BLUE PARROT ENERGY INC.

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION FORM 51-101 F1

PART 1 DATE OF STATEMENT

The relative dates of the company's statement of reserves data and other oil and gas information are.

Table 1-1
Relative Dates

Date of Statement	June 1st, 2006
Effective Date	October 31, 2005
Preparation Date	
Citadel Engineering Ltd.	May 12, 2005
Degolyer & MacNaughton Canada Limited.	May 5, 2005

PART 2 DISCLOSURE OF RESERVES DATA

Blue Parrot Energy Inc's. ("Blue Parrot" or the "Company") oil and gas reserves have been evaluated by Citadel Engineering Ltd. (Citadel) and Degolyer and MacNaughton Canada Limited (D&M). Citadel evaluated the Companies reserves in the Bonnie Glen area of Alberta whereas D&M evaluated the Companies reserves in the Antelope, Campbell, Pincher Creek and Ribstone areas of Alberta. The Citadel and D&M evaluations represents 90% and 10% respectively of the Companies net present value, discounted at 10 percent of the before income tax cash flow for the proved plus probable reserves.

Forecasts of reserves and associated net production revenues are forward looking statements based on judgements regarding future events. The accuracy of reserves estimates and associated economic analysis is, in part, a function of the quality and quantity of available data and of engineering and geological interpretation and judgement. These data should be accepted with the understanding that reservoir and financial performance subsequent to date of the of the estimates may necessitate revision.

All estimates of net present values of future net revenue ("NPV of FNR") are stated prior to provisions for indirect overhead and administrative costs. The NPV of FNR is calculated both before and after the deduction of income taxes. The income tax calculations include the Companies Tax Pools and Tax Loss Carry Forwards.

The Companies' Reserves and NPV of FNR as evaluated by Citadel and D&M are presented on a consolidated basis. Reserves and Net Present Values associated with the Proved Plus Probable Reserves represent the Companies "Best Estimates" of the reserves that are expected to be recovered and the Future Net Revenue associated with the sale and costs associated with the production of these reserves.

Reserves Data (Constant Prices and Costs)

Table 2-1

Summary of Oil and Gas Reserves
As of October 31, 2005
Constant Prices and Costs

	RESERVES							
	LIGHT & MEDIUM		NATURAL GAS 1)		NATURAL GAS		SULPHUR	
RESERVES CATEGORY	Gross	Net	Gross	Net	Gross	Net	Gross	Net
	Mbbl	Mbbl	MMcf	MMcf	Mbbl	Mbbl	MLT	MLT
PROVED								
Developed Producing	175	154	1,379	1,023	6	3	1	1
Developed Non-Producing	34	28	211	169	0	0	0	0
Undeveloped	198	162	2,454	2,059	0	0	0	0
TOTAL PROVED	407	344	4,044	3,251	6	3	1	1
PROBABLE	80	70	415	336	0	0	0	0
TOTAL PROVED + PROBABLE	487	414	4,459	3,587	6	3	1	1

(1) Natural Gas Reserves include Solution Gas and Non-Associated Gas.

Table 2-2
SUMMARY OF NET PRESENT
VALUES OF FUTURE NET REVENUE
AS OF OCTOBER 31, 2005
CONSTANT PRICES AND COSTS

	NET PRESENT VALUE OF FUTURE NET REVENUE									
	BEFORE INCOME TAX DISCOUNTED AT % Year					AFTER INCOME TAX DISCOUNTED AT % Year				
RESERVES CATEGORY	0	5	10	15	20	0	5	10	15	20
	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$
PROVED										
Developed Producing	17,082	13,277	10,830	9,141	7,918	10,966	8,535	6,944	5,862	5,076
Developed Non-Producing	2,951	2,391	1,984	1,679	1,444	1,999	1,637	1,373	1,174	1,020
Undeveloped	28,965	21,538	17,018	14,016	11,897	17,959	13,340	10,554	8,691	7,376
TOTAL PROVED	48,998	37,206	29,832	24,836	21,259	30,924	23,512	18,871	15,727	13,472,
PROBABLE	7,886	5,918	4,628	3,732	3,083	4,980	3,729	2,912	2,346	1,936
TOTAL PROVED PLUS PROBABLE	56,884	43,124	34,460	28,568	24,342	35,904	27,241	21,783	18,073	15,408

