

# COBRA VENTURE CORPORATION

## FORM 51-101F1

### STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

PREPARED ON MARCH 30, 2007

#### CURRENCY AND DEFINITIONS

In this Statement, unless otherwise noted, all dollar amounts are expressed in Canadian dollars.

“Cobra” or the “Corporation” means Cobra Venture Corporation.

#### FORWARD-LOOKING STATEMENTS

Certain statements contained in this Statement and in certain documents incorporated by reference into this Statement, constitute forward-looking statements. These statements relate to future events or the Corporation’s future performance. All statements other than statements of historical fact may be forward-looking statements. Forward-looking statements are often, but not always, identified by the use of words such as “seek”, “anticipate”, “plan”, “continue”, “estimate”, “expect”, “may”, “will”, “project”, “predict”, “potential”, “targeting”, “intend”, “could”, “might”, “should”, “believe” and similar expressions. These statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements. The Corporation believes that the expectations reflected in those forward-looking statements are reasonable but no assurance can be given that these expectations will prove to be correct and such forward-looking statements included in, or incorporated by reference into, this Statement should not be unduly relied upon. These statements speak only as of the date of this Statement or as of the date specified in the documents incorporated by reference into this Statement, as the case may be. The Corporation does not intend, and does not assume any obligation, to update these forward-looking statements.

In particular, this Statement and the documents incorporated by reference contain forward-looking statements pertaining to the following:

- the quantity of reserves;
- oil and natural gas production levels;
- capital expenditure programs;
- projections of market prices and costs;
- supply and demand for oil and natural gas;
- expectations regarding the Corporation’s ability to raise capital and to continually add to reserves through acquisitions and development; and
- treatment under government regulatory and taxation regimes.

The Corporation’s actual results could differ materially from those anticipated in these forward-looking statements as a result of the risk factors set forth below and elsewhere in this Statement:

- volatility in market prices for oil and natural gas;
- liabilities and risks inherent in oil and natural gas operations;
- uncertainties associated with estimating reserves;

- competition for, among other things, capital, acquisitions of reserves, undeveloped lands and skilled personnel;
- incorrect assessments of the value of acquisitions;
- geological, technical, drilling and processing problems;
- fluctuations in foreign exchange or interest rates and stock market volatility; and
- changes in government regulations.

These factors should not be considered exhaustive.

## **PETROLEUM AND NATURAL GAS RESERVES**

### **Principal Properties**

**The following is a description of the Corporation's principal oil and natural gas properties as of December 31, 2006. The term "net", when used to describe the Corporation's share of production, means the total of the Corporation's working interest share before deducting royalties owned by others. Unless otherwise specified, gross and net acres and well count information are as at December 31, 2006. Reserve amounts are stated, before deduction of royalties, as at December 31, 2006 based on escalating cost and price assumptions as evaluated in the Forecast Prices and Costs Economic Evaluation of Certain Petroleum Reserves and Prospective Land Holdings Owned by Cobra Venture Corporation Report dated effective December 31, 2006 (as defined below) prepared by Reliance Engineering Group Ltd. (see "Statement of Reserves Data and Other Oil and Gas Information").**

### **STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION**

The statement of reserves data and other oil and gas information set forth below (the "Statement") is dated March 30, 2007. The effective date of the Statement is December 31, 2006 and the preparation date of the Statement is March 30, 2007.

#### **Disclosure of Reserves Data**

The reserves data set forth below (the "Reserves Data") is based upon an evaluation by Reliance Engineering Group Ltd. ("Reliance") with an effective date of December 31, 2006 contained in a report of Cobra Venture Corporation dated March 30, 2007 (the "Cobra Report"). The Reserves Data summarizes the oil, liquids and natural gas reserves of the Corporation and the net present values of future net revenue for these reserves using constant prices and costs and forecast prices and costs. The Reserves Data conforms with the requirements of National Instrument 51-101 Standards of Disclosure for Oil and Gas Activities ("NI 51-101"). Additional information not required by NI 51-101 has been presented to provide continuity and additional information which we believe is important to the readers of this information. Reliance was engaged by Cobra to provide an evaluation of proved and proved plus probable reserves and no attempt was made to evaluate possible reserves.

All of the Corporation's reserves are in Canada and, specifically, in the province of Saskatchewan and Alberta.

