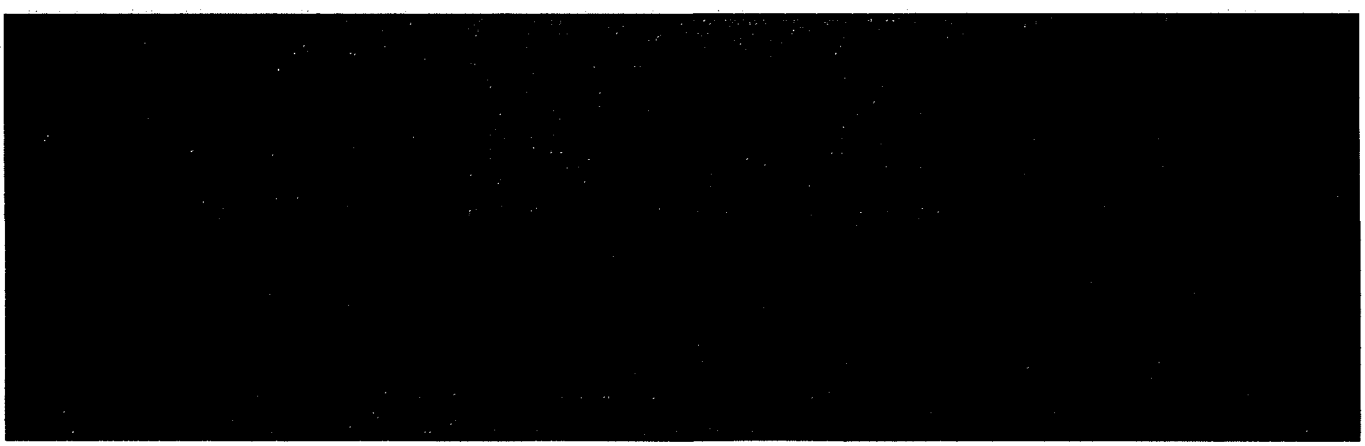
PRINCETON



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, and late in 2002 Petrobank acquired the petroleum and natural gas rights to the basin. Following this we shot a 121-kilometre 2-D seismic program to map the basin and design a drilling strategy. Seismic interpretation confirmed the basin's extent and our ability to map the underlying thick coal sequences. Based on work to date, Petrobank estimates that the potential gas-in-place resource is 250-500 bcf.

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, which could be initiated as early as November 2004, followed by a 6-12 month production-testing period.

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. 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.



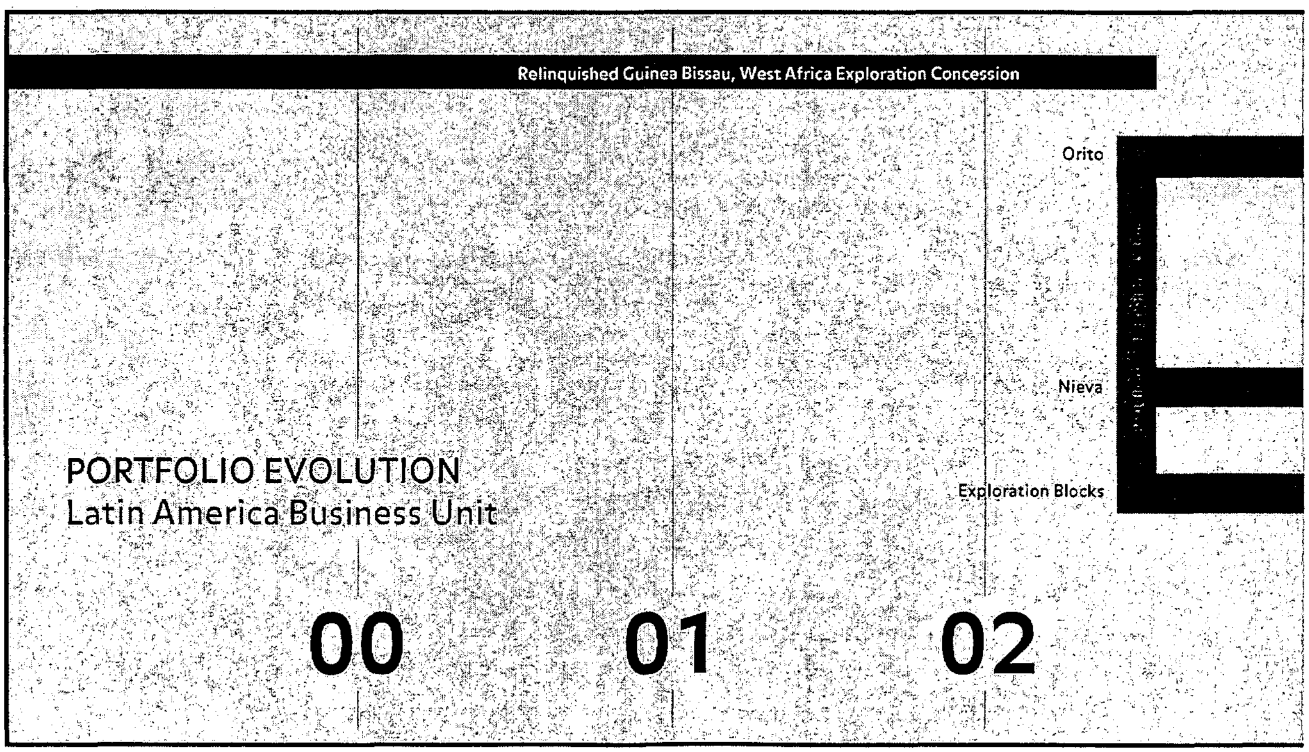
Latin America

What are the main attributes of your Colombian assets?

Steven J. Benedetti
Vice-President Latin America

The Company's Colombian production is derived from two Incremental Production Contracts ("IPCs") at Orito and Neiva, in partnership with the state oil company, Ecopetrol. Each IPC provides Petrobank with a portion of all incremental production generated by our development activities above an established forecast production-decline curve ("baseline"). Petrobank's share of the incremental production, 79 percent at Orito and 69 percent at Neiva, is subject to an initial eight percent government royalty.

The Orito Field is the largest in southern Colombia's Putumayo Basin, containing more than 1.1 billion barrels of original oil-in-place. The most significant of three reservoirs is the Caballos zone, which originally contained more than 800 million barrels of oil-in-place. To date, Orito has produced 227 million barrels of oil, including 187 million barrels from the Caballos zone.