Table 2-3

TOTAL FUTURE NET REVENUE UNDISCOUNTED

AS OF OCTOBER 31, 2005

CONSTANT PRICES AND COSTS

Reserves Category	Revenue	Royalties Plus Mineral Taxes	Operating Costs	Development Costs	Well Abandonment Costs	Future Net Revenue Before Income Taxes	Incomes Taxes	Future Net Revenue After Income Taxes
	M$	M$	M$	M$	M$	M$	M$	M$
Proved	72,843	12,891	9,164	5751	1,213	49,000	18,075	30,924
Proved + Probable	83,040	14,404	9,8941	6341	1,222	56,886	20,980	35,905

Table 2-4
TOTAL FUTURE NET REVENUE
BY PRODUCTION GROUP
AS OF OCTOBER 31, 2005
CONSTANT PRICES AND COSTS

RESERVES CATEGORY	PRODUCTION GROUP	FUTURE NET REVENUE BEFORE INCOME TAX DISCOUNTED AT 10% (M$)
PROVED	LIGHT & MEDIUM OIL	13,896
	HEAVY OIL	--
	NATURAL GAS	15,936

	TOTAL	29,832
PROVED PLUS PROBABLE	LIGHT & MEDIUM OIL	16,966
	HEAVY OIL	--
	NATURAL GAS	17,493

	TOTAL	34,459

Reserves Data (Forecast Prices and Costs)

Table 2-5
SUMMARY OF OIL AND GAS RESERVES
AS OF OCTOBER 31, 2005
FORECAST PRICES AND COSTS

RESERVES CATEGORY	LIGHT AND MEDIUM OIL		NATURAL GAS		NATURAL GAS LIQUIDS		SULPHUR	
	GROSS Mbbl	NET Mbbl	GROSS MMscf	NET MMscf	GROSS Mbbl	NET Mbbl	GROSS LT	NET LT
PROVED								
Developed Producing	179	158	1,376	1,039	5.5	2.8	1,478	1,005
Developed Non- Producing	33.8	27.7	212	172	0	0	0	0
Undeveloped	198	162	2,454	2,059	0	0	0	0
TOTAL PROVED	410.8	347.7	4,042	3,270	5.5	2.8	1,478	1,005
PROBABLE	79.8	69.9	415	341	0.5	0.2	110	76
TOTAL PROVED + PROBABLE	490.6	417.6	4457	3611	6	3	1,588	1,081

Table 2-6

SUMMARY OF NET PRESENT VALUES
OF FUTURE NET REVENUE
AS OF OCTOBER 31, 2005
FORECAST PRICES AND COSTS

RESERVES CATEGORY	NET PRESENT VALUE OF FUTURE NET REVENUE									
	BEFORE INCOME TAX DISCOUNTED AT % Year					AFTER INCOME TAX DISCOUNTED AT % Year				
	0	5	10	15	20	0	5	10	15	20
	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$
PROVED										
Developed Producing	12,946	10,259	8,522	7,308	6,416	8,386	6,629	5,499	4,712	4,135
Developed Non-Producing	2,432	1,990	1,668	1,426	1,238	1,650	1,376	1,171	1,014	890
Undeveloped	21,560	16,202	12,933	10,753,	9,204	13,367	10,045	8,018	6,667,	5,706
TOTAL PROVED	36,938	28,451	23,123	19,487	16,858	23,403	18,050	14,688	12,393	10,731
PROBABLE	6,300	4,744	3,733	3,031	2,524	3,981	2,991	2,349	1,905	1,584
TOTAL PROVED PLUS PROBABLE	43,238	33,195	26,856	22,518	19,382	27,384	21,041	17,037	14,298	12,315

Table 2-7

TOTAL FUTURE NET REVENUE
UNDISCOUNTED

AS OF OCTOBER 31, 2005
FORECAST PRICES AND COSTS

Reserves Category	Revenue	Royalties Plus Mineral Taxes	Operating Costs	Development Costs	Well Abandonment Costs	Future Net Revenue Before Income Taxes	Incomes Taxes	Future Net Revenue After Income Taxes
	M$	M$	M$	M$	M$	M$	M$	M$
Proved	59,121	10,162	10,205	1,271	542	36,941	13,536	23,403
Proved + Probable	67,524	11,3561	11,0451	1,33	553	43,239	15,855	27,384

