TOWER ENERGY LTD.
STATEMENT OF RESERVES DATA
AND OTHER OIL AND GAS INFORMATION
(Form NI 51-101F1)

This statement of reserves data and other oil and gas information has been prepared as at January 31, 2008.

ABBREVIATIONS AND CONVERSION

In this document, the abbreviations set forth below have the following meanings:

Oil and Natural Gas Liquids

Bbl	barrel
Bbls	barrels
Mbbls	thousand barrels
MMbbls	million barrels
MSTB	1,000 stock tank barrels
Bbls/d	barrels per day
BOPD	barrels of oil per day
NGLs	natural gas liquids
STB	stock tank barrels

Natural Gas

Mscf	thousand standard cubic feet
MMscf	million standard cubic feet
Mscf/d	thousand standard cubic feet per day
MMscf/d	million standard cubic feet per day
MMBTU	million British Thermal Units
Bcf	billion cubic feet
GJ	gigajoule

Other

AECO	EnCana Corp.'s natural gas storage facility located at Suffield, Alberta.
BIT	Before Income Tax
AIT	After Income Tax
BOE	barrel of oil equivalent on the basis of 1 BOE to 6 Mscf of natural gas. BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 1 BOE for 6 Mscf is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.
BOE/d	barrel of oil equivalent per day
m^3	cubic metres
$M	thousands of dollars
WTI	West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma for crude oil of standard grade

TOWER ENERGY LTD.

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

(Form NI 51-101F1)

This statement of reserves data and other oil and gas information has been prepared as at October 31, 2007.

Reserves and Future Net Revenue

The following is a summary of the oil and natural gas reserves and the value of future net revenue of TOWER ENERGY LTD. ("Tower" or the "Company") as evaluated by Chapman Petroleum Engineering Ltd. as at October 31, 2007 (the "Chapman Report"). The pricing used in the forecast and constant price evaluations is set forth in the notes to the tables.

All evaluations of future revenue are after the deduction of future income tax expenses, unless otherwise noted in the tables, royalties, development costs, production costs and well abandonment costs but before consideration of indirect costs such as administrative, overhead and other miscellaneous expenses. The estimated future net revenue contained in the following tables do not necessarily represent the fair market value of the Company's reserves. There is no assurance that the forecast price and cost assumptions contained in the Chapman Report will be attained and variances could be material. Other assumptions and qualifications relating to costs and other matters are included in the Chapman Report. The recovery and reserves estimates on the Company's properties described herein are estimates only. The actual reserves on the Company's properties may be greater or less than those calculated.

SUMMARY OF OIL AND GAS RESERVES BASED ON CONSTANT PRICES AND COSTS(9)

	Company Reserves (1)							
	Light and Medium Oil		Heavy Oil		Natural Gas(10)		Natural Gas Liquids	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Reserves Category	MSTB	MSTB	MSTB	MSTB	MMscf	MMscf	Mbbl	Mbbl
PROVED								
Developed Producing(2)(6)	0	0	0	0	0	0	0	0
Developed Non-Producing(2)(7)	0	0	0	0	0	0	0	0
Undeveloped(2)(8)	0	0	0	0	0	0	0	0
TOTAL PROVED(2)	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
PROBABLE(3)	0	0	0	0	1,276	872	36	24
TOTAL PROVED PLUS PROBABLE(2)(3)	**0**	**0**	**0**	**0**	**1,276**	**872**	**36**	**24**

SUMMARY OF NET PRESENT VALUES BASED ON CONSTANT PRICES AND COSTS(9)

	Net Present Values of Future Net Revenue									
	Before Income Tax Discounted at					After Income Tax Discounted at				
	0%/yr	5%/yr.	10%/yr.	15%/yr.	20%/yr.	0%/yr	5%/yr.	10%/yr.	15%/yr.	20%/yr.
Reserves Category	$M	$M	$M	$M	$M	$M	$M	$M	$M	$M
PROVED										
Developed Producing(2)(6)	0	0	0	0	0	0	0	0	0	0
Developed Non-Producing(2)(7)	0	0	0	0	0	0	0	0	0	0
Undeveloped(2)(8)	0	0	0	0	0	0	0	0	0	0
TOTAL PROVED(2)	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
PROBABLE(3)	4,422	3,029	2,253	1,768	1,440	4,178	2,922	2,202	1,742	1,426
TOTAL PROVED PLUS PROBABLE(2)(3)	**4,422**	**3,029**	**2,253**	**1,768**	**1,440**	**4,178**	**2,922**	**2,202**	**1,742**	**1,426**