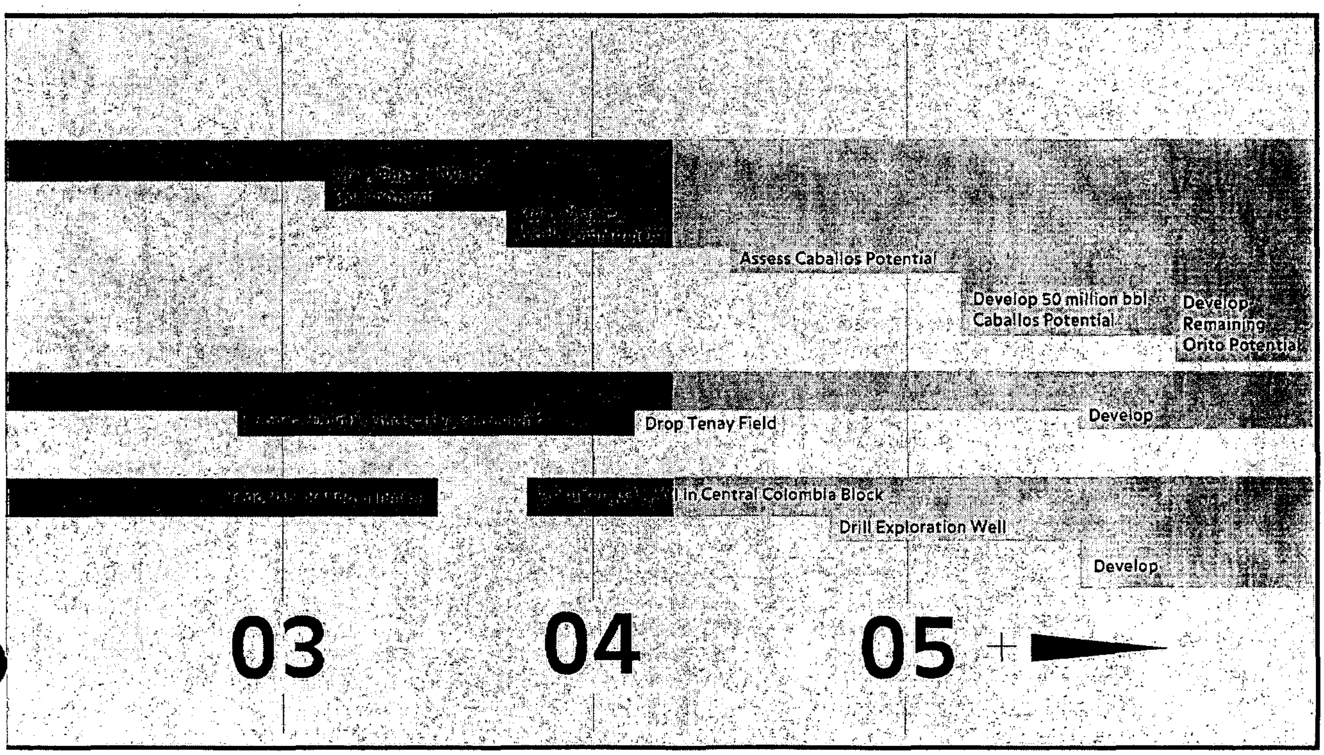


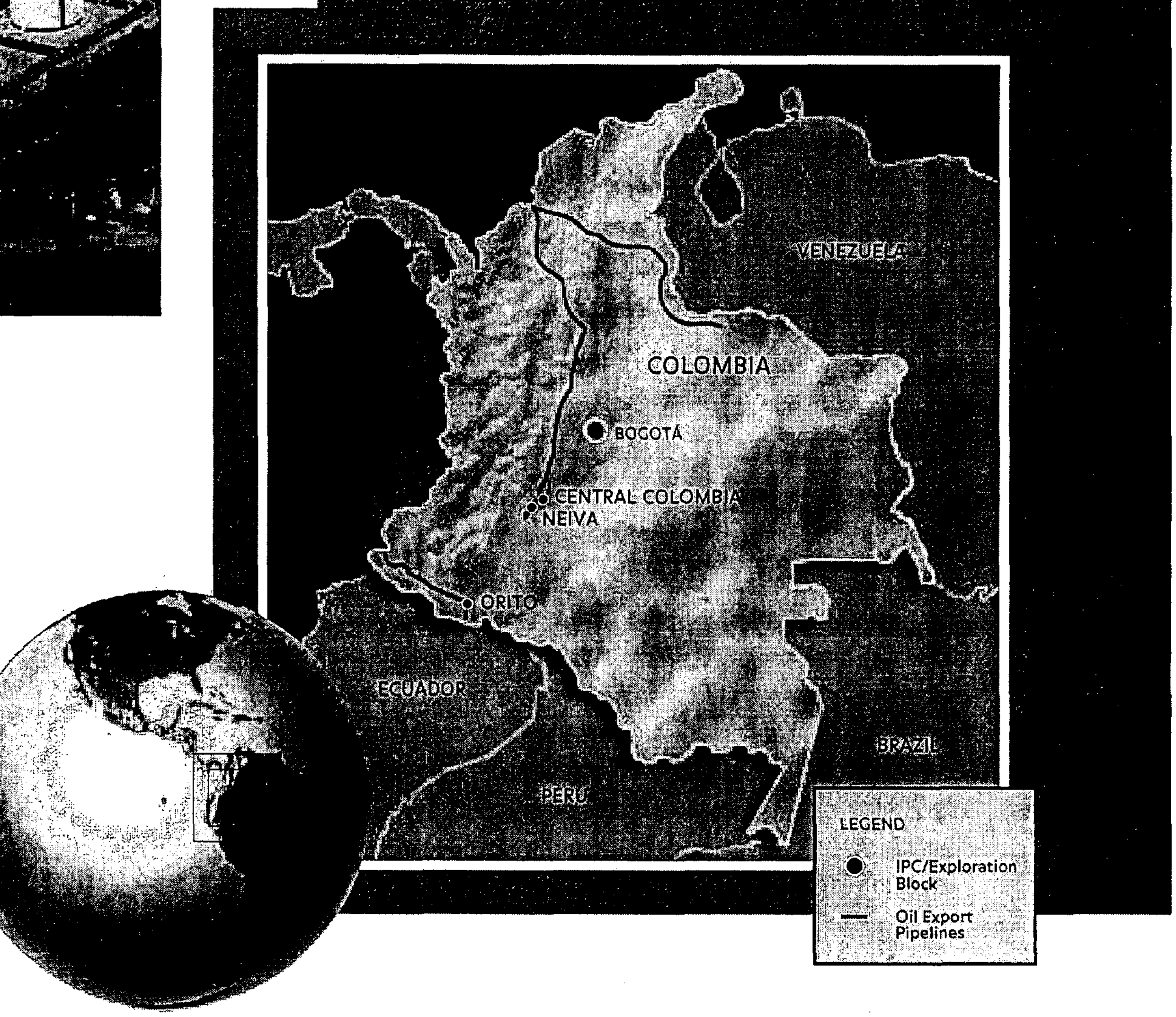
In the Upper Magdalena Valley of central Colombia, the Company is a partner with Ecopetrol in the Neiva IPC and is a one-third partner in the Central Colombia Block, a high-impact exploration project operated by the Chilean state oil company, Sipetrol.

Does Petrobank continue to see Colombia as a central part of its international portfolio?

Petrobank's international business strategy has been to pursue projects in countries with favourable fiscal terms, significant resource potential and where the oil industry is critical to the economy. In those countries we look for under-developed opportunities with an existing base of proven reserves where we can apply Canadian technical expertise. Colombia and our projects at Orito and Neiva meet these criteria. Although Colombia has certain well-publicized security issues, it has the longest-running democracy and in our opinion, the most favourable fiscal regime in Latin America.

Colombia's commitment to the oil industry has been demonstrated by the recent formation of a new national hydrocarbon agency (ANH) and development of a new risk exploration contract. The new risk exploration contract enables a flexible period of exploration, appraisal and development tailored to the operator's circumstances. The contract offers additional benefits for companies that extend existing conventional oil activities to include heavy oil and natural gas. Companies that invest in these new blocks will retain full rights to any successfully delineated field without the government earning a direct interest. The government's commitment to grow the oil industry, combined with the significant remaining potential in Colombia, convince Petrobank that Colombia should be the lynchpin of our Latin American activities and the springboard for regional expansion.





Where will you focus spending in 2004?

Our 2004 capital spending will be focused primarily on tapping the significant potential we have identified at Orito, and over the longer term, we are also intent on pursuing other avenues to expand our presence in Colombia, including acquisition of production and low-risk exploration blocks. Additionally, we continue to evaluate other Latin American opportunities particularly in Venezuela, Ecuador and Peru.

Orito

With the completion of our initial investment commitment in 2003, the Orito IPC will enter the 19-year complementary phase of the contract during which Petrobank will be responsible for developing the field's significant potential. Petrobank will continue to receive 79 percent of production above the predefined baseline curve. Current baseline production is 3,200 barrels per day, while incremental production is approximately 1,700 barrels per day (1,350 barrels per day net to Petrobank less an eight-percent royalty).

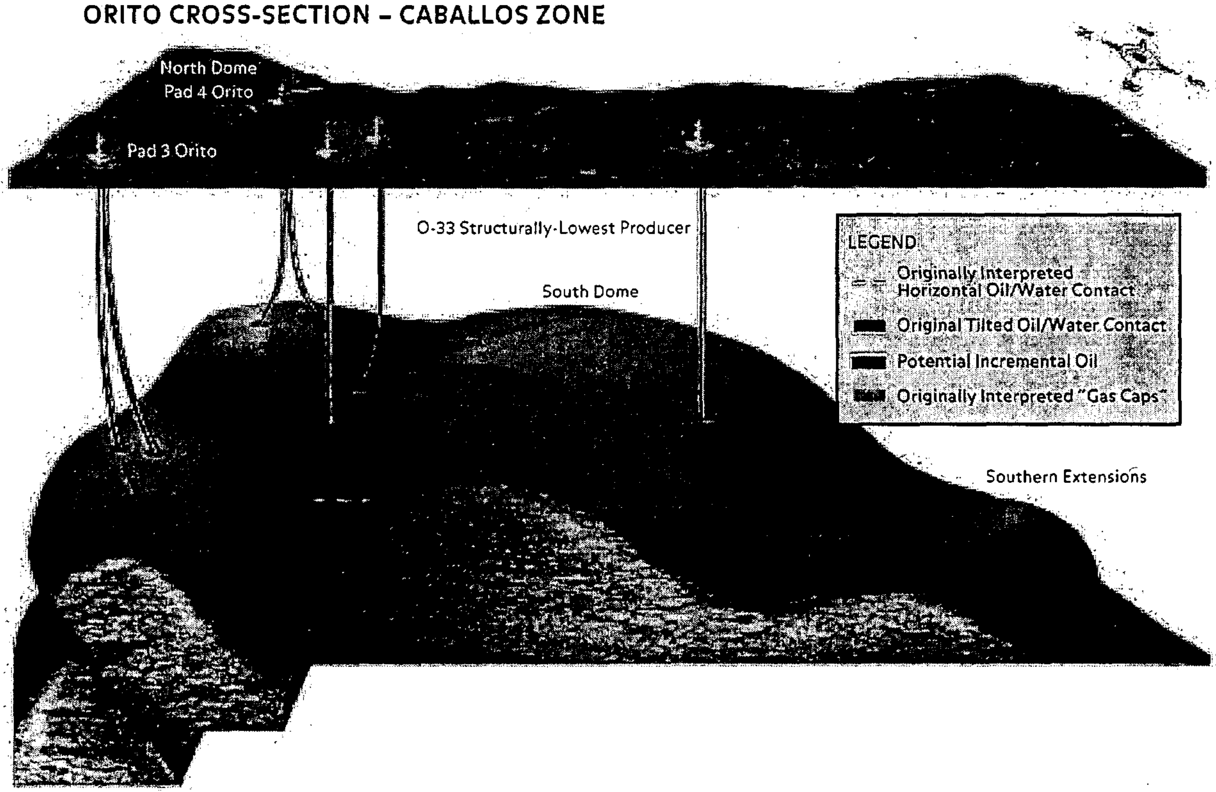
In 2003, all of Petrobank's wells were successful to varying degrees. The Orito-112, 113 and 115 wells are capable of producing approximately 1,000 barrels of oil per day combined. The structurally-lower Orito-114 well produced water from the lower Caballos and has been shut-in. Petrobank may re-enter this well, plug back and isolate the shallower Caballos zones that produced oil during early testing.