Table 2-8
TOTAL FUTURE NET REVENUE
BY PRODUCTION GROUP
AS OF OCTOBER 31, 2005
FORECAST PRICES AND COSTS

RESERVES CATEGORY	PRODUCTION GROUP	FUTURE NET REVENUE BEFORE INCOME TAX DISCOUNTED AT 10% (M$)
PROVED	LIGHT & MEDIUM OIL	11,124
	HEAVY OIL	--
	NATURAL GAS	11,999

	TOTAL	23,123
PROVED PLUS PROBABLE	LIGHT & MEDIUM OIL	13,439
	HEAVY OIL	--
	NATURAL GAS	13,417

	TOTAL	26,856

PART 3 PRICING ASSUMPTIONS

The following tables present the Pricing Assumptions used by Citadel and D&M on their respective evaluations.

Table 3-1
PRODUCT PRICE SCHEDULES
OCTOBER 31, 2005
CITADEL ENGINEERING LTD.

CONSTANT

YEAR	OIL $/bbl	GAS PRICE $/Mcf(1)	SULPHUR $/LT
2005	74.57	10.48	-

Notes: (1) Price based upon October 31, 2004 NYMEX quoted prices. Prices shown have been adjusted for transportation and treating.
(2) Prices were not escalated thereafter.

FORECAST

YEAR	OIL $/bbl	GAS PRICE $/Mcf(1)	SULPHUR $/LT
2005	69.2	8.65	-
2006	69.34	9.14	-
2007	71.24	8.15	-
2008	68.5	7.95	-
2009	63.75	7.35	-
2010(2)	59	7.15	-

Notes: (1) Price based upon future predicted product prices. Prices shown have been adjusted for transportation and treating.
(2) Prices were escalated at a rate of 1.50 percent per annum thereafter.

Table 3-2

PRODUCT PRICE SCHEDULE
OCTOBER 31, 2005

DEGOLYER AND MACNAUGHTON
CANADA LIMITED

CONSTANT

Year	Edmonton Light Oil	AECO Spot Gas	Condensate	Sulphur
	$/bbl	$/Mcf	$/bbl	$/LT
October 31, 2005	70.16	10.48	75.33	35.00

FORECAST

Year	W.LT. Cushing Oklahoma	Edmonton Oil Price	Alberta Aggregator	Plantgate Spot	Pentanes Plus	Plantgate Sulphur	Inflation Rates	Exchange Rates
	$US/bbl	$/bbl	$/Mcf	$/Mcf	$/bbl	$/LT	%Yr	$US/$CDN
Historical								
2000	30.36	44.62	4.65	5.19	46.28	13.77	2.40	0.67
2001	25.82	39.48	5.29	5.24	42.60	(10.47)	2.40	0.65
2002	26.04	40.11	3.82	3.87	40.85	8.56	2.40	0.64
2003	30.99	43.52	5.99	6.33	44.42	40.84	2.50	0.72
2004	41.39	53.06	6.28	6.22	54.81	39.74	2.00	0.77
2005 9 Mths	55.36	68.43	6.81	7.05	68.38	38.08	2.00	0.82
Forecast								
2005 3 Mths	62.00	70.16	13.06	13.40	71.57	35.00	0.00	0.85
2006	61.50	69.50	10.64	10.91	70.89	25.00	2.00	0.85
2007	57.78	65.06	9.05	9.25	66.36	20.00	2.00	0.85
2008	53.84	60.35	8.09	8.23	61.56	17.50	2.00	0.85
2009	52.72	58.98	7.56	7.63	60.16	15.50	2.00	0.85
2010	53.78	60.16	7.03	7.03	61.36	16.00	2.00	0.85
2011	54.85	61.36	7.12	7.12	62.59	16.50	2.00	0.85
2012	55.95	62.59	7.20	7.20	63.84	17.00	2.00	0.85
2013	57.07	63.84	7.29	7.29	65.11	17.50	2.00	0.85
2014	58.21	65.11	7.37	7.32	66.42	18.00	2.00	0.85
2015	59.38	66.42	7.46	7.46	67.74	18.50	2.00	0.85
2016	60.56	64.74	7.55	7.55	69.10	19.00	2.00	0.85
Thereafter	Thereafter escalate oil, gas and product prices at 2.0% per year.						2.00	0.85

(1) These prices have been adjusted for transportation and quality.