TOTAL FUTURE NET REVENUE (UNDISCOUNTED) BASED ON CONSTANT PRICES AND COSTS(9)

	Revenue ($M)	Royalties ($M)	Operating Costs ($M)	Development Costs ($M)	Abandonment and Reclamation Costs ($M)	Future Net Revenue Before Income Taxes ($M)	Income Taxes ($M)	Future Net Revenue After Income Taxes ($M)
Total Proved(2)	0	0	0	0	0	0	0	0
Total Proved Plus Probable(2)(3)	8,756	2,749	1,217	360	8	4,422	244	4,178

FUTURE NET REVENUE BY PRODUCTION GROUP BASED ON CONSTANT PRICES AND COSTS(9)

Reserve Category	Production Group	Future Net Revenue Before Income Taxes (Discounted at 10%/Year) ($M)
Total Proved(2)	Light and Medium Oil (including solution gas and other by-products)	0
	Heavy Oil (including solution gas and other by-products)	0
	Natural Gas (including by-products but not solution gas)	0
Total Proved Plus Probable(2)(3)	Light and Medium Oil (including solution gas and other by-products)	0
	Heavy Oil (including solution gas and other by-products)	0
	Natural Gas (including by-products but not solution gas)	2,253

SUMMARY OF OIL AND GAS RESERVES BASED ON FORECAST PRICES AND COSTS(9)

	Company Reserves(1)							
	Light and Medium Oil		Heavy Oil		Natural Gas(10)		Natural Gas Liquids	
Reserves Category	Gross MSTB	Net MSTB	Gross MSTB	Net MSTB	Gross MMscf	Net MMscf	Gross Mbbl	Net Mbbl
PROVED								
Developed Producing(2)(6)	0	0	0	0	0	0	0	0
Developed Non-Producing(2)(7)	0	0	0	0	0	0	0	0
Undeveloped(2)(8)	0	0	0	0	0	0	0	0
TOTAL PROVED(2)	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
TOTAL PROBABLE(2)	0	0	0	0	1,276	872	35	24
TOTAL PROVED PLUS PROBABLE(2)(3)	**0**	**0**	**0**	**0**	**1,276**	**872**	**35**	**24**

SUMMARY OF NET PRESENT VALUES BASED ON FORECAST PRICES AND COSTS(9)

	Net Present Values of Future Net Revenue									
	Before Income Tax Discounted at					After Income Tax Discounted at				
Reserves Category	0%/yr $M	5%/yr. $M	10%/yr. $M	15%/yr. $M	20%/yr. $M	0%/yr $M	5%/yr. $M	10%/yr. $M	15%/yr. $M	20%/yr. $M
PROVED										
Developed Producing(2)(6)	0	0	0	0	0	0	0	0	0	0
Developed Non-Producing(2)(7)	0	0	0	0	0	0	0	0	0	0
Undeveloped(2)(8)	0	0	0	0	0	0	0	0	0	0
TOTAL PROVED(2)	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
PROBABLE(3)	6,981	4,676	3,441	2,690	2,190	6,098	4,204	3,163	2,516	2,075
TOTAL PROVED PLUS PROBABLE(2)(3)	**6,981**	**4,676**	**3,441**	**2,690**	**2,190**	**6,098**	**4,204**	**3,163**	**2,516**	**2,075**

TOTAL FUTURE NET REVENUE (UNDISCOUNTED) BASED ON FORECAST PRICES AND COSTS(9)

	Revenue ($M)	Royalties ($M)	Operating Costs ($M)	Development Costs ($M)	Abandonment and Reclamation Costs ($M)	Future Net Revenue Before Income Taxes ($M)	Income Taxes ($M)	Future Net Revenue After Income Taxes ($M)
Total Proved(2)	0	0	0	0	0	0	0	0
Total Proved Plus Probable(2)(3)	12,837	4,003	1,475	367	11	6,981	883	6,098

FUTURE NET REVENUE BY PRODUCTION GROUP BASED ON FORECAST PRICES AND COSTS(9)

Reserve Category	Production Group	Future Net Revenue Before Income Taxes (Discounted at 10%/Year) ($M)
Total Proved(2)	Light and Medium Oil (including solution gas and other by-products)	0
	Heavy Oil (including solution gas and other by-products)	0
	Natural Gas (including by-products but not solution gas)	0
Total Proved Plus Probable(2)(3)	Light and Medium Oil (including solution gas and other by-products)	0
	Heavy Oil (including solution gas and other by-products)	0
	Natural Gas (including by-products but not solution gas)	3,441