**It should not be assumed that the estimates of future net revenues presented in the tables below represent the fair market value of the reserves. There is no assurance that the constant prices and costs assumptions and forecast prices and costs assumptions will be attained and variances could be material.**



**FUTURE NET REVENUE  
BY PRODUCTION GROUP  
as of December 31, 2006  
CONSTANT PRICES AND COSTS**

<b>RESERVES CATEGORY</b>	<b>PRODUCTION GROUP</b>	<b>FUTURE NET REVENUE BEFORE INCOME TAXES (discounted at 10%/year) (M\$)</b>
Proved Reserves	Light and Medium Crude Oil (including solution gas and other by-products)	621
	Heavy Oil (including solution gas and other by-products)	Nil
	Natural Gas (including by-products but excluding solution gas from oil wells)	Nil
Proved Plus Probable Reserves	Light and Medium Crude Oil (including solution gas and other by-products)	1,683
	Heavy Oil (including solution gas and other by-products)	Nil

*Reserves Data (Forecast Prices and Costs)*

**SUMMARY OF OIL AND GAS RESERVES  
AND NET PRESENT VALUES OF FUTURE NET REVENUE  
as of December 31, 2006  
FORECAST PRICES AND COSTS**

<b>RESERVES CATEGORY</b>	<b>RESERVES</b>							
	<b>LIGHT AND MEDIUM OIL</b>		<b>HEAVY OIL</b>		<b>NATURAL GAS</b>		<b>NATURAL GAS LIQUIDS</b>	
	<b>Gross (Mbbl)</b>	<b>Net (Mbbl)</b>	<b>Gross (Mbbl)</b>	<b>Net (Mbbl)</b>	<b>Gross (MMcf)</b>	<b>Net (MMcf)</b>	<b>Gross (Mbbl)</b>	<b>Net (Mbbl)</b>
<b>PROVED</b>								
Developed Producing	Nil	10.9	Nil	Nil	Nil	Nil	Nil	Nil
Developed Non-Producing	Nil	Nil	Nil	Nil	Nil	Nil	Nil	Nil
Undeveloped	Nil	Nil	Nil	Nil	Nil	Nil	Nil	Nil
<b>TOTAL PROVED</b>	Nil	10.9	Nil	Nil	Nil	Nil	Nil	Nil
<b>PROBABLE</b>	Nil	19.0	Nil	Nil	75	66	Nil	Nil
<b>TOTAL PROVED PLUS PROBABLE</b>	Nil	29.9	Nil	Nil	75	66	Nil	Nil

<b>NET PRESENT VALUES OF FUTURE NET REVENUE</b>										
<b>RESERVES CATEGORY</b>	<b>BEFORE INCOME TAXES DISCOUNTED AT (%/year)</b>					<b>AFTER INCOME TAXES DISCOUNTED AT (%/year)</b>				
	<b>0 (M\$)</b>	<b>5 (M\$)</b>	<b>10 (M\$)</b>	<b>15 (M\$)</b>	<b>20 (M\$)</b>	<b>0 (M\$)</b>	<b>5 (M\$)</b>	<b>10 (M\$)</b>	<b>15 (M\$)</b>	<b>20 (M\$)</b>
PROVED										
Developed	713	662	618	581	550	579	539	505	476	452
Producing										
Developed	Nil	Nil	Nil	Nil	Nil	Nil	Nil	Nil	Nil	Nil
Non-Producing										
Undeveloped	Nil	Nil	Nil	Nil	Nil	Nil	Nil	Nil	Nil	Nil
TOTAL PROVED	713	662	618	581	550	579	539	505	476	452
PROBABLE	1,524	1,373	1,254	1,157	1,077	1,033	927	844	777	721
TOTAL PROVED PLUS PROBABLE	2,237	2,035	1,872	1,738	1,627	1,612	1,466	1,349	1,253	1,173