We also performed seven workovers, 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. Future workovers will be limited to locations with appropriate downhole and surface conditions.

Petrobank has refined several step-out locations and development concepts at Orito. With moderate success we hope to realize an estimated 50 million gross barrels of incremental reserves.

Petrobank's 2004 plan for Orito will begin with completion of our revised reservoir model that incorporates our new understanding of the Caballos reservoir's complex architecture and distribution of hydrocarbons and water. This will be followed by a two- to three-well drilling program focused on the high-potential areas of the field. If these wells confirm our revised understanding of the

ORITO CROSS-SECTION – CABALLOS ZONE

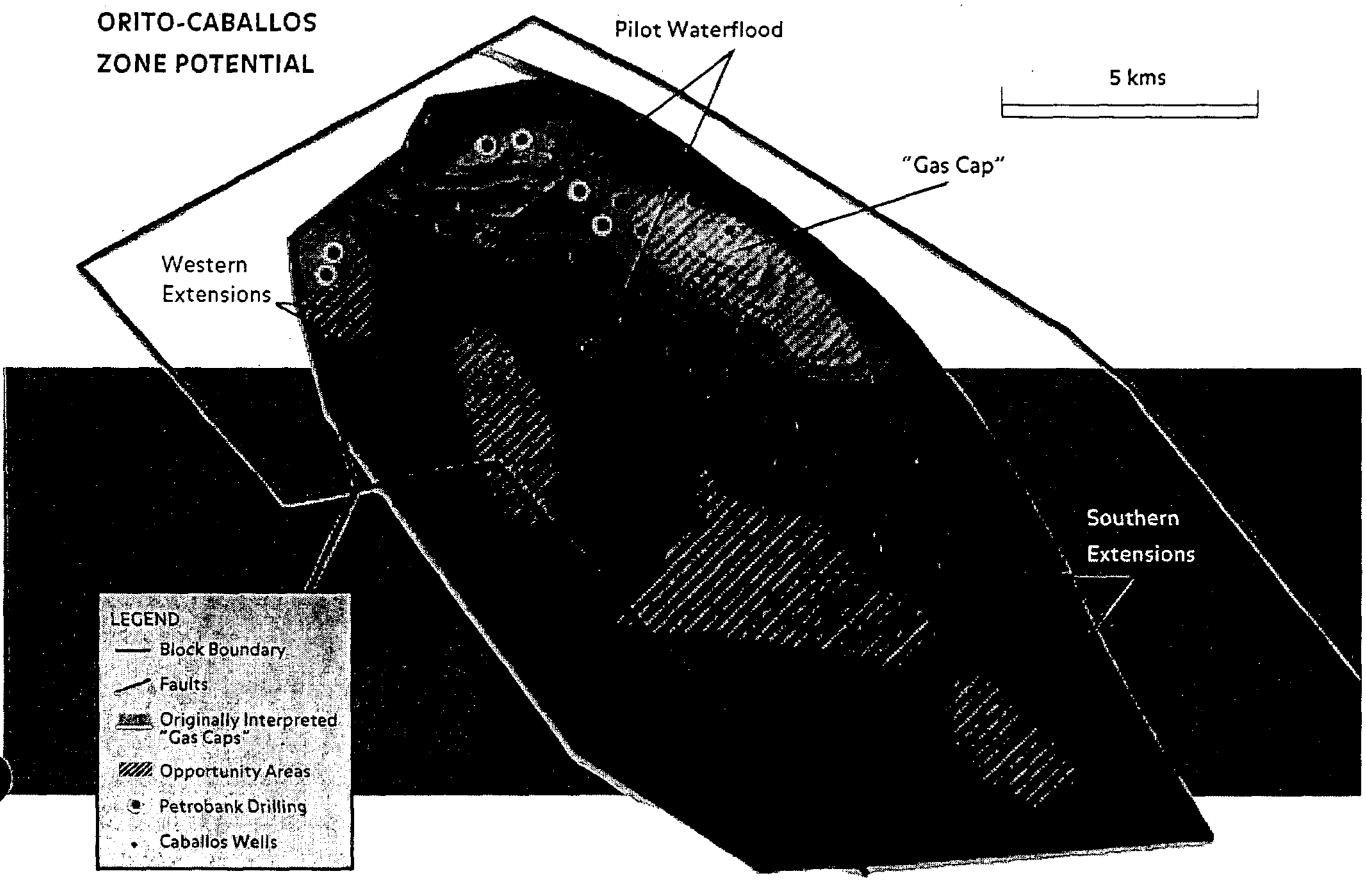


Caballos reservoir, we would anticipate proceeding with a full-scale delineation program extending through 2005 and beyond. Petrobank will also launch a pilot-scale waterflood in the Caballos in 2004. A successful pilot could lead to a full-field waterflood, which could generate significant additional reserves and production.

The Orito Field is a large structural trap consisting of three primary sandstone reservoirs, the Eocene Pepino and the Cretaceous Villeta and Caballos. The Caballos, a complex series of fluvial/deltaic and marginal marine sands, is the primary producing reservoir.

Petrobank's recent activities have clarified and highlighted many of the complex variables controlling the productivity of the various reservoir units. In addition to porosity and permeability variation, we have confirmed the field has a tilted oil/water contact and marked gradations in crude quality. The tilted contact resulted from a hydrodynamic drive dipping northeast-southwest at least 280 metres within the field. The implication is that a large prospective area remains down-dip that was previously thought to be water-bearing. The field's crude quality varies from near 29° API in structurally-low areas to as high as 43° plus gas condensate in the northern, up-dip areas. This suggests that an originally interpreted gas cap area in the heart of the field may instead contain significant light oil reserves.

ORITO-CABALLOS ZONE POTENTIAL



To date our Caballos reservoir model has confirmed the resource's original size at 800-850 million barrels of original oil-in-place, the lateral and vertical reservoir quality variations and the probability of oil in a large, undeveloped area originally thought to be a gas cap. With the addition of new petrophysical data and completion of the reservoir simulation's next phase, we expect to have identified the location and distribution of at least 50 million incremental barrels in the Caballos zone.

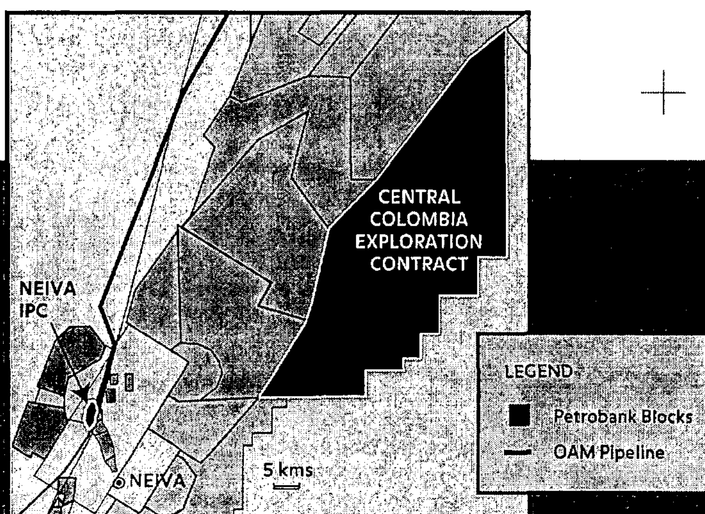
We have also identified two additional step-out areas, similar to the successful Orito-112 and 113 discovery wells, and we plan to acquire additional 3-D seismic to refine these opportunities.