RECONCILIATION OF COMPANY NET RESERVES BY PRINCIPAL PRODUCT TYPE BASED ON FORECAST PRICES AND COSTS (9)

The following table sets forth a reconciliation of the changes in the Company's net reserves as at October 31, 2007 against such reserves as at October 31, 2006 based on the forecast price and cost assumptions set forth in note 9:

	Light and Medium Oil			Heavy Oil			Associated and Non-Associated Gas		
	Net Proved (Mbbl)	Net Probable (Mbbl)	Net Proved Plus Probable (Mbbl)	Net Proved (Mbbl)	Net Probable (Mbbl)	Net Proved Plus Probable (Mbbl)	Net Proved (MMscf)	Net Probable (MMscf)	Net Proved Plus Probable (MMscf)
At October 31, 2006	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**824**	**824**
Production(Sales)	0	0	0	0	0	0	0	0	0
Dispositions & Acquisitions	0	0	0	0	0	0	0	50	50
Discoveries	0	0	0	0	0	0	0	0	0
Extensions	0	0	0	0	0	0	0	0	0
Revisions to Previous Estimates	0	0	0	0	0	0	0	0	0
Economic Factors	0	0	0	0	0	0	0	(2)	(2)
Technical	0	0	0	0	0	0	0	0	0
Improved Recovery	0	0	0	0	0	0	0	0	0
At October 1, 2007	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**872**	**872**

RECONCILIATION OF CHANGES IN NET PRESENT VALUES OF FUTURE NET REVENUE DISCOUNTED AT 10% BASED ON CONSTANT PRICES AND COSTS

There are no net proved reserves associated with this report, therefore no future net revenue reconciliation based on proved reserves is possible.

Notes for Reserves and Revenue Information Tables:

1. "Gross Reserves" are the Company's working interest (operating or non-operating) share before deducting of royalties and without including any royalty interests of the Company. "Net Reserves" are the Company's working interest (operating or non-operating) share after deduction of royalty obligations, plus the Company's royalty interests in reserves.
2. "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.
3. "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.
4. "Possible" reserves are those additional reserves that are less certain to be recovered than probable reserves. It is unlikely that the actual remaining quantities recovered will exceed the sum of the estimated proved plus probable plus possible reserves.
5. "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 (e.g. when compared to the cost of drilling a well) to put the reserves on production.
6. "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.
7. "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.
8. "Undeveloped" reserves are those reserves expected to be recovered from know 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, possible) to which they are assigned.
9. The pricing assumptions used in the Chapman Report with respect to net values of future net revenue (forecast) as well as the inflation rates used for operating and capital costs are set forth below along with the product prices used in the constant price and cost evaluations. Chapman Petroleum Engineering Ltd. is an independent qualified reserves evaluator appointed pursuant to NI 51-101.
10. Includes associated, non-associated and solution gas where applicable.

CRUDE OIL
CONSTANT PRICES & PRICE FORECASTS

November 1, 2007

Date	WTI [1] $US/STB	Alberta Par Price [2] $CDN/STB	Alberta Heavy [3] $CDN/STB	Sask. Light [4] $CDN/STB	Sask. Heavy [5] $CDN/STB	B.C. Light [6] $CDN/STB
HISTORICAL PRICES						
1994	17.16	22.27	18.19	20.76	19.16	21.12
1995	18.41	25.11	19.76	22.77	20.57	23.85
1996	21.98	29.39	25.09	28.41	26.07	27.99
1997	20.59	27.90	21.15	26.52	23.73	26.32
1998	14.46	20.39	14.68	19.31	17.01	19.38
1999	19.21	27.88	23.71	27.23	25.65	27.42
2000	30.39	44.90	34.51	43.37	40.12	n/a
2001	25.98	39.66	25.41	35.57	31.84	n/a
2002	26.09	40.63	32.20	37.67	34.57	n/a
2003	30.84	43.57	32.65	40.13	37.64	n/a
2004	41.48	52.89	37.52	48.96	45.74	n/a
2005	56.62	69.16	43.25	62.04	56.53	n/a
2006	65.91	72.88	50.40	66.77	61.23	n/a
2007 (10 months)	68.11	74.15	52.02	70.11	58.11	n/a
CONSTANT PRICES						
October 31, 2007 [8]	94.53	86.39	60.01	74.40	73.61	84.23
CURRENT YEAR FORECAST						
2007 (2 months)	73.00	74.84	51.64	68.11	61.98	72.97
FUTURE FORECAST						
2008	68.00	71.91	49.62	65.44	59.55	70.12
2009	65.00	71.03	49.01	64.64	58.82	69.26
2010	63.00	68.79	47.46	62.60	56.96	67.07
2011	58.00	63.17	43.59	57.48	52.31	61.59
2012	59.16	64.47	44.49	58.67	53.39	62.86
2013	60.34	65.80	45.40	59.88	54.49	64.16
2014	61.55	67.16	46.34	61.11	55.61	65.48
2015	62.78	68.54	47.29	62.37	56.76	66.83
2016	64.04	69.95	48.27	63.66	57.93	68.20
2017	65.32	71.39	49.26	64.97	59.12	69.61
2018	66.62	72.86	50.27	66.30	60.33	71.04
2019	67.96	74.36	51.31	67.66	61.57	72.50
2020	69.32	75.88	52.36	69.05	62.84	73.99
2021	70.70	77.44	53.43	70.47	64.13	75.50
2022	72.12	79.03	54.53	71.92	65.44	77.05
Constant thereafter						