**TOTAL FUTURE NET REVENUE  
(UNDISCOUNTED)  
as of December 31, 2006  
FORECAST PRICES AND COSTS**

<b>RESERVES CATEGORY</b>	<b>REVENUE (M\$)</b>	<b>ROYALTIES (M\$)</b>	<b>OPERATING COSTS (M\$)</b>	<b>DEVELOPMENT COSTS (M\$)</b>	<b>WELL ABANDON- MENT COSTS (M\$)</b>	<b>FUTURE NET REVENUE BEFORE INCOME TAXES (M\$)</b>	<b>INCOME TAXES (M\$)</b>	<b>FUTURE NET REVENUE AFTER INCOME TAXES (M\$)</b>
Proved Reserves	738	Nil	24	Nil	Nil	714	135	579
Proved Plus Probable Reserves	2,583	69	246	20	11	2,237	625	1,612

**FUTURE NET REVENUE  
BY PRODUCTION GROUP  
as of December 31, 2006  
FORECAST PRICES AND COSTS**

<b>RESERVES CATEGORY</b>	<b>PRODUCTION GROUP</b>	<b>FUTURE NET REVENUE BEFORE INCOME TAXES (discounted at 10%/year) (M\$)</b>
Proved Reserves	Light and Medium Crude Oil (including solution gas and other by-products)	618
	Heavy Oil (including solution gas and other by-products)	Nil
	Natural Gas (including by-products but excluding solution gas from oil wells)	Nil
Proved Plus Probable Reserves	Light and Medium Crude Oil (including solution gas and other by-products)	1,674
	Heavy Oil (including solution gas and other by-products)	Nil
	Natural Gas (including by-products but excluding solution gas from oil wells)	198

## Definitions and Other Notes

In the tables set forth above in “Disclosure of Reserves Data” and elsewhere in this Statement the following definitions and other notes are applicable:

1. “Gross” means:
  - (a) in relation to the Corporation’s interest in production and reserves, its “Corporation gross reserves”, which are the Corporation’s interest (operating and non-operating) share before deduction of royalties and without including any royalty interest of the Corporation;
  - (b) in relation to wells, the total number of wells in which the Corporation has an interest; and
  - (c) in relation to properties, the total area of properties in which the Corporation has an interest.
2. “Net” means:
  - (a) in relation to the Corporation’s interest in production and reserves, its “Corporation gross reserves”, which are the Corporation’s interest (operating and non-operating) share after deduction of royalties obligations, plus the Corporation’s royalty interest in production or reserves.
  - (b) in relation to wells, the number of wells obtained by aggregating the Corporation’s working interest in each of its gross wells; and
  - (c) in relation to the Corporation’s interest in a property, the total area in which the Corporation has an interest multiplied by the working interest owned by the Corporation.
3. Definitions used for reserve categories are as follows:

The following definitions apply to both estimates of individual reserves entities and the aggregate of reserves for multiple entities.

### Reserve Categories

Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, from a given date forward, based on

- (a) analysis of drilling, geological, geophysical and engineering data;
- (b) the use of established technology; and
- (c) specified economic conditions (see the discussion of “Economic Assumptions” below).

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

- (a) Proved reserves are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.
- (b) Probable reserves are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

“Economic Assumptions” will be the prices and costs used in the estimate, namely:

- (a) constant prices and costs as at the last day of the Corporation’s financial year; and
- (b) forecast prices and costs.

### **Development and Production Status**

Each of the reserve categories (proved and probable) may be divided into developed and undeveloped categories:

- (a) Developed reserves are those reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (for example, when compared to the cost of drilling a well) to put the reserves on production. The developed category may be subdivided into producing and non-producing.
  - (i) Developed producing reserves are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut-in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.
  - (ii) Developed non-producing reserves are those reserves that either have not been on production, or have previously been on production, but are shut-in, and the date of resumption of production is unknown.
- (b) Undeveloped reserves are those reserves expected to be recovered from known accumulations where a significant expenditure (for example, when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves classification (proved, probable) to which they are assigned.

**In multi-well pools it may be appropriate to allocate total pool reserves between the developed and undeveloped categories or to subdivide the developed reserves for the pool between developed producing and developed non-producing. This allocation should be based on the estimator’s assessment as to the reserves that will be recovered from specific wells, facilities and completion intervals in the pool and their respective development and production status.**

### **Levels of Certainty for Reported Reserves**

The qualitative certainty levels referred to in the definitions above are applicable to individual reserve entities (which refers to the lowest level at which reserves calculations are performed) and to reported reserves (which refers to the highest level sum of individual entity estimates for which reserves are presented). Reported reserves should target the following levels of certainty under a specific set of economic conditions:

- (a) at least a 90 percent probability that the quantities actually recovered will equal or exceed the estimated proved reserves; and
- (b) at least a 50 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable reserves.

