FORM 51-101F1

STATEMENT OF RESERVES DATA
AND OTHER OIL AND NATURAL GAS INFORMATION

Valeura Energy Inc. (the "**Corporation**") engaged GLJ Petroleum Consultants ("**GLJ**") to prepare a report relating to the Corporation's reserves as at December 31, 2010. The reserves on the properties described herein are estimates only. Actual reserves on these properties may be greater or less than those estimated.

The Corporation's crude oil and natural gas reserves are located in Alberta, Canada. Set out below is a summary of the crude oil and natural gas reserves and the value of future net revenue of the Corporation as at December 31, 2010 as evaluated by GLJ in its report dated February 16, 2011 (the "**GLJ Report**"). The preparation date of the GLJ Report is February 10, 2011. The pricing used in the forecast price evaluations is set forth in the notes to the tables.

The GLJ Report was prepared using assumptions and methodology guidelines outlined in the Canadian Oil and Gas Evaluation Handbook and in accordance with National Instrument 51-101 - *Standards of Disclosure for Oil and Gas Activities* ("**NI 51-101**").

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 Corporation's reserves. There is no assurance that the forecast price and cost assumptions contained in the GLJ Report will be attained and variances could be material. Other assumptions and qualifications relating to costs and other matters are included in the GLJ Report. The recovery and reserves estimates on the Corporation's properties described herein are estimates only. The actual reserves on the Corporation's properties may be greater or less than those calculated.

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

	Light and Medium Oil		Heavy Oil		Natural Gas		Natural Gas Liquids		Total Oil Equivalent	
	Gross(1) (Mbbl)	Net(1) (Mbbl)	Gross(1) (Mbbl)	Net(1) (Mbbl)	Gross(1) (MMcf)	Net(1) (MMcf)	Gross(1) (Mbbl)	Net(1) (Mbbl)	Gross(1) (Mboe)	Net(1) (Mboe)
Proved Developed Producing(2)(6)	90	80	10	9	954	861	24	18	283	250
Proved Developed Non-Producing(2)(7)	26	23	0	0	94	77	2	1	44	37
Proved Undeveloped(2)(8)	0	0	0	0	0	0	0	0	0	0
Total Proved(2)	116	104	10	9	1,047	938	26	19	327	288
Total Probable(3)	208	181	5	4	1,640	1,425	67	49	554	471
Total Proved Plus Probable(2)(3)	324	284	15	13	2,687	2,363	93	68	880	759

NET PRESENT VALUES OF FUTURE NET REVENUE BASED ON FORECAST PRICES AND COSTS[9]

	Before Deducting Income Taxes Discounted At					After Deducting Income Taxes Discounted At				
	0% (M$)	5% (M$)	10% (M$)	15% (M$)	20% (M$)	0% (M$)	5% (M$)	10% (M$)	15% (M$)	20% (M$)
Proved Developed Producing[2][6]	4,402	3,805	3,375	3,045	2,783	4,402	3,805	3,375	3,045	2,783
Proved Developed Non-Producing[2][7]	1,657	1,310	1,060	874	732	1,657	1,310	1,060	874	732
Proved Undeveloped[2][8]	0	0	0	0	0	0	0	0	0	0
Total Proved[2]	6,059	5,115	4,435	3,919	3,515	6,059	5,115	4,435	3,919	3,515
Total Probable[3]	13,669	9,541	7,057	5,441	4,326	13,669	9,541	7,057	5,441	4,326
Total Proved Plus Probable[2][3]	19,728	14,656	11,492	9,360	7,841	19,728	14,656	11,492	9,360	7,841

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

	Revenue (M$)	Royalties (M$)	Operating Costs (M$)	Development Costs (M$)	Abandonment Costs (M$)	Future Net Revenue Before Income Taxes (M$)	Income Taxes (M$)	Future Net Revenue After Income Taxes (M$)
Total Proved[2]	17,562	2,014	8,689	493	307	6,059	0	6,059
Total Proved Plus Probable[2][3]	50,711	6,416	21,121	2,981	464	19,728	0	19,728

FUTURE NET REVENUE BY PRODUCTION GROUP BASED ON FORECAST PRICES AND COSTS[9]