Neiva

Petrobank in 2003 completed its initial investment of more than US$11 million. Later in 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 barrels of oil per day while incremental production is approximately 650 barrels per day (450 barrels per day net to Petrobank less an eight-percent royalty).

To date Petrobank has drilled five Honda zone wells, one Doima-Chicoral well and performed 13 workovers. Unfortunately, the current IPC terms make further drilling marginally economic. Petrobank has begun discussions with Ecopetrol regarding improving field economics to enable continued development.

UPPER MAGDALENA VALLEY, COLOMBIA



Exploration

Exploration also remains important to Petrobank, and in 2003 we re-positioned our exploration portfolio in Colombia. The Company negotiated its release from three potentially costly exploration blocks that Petrobank acquired along with our other Colombian assets in 2002. These entailed estimated work commitments of US$8.5 million and were released at a cost of US$750,000.

Central Colombia Block

Petrobank has a 33 percent working interest in a new exploration contract covering the Central Colombia Block where we see significant promise. Initial geological and geophysical studies have identified a large structure that could hold a 60 million barrel prize. As at Orito, the target reservoir is the Cretaceous Caballos. Sipetrol, Petrobank's partner and operator, plans to finalize its interpretation in the first half of 2004, at which time we expect to make the decision to proceed to the next phase of the exploration contract, with the option of drilling an initial exploratory well or acquiring 3-D seismic, as early as the fourth quarter of this year.

Heavy Oil

As a follow-up to the 2004 initiation of our THAI™ pilot project in Alberta, we have begun evaluating the potential of similar heavy oil projects in Colombia and Venezuela. Discussions are being held with Ecopetrol and the new national hydrocarbon agency in Colombia, with PDVSA and the Ministry of Energy and Mines in Venezuela, and with several potential project partners.

Environment, Security and Community Relations

Environment

The cornerstones of our environmental management system in Colombia are Environmental Management Plans ("PMAs"), which define the environmental baseline for a given activity and provide a response plan in the event of an environmental emergency. Such plans have been prepared for every activity we are associated with by our Health, Safety, Environmental, and Community Relations ("HSE&C") team, assuring compliance with national and regional regulations.

Based on the final PMA, a report is submitted to the Ministry of Environment. Relative to our HSE&C commitments for our 2002 and 2003 drilling programs, Petrobank is 100 percent in compliance with the Ministry. We will continue to comply with all Colombian environmental regulations and World Bank reference standards.

Security

In November 2003 we were impacted by a narco-terrorist attack against the state-owned facilities in Orito. Although the attack was not directed at Petrobank, damage suffered by Ecopetrol facilities led to the temporary shut-down of our production, which resumed following repairs. One well that was shut down has yet to recover its original production rate, but recent work has restored the overall field's production to near pre-attack levels.

Although there are certain security risks associated with operating in Colombia, as there are in many places worldwide, we believe these risks can be effectively managed. Colombia's President Uribe has implemented many changes to improve security and strengthen the Colombian economy and the Colombian military has increasingly been taking the offensive against the narco-terrorists.

Working with local communities promotes an atmosphere of mutual respect, benefit and trust, and thereby decreases the risk of serious security issues. Within Bogotá and in our field operating areas, Petrobank maintains contact with appropriate local, regional and national bodies to monitor any local security situations and mitigate risk.

Community Relations

Petrobank has developed an industry-leading community relations program based on three strategies:

- creating local job opportunities;
- empowering local communities and governments to play an increased role in regional development efforts; and
- involving the community in environmental management and regulatory compliance.

This approach has been applied at Orito and Neiva. Specifically, we have worked with four community settlements and 10 indigenous communities in Orito and five community settlements in Neiva.

Our local job opportunity program has filled 100 percent of non-qualified and qualified temporary labour with local personnel. In Orito this has amounted to 872 jobs and in Neiva, 577 jobs, both temporary and full-time.

As part of our early environmental and social planning we assessed the level of government presence in the Orito municipality and the efficiency of local development plans. We established training programs to increase regional funding and to improve involvement in the local development planning process.

Community involvement in environmental management has been a key issue in fortifying the relationships that Petrobank has established with local groups, to the point that local communities play an integrated role around our operations.

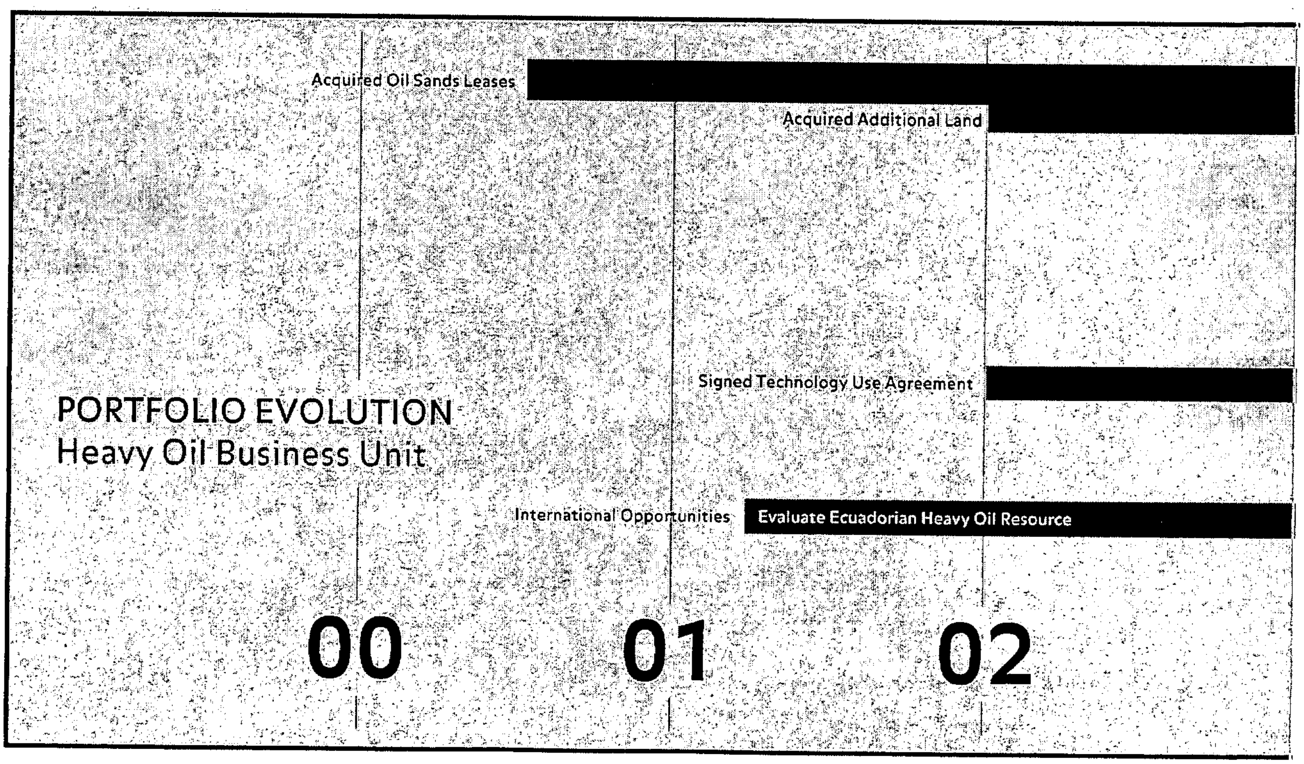
Our efforts devoted to date on HSE&C activities have already paid dividends and position the Company to benefit further as local communities, Ecopetrol and the government recognize Petrobank as a preferred partner.

WHITESANDS Heavy Oil Project

Chris J. Bloomer
Vice-President Heavy Oil and
Chief Financial Officer

What is the THAI™ technology?

THAI™ is a revolutionary new air injection-combustion process for the *in-situ* recovery of oil sands and heavy oil. It uniquely combines existing technology to vastly improve the recovery and operational parameters of *in-situ* production. In the process a vertical air injection well is placed at the "toe" or end of a horizontal production well. Air is injected into the vertical well and a combustion front is created, burning a portion of the oil in the reservoir. The heat generated from combustion reduces the viscosity of the remaining oil, enabling it to flow by gravity to the horizontal production well, and then to the surface. The combustion front sweeps the oil from the toe to the "heel" of the horizontal producing well, recovering up to an estimated 80 percent of the original oil-in-place while partially upgrading the crude oil *in-situ*. The THAI™ process will operate with virtually no natural gas or fresh water use.

