NORTHERN SPIRIT RESOURCES INC.
STATEMENT OF RESERVES DATA
AND OTHER OIL AND GAS INFORMATION
(Form 51-101F1)

Part 1 – Date of Statement

This statement of reserves data and other oil and gas information is dated December 31, 2009.

The effective date is December 31, 2009.

The preparation date is April 14, 2010.

Part 2 – Disclosure of Reserves Data

The following is a summary of the oil and natural gas reserves and the value of future net revenue of Northern Spirit Resources Inc. (the "Company") as evaluated by Chapman Petroleum Engineering Ltd. ("Chapman") as at December 31, 2009, and dated April 14, 2010 (the "Chapman Report"). Chapman is an independent qualified reserves evaluator and auditor.

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 does 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 FORECAST PRICES AND COSTS
AS AT DECEMBER 31, 2009

	Company Reserves(1)							
	Light and Medium Oil		Heavy Oil		Natural Gas(9)		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)	53	39	0	0	18	15	0	0
Undeveloped(2)(8)	0	0	0	0	0	0	0	0
TOTAL PROVED(2)	**53**	**39**	**0**	**0**	**18**	**15**	**0**	**0**
TOTAL PROBABLE(3)	43	34	0	0	953	719	14	11
TOTAL PROVED + PROBABLE(2)(3)	**96**	**73**	**0**	**0**	**971**	**734**	**14**	**11**
TOTAL POSSIBLE(4)	0	0	**0**	**0**	**640**	**326**	**0**	**0**
TOTAL PROVED + PROBABLE + POSSIBLE	**96**	**73**	**0**	**0**	**1,612**	**1,061**	**14**	**11**

SUMMARY OF NET PRESENT VALUES
BASED ON FORECAST PRICES AND COSTS
AS AT DECEMBER 31, 2009

	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)	2,694	2,258	1,936	1,691	1,500	2,574	2,163	1,860	1,629	1,449
Undeveloped(2)(8)	0	0	0	0	0	0	0	0	0	0
TOTAL PROVED(2)	**2,694**	**2,258**	**1,936**	**1,691**	**1,500**	**2,574**	**2,163**	**1,860**	**1,629**	**1,449**
TOTAL PROBABLE(3)	6,216	4,312	3,223	2,538	2,075	4,760	3,271	2,427	1,901	1,548
TOTAL PROVED + PROBABLE(2)(3)	**8,910**	**6,570**	**5,159**	**4,229**	**3,575**	**7,334**	**5,434**	**4,287**	**3,530**	**2,997**
TOTAL POSSIBLE(4)	1,395	1,061	829	663	541	1,006	760	589	466	376
TOTAL PROVED + PROBABLE + POSSIBLE	**10,305**	**7,631**	**5,988**	**4,892**	**4,116**	**8,340**	**6,194**	**4,876**	**3,996**	**3,373**

TOTAL FUTURE NET REVENUE
(UNDISCOUNTED)
BASED ON FORECAST PRICES AND COSTS
AS AT DECEMBER 31, 2009

	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)	4,866	1,258	667	215	32	2,694	(120)	2,574
Total Proved Plus Probable(2)(3)	16,877	4,161	2,816	897	93	8,910	(1,576)	7,334
Total Proved Plus Probable Plus Possible(4)	21,432	6,380	3,463	1,151	132	10,305	(1,965)	8,340

FUTURE NET REVENUE BY PRODUCTION GROUP
BASED ON FORECAST PRICES AND COSTS
AS AT DECEMBER 31, 2009

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)	1,935
	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)	3,135
	Heavy Oil (including solution gas and other by-products)	0
	Natural Gas (including by-products but not solution gas)	2,024
Total Proved Plus Probable Plus Possible(4)	Light and Medium Oil (including solution gas and other by-products)	3,135
	Heavy Oil (including solution gas and other by-products)	0
	Natural Gas (including by-products but not solution gas)	2,853

OIL AND GAS RESERVES AND NET PRESENT VALUES BY PRODUCTION GROUP
BASED ON FORECAST PRICES AND COSTS
AS AT DECEMBER 31, 2009