		Future Net Revenue Before Income Taxes (Discounted at 10%/Year)		
	Production Group	(M$)	$/boe[10]	$/Mcfe[11]
Total Proved[2]	Light and medium crude oil[12]	3,294	19.45	3.24
	Heavy oil[12]	320	30.99	5.17
	Natural gas[13]	821	7.61	1.27
Total Proved[2]		4,435	15.42	2.57
Total Proved Plus Probable[2][3]	Light and medium crude oil[12]	9,220	17.48	2.91
	Heavy oil[12]	411	26.86	4.48
	Natural gas[13]	1,861	8.62	1.44
Total Proved Plus Probable[2][3]		11,492	15.15	2.52

The pricing assumptions used in the GLJ Report with respect to net present values of future net revenue (forecast) as well as the inflation rates used for operating and capital costs are set forth below. GLJ is an independent qualified reserves evaluator appointed pursuant to NI 51-101.

FORECAST PRICES, INFLATION & EXCHANGE RATES USED IN GLJ REPORT

	Natural Gas		Natural Gas Liquids Edmonton						Inflation Rate	Exchange Rate
Year	**AECO Gas Price ($CDN/mmbtu)**	**Henry Hub NYMEX Near Month Contract ($US/mmbtu)**	**Edmonton Propane ($CDN/bbl)**	**Edmonton Butane ($CDN/bbl)**	**Edmonton Pentanes Plus ($CDN/bbl)**	**Spec Ethane ($CDN/bbl)**	**Light Sweet Crude Oil (40 API, 0.3%S) at Edmonton**	**NYMEX WTI Near Month Futures Contract Crude Oil at Cushing Oklahoma ($US/bbl)**	**%/year**	**$US/$CDN**
2011	4.16	4.50	54,32	67.26	90.54	13.66	86.22	88.00	2.0	0.98
2012	4.74	5.15	56.25	68.75	91.96	15.68	89.29	89.00	2.0	0.98
2013	5.31	5.75	57.28	70.01	92.74	17.62	90.92	90.00	2.0	0.98
2014	5.77	6.25	58.56	71.58	94.82	19.21	92.96	92.00	2.0	0.98
2015	6.22	6.75	60.60	74.07	98.12	20.79	96.19	95.17	2.0	0.98
2016	6.53	7.10	62.13	75.94	100.59	21.85	98.62	97.55	2.0	0.98
2017	6.76	7.32	63.87	78.07	103.42	22.62	101.39	100.26	2.0	0.98
2018	6.90	7.47	65.47	80.02	106.00	23.14	103.92	102.74	2.0	0.98
2019	7.06	7.62	67.21	82.15	108.82	23.67	106.68	105.45	2.0	0.98
2020	7.21	7.77	68.57	83.80	111.01	24.20	108.84	107.56	2.0	0.98
2021+	+2.0%/yr thereafter	+2.0%/yr thereafter	+2.0%/yr thereafter	+2.0%/yr thereafter	+2.0%/yr thereafter	+2.0%/yr thereafter	+2.0%/yr thereafter	+2.0%/yr thereafter	2.0	0.98

The Corporation's weighted average historical prices for the year ended December 31, 2010 were:

Natural Gas ($CDN/mcf)	**Light and Medium Oil ($CDN/bbl)**	**Natural Gas Liquids ($CDN/bbl)**
3.93	68.20	44.63

RECONCILIATION OF THE CORPORATION'S GROSS RESERVES BY PRINCIPAL PRODUCT TYPE BASED ON FORECAST PRICES AND COSTS (9)

The following table sets forth a reconciliation of the changes in the Corporation's working interest, before royalties, of light and medium crude oil, heavy oil, natural gas, natural gas liquids and oil equivalent reserves as at December 31, 2010 against such reserves as at December 31, 2009 based on the forecast price and cost assumptions set forth in Note 9:

	Light and Medium Oil			**Heavy Oil**			**Natural Gas**		
	Gross Proved (Mbbl)	**Gross Probable (Mbbl)**	**Gross Proved Plus Probable (Mbbl)**	**Gross Proved (Mbbl)**	**Gross Probable (Mbbl)**	**Gross Proved Plus Probable (Mbbl)**	**Gross Proved (MMcf)**	**Gross Probable (MMcf)**	**Gross Proved Plus Probable (MMcf)**
At December 31, 2009	130	206	336	0	0	0	1,067	1,674	2,741
Extensions	0	0	0	0	0	0	0	0	0
Improved Recovery	0	0	0	0	0	0	0	0	0
Technical Revisions	(7)	(1)	(8)	0	0	0	(24)	(209)	(232)
Discoveries	0	0	0	0	0	0	0	0	0
Acquisitions	16	3	19	11	5	16	324	174	498
Dispositions	0	0	0	0	0	0	0	0	0
Economic Factors	0	0	0	0	0	0	0	0	0
Production	(23)	0	(23)	(1)	0	(1)	(320)	0	(320)
At December 31, 2010	116	208	324	10	5	15	1,047	1,640	2,687

	Natural Gas Liquids			Oil Equivalent		
	Gross Proved (Mbbl)	**Gross Probable (Mbbl)**	**Gross Proved Plus Probable (Mbbl)**	**Gross Proved (Mboe)**	**Gross Probable (Mboe)**	**Gross Proved Plus Probable (Mboe)**
At December 31, 2009	43	41	84	351	526	877(14)
Extensions	0	0	0	0	0	0
Improved Recovery	0	0	0	0	0	0
Technical Revisions	(11)	26	15	(22)	(10)	(32)
Discoveries	0	0	0	0	0	0
Acquisitions	1	0	1	82	37	119
Dispositions	0	0	0	0	0	0
Economic Factors	0	0	0	0	0	0
Production	(7)	0	(7)	(84)	0	(84)
At December 31, 2010	26	67	93	327	554	880

Notes:

1. "**Gross Reserves**" are the Corporation's working interest (operating or non-operating) share before deducting of royalties and without including any royalty interests of the Corporation. "**Net Reserves**" are the Corporation's working interest (operating or non-operating) share after deduction of royalty obligations, plus the Corporation'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 GLJ 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 in the preceding table titled "**Forecast Prices, Inflation & Exchange Rates Used in GLJ Report**". The Forecast Prices, Inflation & Exchange rates were developed by GLJ as at January 1, 2011 and reflect the then current year forecast prices, inflation and exchange rates. GLJ is an independent qualified reserves evaluator appointed pursuant to NI 51-101.

10. "**boe**" means barrel of oil equivalent, derived by converting gas to oil in the ratio of six thousand cubic feet of gas to barrel of oil. Boes may be misleading, particularly if used in isolation. A boe conversion ratio of 6 Mcf to 1bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

11. "**Mcfe**" means thousand cubic feet of sales gas equivalent derived by converting oil to gas in the ratio of one barrel of oil to six thousand cubic feet of gas. Mcfes may be misleading, particuarly if used in isolation. A Mcfe conversion ratio of 1 bbl to 6 Mcf is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

12. Including solution gas and other by-products associated with oil production.

13. Including non-associated gas by-products but excluding solution gas.

14. The Corporation is the resulting entity following the Corporation's acquisition of all of the issued and outstanding common shares of Northern Hunter Energy Inc. ("**Northern Hunter**"), a private oil and gas company, on April 9, 2010, pusuant to a plan of arrangement under the *Business Corporations Act* (Alberta). The Corporation's acquisition of all of the issued and oustanding Northern Hunter common shares pursuant to the arrangement was accounted for under Generally Accepted Accounting Principles as a reverse take-over of the Corporation by Northern Hunter. As such, reserves of the Corporation at December 31, 2009 are those of Northern Hunter, and exclude at such date the Corporation's gross proved plus probable reserves of 46 Mboe (as evaluated by Sproule Associates Limited in a report dated April 9, 2010 with an effective date of December 31, 2009) and which are included in reserves acquired in 2010 as set forth in the table above.

Proved Undeveloped Reserves

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

	Light and Medium Oil (Mbbl)	Heavy Oil (Mbbl)	Natural Gas (MMcf)	Natural Gas Liquids (Mbbl)	Oil Equivalent (Mboe)
Aggregate prior to December 31, 2008	--- (1)	--- (1)	--- (1)	--- (1)	--- (1)
December 31, 2008	26(2)	-- (2)	10(2)	-- (2)	-- 28(2)
December 31, 2009	--	--	--	--	--
December 31, 2010	--	--	--	--	--

Notes:

1. Prior to December 31, 2009, Northern Hunter did not request its reserve evaluator to prepare attribution information as Northern Hunter was a private company; thus, no attribution information is available for the Northern Hunter portion of the Corporation's reserves for the years prior to 2008. For the year ended December 31, 2009, the Corporation (formerly PanWestern Energy Inc. ("**PWE**") and managed by a previous management team) filed its Statement of Reserves Data on SEDAR (www.sedar.com), which listed no attributions of Proved Undeveloped Reserves for the years prior to 2008.
2. As evaluated by Sproule Associates Limited in a report dated April 9, 2010 with an effective date of December 31, 2009.