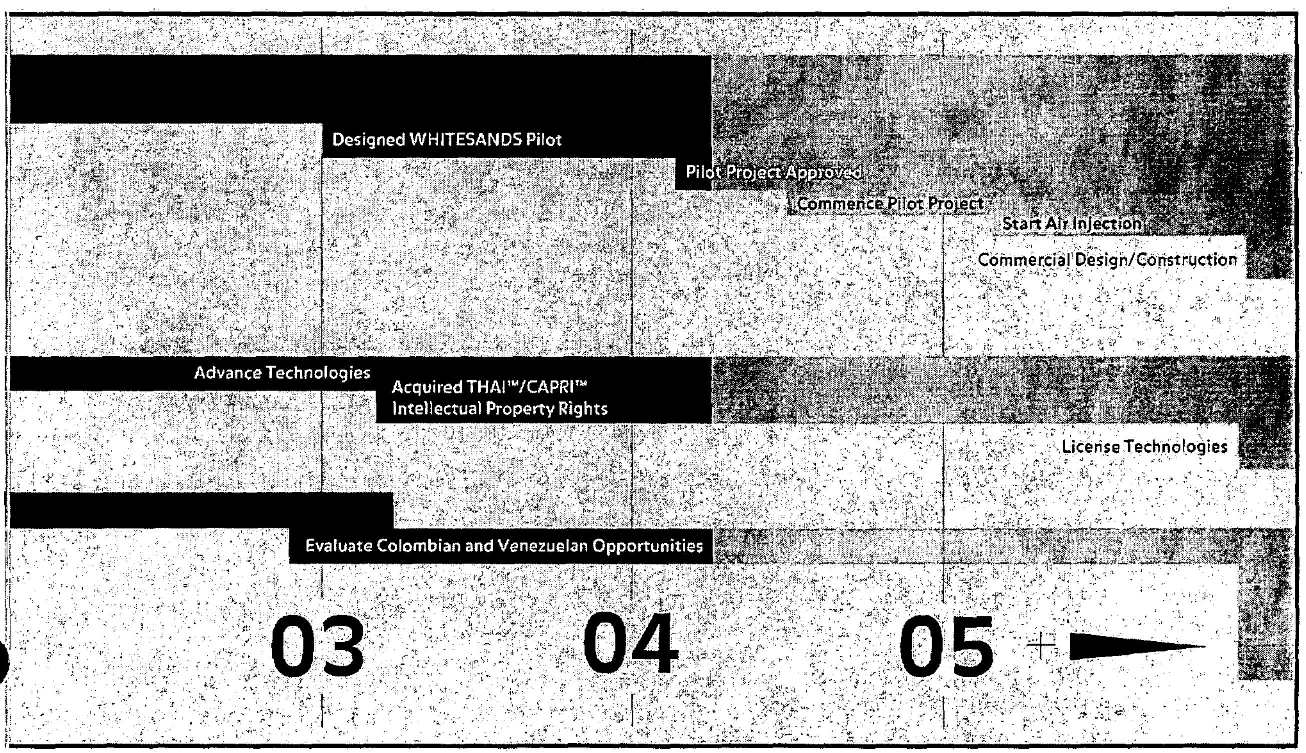


The CAPRI™ process incrementally enhances the THAI™ technology through the addition of a catalyst around the horizontal well-bore, which further upgrades the crude oil *in-situ*.

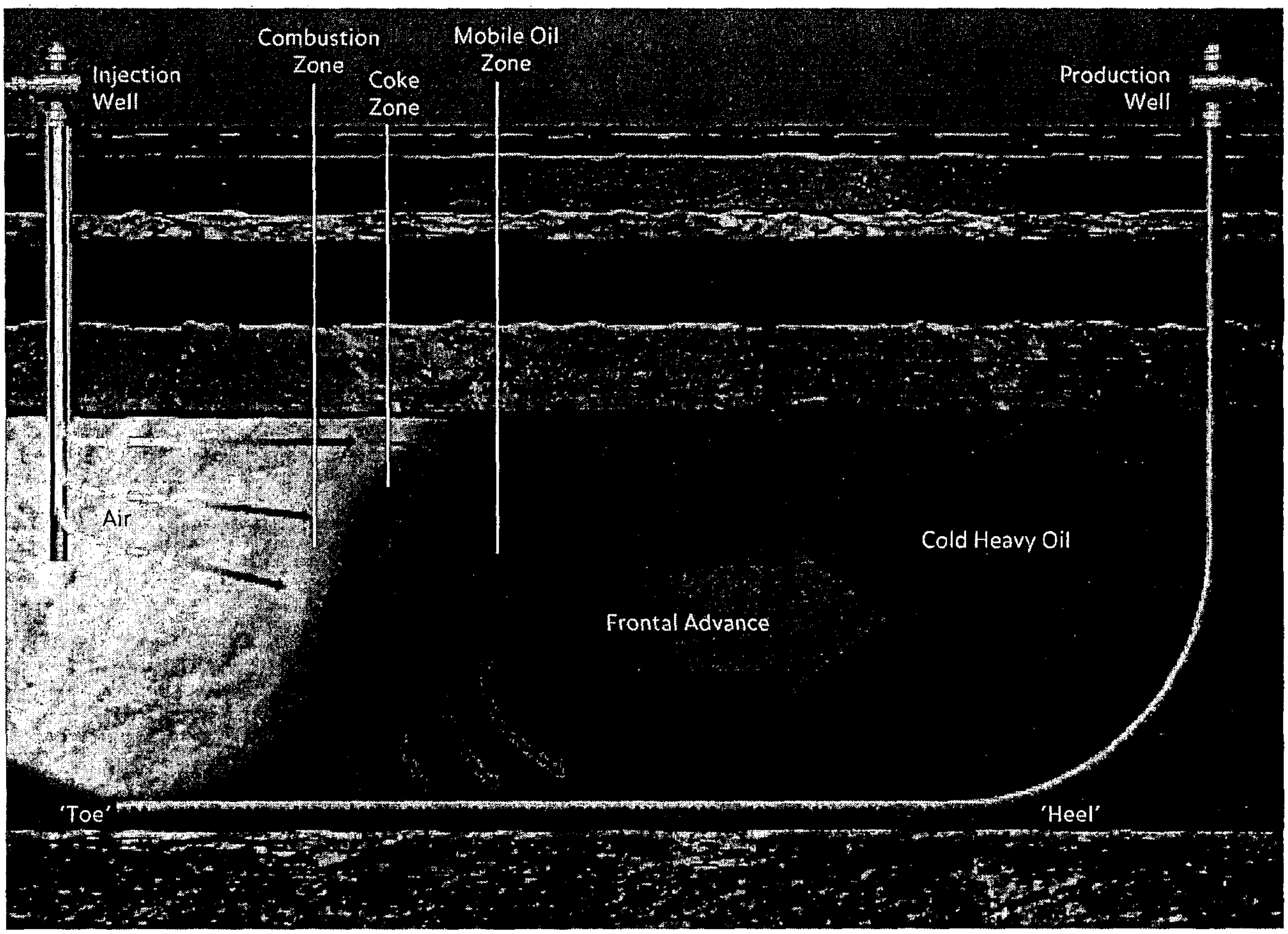
The THAI™ and CAPRI™ technologies integrate existing proven technologies and provide the opportunity to create a step-change in the development of heavy oil resources globally. Petrobank owns all the intellectual property rights associated with both these technologies.

What are the main technological risks?

The oil and gas business has its own inherent risks, but the THAI™ process, while novel, does not rely on any unknown technologies. Air injection-combustion has operated since the 1920s using a vertical air injection well and a vertical producing well. The ability to drill and operate horizontal wells is proven and is well-demonstrated in thermal SAGD operations. Processes involved in *in-situ* combustion are well-known and similar to a coker in a crude oil refinery. The THAI™ process builds on the history of *in-situ* combustion and has been thoroughly demonstrated in scaled laboratory tests and in field-scale numerical simulation. The next step is to demonstrate it in the field. The field pilot has been specifically engineered to mitigate two areas of technical risk – excess temperature and oxygen breakthrough in the horizontal well.



THAI™ PROCESS



Air is injected at the top of the reservoir near the toe of the horizontal well. After combustion commences, very hot combustion gases mix with the oil ahead of the front, reducing its viscosity and partially upgrading it through thermal cracking. The combustion gases, oil and steam (from *in-situ* water) drain into the horizontal production well. Drainage occurs via gravity and pressure differential into the horizontal well at the base of the formation. Fluids are moved to the surface via combustion gas lift, eliminating the need for artificial lift. Coke, shown in red above, is left behind the moveable oil, thus providing the fuel to sustain the combustion front. The process operates in a stable and continuous manner. All of the wells and surface facilities are conventional oil and natural gas materials, equipment and processes. The *in-situ* reactions are well understood and are similar to those of a refinery coker.