A qualitative measure of the certainty levels pertaining to estimates prepared for the various reserves categories is desirable to provide a clearer understanding of the associated risks and uncertainties. However, the majority of reserves estimates will be prepared using deterministic methods that do not provide a mathematically derived quantitative measure of probability. In principle, there should be no difference between estimates prepared using probabilistic or deterministic methods.

4. Forecast prices and costs

Future prices and costs that are:

- (a) generally acceptable as being a reasonable outlook of the future; and
- (b) if and only to the extent that, there are fixed or presently determinable future prices or costs to which the Corporation is legally bound by a contractual or other obligation to supply a physical product, including those for an extension period of a contract that is likely to be extended, those prices or costs rather than the prices and costs referred to in paragraph (a).

The forecast summary table under “- Pricing Assumptions” identifies benchmark reference pricing that apply to the Corporation.

5. Constant prices and costs

Prices and costs used in an estimate that are:

- (a) the Corporation’s prices and costs as at the effective date of the estimation, held constant throughout the estimated lives of the properties to which the estimate applies; and
- (b) if, and only to the extent that, there are fixed or presently determinable future prices or costs to which the Corporation is legally bound by a contractual or other obligation to supply a physical product, including those for an extension period of a contract that is likely to be extended, those prices or costs rather than the prices and costs referred to in paragraph (a).

For the purposes of paragraph (a), the Corporation’s prices are the posted prices for oil and the spot price for gas, after historical adjustments for transportation, gravity and other factors..

6. Future income tax expense

Future income tax expenses estimate:

- (a) making appropriate allocations of estimated unclaimed costs and losses carried forward for tax purposes;
- (b) without deducting estimated future costs that are not deductible in computing taxable income;
- (c) taking into account estimated tax credits and allowances;
- (d) applying to the future pre-tax net cash flows relating to the Corporation’s oil and gas activities the appropriate year-end statutory rates, taking into account future tax rates already legislated.

7. “Development well” means a well that is not a development well, a service well or a stratigraphic test well.

8. “Development costs” means costs incurred to obtain access to reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas from reserves. More specifically, development costs, including applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

- (a) gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground draining, road building, and relocating public roads, gas lines and power lines, pumping equipment and wellhead assembly;

- (b) drill and equip development wells, development type stratigraphic test wells and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment and wellhead assembly;
  - (c) acquire, construct and install production facilities such as flow lines, separators, treaters, heaters, manifolds, measuring devices and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems; and
  - (d) provide improved recovery systems.
9. “Exploration well” means a well drilled inside the established limits of an oil and gas reservoir, or in close proximity to the edge of the reservoir, to the depth of a stratigraphic horizon known to be productive.
10. “Exploration costs” means costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects that may contain oil and gas reserves, including costs of drilling exploratory wells and exploratory type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property and after acquiring the property. Exploration costs, which include applicable operating costs of support equipment and facilities and other costs of exploration activities, are:
- (a) costs of topographical, geochemical, geological and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews and others conducting those studies;
  - (b) costs of carrying and retaining unproved properties, such as delay rentals, taxes (other than income and capital taxes) on properties, legal costs for title defence, and the maintenance of land and lease records;
  - (c) dry hole contributions and bottom hole contributions;
  - (d) costs of drilling and equipping exploratory wells; and
  - (e) costs of drilling exploratory type stratigraphic test wells.
11. “Service well” means a well drilled or completed for the purpose of supporting production in an existing field. Wells in this class are drilled for the following specific purposes: gas injection (natural gas, propane, butane or flue gas), water injection, steam injection, air injection, salt water disposal, water supply for injection, observation or injection for combustion.
12. Numbers may not add due to rounding.
13. The estimates of future net revenue presented in the tables above do not represent fair market value.

### **Pricing Assumptions**

The following sets forth the benchmark reference prices, as at December 31, 2006, reflected in the Reserves Data. These price assumptions were provided to the Corporation by Reliance Engineering Group Ltd., the Corporation’s independent qualified reserves evaluator.