	Reserves						Net Present Value (BIT)	Unit Values @ 10%/yr
	Oil		Gas(9)		NGL			
Reserve Group by Category	Gross MSTB	Net MSTB	Gross MMscf	Net MMscf	Gross Mbbl	Net Mbbl	10% M$	
Light and Medium Oil								
Proved								
Developed Producing	0	0	0	0	0	0	0	N/A
Developed Non-Producing	53	39	18	15	0	0	1,936	49.64
Undeveloped	0	0	0	0	0	0	0	N/A
Total Proved	**53**	**39**	**18**	**15**	**0**	**0**	**1,936**	**49.64**
Probable	43	34	15	12	0	0	1,199	35.26
Proved Plus Probable	**96**	**73**	**33**	**27**	**0**	**0**	**3,135**	**42.95**
Possible	0	0	0	0	0	0	0	N/A
Proved + Probable + Possible	**96**	**73**	**33**	**27**	**0**	**0**	**3,135**	**42.95**
Assoc & Non-Assoc Gas								
Proved								
Developed Producing	0	0	0	0	0	0	0	N/A
Developed Non-Producing	0	0	0	0	0	0	0	N/A
Undeveloped	0	0	0	0	0	0	0	N/A
Total Proved	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**N/A**
Probable	0	0	938	707	14	11	2,024	2.86
Proved Plus Probable	**0**	**0**	**938**	**707**	**14**	**11**	**2,024**	**2.86**
Possible	0	0	640	326	0	0	829	2.54
Proved + Probable + Possible	**0**	**0**	**1,578**	**1,033**	**14**	**11**	**2,853**	**2.76**

Notes:

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. Includes associated, non-associated and solution gas where applicable.

Part 3 - Pricing Assumptions

The following tables detail the benchmark reference prices for the regions in which the Company operated, as at December 31, 2009, reflected in the reserves data disclosed above under "Part 2 – Disclosure of Reserves Data". The forecast price assumptions assume the continuance of current laws and regulations and take into account inflation with respect to future operating and capital costs. There will be adjustments to field prices from the benchmarks below

CRUDE OIL
HISTORICAL, CONSTANT, CURRENT AND FUTURE PRICES
January 1, 2010

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	Bank of Canada Average Noon Exchange rate $US/$CDN
HISTORICAL PRICES							
1994	17.16	22.27	18.19	20.76	19.16	21.12	0.73
1995	18.41	25.11	19.76	22.77	20.57	23.85	0.73
1996	21.98	29.39	25.09	28.41	26.07	27.99	0.73
1997	20.59	27.90	21.15	26.52	23.73	26.32	0.72
1998	14.46	20.39	14.68	19.31	17.01	19.38	0.68
1999	19.21	27.88	23.71	27.23	25.65	27.42	0.67
2000	30.39	44.90	34.51	43.37	40.12	n/a	0.67
2001	25.98	39.66	25.41	35.57	31.84	n/a	0.65
2002	26.09	40.63	32.20	37.67	34.57	n/a	0.64
2003	30.84	43.57	32.65	40.13	37.64	n/a	0.72
2004	41.48	52.89	37.52	48.96	45.74	n/a	0.77
2005	56.62	69.16	43.25	62.04	56.53	n/a	0.83
2006	65.91	72.88	50.40	66.77	61.23	n/a	0.88
2007	70.61	75.57	53.17	71.42	64.55	n/a	0.94
2008	99.70	102.98	83.88	98.02	92.45	n/a	0.94
2009	61.64	68.91	58.48	65.15	63.48	n/a	0.88
CONSTANT PRICES							
December 31, 2009 [7]	79.39	85.15	75.21	80.46	77.75	83.02	0.96
CURRENT YEAR FORECAST							
2010	80.00	83.21	70.31	78.38	75.17	81.13	0.95
FUTURE FORECAST							
2011	83.00	86.37	72.98	81.36	78.02	84.21	0.95
2012	86.00	89.53	75.65	84.33	80.88	87.29	0.95
2013	90.00	93.74	79.21	88.30	84.68	91.39	0.95
2014	94.00	97.95	82.77	92.27	88.48	95.50	0.95
2015	98.00	102.16	86.32	96.23	92.29	99.60	0.95
2016	101.00	105.32	88.99	99.21	95.14	102.68	0.95
2017	103.02	107.44	90.79	101.21	97.06	104.76	0.95
2018	105.08	109.61	92.62	103.25	99.02	106.87	0.95
2019	107.18	111.82	94.49	105.34	101.02	109.03	0.95
2020	109.33	114.08	96.40	107.46	103.06	111.23	0.95
2021	111.51	116.38	98.34	109.63	105.14	113.47	0.95
2022	113.74	118.73	100.33	111.84	107.26	115.76	0.95
2023	116.02	121.12	102.35	114.10	109.42	118.10	0.95
2024	118.34	123.57	104.41	116.40	111.63	120.48	0.95
2025	120.70	126.06	106.52	118.75	113.88	122.91	0.95
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 0.95US$/C$ from 2009 to 2025 during forecasting period and transportation differential of $1.00 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] December 31, 2009 is the last trading day of 2009.