PART 4 RECONCILIATION OF CHANGES ON RESERVES AND FUTURE NET REVENUE

Table 4-1

RECONCILIATION OF COMPANY NET RESERVES BY PRINCIPAL PRODUCT TYPES CONSTANT PRICES AND COSTS

FACTORS	LIGHT AND MEDIUM OIL			SOLUTION AND NON-ASSOCIATED GAS		
	Net Proved Mbbl	Net Probable Mbbl	Net Proved Plus Probable Mbbl	Net Proved MMcf	Net Probable MMc	Net Proved Plus Probable MMcf
October 31, 2004	300	88	888	5378	211	5589
Extensions						
Improved Recovery				147	11	158
Technical Revisions	-459 (l)	-27 (1)	-486 (1)	-2324 (l)	-1 (1)	-2325 (1)
Discoveries	28	9	37	171	-21	292
Acquisitions						
Dispositions						
Economic Factors						
Production	-21		-21	-103		-103
October 31, 2005	348	70	418	3270	523	3611

Note: (1) The Technical Revisions are mainly a result of reduction in Proved and Probable Undeveloped Reserves in the Pembina area. Previous estimates of undeveloped reserves did not materialize due to a poor performance of an infill drilling program during the most recently completed financial year.

Table 4-2

RECONCILIATION OF CHANGES IN NET PRESENT VALUES OF FUTURE NET REVENUE DISCOUNTED AT 10% PER YEAR

PROVED RESERVES CONSTANT PRICES AND COSTS

FACTORS	Net Present Value of Future Net Revenue Discounted at 10%IYr $M
Estimates Future Net Revenue at October 31, 2004	26,717
Sales and Transfers of Oil and Gas produced, Net of Production Costs and Royalties	-1,223
Net Change in Prices, Production Costs and Royalties Related to Future Production	14,124
Changes in Previously Estimated Development Costs Incurred During the Period	-1,262
Changes in Estimated Future Development Costs	40
Extensions and Improved Recovery	622
Discoveries	2,052

Acquisitions of Reserves	
Dispositions of Reserves	
Net Change Resulting from Revisions in Quantity Estimates	-26,505 (1)
Accretion of Discount	3,817
Net Change in Income Taxes	489
Estimates Future Net Revenue at October 31, 2005	18,871

Note: (1) The Net Change Resulting from Revisions in Quantity Estimates is mainly a result of a reduction in Proved and Proved plus Probable Undeveloped Reserves in the Pembina area. Previously estimates of undeveloped reserves did not materialize due to a poor performance of an infill drilling program during the most recently completed financial year.

PART 5 ADDITIONAL INFORMATION RELATING TO RESERVES DATA UNDEVELOPED RESERVES

Table 5-1

PROVED UNDEVELOPED NET RESERVES
MOST RECENT FIVE YEARS FORECAST
PRICES AND COSTS

	Light and Medium Oil		Solution Gas	
Year End October 31	1 st Attributed (Mbbl)	Cummulative At Year End (Mbbl)	1st Attributed (MMcfl	Cummulative At Year End (MMcfl
2001	--	--	--	-
2002	1796	1796	1586	1586
2003		672	918	2504
2004		639	897	3401
2005		162		2059

Table 5-2

PROBABLE UNDEVELOPED NET RESERVES
MOST RECENT FIVE YEARS FORECAST
PRICES AND COSTS

	Light and Medium Oil		Solution Gas	
Year End October 31	1st Attributed (Mbbl)	Cummulative At Year End (Mbbl)	1st Attributed (MMcf)	Cummulative At Year End (MMcf)
2001	--	-	--	-
2002	800	800		
2003		800		
2004		88	211	211
2005		70	130	341