How does THAI™ compare to SAGD – the current industry standard *in-situ* process?

THAI™ builds from, and improves upon the empirical success of SAGD technology. THAI™ offers many potential advantages over SAGD, including higher resource recovery (70–80 percent of the original oil-in-place), lower production and capital costs (one horizontal well and no water treating and handling), minimal usage of natural gas and fresh water, a partially upgraded crude oil product, reduced diluent requirements for transportation, and lower greenhouse gas emissions (estimated 34 percent lower CO_2 and nil NOX). The THAI™ process also has potential to operate in reservoirs that are lower in pressure, shalier, lower in quality, thinner and deeper than SAGD.

Potential THAI™ Benefits (vs. SAGD and other in-situ methods)

Resource Recovery Advantage

- high resource recovery (THAI™ – 70-80 percent versus approximately 50% for SAGD)
- potential to operate in heavy oil reservoirs where SAGD would not be economic

THAI™ Oil Quality

- upgraded in-situ from 10° to 20° API
- viscosity reduced to 45 centistokes at 15°C
- reduced metals
- reduced sulphur
- reduced bottoms
- increased saturates
- compatible with a wide range of refineries

Estimated Netback Advantage

- US$6–US$7 per barrel higher netbacks than SAGD
- much lower diluent requirements
- lower natural gas usage
- lower non-fuel operating costs

Capital Cost Advantage

- capital cost savings of approximately $3,000–$4,000 (30 percent) per flowing barrel versus existing and developing SAGD projects.
- 50,000 barrels-of-oil-per-day commercial project estimated to cost $400 million.

Environmental Benefits

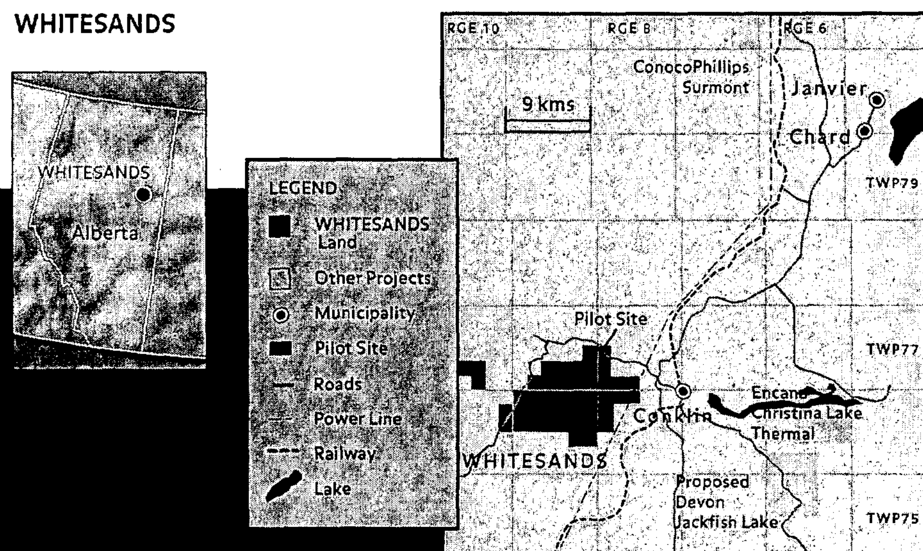
- minimal fresh water used
- minimal natural gas consumed
- 85 percent less water produced; produced water is industrial quality
- heat recovery can generate electricity
- upgraded oil reduces diluent and refining requirements
- 34 percent less CO_2 emitted than SAGD

Evolution of the WHITESANDS Project

We began 2003 with a promising technology and a significant land base in a prime oil sands fairway. Throughout the year much was accomplished. We advanced key aspects of the THAI™ process which further substantiated the fundamental aspects of the technology. We identified a significant, high-quality bitumen resource on our lands. Most significantly, we filed a comprehensive pilot project application which received approval from the Alberta Energy and Utilities Board (AEUB) and Alberta Environment (AENV) in February 2004. The approval was the culmination of rigorous technical and environmental scrutiny by the regulatory authorities, which evaluated not only the project's compliance with respect to oil sands regulations, but also its technical merits. This significant accomplishment was completed in a very short time frame when compared to other projects and at

a minimum cost, resulting in considerable potential value for Petrobank shareholders.

The Company's 45 sections of 100-percent working-interest oil sands leases in the Christina Lake region of Alberta are located in the oil sands fairway and are near Devon's proposed Jackfish project and Encana's Christina Lake project. OPTI-Nexen lands, for their future Jackfish project, are due east and contiguous with our lands. In 2003 we completed a 20-square-kilometre 3-D seismic survey and cored three stratigraphic test wells in the area of the pilot project. In early 2004 Fekete Associates completed an independent resource evaluation that incorporated all existing well data over the leases plus our work to date. Fekete estimates a bitumen resource of more than one billion barrels-in-place, including 831 million barrels in the Middle McMurray sands and 484 million barrels in the Upper McMurray sands. The bitumen resource on the WHITESANDS leases is sufficient to support a THAI™ commercial development and is also ideal for a commercial SAGD projects.



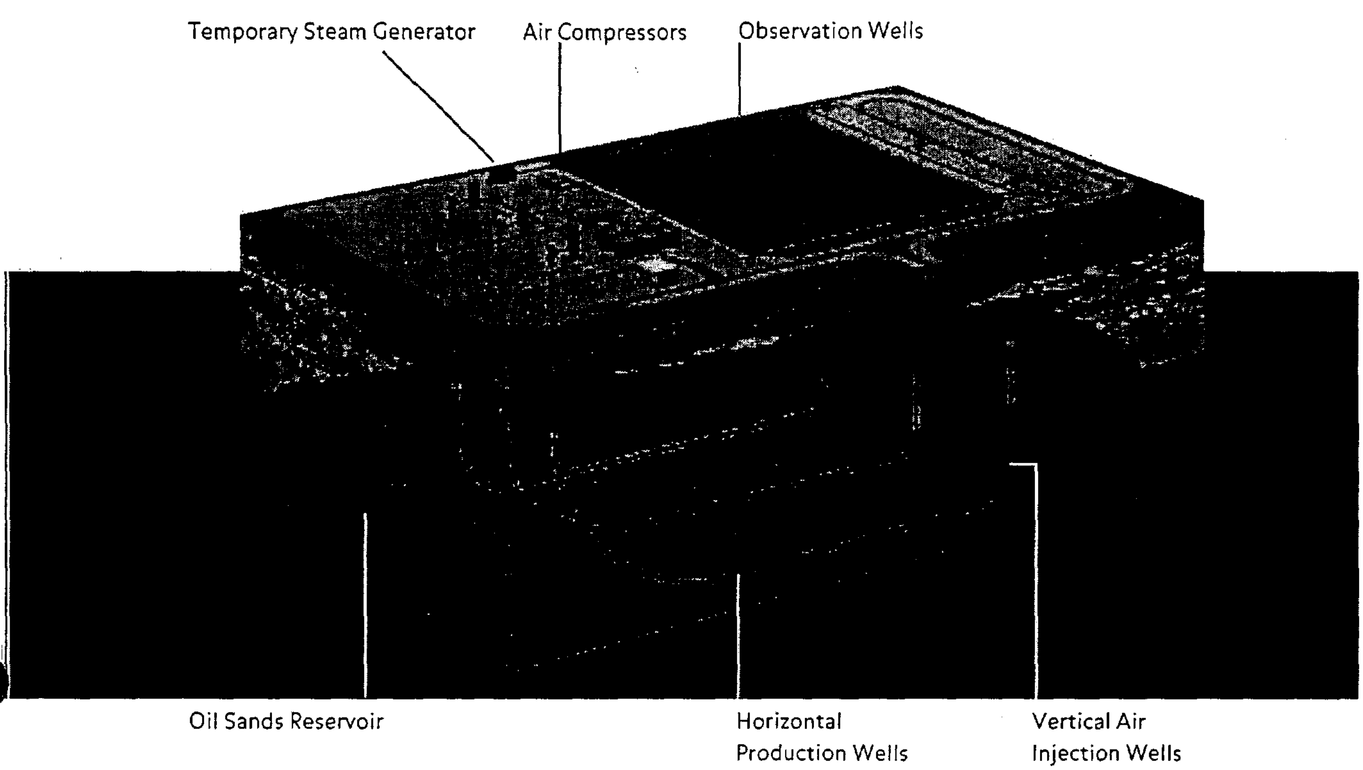
In 2003 a total of $4 million was invested to evaluate our lands and to develop the successful pilot project application. In addition, the pilot project was deemed eligible for SRED tax treatment whereby all eligible expenses are 100 percent deductible.