NATURAL GAS & BY-PRODUCTS
HISTORICAL, CONSTANT, CURRENT AND FUTURE PRICES
January 1, 2010

Date	GRP [1] $/MMBTU	GRP [1] $/GJ	AECO Spot Gas $/MMBTU	Sask. Gas [2] $/MMBTU	B.C. Gas [3] $/MMBTU	Propane [4] $/BBL	Butane [4] $/BBL	Pentanes Plus [4] $/BBL	NGL Mix [5] $/BBL
HISTORICAL PRICES									
1994	1.82	1.72	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	1.54	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	5.41	5.12	5.44	5.48	6.12	31.27	30.27	44.98	35.08
2002	3.89	3.68	4.13	4.17	3.85	19.14	25.11	40.72	27.41
2003	6.14	5.81	7.03	6.47	6.45	28.85	32.15	44.23	34.46
2004	6.31	5.98	6.60	6.56	6.25	31.95	38.40	54.06	40.52
2005	8.31	7.87	8.82	8.56	8.31	38.03	46.31	69.32	49.90
2006	6.57	6.22	6.55	6.82	6.57	38.97	50.42	76.08	53.54
2007	6.21	5.88	6.47	6.46	6.21	40.47	49.76	75.96	53.90
2008	7.89	7.47	8.17	8.14	8.61	44.69	54.08	104.75	65.53
2009	3.85	3.65	3.99	4.10	6.12	19.68	21.04	67.64	34.48
CONSTANT PRICES									
December 31, 2009 [6]	5.50	est. 5.21	5.79	5.75	6.71	48.18	28.62	75.67	50.56
CURRENT YEAR FORECAST									
2010	5.50	5.21	5.89	5.75	7.17	42.48	49.09	84.04	56.93
FUTURE FORECAST									
2011	6.20	5.68	6.63	6.45	7.91	43.84	50.96	87.23	58.99
2012	6.50	5.97	6.96	6.75	8.24	45.20	52.82	90.42	61.05
2013	7.00	6.25	7.49	7.25	8.77	47.01	55.30	94.67	63.80
2014	7.20	6.44	7.70	7.45	8.98	48.82	57.79	98.93	66.54
2015	7.40	6.63	7.92	7.65	9.20	50.63	60.27	103.18	69.29
2016	7.60	6.76	8.13	7.85	9.41	51.99	62.14	106.37	71.35
2017	7.90	6.90	8.45	8.15	9.73	52.90	63.39	108.52	72.73
2018	8.20	7.04	8.77	8.45	10.05	53.83	64.67	110.71	74.15
2019	8.36	7.18	8.95	8.61	10.23	54.78	65.98	112.94	75.59
2020	8.53	7.32	9.13	8.78	10.41	55.75	67.31	115.22	77.06
2021	8.70	7.47	9.31	8.95	10.59	56.74	68.66	117.55	78.56
2022	8.88	7.62	9.50	9.13	10.78	57.75	70.05	119.92	80.09
2023	9.05	7.77	9.69	9.30	10.97	58.78	71.46	122.33	81.65
2024	9.23	7.92	9.88	9.48	11.16	59.83	72.90	124.80	83.24
2025	9.42	8.08	10.08	9.67	11.36	60.90	74.37	127.32	84.87

Constant thereafter

Notes:

[1] Alberta 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] December 31, 2009 is the last trading day of 2009.

The Company's weighted average prices received this fiscal year are: $3.42/Mscf for natural gas.