**SUMMARY OF PRICING ASSUMPTIONS  
as of December 31, 2006  
CONSTANT PRICES AND COSTS**

Year	OIL <sup>(1)</sup>						
	WTI Cushing Oklahoma (\$US/bbl)	Edmonton Par Price 40° API (\$Cdn/bbl)	Hardisty Heavy 12° API (\$Cdn/bbl)	Cromer Medium 29.3° API (\$Cdn/bbl)	NATURAL GAS <sup>(1)</sup> AECO Gas Price (\$Cdn/MMBtu)	NATURAL GAS LIQUIDS FOB <sup>(1)</sup> Field Gate (\$Cdn/BBL)	EXCHANGE RATE <sup>(2)</sup> (\$US/\$Cdn)
Historical <sup>(3)</sup>							
2006	61.98	68.59	42.57	59.90	7.96	58.02	0.87

Notes:

- (1) This summary table identifies benchmark reference pricing schedules that might apply to a *reporting issuer*.
- (2) The exchange rate used to generate the benchmark reference prices in this table.
- (3) As at December 31.

**SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS  
as of December 31, 2006  
FORECAST PRICES AND COSTS**

Year	OIL <sup>(1)</sup>							INFLATION RATES <sup>(2)</sup> %/Year	EXCHANGE RATE <sup>(3)</sup> (\$US/\$Cdn)
	WTI Cushing Oklahoma (\$US/bbl)	Edmonton Par Price 40° API (\$Cdn/bbl)	Hardisty Heavy 12° API (\$Cdn/bbl)	Cromer Medium 29.3° API (\$Cdn/bbl)	NATURAL GAS <sup>(1)</sup> AECO Gas Price (\$Cdn/MMBtu)	NATURAL GAS LIQUIDS FOB <sup>(1)</sup> Field Gate (\$Cdn/BBL)			
Forecast									
2007	62.00	70.25	39.25	61.25	7.00	59.10	1.50	0.87	
2008	60.00	68.00	40.00	59.25	7.25	55.85	1.50	0.87	
2009	58.00	65.75	39.75	57.25	7.55	54.05	1.50	0.87	
2010	57.00	64.50	39.75	56.00	7.60	53.00	1.50	0.87	
2011	57.00	64.50	40.25	56.00	7.65	53.00	1.50	0.87	
2012	57.50	65.00	41.50	56.50	7.95	53.35	1.50	0.87	
Thereafter	1.5%	1.5%	1.5%	1.5%	1.5%	1.50	1.50	0.87	

Notes:

- (1) This summary table identifies benchmark reference pricing schedules that might apply to a *reporting issuer*.
- (2) Inflation rates for forecasting prices and costs.
- (3) Exchange rates used to generate the benchmark reference prices in this table.

Weighted average historical prices realized by the Corporation for the year ended December 31, 2006, were \$70.62/bbl for crude oil.

### Reconciliations of Changes in Reserves and Future Net Revenue

The following table sets forth a reconciliation of the Corporation's total net proved, probable and proved plus probable reserves as at December 31, 2006 against such reserves as at December 31, 2005 based on constant price and cost assumptions:

FACTORS	LIGHT AND MEDIUM OIL			HEAVY OIL			ASSOCIATED AND NON-ASSOCIATED GAS		
	Net Proved (Mbbbl)	Net Probable (Mbbbl)	Net Proved Plus Probable (Mbbbl)	Net Proved (Mbbbl)	Net Probable (Mbbbl)	Net Proved Plus Probable (Mbbbl)	Net Proved (MMcf)	Net Probable (MMcf)	Net Proved Plus Probable (MMcf)
	December 31, 2005 <sup>(1)</sup>	1.5	Nil	1.50	Nil	Nil	Nil	Nil	Nil
Extensions	Nil	Nil	Nil	Nil	Nil	Nil	Nil	Nil	Nil
Improved Recovery	Nil	Nil	Nil	Nil	Nil	Nil	Nil	Nil	Nil
Technical Revisions	2.2	Nil	2.2	Nil	Nil	Nil	Nil	Nil	Nil
Discoveries	9.5	19.0	28.5	Nil	Nil	Nil	Nil	66	66
Acquisitions	Nil	Nil	Nil	Nil	Nil	Nil	Nil	Nil	Nil
Dispositions	Nil	Nil	Nil	Nil	Nil	Nil	Nil	Nil	Nil
Economic Factors	Nil	Nil	Nil	Nil	Nil	Nil	Nil	Nil	Nil
Production	(2.3)	Nil	(2.3)	Nil	Nil	Nil	Nil	Nil	Nil
December 31, 2006	10.9	19.0	29.9	Nil	Nil	Nil	Nil	66	66