The pilot project design was engineered in 2003 and will consist of three horizontal wells (500 metres long and 100 metres apart), three vertical air injection wells and 19 vertical observation wells (17 for temperature and two for pressure observations). Peak production from the three wells is estimated at 1,800 barrels per day or 600 barrels of oil per day per horizontal well. The total capital cost of the project is estimated to be Cdn$30 million. First results are expected in early 2005. With early positive results the design of a commercial project could begin as early as 2006.

How will the pilot be financed?

We have entered into an agency agreement with TD Securities Inc. and Tristone Capital Inc. to arrange private equity financing for the estimated $30 million capital cost of the pilot project. The financing will be effected by the issuance of up to a 40 percent equity interest in Petrobank's subsidiary, WHITESANDS INSITU Ltd.

PILOT PROJECT DESIGN LAYOUT



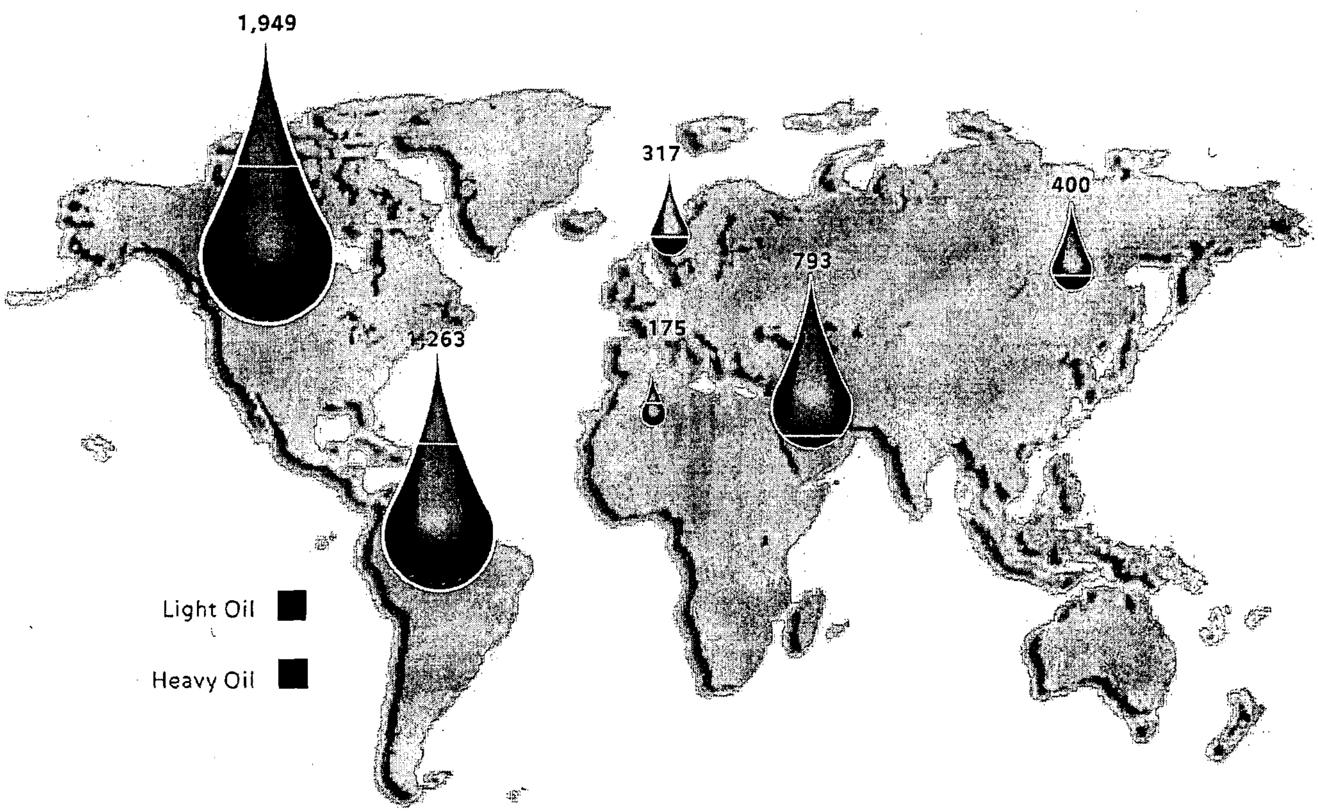
Describe the economic implications of a commercial THAI™ project.

The estimated capital cost of a 50,000-barrel-per-day THAI™ project is $400 million. A successful commercial project of this scale could generate annual net cash flow of approximately $250 million at US$26 per barrel WTI Petrobank's shareholders stand to benefit significantly given the commercial opportunity on our existing land base, combined with our future ability to license the technologies and capture additional resource domestically and internationally.

Applying THAI™/CAPRI™

World Oil Resources-in-Place

(billions of barrels)



What is the application of THAI™/CAPRI™ worldwide?

The THAI™ process is a global technology with the potential to be applied to the majority of the world's heavy oil accumulations, especially those in the Canadian oil sands and the Orinoco heavy oil belt in Venezuela. In addition to implementing the Canadian pilot project, the Company is evaluating potential for various international projects. Petrobank is active in Colombia and Venezuela, where there is significant interest in the potential of the THAI™ process.

Operations Statistical Review

Land

The Company currently holds 624,000 (515,000 net) acres in western Canada, including 150,000 fee-title acres. These fee-title lands are not encumbered by any lessor royalties or expiry constraints. In Colombia, our Orito and Neiva incremental production blocks cover 45,000 gross acres and our Central Colombia exploration block covers 400,000 gross acres.

Land Summary (thousands of acres)

At December 31, 2003

	Developed		Undeveloped		Total		Avg.
Area	Gross	Net	Gross	Net	Gross	Net	WI%
Alberta	73	42	237	189	310	231	75%
Saskatchewan	8	7	227	218	235	225	96%
British Columbia	–	–	38	23	38	23	61%
Other	1	0.3	40	36	41	36	88%
Total Canada	**82**	**49**	**542**	**466**	**624**	**515**	**83%**
Colombia	45	36	400	133	445	169	38%
Total Company	**127**	**85**	**942**	**599**	**1,069**	**684**	**64%**

2003 Drilling Program

Canada

	Exploratory		Development		Total	
Status	Gross	Net	Gross	Net	Gross	Net
Oil	4	1.8	19	18.4	23	20.2
Gas	16	12.1	16	10.4	32	22.5
Successful	20	13.9	35	28.8	55	42.7
Dry	9	8.4	5	4.7	14	13.1
Total Canada	**29**	**22.3**	**40**	**33.5**	**69**	**55.8**
Success rate	69%	62%	88%	86%	80%	77%

Colombia

	Exploratory		Development		Total	
Status	Gross	Net	Gross	Net	Gross	Net
Oil	–	–	10	7.3	10	7.3
Dry	–	–	–	–	–	–
Total Colombia	**–**	**–**	**10**	**7.3**	**10**	**7.3**
Success rate			100%	100%	100%	100%

Production

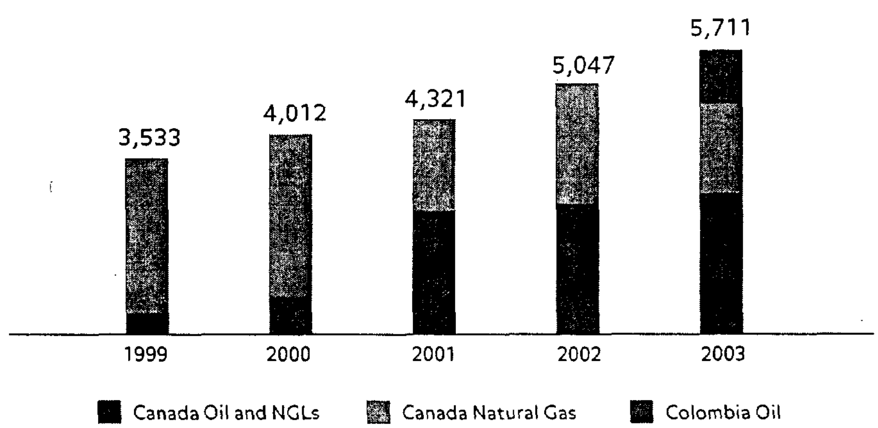
The following table summarizes the Company's production by core area in 2003 and the fourth quarter of 2003, both including and excluding production from the Company's Wapella (Southeast Saskatchewan) property that was sold in January 2004.