Part 4 – Reconciliation of Changes in Reserves

The Company is filing the first Reserves statement. The company had no reserves as of December 31, 2008 since the major transaction was not complete until January 6, 2009. Therefore there is no comparison or reconciliation of reserves possible.

Part 5 – Additional Information Relating to Reserves Data

Undeveloped Reserves

The Company had no proved undeveloped reserve as at December 31, 2009 or in prior years.

The following table sets forth the volumes of probable undeveloped net reserves that were attributed for each of the Company's product types for the most recent three financial years and in the aggregate before that time:

	Light and Medium Oil (Mbbl)	**Heavy Oil (Mbbl)**	**Natural Gas (MMscf)**	**Natural Gas Liquids (Mbbl)**
Aggregate prior to 2006	0	0	0	0
2007	0	0	0	0
2008	0	0	0	0
2009	0	0	430	7

The following table sets forth the volumes of possible undeveloped reserves that were attributed for each of the Company's product types for the most recent three financial years and in the aggregate before such time:

	Light and Medium Oil (Mbbl)	**Heavy Oil (Mbbl)**	**Natural Gas (MMscf)**	**Natural Gas Liquids (Mbbl)**
Aggregate prior to 2006	0	0	0	0
2007	0	0	0	0
2008	0	0	0	0
2009	0	0	551	0

The following discussion generally describes the basis on which the Company attributes probable and possible undeveloped reserves and its plans for developing those undeveloped reserves.

<u>Probable Undeveloped Reserves</u>

The Company's probable undeveloped reserves are in the Montney formation in the Gold Creek area of north western Alberta which has been logged and tested in a vertical well but requires a fractured horizontal well to be drilled to obtain commercial production. The horizontal well is forecast to be drilled in 2011.

<u>Possible Undeveloped Reserves</u>

The Company's Possible Undeveloped reserves are located in the Cardium formation in the Noel area of north eastern British Columbia where log analysis indicates that hydrocarbons are present but since only one well in the area has been productive from the Cardium there is some uncertainty as to whether commercial production can be obtained from this zone on Company lands. A shallow twin well is scheduled to be drilled in 2011 to develop this reserve.

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.

Certain information regarding the Company set forth in this report, including management's assessment of the Company's future plans and operations contain forward-looking statements that involve substantial known and unknown risks and uncertainties. These risks include, but are not limited to: the risks associated with the oil and gas industry, commodity prices and exchange rates; industry related risks could include, but are not limited to, operational risks in exploration, development and production, delays or changes in plans, risks associated with the uncertainty of reserve estimates, health and safety risks and the uncertainty of estimates and projections of production, costs and expenses. Competition from other producers, the lack of available qualified personnel or management, stock market volatility and ability to access sufficient capital from internal and external sources are additional risks the Company faces in this market. The Company's actual results, performance or achievements could differ materially from those expressed in, or implied by, these forward looking statements and accordingly, no assurance can be given that any events anticipated by the forward looking statements will transpire or occur, if any of them do, what benefits the Company can derive from. The reader is cautioned not to place undue reliance on this forward looking information.

Future Development Costs

The following table shows the development costs anticipated in the next five years, which have been deducted in the estimation of the future net revenues of the proved and probable reserves.

	Total Proved Estimated Using Forecast Prices and Costs (Undiscounted) ($M)	**Total Proved Plus Probable Estimated Using Forecast Prices and Costs (Undiscounted)** ($M)
2010	200	359
2011	20	534
2012	0	0
2013	0	0
2014	0	0
Total for five years	220	893
Remainder	0	0
Total for all years	220	893

The Company has been successful in raising its required capital through equity financings and plans to continue to do so for the development costs specified above. The effect of the costs of the expected funding would have no impact on the revenues or reserves currently being reported.

Part 6 – Other Oil and Gas Information

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 December 31, 2009:

	Oil		Natural Gas	
	Gross(1)	Net(1)	Gross(1)	Net(1)
Noel, BC Area				
Producing	-	-	1	0.2850
Non-producing	-	-	-	-
Innisfail, AB Area				
Producing	-	-	-	-
Non-producing	1	1	-	-
Gold Creek, AB Area				
Producing	-	-	-	-
Non-producing	-	-	2	0.3780
Total for All Areas:	1	1	3	0.6630

All of the Company's wells are located onshore in the western Canadian provinces of Alberta and British Columbia in or near active oil or gas fields.