Notes:

[1] West Texas Intermediate quality (D2/S2) crude landed in Cushing, Oklahoma.

[2] Equivalent price for Light Sweet Crude (D2/S2) landed in Edmonton, Alberta after exchange of 0.95$US/$CDN in 2007, 0.92$US/$CDN in 2008, 0.89$US/$CDN in 2009, and thereafter, and transportation differential of $2.00 CDN/STB.

[3] Bow River at Hardisty, Alberta (905 kg/m3, 2.1% sulphur).

[4] Light Sour Blend at Cromer, Saskatchewan (850 kg/m3, 1.2% sulphur).

[5] Midale at Cromer, Saskatchewan (880 kg/m3, 2.0% sulphur).

[6] B.C. Light at Taylor, British Columbia (825 kg/m3, 0.5% sulphur).

[7] The Alberta Energy Minister confirmed end of Alberta Royalty Tax Credits as of January 1, 2007, http://www.gov.ab.ca/acn/200609/20527D0EDD3BF-A8A0-2F29-960D7A45197E3999.html

[8] October 31, 2007 is the last trading day of October 2007.

[9] Capital expenditures and operating costs are escalated at 2.0% per year until 2022.

NATURAL GAS & BY-PRODUCTS
CONSTANT PRICES & PRICE FORECASTS
November 1, 2007

NATURAL GAS & BY-PRODUCTS

HISTORICAL, CONSTANT, CURRENT AND FUTURE PRICES

November 1, 2007

	GRP [1]		AECO Spot Gas [NIT]	Sask. Gas [2]	B.C. Gas [3]	Propane [4]	Butane [4]	Pentanes Plus [4]	NGL Mix [5]
Date	**$/MMBTU**	**$/GJ**	**$/MMBTU**	**$/MMBTU**	**$/MMBTU**	**$/BBL**	**$/BBL**	**$/BBL**	**$/BBL**
HISTORICAL PRICES									
1994	1.82	1.73	1.78	1.88	1.81	12.72	13.44	21.67	15.62
1995	1.31	1.24	1.08	1.35	1.29	14.38	13.97	24.11	17.18
1996	1.63	1.55	1.33	1.52	1.50	22.95	17.19	30.05	23.35
1997	1.97	1.87	1.67	1.84	1.80	17.73	19.07	30.90	22.08
1998	1.94	1.84	1.94	2.05	1.94	11.13	12.06	21.86	14.63
1999	2.48	2.35	2.82	2.83	2.51	15.93	18.01	27.73	20.09
2000	4.50	4.27	5.56	4.85	4.00	31.38	35.01	46.35	36.96
2001	5.78	5.48	5.44	5.48	6.12	31.27	30.27	44.98	35.08
2002	3.86	3.66	4.13	4.17	3.85	19.14	25.11	40.72	27.41
2003	6.45	6.11	7.03	6.47	6.45	28.85	32.15	44.23	34.46
2004	6.25	5.92	6.60	6.50	6.25	31.95	38.40	54.06	40.52
2005	8.30	7.87	8.82	8.55	8.30	38.03	46.31	69.32	49.90
2006	6.57	6.23	6.55	6.82	6.57	38.97	50.42	76.08	53.54
2007 (10 months Est)	6.22	5.90	6.57	6.47	6.22	39.07	47.54	73.35	51.89
CONSTANT PRICES									
October 31, 2007	4.86	4.61	6.32	5.11	4.86	49.60	62.80	89.98	65.68
CURRENT YEAR FORECAST									
2007 (2 months)	7.00	6.64	7.25	7.25	7.00	40.41	51.64	77.09	54.78
FUTURE FORECAST									
2008	7.75	7.35	8.00	8.00	7.75	38.83	49.62	74.07	52.64
2009	7.50	7.11	7.75	7.75	7.50	38.36	49.01	73.16	52.00
2010	7.40	7.01	7.65	7.65	7.40	37.14	47.46	70.85	50.35
2011	7.55	7.15	7.80	7.80	7.55	34.11	43.59	65.06	46.24
2012	7.70	7.30	7.95	7.95	7.70	34.81	44.49	66.41	47.19
2013	7.85	7.44	8.10	8.10	7.85	35.53	45.40	67.78	48.17
2014	8.01	7.59	8.26	8.26	8.01	36.26	46.34	69.17	49.16
2015	8.17	7.74	8.42	8.42	8.17	37.01	47.29	70.60	50.17
2016	8.33	7.90	8.58	8.58	8.33	37.77	48.27	72.05	51.20
2017	8.50	8.06	8.75	8.75	8.50	38.55	49.26	73.53	52.26
2018	8.67	8.22	8.92	8.92	8.67	39.34	50.27	75.04	53.33
2019	8.84	8.38	9.09	9.09	8.84	40.15	51.31	76.59	54.43
2020	9.02	8.55	9.27	9.27	9.02	40.98	52.36	78.16	55.55
2021	9.20	8.72	9.45	9.45	9.20	41.82	53.43	79.76	56.69
2022	9.38	8.90	9.63	9.63	9.38	42.68	54.53	81.40	57.85
Constant thereafter									