The following table sets forth a reconciliation of the Corporation's estimate of future net revenue discounted at 10%, attributable to net proved reserves:

PERIOD AND FACTOR	2006(M\$)
Estimated Future Net Revenue at Beginning of Year (December 31,2005)	73.5
Sales and Transfers of Oil and Gas Produced, Net of Production Costs and Royalties	(103.8)
Net Change in Prices, Production Costs and Royalties Related to Future Production	16.7
Changes in Previously Estimated Development Costs Incurred During the Period	Nil
Changes in Estimated Future Development Costs	Nil
Extensions and Improved Recovery	45.3
Discoveries	587.5
Acquisitions of Reserves	Nil
Dispositions of Reserves	Nil
Net Change Resulting from Revisions in Quantity Estimates	Nil
Accretion of Discount	1.8
Net Change in Income Taxes	Nil
Estimated Future Net Revenue at End of Year (December 31,2006)	620.8

## Significant Factors or Uncertainties

The process of estimating reserves is complex. It requires significant judgments and decisions based on available geological, geophysical, engineering and economic data. These estimates may change substantially as additional data from ongoing development activities and production performance becomes available and as economic conditions impacting oil and gas prices and costs change. The reserve estimates contained herein are based on current production forecasts, commodity prices and economic conditions. The Corporation's reserves are evaluated by Reliance Engineering Group Ltd., an independent petroleum engineering firm.

Estimates made are reviewed and revised, either upward or downward, as warranted by the new information. Revisions are often required due to changes in well performance, commodity prices, economic conditions and governmental restrictions. Although every reasonable effort is made to ensure that reserve estimates are accurate, reserve estimation is an inferential science. The Corporation's actual production, revenues, taxes, development and operating expenditures with respect to its reserves may vary from such estimates, and such variances could be material.

## Future Development Costs

The following table sets forth development costs deducted in the estimation of the Corporation's future net revenue attributable to the reserve categories noted below.

Year	Forecast Prices and Costs				Constant Prices and Costs	
	Proven Reserves		Proved Plus Probable Reserves		Proved Reserves	
	0%	10%	0%	10%	0%	10%
2007	Nil	Nil	20,250	19,307	20,250	19,307
2008	Nil	Nil	Nil	Nil	Nil	Nil
2009	Nil	Nil	Nil	Nil	Nil	Nil
2010	Nil	Nil	Nil	Nil	Nil	Nil
2011	Nil	Nil	Nil	Nil	Nil	Nil
Thereafter	Nil	Nil	Nil	Nil	Nil	Nil
Total	Nil	Nil	20,250	19,307	20,250	19,307

The Company has yet to earn significant revenues and is considered to be in the development stage. Continued operations of the Company are dependent on the Company's ability to receive continued financial support, complete public equity financing, or generate profitable operations in the future. The Corporation anticipates it will raise equity capital through a flow-through offering in 2007.

## Other Oil and Gas Information

### *Oil and Gas Properties*

#### **The Company has properties located in Alberta, Saskatchewan and British Columbia.**

#### **Viewfield/ Stoughton Area, Saskatchewan**

The Corporation holds free hold title and crown lease acreage in the Viewfield/Stoughton region of southeast Saskatchewan.

On October 19, 2006 the Company entered into a multi well farmout with Acero Energy of Calgary, Alberta covering the Company's lands located in the Viewfield/ Stoughton area of SE Saskatchewan.

Under the terms of the Cobra/Acero agreement, it is contemplated that Acero will drill a minimum of 3 wells to test the Frobisher and Bakken formations. The first test well, a Frobisher horizontal well was drilled, cased and producing as of early December 2006.

### Central, Alberta

The petroleum and natural gas assets of the Corporation in Alberta consist of approximately 2560 gross and 520 net undeveloped acres, held by crown lease expiring June 17, 2009 in Central, Alberta.