Probable Undeveloped Reserves

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

	Light and Medium Oil (Mbbl)	Heavy Oil (Mbbl)	Natural Gas (MMcf)	Natural Gas Liquids (Mbbl)	Oil Equivalent (Mboe)
Aggregate prior to December 31, 2008	--- (1)	--- (1)	--- (1)	--- (1)	--- (1)
December 31, 2008	9(2)	--(2)	3(2)	--(2)	9(2)
December 31, 2009	82	--	624	14	200
December 31, 2010	--	--	--	--	--

Notes:

1. Prior to December 31, 2009, Northern Hunter did not request its reserve evaluator to prepare attribution information as Northern Hunter was a private company; thus, no attribution information is available for the Northern Hunter portion of the Corporation's reserves for the years prior to 2008. For the year ended December 31, 2009, the Corporation (formerly PanWestern Energy Inc. ("**PWE**") and managed by a previous management team) filed its Statement of Reserves Data on SEDAR (www.sedar.com), which listed no attributions of Proved Undeveloped Reserves for the years prior to 2008.
2. As evaluated by Sproule Associates Limited in a report dated April 9, 2010 with an effective date of December 31, 2009.

The majority of Probable Undeveloped Reserves are assigned in the Grand Forks/Hays area and are related to three offset Probable well locations immediately adjacent to producing wells. These offset well locations are in the process of technical review for development and if the Corporation, based on such technical review, decides to develop such Probable Undeveloped Reserves, such development is expected to occur within the next two years.

Significant Factors or Uncertainties

The process of evaluating reserves is inherently 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, prices and economic conditions and other factors and assumptions that may affect the reserve estimates and the present worth of future net revenue there from. These factors and assumptions include, among others: (i) historical production in the area compared with production rates from analogous areas; (ii) initial production rates; (iii) production decline rates; (iv) ultimate recovery of reserves; (v) success of future development activities; (vi) marketability of production; (vii) effect of government regulations; and (viii) other government levies imposed over the life of the reserves.

As circumstances change and additional data becomes available, reserve estimates also change. Estimates are reviewed and revised, either upward or downward, as warranted by the new information. Revisions are often required due to changes in well performance, prices, economic conditions and government restrictions. Revisions to reserve estimates can arise from changes in year end prices, reservoir performance and geological conditions or production. These revisions can be either positive or negative.

While we do not anticipate any significant economic factors or significant uncertainties will affect any particular component of the reserve data, the reserves can be affected significantly by fluctuations in product pricing, capital expenditures, operating costs, royalty regimes and well performance that are beyond the Corporation’s control.

Future Development Costs

The following table sets forth the development costs deducted in the estimation of future net revenue attributable to each of the following reserves categories contained in the GLJ Report:

	Total Proved Estimated Using Forecast Prices and Costs (M$)	**Total Proved Plus Probable Estimated Using Forecast Prices and Costs** (M$)
2011	399	544
2012	94	2,389
2013	0	7
2014	0	0
2015	0	9
Remainder	0	32
Total for all years undiscounted	493	2,981

The Corporation’s primary source of liquidity to fund its estimated future development costs, as outlined in the above table, is derived from the Corporation’s internally-generated cash flow, debt financing when deemed appropriate and new equity issues if made on favourable terms.

In order to continually grow and expand the oil and gas reserves and production base of the Corporation, disciplined operating cash flow reinvestment into high rate of return capital projects, in conjunction with sound financial management, will be one of the Corporation’s business philosophies.

Oil and Gas Properties and Wells

The Corporation's major property is Grand Forks/Hays located in the province of Alberta and its production is oil, gas and natural gas liquids. Oil is trucked for processing and sold to a third party marketer. Raw gas is pipelined to a third party facility for processing. Processed natural gas and natural gas liquids are sold to a third party from the processing facility. All other properties of the Corporation are considered minor with raw production either trucked or pipelined for processing and sales via third party marketing contracts. All of the Corporation's production is onshore and located in the province of Alberta.