Notes:

[1] Gas Reference Price (GRP) represents the average of all system and direct (spot and firm) sales.

[2] Price paid at field delivery point.

[3] Price paid by CanWest net of raw gas gathering and processing charges but before deduction of field gathering and compression charges.

[4] Reference point is FOB Edmonton for fractionated product.

[5] Natural Gas Liquids blended mix price assuming typical liquid composition of 40% propane, 30% butane and 30% pentanes plus.

[6] October 31, 2007 is the last trading day of October 2007.

[7] Capital expenditures and operating costs are escalated at 2.0% per year until 2022.

Undeveloped Reserves

The following discussion generally describes the basis on which the Company attributes Proved and Probable Undeveloped reserves and its plans for developing those Undeveloped Reserves.

Proved Undeveloped Reserves

Proved Undeveloped reserves are generally those reserves related to wells that have been tested and not yet tied-in for production or wells drilled near the end of the fiscal year. In addition, such reserves may relate to planned infill drilling locations. The Company has no reserves attributed to this category.

Probable Undeveloped Reserves

Probable Undeveloped reserves are generally those reserves have been tested or indicated by analogy to be productive, infill drilling locations and land contiguous to production. The Company has reserves attributed to this category. The Company has plans to drill and tie-in one location in Sarcee, Alberta in 2008.

Future Development Costs

FUTURE DEVELOPMENT COSTS

	Total Proved Estimated Using Constant Prices and Costs ($M)	**Total Proved Estimated Using Forecast Prices and Costs** ($M)	**Total Proved Plus Probable Estimated Using Forecast Prices and Costs** ($M)
2007	-	-	-
2008	-	-	367
2009	-	-	-
2010	-	-	-
2011	-	-	-
Total for all years undiscounted	-	-	**367**
Total for all years discounted at 10%/year	-	-	**345**

Significant Factors or Uncertainties

The estimation of reserves requires significant judgment and decisions based on available geological, geophysical, engineering and economic data. These estimates can change substantially as additional information from ongoing development activities and production performance becomes available and as economic and political conditions impact oil and gas prices and costs change. The Company's estimates are based on current production forecast, prices and economic conditions. All of the Company's reserves are evaluated by Chapman Petroleum Engineering Ltd., an independent engineering firm.

As circumstances change and additional data becomes available, reserve estimates also change. Based on new information, reserves estimates are reviewed and revised, either upward or downward, as warranted. Although every reasonable effort has been made by the Company to ensure that reserves estimate are accurate, revisions may arise as new information becomes available. As new geological, production and economic data is incorporated into the process of estimating reserves the accuracy of the reserve estimate improves.