Future Development Costs

Table 5-3

FUTURE DEVELOPMENT COSTS As of October 31, 2005

Year	Constant Prices and Costs		Forecast Prices and Costs			
	Proved Reserves		Proved Reserves		Proved + probable Reserves	
	Undiscounted M$	Discounted At 10% /YR M$	Undiscounted M$	Discounted At 10% /YR M$	Undiscounted M$	Discounted At 10% IYR M$
2005 2 Mths	118	117	118	117	118	117
2006	458	429	461	433	521	489
2007	-	-				-
2008	-	-	-	-	-	-
2009	-	-	-	-	-	-
2010	-	-	-	-	-	-
5 Yr Total	576	546	579	550	639	606
Remaining	-	-	-	-	-	
Total	576	546	579	550	639	606

Development Plans Refer to Part 6 -Oil and Gas Properties, for a descriptions of the Companies plans to develop the undeveloped reserves.

Significant Factors and Uncertainties For details of important economic factors or significant uncertainties that may affect the components of the reserves data, see "Management's discussion and Analysis" and "Risk Factors" in this Annual Information Form.

Sources of Funding The Corporation anticipates that the future exploration and development costs will be financed through a combination of internally generated cash flow, flow-through and /or equity financing. The Corporation has an established Line of Credit for debt financing in the amount of Four (4) million dollars, which could be used for both operations and/or acquisitions.

Future Commitments The Corporation's production, operated and non-operated, is sold into the spot market.

PART 6 OTHER OIL AND GAS INFORMATION

Oil and Gas Properties

Bonnie Glen

The new collector pipeline was completed June 28 2005, gathering gas to the 5-1946-27W4 battery and transporting it to 1-35-46-27W4 Blue Parrot's main battery, to be sold to the Esso's Bonnie Glen Leduc Plant. We are looking at alternative Tie-ins with Provident energy to sell our gas through to the Gulf plant at Wizard lake to lower our processing fees (currently-$1.50 Mcfl. Wells 11-24 46-27W4 and 13-24-46-27W4 are being produced four days on, three days off, to reduce operating costs due to low productivity and high propane costs. We are currently looking at electrifying the four wells at the 5-19 battery, with a nearby three-phase transformer. Three of the four Tribal counsels in the Four Nations have signed the surface agreement for the surface location 2-34-46-28W4. We are waiting on Samson band to sign. Compressor problems still plague 5-19 battery, which has lead to the review of the possibility of changing compressors.

Antelope East

Two Exploration wells (both 40%W.L) were drilled at Antelope in 2005. 1-29-301 W4 was drilled in February 2005 but was uneconomic and abandoned. 15-12-302W4 was drilled and tested 120 Mcf/d in the Viking and is waiting on tie-in. In October 2005, Blue Parrot has entered into a JVA with Fair West Energy Corp. (Jim Gettis) for all of our lands at Antelope (6 sections and five wells). Blue Parrot will retain a 50% W.I. In late December 2005, 3-D seismic was shot over our twelve sections of land and nine multi-zoned locations were identified. Three new sections of land were bought at the two Crown land sales and a Pennwest farm-in added five more sections all covered by our 3-D program. The Nine well drilling program will commence as soon as break-up is over, currently estimated to be between June 1st and 10th 2006.

Pincher Creek

1-5-3-28W4 was completed and producing in December 2005. Currently it is producing between 2 to 3 MMcf/d with 15 to 20 bbls of condensate per MMcf of gas (BPO 5%-APO 2.5%). Blue Parrot purchased a 2.5% W.I. in 15-5-3-28 W4 on April 1, 2006 as part of an option with Choice energy. This well has been on production for sometime and is currently producing between rates of 200 to 400 Mcf/d with 8 to 10 bbls of condensate per MMcf.

Wallace

Drilling was completed on both exploratory wells 16-31-69-13 WS and 6-9-7013W5 in December 2005 and January 2006. The Primary target was the Mississippian section (Debolt and Elkton) with the Mannville and Viking as uphole potential targets. Both wells were cased and tested but no commercial hydrocarbons found in either well. The play is currently under review to increase success on future wells (7.5%BPO, 4.125%APO. in 16-31-69-13W5, and 10.0% W.I. in 6-970-13W5).