All of Corporation's oil and gas wells are in the province of Alberta. The Corporation has two wells that are owned 100% on a helium prospect in Saskatchewan. A listing of producing and non producing wells not including the two Saskatchewan helium wells (2 Gross and Net wells) are listed below:

	Oil Wells		Natural Gas Wells	
	Gross(1)	**Net(2)**	**Gross(1)**	**Net(2)**
Producing	20	7.8	13	3.7
Non-producing	7	1.0	3	1.3
Total	27	8.8	16	5.0

Notes:

1. "**Gross Wells**" are the total number of wells in which the Corporation has an interest.
2. "**Net Wells**" are the number of wells obtained by aggregating the Corporation's working interest in each of its gross wells.

Properties with No Attributed Reserves

The following table sets out the Corporation's undeveloped land position effective December 31, 2010:

	Undeveloped Acreage	
	Gross(1)	**Net(1)**
Saskatchewan	150,374	150,374
Alberta	20,264	11,496
Total	170,638	161,870

Note:

1. "**Gross**" means the total number of acres in which the Corporation has a working interest. "**Net**" means the number of acres obtained by aggregating the Corporations's working interest in each of its acreage positions.

A total of 13,100 net acres of land will expire or will require conversion from a permit to lease in 2011. The permit portion of the expiring acreage is 10,689 acres associated with the Corporation's Saskatchewan helium properties. The Corporation is evaluating the possible farm-out of these permit lands and other lands in the area. Failing a successful conclusion of a farm-out of the permit lands, the Corporation will evaluate what portion of the expiring permit lands will be retained under a lease application.

Significant Factors or Uncertainties Relevant to Properties with No Attributed Reserves

At this time the Corporation has no material value expectations for any of its Canadian properties that have no attributed reserves.

Forward Contracts

Currently there are no material forward contracts or commitments.

Abandonment and Reclamation Costs

All producing or wells assigned reserves are included in the GLJ Report and are assigned abandonment costs.

Abandonment costs are estimated on an area by area basis by GLJ. The industry's historical costs are used when available. If representative comparisons are not readily available, an estimate is prepared based on the various regulatory abandonment requirements. The Corporation currently has 13.8 net wells for which abandonment and reclamation costs are expected to be incurred.

The total abandonment cost in respect of proved reserves using forecast prices is $0.3 million (undiscounted) and $0.2 million (discounted at 10%). 100% of such amounts were deducted as abandonment costs in estimating the Corporation's future net revenue as disclosed above.

Well abandonment costs for all wells with reserves have been included at the property level. Additional abandonment costs associated with non-reserves wells, lease reclamation costs and facility abandonment and reclamation expenses have not been included in this analysis.

Tax Horizon

The Corporation was not required to pay any cash income taxes for the period ended December 31, 2010. Based on current estimates of the Corporation's future taxable income and levels of tax deductible expenditures, management believes that the Corporation will not be required to pay cash income taxes for the life of the Total Proved Reserves.

Costs Incurred

The following table summarizes the capital expenditures made by the Corporation on oil and natural gas properties for the year ended December 31, 2010.

	Property Acquisition Costs (M$)		**Exploration Costs (M$)**	**Development Costs (M$)**
	Proved Properties	**Unproved Properties**		
Canada	0	3	0	1,482
Turkey	0	0	4,440	943
	0	0	4,440	2,425

Exploration and Development Activities

The following table sets forth the number of wells the Corporation drilled for the year ended December 31, 2010:

	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	1	0.5	0	0
Total Wells	1	0.5	0	0

Note:

1. "**Gross Wells**" are the total number of wells in which the Corporation has an interest. "**Net Wells**" are the number of wells obtained by aggregating the Corporation's working interest in each of its gross wells.

The Corporation has interests in 10 gross wells in the Grand Forks/Hays area and holds a 50% to 100% working interest position in 22.5 sections of land in the Grand Forks/Hays area. The main producing intervals are the Nisku-Arcs and Sawtooth formations.