### Pembina Area, Alberta

On November 14, 2005, the Company entered into a Participation Agreement with an operating industry partner to participate in the drilling of an initial three exploration wells and earn a working interest in seven sections in the Pembina area of Alberta. The program will target multiple natural gas prospective zones. The Company has the right to earn a 27% working interest by paying 45% of all costs associated with the drilling program and will earn a 40% working interest in the prospect area comprised of seven sections or approximately 4,480 acres.

In the summer of 2006, the Company participated in the drilling of two natural gas wells. These wells encountered multiple natural gas zones, and a completion and tie-in program is currently under way. Pembina 01/05-19-48-8-W5M came on stream in November 2006 at approximately 300,000 to 500,000 cubic feet per day. Pembina 02/10-24-48-9-W5M is currently standing as a potential Belly River oil well. Cobra has earned a 27% net interest in each of these two wells.

### Inga Area N.E. British Columbia

Early in the summer of 2006, having reviewed seismic data, Cobra obtained one section of land underlying a significant structure in Northeastern British Columbia. Cobra's net working interest is 75%, and additional seismic structures are being reviewed with the intent to accumulate a large land position in the prospect area. A two well drill program is being planned for 2007.

The Company is continuing on a strategy of participating in large multi-well drilling programs as a non-operating participant and negotiating large net working interests. The Company employs a land acquisition strategy to build a meaningful land base for joint venture, farm-out or drilling participation.

### Oil And Gas Wells

The following table sets forth the number and status of wells in which the Corporation has a working interest/royalty interest as at December 31, 2006.

	Oil Wells				Natural Gas Wells			
	Producing		Non-Producing		Producing		Non-Producing	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta	Nil	Nil	Nil	Nil	Nil	Nil	2	0.54
British Columbia	Nil	Nil	Nil	Nil	Nil	Nil	Nil	Nil
Saskatchewan	5	0.62	Nil	Nil	Nil	Nil	Nil	Nil
Total	5	0.62	Nil	Nil	Nil	Nil	2	0.54

The following table sets out the Corporation's developed and undeveloped land holdings as at December 31, 2006.

	Developed Acres		Undeveloped Acres		Total Acres	
	Gross	Net	Gross	Net	Gross	Net
Alberta	Nil	Nil	2560	520	2560	520
British Columbia	Nil	Nil	640	480	640	480
Saskatchewan	320	320	1440	1080	1760	1400
Total	320	320	4640	2080	4560	2080

### Forward Contracts

The Company may use certain financial instruments to hedge its exposure to commodity price fluctuations on a portion of its crude oil and natural gas production. Cobra currently has no hedges in place.

### Tax Horizon

During the 2006 fiscal year, the Company issued common shares on a flow-through basis for gross proceeds of \$415,000. The flow-through agreements require the Company to renounce certain tax deductions for Canadian exploration expenditures incurred on the Company's oil and gas interests. The total expenditures were renounced, resulting in a future tax liability of \$145,000.

The Company has available for deduction against future taxable income non-capital losses of approximately \$Nil.

### Costs Incurred

The following tables summarize capital expenditures (net of incentives and net of certain proceeds and including capitalized general and administrative expenses) related to the Corporation's activities for the year ended November 30, 2006:

Property acquisition costs	
Proved properties	Nil
Undeveloped properties	\$175,051.00
Exploration costs	\$977,356.00
Development costs	Nil
Total	<u>\$1,152,407.00</u>

### Exploration and Development Activities

The following table sets forth the gross and net exploratory and development wells in which the Corporation participated during the year ended December 1, 2006:

	Gross	Net
Light and Medium Oil	Nil	Nil
Natural Gas	2	0.54
Service	Nil	Nil
Dry	Nil	Nil
Total:	<u>2</u>	<u>0.54</u>

The Corporation has entered into a participation agreement with an operating industry partner to participate in the drilling of an initial three exploration wells and earn a working interest in seven sections in the Pembina area of Alberta. The program will target multiple natural gas prospective zones. The Corporation has the right to earn a 27% working interest by paying 45% of all costs associated with the drilling program and will earn a 40% working interest in the prospect area comprised of seven sections or approximately 4,480 acres on which an additional nine target locations have been identified. Drilling operations commenced in late May, 2006 with an exploration budget of approximately \$500,000.00.