Properties with No Attributed Reserves

The Company owns one section of land containing one non-producing gas well in the Valhalla area of north western Alberta to which no reserves have been attributed due to insufficient information being available at the time the report was prepared, but which appears to be prospective for gas production from the Montney.

Forward Contracts

Currently, the Company has no forward contracts.

Additional Information Concerning Abandonment and Reclamation Costs

The estimated abandonment and restoration costs used by Chapman are based on the AEUB Directive 11, which details the typical costs of abandonment and reclamation by well type in each specific geographic region. The Company expects to have costs relating to 2.1 net wells, including the locations to be drilled. Costs have been included in the Chapman report for all wells and locations except for one Gold Creek area well to which no reserves were assigned. This well is estimated to have an abandonment cost of $12,500 to the Company in addition to the values presented below.

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)
2010	0	0	0	0
2011	0	0	0	0
2012	0	0	0	0
Total for three years	0	0	0	0
Remainder	32	10	93	18
Total for all years	32	10	93	18

Tax Horizon

The Company is expected to become taxable in 2012 and thereafter in the total proved case and in 2011 and thereafter in the proved plus probable case.

Costs Incurred

The following table summarizes the capital expenditures made by the Company on oil and natural gas properties for the year ended December 31, 2009.

Property Acquisition Costs ($M)		Exploration Costs ($M)	Development Costs ($M)
Proved Properties	Unproved Properties		
-	992,535	47,812	158,889

Exploration and Development Activities

The following table sets forth the number of exploratory and development wells which the Company completed during its 2009 financial year:

	Exploratory Wells		Development Wells	
	Gross[(1)]	Net[(1)]	Gross[(1)]	Net[(1)]
Oil Wells	0	0	0	0
Gas Wells	0	0	0	0
Service Wells	0	0	0	0
Dry Holes	0	0	0	0
Total Completed Wells	0	0	0	0

The Company did not drill or develop any additional reserves in the fiscal year. The Company conducted one well tie-in and two well workovers during the fiscal year ended December 31, 2009.

Production Estimates

The following table sets forth the volume of production estimated by Chapman for 2010 (12 mo.):

TOTAL PROVED RESERVES

AREA	Light and Medium Oil (Mbbl)	Heavy Oil (Mbbl)	Natural Gas (MMscf)	Natural Gas Liquids (Mbbl)
Gold Creek, AB	0	0	0	0
Innisfail, AB	11	0	0	0
Noel, BC	0	0	0	0
Total for all areas	**11**	**0**	**0**	**0**

TOTAL PROVED PLUS PROBABLE RESERVES

AREA	Light and Medium Oil (Mbbl)	Heavy Oil (Mbbl)	Natural Gas (MMscf)	Natural Gas Liquids (Mbbl)
Gold Creek, AB	0	0	47	1
Innisfail, AB	14	0	0	0
Noel, BC	0	0	11	0
Total for all areas	**14**	**0**	**58**	**1**

These values are gross to Company's working interest before 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 March 31, 2009	Three Months Ended June 30, 2009	Three Months Ended September 30, 2009	Three Months Ended December 31, 2009
Average Daily Production				
Light and Medium Oil (Bbl/d)				
Natural Gas (Mscf/d)	94	85	62	88
Average Net Prices Received				
Light and Medium Oil ($/Bbl)				
Natural Gas ($/Mscf)	4.4	2.8	2.0	3.9
Royalties				
Light and Medium Oil ($/Bbl)				
Natural Gas ($/Mscf)	.53	.21	.10	.37
Production Costs				
Light and Medium Oil ($/Bbl)				
Natural Gas ($/Mscf)	2.22	3.44	5.49	2.98
Netback Received				
Light and Medium Oil ($/Bbl)				
Natural Gas ($/Mscf)	1.1	-1.21	-3.76	-.15

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
NGLs	natural gas liquids
STB	stock tank barrels of oil
STB/d	stock tank barrels of oil per day

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
Bscf	billion standard cubic feet
GJ	gigajoule

Other

AECO	Niska Gas Storage'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