David Lake /Dolcy

The well 16-32-41-4W4 was drilled and tested in October 2005. The well TD'ed (750m) in the Leduc, which was tight. The Nisku was tested but showed no gas (Tight limestone) and both lower Mannville and Colony zones were wet. Well abandoned (50%W.L).

Sunken Lake /Ribstone

Well 16-22-42-4W4 was our 2°d well drilled to the Leduc (790m). Both Leduc and Mannville zones were wet and we are awaiting completion of the Colony. Partners are reviewing data at the end of May 2006 to decide weather or not to proceed with the Colony completion. Potential gas estimated at 80 to 150 Mcf/d. BPO 30% APO 16.5%.

Campbell

The EUB has granted the operator with New Pool Wildcat status for the well 15-3354-25W4 as of January 28, 2006. The operator (Dewinton) ran into financial difficulties and was forced to sell their 50% working interested. The new operator Arapahoe Energy has committed to get the well on production by the end of May or the first part of June 2006. This well tested at 1.6 MMcf/d and approx 144 bbls/d of oil. In the interim we have picked up two more sections of land, which extend our B.Q. play to the North. This well is expected to add 25 bbUd of oil and 400 Mcf/d of gas (before payout) to Blue Parrots production. We are currently trying to obtain additional interests from other partners. (BPO 25%- APO 12.5%).

Chigwell

The new operator (Seabring) is in the process of completing the Viking Zone (potential gas production estimated to be between 90 & 120 Mcf/d in the well 7-11-42-25W4). Problems with partners unable to pay have prevented the well from being completed. The Ellerslie proved to have too much water to be economical so it was abandoned (BPO 20% for APO 12.50%).

Table 6-1

CURRENT OIL AND GAS WELLS

Location	Producing Wells				Non-Producing Wells			
	OIL		GAS		OIL		GAS	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Bonnie Glen	17.00	16.80			3.00	2.90		
Chi well42-25W4							1.00	0.20
Antelope 30-2W4							2.00	0.80
Dolcy 41-4W4							1.00	0.50
Ribstone 42-4W4							1.00	0.30
Campbell 54-25W4							1.00	0.25
Pincher Creek 29-5W5			1.00	0.05				
Total	17.00	16.80	1.00	0.05	3.00	2.90	6.00	2.05

Forward Contracts

Currently, Blue Parrot Energy has no forward contracts.

Properties With No Attributed Reserves

Table 6-2
UNPROVED PROPERTIES

Location	Current Land Holdings		Expires Within One Year		Work Commitments	
	Gross Acres	Net Acres	Gross Acres	Net Acres	Gross Acres	Net Acres
Bonnie Glen	1,200	1,183				
Chi well	640	80				
Antelope	6,400	3,200				
Campbell	1,920	480				
Wallace	3,200	178				
David Lake 50%	1,280	640				
Ribstone 30%	640	192				
Total	15,280	5,953	0	0	0	0

Abandonment and Reclamation Costs

Table 6-3

Well Abandonment and Disconnect Costs
Net of Salvage Value Proved Plus
Probable Reserves Forecast Prices and Costs

		Abandonment & Disconnect Costs	
Year	No. of Wells	Undiscounted	Discounted 10%/YR
2005 2 Mths	0	0	0
2006	0	0	0
2007	1	78	62
2008	1	71	51
Sub Total	2	150	113
Remaining	20	1096	370
Total	22	1246	483

Note: The remaining Abandonment and Reclamation Costs are included in the Financial Statements.

Tax Horizon

The Company did not pay income taxes in the most recently completed financial year. It is expected that income taxes will become payable in the next financial year October 31, 2005 to October 31,2006. The Companies Tax Pools and Tax Loss Carry Forwards are presented in the following table. Since the Company used two evaluation firms, the Tax Pools and Tax Loss Carry Forwards have been allocated to each firm based on the respective net present values of the proved plus probable reserves before income taxes respectively.