Average Daily Production

	Oil and NGLs (bbls/d)		Natural Gas (mcf/d)		Total (boepd)	
	2003	Q4 2003	2003	Q4 2003	2003	Q4 2003
Nevis/Red Willow	66	282	3,465	11,936	643	2,271
Southeast Saskatchewan	1,432	1,354	-	-	1,432	1,354
Western Saskatchewan	635	737	63	87	645	751
Northwest Alberta	328	263	3,499	1,048	911	438
Jumpbush	50	58	1,540	2,201	307	425
Other	329	237	2,254	2,430	705	642
Total - Canada	2,840	2,931	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 Company	3,908	4,305	10,821	17,702	5,711	7,255
Pro-forma excluding Wapella	2,506	2,981	10,821	17,702	4,309	5,931

Five Year Production History

(boepd)



Reserves

Petrobank's Canadian and Colombian reserves evaluation at January 1, 2004 was performed by Gilbert Laustsen Jung Associates Ltd. (GLJ) and is summarized as follows:

Canada

	Reserve Volumes					
	Light and Medium Oil (mbbls)	Heavy Oil (mbbls)	Natural Gas Liquids (mbbls)	Natural Gas (bcf)	Mboe (6:1)	NPV 10% ($MM) [1]
Proved producing	3,910	659	258	19.4	8,067	96.3
Total proved	4,672	1,123	354	28.0	10,821	117.1
Total proved and probable	6,674	2,345	450	39.1	15,995	156.2

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.

Canada (excluding Wapella)

	Reserve Volumes					
	Light and Medium Oil (mbbls)	Heavy Oil (mbbls)	Natural Gas Liquids (mbbls)	Natural Gas (bcf)	Mboe (6:1)	NPV 10% ($MM) [1]
Proved producing	1,282	659	258	19.4	5,439	73.6
Total proved	1,319	1,123	354	28.0	7,468	90.6
Total proved and probable	1,984	2,345	450	39.1	11,305	119.4

Colombia

The Colombian reserves evaluation as at January 1, 2004, 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.

	Light and Medium Oil (mbbls)	NPV 10% (US$MM) [1]
Proved producing	2,149	26.1
Total proved	4,062	40.1
Total proved and probable	6,836	60.9

(1) Based on the April 1, 2004 GLJ 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.

Reserves Reconciliation

January 1, 2003 probable reserves are risked at 50 percent to allow comparison to the new definition of proved plus probable reserves under NI 51-101.

After accounting for dispositions totaling 4.8 million boe, Petrobank's Canadian proved reserves year-over-year decreased by 25 percent to 7.5 million boe. Canadian total proved plus probable reserves decreased by 17 percent to 11.3 million boe, after accounting for dispositions of 6.8 million boe.

Canada

	Total Proved (mboe)	Proved and Probable (mboe)
January 1, 2003 reserves	9,973	13,694
2003 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
Wapella disposition	(3,353)	(4,690)
Pro-forma January 1, 2004 reserves	7,468	11,305

Colombia

Petrobank's Colombian total proved reserves year-over-year decreased by 12 percent to 4.1 million barrels. Colombian total proved plus probable reserves increased by six percent to 6.8 million barrels.

	Total Proved (mboe)	Proved and Probable (mboe)
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

Net Capital Expenditures by Business Unit

	2003			
($000s)	Canada	Colombia	Heavy Oil	Total
Drilling and completions	$ 26,321	$ 62,949	$ 758	$ 90,028
Facilities and equipment	5,418	3,391	–	8,809
Land	3,280	–	273	3,553
Seismic, net of sales	(1,712)	–	1,238	(474)
Asset acquisitions	5,473	–	–	5,473
Other	1,917	5,002	563	7,482
Pilot design, technology acquisition and engineering	–	–	1,189	1,189
Asset dispositions	(20,448)	–	–	(20,448)
Net expenditures on oil and natural gas assets	$ 20,249	$ 71,342	$ 4,021	$ 95,612

Finding, Development and Acquisition Costs (FD&A)

January 1, 2003 probable reserves are risked at 50 percent to allow comparison to the new definition of proved plus probable reserves under NI 51-101.

Canada

	2003	Three-Year
Capital expenditures ($000s) – Canada	**40,697**	92,733
Asset dispositions	**(20,448)**	(84,374)
Corporate acquisitions	**39,559**	154,881
Total expenditures	**59,808**	163,240
Change in future costs to develop ($000s)		
Proved	**4,395**	14,444
Proved and probable	**7,159**	24,113
Total costs ($000s)		
Proved	**64,203**	177,684
Proved and probable	**66,967**	187,353
Net reserve additions (mboe)		
Proved	**2,547**	15,663
Proved and probable	**4,000**	20,742
FD&A costs ($ per boe)		
Proved	**25.21**	11.34
Proved and probable	**16.74**	9.03

Colombia

	2003	2002 & 2003
Capital expenditures ($000s) – Colombia	**71,342**	86,977
Change in future costs to develop ($000s)		
Proved	**(17,129)**	14,400
Proved and probable	**(14,453)**	24,400
Total costs ($000s)		
Proved	**54,213**	101,377
Proved and probable	**56,889**	111,377
Net reserve additions (mboe - 6:1)		
Proved	**(167)**	4,452
Proved and probable	**751**	7,226
FD&A costs ($ per boe)		
Proved	**N/A**	22.77
Proved and probable	**75.75**	15.41

Net Asset Value

(millions, except per share amounts) As at December 31,		2003
Proved and probable reserves, discounted at 10% before tax		
Canada	$	**119.4**
Colombia		**81.2**
Canadian undeveloped land and proprietary seismic – ($50/acre)		**25.3**
Wapella sale proceeds		**36.0**
Fair value of financial commodity hedging contracts (1)		**(5.2)**
Secured debt and working capital deficit		**(57.5)**
Carrying value of 9% subordinated debt (2)		**(93.4)**
Basic net asset value	$	**105.8**
Proceeds on exercise of in-the-money stock options and warrants (3)		**5.7**
Diluted net asset value	$	**111.5**
Basic common shares outstanding		**54.5**
Net asset value per basic common share	$	**1.94**
Diluted common shares outstanding (3)		**57.2**
Net asset value per diluted common share	$	**1.95**

(1) Petrobank's physical natural gas sale and transportation contracts are reflected in GLJ's reserve economics.

(2) At December 31, 2003 face value and trading value were $100.4 million and $93.4 million, respectively.

(3) Assumes that 2,704,000 in-the-money stock options are exercised for proceeds of $5.7 million.

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 Q4	2003 Q3	2003 Q2	2003 Q1	2002 Q4	2002 Q3	2002 Q2	2002 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.

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

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" "SIGNED"

James D. Tocher
Chairman

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

Corporate Information

Head Office
2600, 240-4th Avenue S.W.
Calgary AB T2P 4H4
Tel: (403) 750-4400
Fax: (403) 266-5794

Directors
James D. Tocher (1)(3)
Chairman
Calgary, Alberta

John A. Brussa (1)(2)
Calgary, Alberta

M. Bruce Chernoff (1)(2)(3)
Calgary, Alberta

Louis L. Frank
North Woodstock,
New Hampshire

Kenneth R. McKinnon
Calgary, Alberta

Jerald L. Oaks (2)(3)
Denver, Colorado

John D. Wright
Calgary, Alberta

(1) Member of the Compensation Committee
(2) Member of the Audit Committee
(3) Member of the Reserves Committee

Officers
John D. Wright
President and
Chief Executive Officer

Steven J. Benedetti
Vice President Latin America

Chris J. Bloomer
Vice President Heavy Oil and
Chief Financial Officer

Garry T. Hides
Vice President Land

Rene J. Laprade
Vice President Operations

Doreen M. Scheidt
Corporate Controller

R. Gregg Smith
Vice President Canada

Bankers
Bank of Nova Scotia
Calgary, Alberta

Auditors
Deloitte & Touche LLP
Calgary, Alberta

Reserve Engineers
Gilbert Laustsen Jung Associates Ltd.
Calgary, Alberta

Exchange Listing
The Toronto Stock Exchange
Symbols: PBG, PBG.N
(PBG.NT.A, on July 14, 2004)

Registrar and Transfer Agent
Computershare Investor Services
Calgary, Alberta

Legal Counsel
Burnet, Duckworth and Palmer LLP
Calgary, Alberta

Abbreviations

bbls	barrels
bcf	billion cubic feet
boe	barrel of oil equivalent
bopd	barrels of oil per day
boepd	barrel of oil equivalent per day
bpd	barrels per day
CBM	coalbed methane
GJ	Gigajoules
GLJ	Gilbert, Laustsen Jung Associates Ltd. (Independant Reserve Engineers)
IPC	Incremental Production Contract
mbbl	thousand barrels
mboe	thousand barrels of oil equivalent
mcf	thousand cubic feet
mcfpd	mcf per day
mmbtu	millions of British thermal units
mmcf	million cubic feet
WI	working interest
WTI	West Texas Intermediate

Information requests and other investor relations inquiries can be directed to:

ir@petrobank.com

Additional corporate information can be obtained through the Company's website at: www.petrobank.com

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PETROBANK
ENERGY AND RESOURCES LTD.

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Calgary AB T2P 4H4
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Fax: (403) 266-5794
www.petrobank.com