In mid 2007, the Alberta government announced plans to change Crown royalty calculations, effective January 1, 2009. Since the exact nature of the changes have not been finalized, this evaluation has been prepared utilizing the existing regulations, in accordance with advice from the ASC and as recommended by the SPEE. It is expected that the final regulations will be balanced to moderately increase government revenues while not greatly reducing the opportunities for industry to remain active and profitable.

Oil and Gas Properties and Wells

The following table sets forth the number of wells in which the Company held a working interest as at October 31, 2007

	Oil		Natural Gas	
Area	Gross(1)	Net(1)	Gross(1)	Net(1)
Producing	0	0	0	0
Non-producing	0	0	2	0.0627

All of the Company's wells are located in Alberta, Canada

The following descriptions are applicable to the Company properties as at October 31, 2007.

Sarcee, Alberta

The Company owns a five percent working interest in 2,560 acres of land in this area. These lands contain one non producing gas well and one identified development drilling location. Production will be subject to Indian Royalties which are equivalent to Alberta New Crown royalties plus a 6.5 percent gross overriding royalty. The unit of interest is the Mississippian (Visean) age Turner Valley Formation of the Rundle Group.

Strachan, Alberta

The Company owns a 1.271 percent working interest in 640 acres of land containing one well which has been on production and is currently being deepened and recompleted for non-associated gas production from the Leduc D-3 Formation. Production is subject to New Crown royalties.

Costs Incurred

The following table summarizes the capital expenditures made by the Company on oil and natural gas properties for the year ending October 31, 2007.

Property Acquisition Costs ($M)		Exploration Costs ($M)	Development Costs ($M)
Proved Properties	Unproved Properties		
-	-	329,874	300,000

Discussion

Exploration and Development Activities

The following table sets forth the number of exploratory and development wells which the Company completed during its 2007 financial year:

	Exploratory Wells		Development Wells	
	Gross(1)	Net(1)	Gross(1)	Net(1)
Oil Wells	-	-	-	-
Gas Wells	1	-	-	-
Service Wells	-	-	-	-
Dry Holes	-	-	-	-
Total Completed Wells	-	-	-	-

Properties with No Attributed Reserves

The Company currently holds no properties with no attributed reserves.

Forward Contracts

Currently, the Company has no forward contracts.

Abandonment and Reclamation Costs

The abandonment and restorations costs are based on the AEUB Directive 11, which details the costs of abandonment and reclamation by well type in each specific geographic region, and are included in the Chapman Report.

FUTURE ABANDONMENT AND RESTORATION COSTS

	Total Proved Estimated Using Forecast Prices and Costs (Undiscounted) ($M)	**Total Proved Estimated Using Forecast Prices and Costs (10% Discounted)** ($M)	**Total Proved Plus Probable Estimated Using Forecast Prices and Costs (Undiscounted)** ($M)	**Total Proved Plus Probable Estimated Using Forecast Prices and Costs (10% Discounted)** ($M)
2007	0	0	0	0
2008	0	0	0	0
2009	0	0	0	0
Total for three years	0	0	0	0
Remainder	0	0	11	1
Total for all years	**0**	**0**	**11**	**1**

Tax Horizon

The Company will become taxable in 2013 under the forecast.

Production Estimates

The following table sets forth the volume of production estimated for the year ending October 31, 2008:

	Light and Medium Oil (Mbbl)	**Natural Gas (MMscf)**
Area	0	5

These values are net to Company's working interest after the deduction of royalties payable to others.

Production History

The following table sets forth certain information in respect of production, product prices received, royalties, production costs and netbacks received by the Company for each quarter of its most recently completed financial year:

	Three Months Ended January 31, 2007	**Three Months Ended April 30, 2007**	**Three Months Ended July 31, 2007**	**Three Months Ended October 31, 2007**
Average Daily Production				
Light and Medium Oil (Mbbl/d)	-	-	-	-
Natural Gas (MMscf/d)	-	-	-	-
Average Net Prices Received				
Light and Medium Oil ($/Mbbl)	-	-	-	-
Natural Gas ($/MMscf)	-	-	-	-
Royalties				
Light and Medium Oil ($/Mbbl)	-	-	-	-
Natural Gas ($/MMscf)	-	-	-	-

	Three Months Ended January 31, 2007	Three Months Ended April 30, 2007	Three Months Ended July 31, 2007	Three Months Ended October 31, 2007
Production Costs				
Light and Medium Oil ($/Mbbl)	-	-	-	-
Natural Gas ($/MMscf)	-	-	-	-
Netback Received				
Light and Medium Oil ($/Mbbl)	-	-	-	-
Natural Gas ($/MMscf)	-	-	-	-