Table 6-4

Tax Pools and Tax Loss Carry Forwards As of October 31, 2005

Tax Pools	Total Company M$	Allocation Citadel 90% M$	 D&M 10% M$
Unclaimed Capital Cost Class 41 UCC	2,721	2,449	272
Canadian Exploration Expense CEE	1,082	974	108
Canadian Development Expense CDE	2,919	2,627	292
Canadian Oil and Gas Property Expense COGPE	1,296	1,166	130
Foreign Exploration and Development Expense	87	78	9
Tax Loss Carry Forwards	936	842	94

Table 6-5
Costs Incurred During
October 31, 2004 to October 31, 2005

Location	**Property Acquisition Costs** **Proved Properties**	 **Unproved Properties**	**Exploration Costs**	**Development Costs**
	M$US	M$US	M$US	M$US
Canada	---	9,249	1,329,455	303,802
Total	---	9,249	1,329,455	303,802

PRODUCTION ESTIMATES

Table 6 -6

OCTOBER 31, 2005 - OCTOBER 31, 2006
PRODUCTION ESTIMATES
CONSTANT PRICES AND COSTS

RESERVES CATEGORY	Annual Production Estimates							
	LIGHT AND MEDIUM OIL		NON-ASSOCIATED AND SOLUTION GAS		NATURAL GAS LIQUIDS		SULPHUR	
	GROSS Mbbl	NET Mbbl	GROSS MMcf	NET MMcf	GROSS Mbbl	NET Mbbl	GROSS LT	NET LT
PROVED								
Developed Producing	25,254	22,251	126,518	99,102	552	263	147	86
Developed Non-Producing	4,053	3,324	27	22				
Undeveloped	12,829	10,344	268,560	226,262				
TOTAL PROVED	42,136	35,919	395,105	325,386	552	263	147	96
PROBABLE	23	19	16	20	1	1		
TOTAL PROVED+PROBABLE	42,158	35,938	395,121	325,406	553	264	147	96

Table 6 -7

OCTOBER 31, 2005 - OCTOBER 31, 2006

PRODUCTION ESTIMATES FORECAST PRICES AND COSTS

RESERVES CATEGORY	Annual Production Estimates							
	LIGHT AND MEDIUM OIL		NON-ASSOCIATED AND SOLUTION GAS		NATURAL GAS LIQUIDS		SULPHUR	
	GROSS	NET	GROSS	NET	GROSS	NET	GROSS	NET
	Mbbl	Mbbl	MMcf	MMcf	Mbbl	Mbbl	LT	LT
PROVED								
Developed Producing	25,903	22,871	126,516	99,103	511	247	136	90
Developed Non-Producing	4,042	3,314	27	22				
Undeveloped	12,829	10,344	268,560	226,262				
TOTAL PROVED	42,774	36,529	395,103	325,381	511	247	136	90
PROBABLE	22	19	17	12	2	2		
TOTAL PROVED+PROBABLE	42,796	36,548	395,120	325,399	513	249	136	90

PRODUCTION HISTORY

Table 6 -8

OCTOBER 31, 2004-OCTOBER 31, 2005

PRODUCTION HISTORY, PRICES ROYALTIES, COSTS AND NETBACKS

Product Type	Gross Average Daily Production	Average Per Unit of Daily Production			
		Price	Royalties (1)	Costs(1)	Netbacks
	bbl/day	$/bbl	$/bbl	$/bbl	$/bbl
Lightand Medium Oil					
1 st Quarter	83.39	53.66	13.73	20.11	19.82
2nd Quarter	76.18	62.00	18.13	16.82	27.05
3rd Quarter	64.68	64.87	16.54	33.53	14.80
4th Quarter	80.57	73.62	18.40	24.27	30.95
Total 2005	76.201	63.41	16.65	23.29	23.47
Product Type	Gross Average Daily Production	Average Per Unit of Daily Production			
		Price	Royalties (1)	Costs(1)	Netbacks
	Mcf/day	$/Mcf	$/Mcf	$/Mcf	$/Mcf
Solution Gas 2					
1 st Quarter	429.67	9.49	2.43	3.55	3.51
2nd Quarter	438.76	9.38	2.75	2.55	4.08
3rd Quarter	328.18	9.33	3.26	4.82	1.25
4th Quarter	328.15	13.30	3.32	4.48	5.50
Total 2005	380.71	10.25	2.70	ˉ175	3.80

(1) Royalties and costs have been allocated between the Light and Medium Oil and Solution Gas by the respective Gross Revenues.

(2) In the year from October 31, 2004 to October 31, 2005 the Company had no Associated and Non-Associated Gas Reserves.