In the summer of 2006, the Company participated in the drilling of two natural gas wells. These wells encountered multiple natural gas zones, and a completion and tie-in program is currently under way. Pembina 01/05-19-48-8-W5M came on stream in November 2006 at approximately 300,000 to 500,000 cubic feet per day. Pembina 02/10-24-48-9-W5M is currently standing as a potential Belly River oil well. Cobra has earned a 27% net interest in each of these two wells.

**Production Estimates**

The following table sets out proven plus probable volume of the Corporation's production estimated for the year ended December 31, 2006 which is reflected in the estimate of future net revenue disclosed in the tables contained under "Disclosure of Reserves Data".

	<b>Light and Medium Oil (Bbls/d)</b>	<b>Heavy Oil (Bbls/d)</b>	<b>Natural Gas (Mcf/d)</b>	<b>Natural Gas Liquids (Bbls/d)</b>	<b>BOE (BOE/d)</b>
2007	37.9	Nil	19	Nil	41.0

**Production History, Prices Received And Capital Expenditures**

The following tables summarize certain information in respect of production, product prices received, royalties paid, operating expenses and resulting netback for the periods indicated below:

	<b>Quarter Ended</b>			
	<b>2006</b>			
(6:1)	<b>Mar. 31</b>	<b>June. 30</b>	<b>Sep. 30</b>	<b>Dec. 31</b>
<b>Average Daily Production</b>				
Light and Medium Crude Oil (Bbls/d)	3.7	3.3	3.0	6.7
Heavy Oil (Bbls/d)	Nil	Nil	Nil	Nil
Gas (Mcf/d)	Nil	Nil	Nil	Nil
NGLs (Bbls/d)	Nil	Nil	Nil	Nil
Combined (BOE/d)	Nil	Nil	Nil	Nil
<b>Average Price Received</b>				
Light and Medium Crude Oil (\$/Bbl)	66.97	75.73	77.09	62.62
Heavy Oil (Bbls/d)	Nil	Nil	Nil	Nil
Gas (\$/Mcf)	Nil	Nil	Nil	Nil
NGLs (Bbls/d)	Nil	Nil	Nil	Nil
Combined (\$/BOE)	Nil	Nil	Nil	Nil
<b>Royalties</b>				
Light and Medium Crude Oil (Bbls/d)	Nil	Nil	Nil	Nil
Heavy Oil (Bbls/d)	Nil	Nil	Nil	Nil
Gas (Mcf/d)	Nil	Nil	Nil	Nil
NGLs (Bbls/d)	Nil	Nil	Nil	Nil
Combined (BOE/d)	Nil	Nil	Nil	Nil
<b>Operating expenses (\$/BOE)</b>				
Light and Medium Crude Oil (Bbls/d)	Nil	Nil	Nil	Nil
Heavy Oil (Bbls/d)	Nil	Nil	Nil	Nil
Gas (Mcf/d)	Nil	Nil	Nil	Nil
NGLs (Bbls/d)	Nil	Nil	Nil	Nil
Combined (BOE/d)	Nil	Nil	Nil	Nil

(6:1)	<b>Quarter Ended</b>			
	<b>2006</b>			
	<b>Mar. 31</b>	<b>June. 30</b>	<b>Sep. 30</b>	<b>Dec. 31</b>
Netback Received (\$/BOE)				
Light and Medium Crude Oil (Bbls/d)	66.97	75.73	77.09	62.62
Heavy Oil (Bbls/d)	Nil	Nil	Nil	Nil
Gas (Mcf/d)	Nil	Nil	Nil	Nil
NGLs (Bbls/d)	Nil	Nil	Nil	Nil
Combined (BOE/d)	Nil	Nil	Nil	Nil

The following table indicates the Corporation's average daily production from its important fields for the year ended December 31, 2006:

	<b>Light and Medium Crude Oil (Bbls/d)</b>	<b>Heavy Oil (Bbls/d)</b>	<b>Gas (Mcf/d)</b>	<b>NGLS (Bbls/d)</b>	<b>BOE (BOE/d)</b>
Viewfield,Sask.	4.2	Nil	Nil	Nil	Nil
Total Saskatchewan	4.2	Nil	Nil	Nil	Nil
Total	4.2	Nil	Nil	Nil	Nil