Production Estimates

The following table sets forth the volume of working interest production, before royalties, estimated for 2011 which is reflected in the estimate of future net revenue disclosed in the tables of reserve information in respect of gross proved and probable reserves:

	Light and Medium Oil (bbl/d)	**Heavy Oil (bbl/d)**	**Natural Gas (Mcf/d)**	**Natural Gas Liquids (bbl/d)**
Proved Developed Producing(2)(6)				
Grand Forks/Hays	43	0	285	9
Other Properties	12	4	232	7
Total Proved Developed Producing	54	4	517	16
Proved Developed Non-Producing(2)(7)				
Grand Forks/Hays	7	0	0	0
Other Properties	0	0	0	0
Total Proved Developed Non-Producing	7	0	0	0
Proved Undeveloped(2)(8)				
Grand Forks/Hays	0	0	0	0
Other Properties	0	0	0	0
Total Proved Undeveloped	0	0	0	0
Total Proved(2)				
Grand Forks/Hays	50	0	285	9
Other Properties	12	4	232	7
Total Proved	61	4	517	16
Total Probable(3)				
Grand Forks/Hays	13	0	32	1
Other Properties	0	0	8	0
Total Probable	13	0	40	1
Total Proved Plus \ Probable(2)(3)				
Grand Forks/Hays	62	0	317	10
Other Properties	12	4	240	7
Total Proved Plus Probable	75	4	557	17

Note:

See Notes that follow the preceding table titled "**Reconciliation of the Corporation's Gross Reserves by Principal Product Type Based on Forecast Prices and Costs**".

Production History

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

	Three Months Ended March 31, 2010	Three Months Ended June 30, 2010	Three Months Ended September 30, 2010	Three Months Ended December 31, 2010
Average Daily Production				
Light and Medium Oil (bbl/d)	53	76	72	60
Heavy Oil (bbl/d)	0	0	0	0
Natural Gas (Mcf/d)	967	994	906	714
Natural Gas Liquids (bbl/d)	24	21	20	14
BOEs (boe/d	239	263	243	193
Average Net Prices Received				
Light and Medium Oil ($/bbl)	71.36	66.44	65.06	71.42
Heavy Oil ($/bbl)	-	-	-	-
Natural Gas ($/Mcf)	4.82	3.83	3.49	3.46
Natural Gas Liquids ($/bbl)	45.23	45.84	38.95	49.75
BOEs ($/boe)	40.08	37.35	35.54	38.63
Royalties				
Light and Medium Oil ($/bbl)	4.63	11.80	7.03	1.26
Heavy Oil ($/bbl)	-	-	-	-
Natural Gas ($/Mcf)	0.25	0.09	(0.07)	(0.27)
Natural Gas Liquids ($/bbl)	13.32	15.22	19.18	17.21
BOEs ($/boe)	3.42	4.99	3.40	0.65
Production Costs				
Light and Medium Oil ($/bbl)	23.64	25.59	26.73	22.46
Heavy Oil ($/bbl)	-	-	-	-
Natural Gas ($/Mcf)	2.82	2.75	2.88	3.22
Natural Gas Liquids ($/bbl)	14.22	19.60	18.52	17.75
BOEs ($/boe)	18.14	19.36	20.18	20.19
Transportation				
Light and Medium Oil ($/bbl)	-	-	-	-
Heavy Oil ($/bbl)	-	-	-	-
Natural Gas ($/Mcf)	0.25	0.27	0.27	0.19
Natural Gas Liquids ($/bbl)	-	-	-	-
BOEs ($/bbl)	1.02	1.00	1.02	0.71
Netback Received				
Light and Medium Oil ($/bbl)	43.09	29.05	31.30	47.70
Heavy Oil ($/bbl)	-	-	-	-
Natural Gas ($/Mcf)	1.50	0.72	0.41	0.32
Natural Gas Liquids ($/bbl)	17.69	11.02	1.25	14.79
BOEs ($/bbl)	17.50	12.00	10.94	17.08

The following table sets forth certain information in respect of production that is included in the preceding table and is attributable to Grand Forks/Hays property:

	Three Months Ended March 31, 2010	Three Months Ended June 30, 2010	Three Months Ended September 30, 2010	Three Months Ended December 31, 2010
Average Daily Production				
Light and Medium Oil (bbl/d)	50	53	51	42
Heavy Oil (bbl/d)	-	-	-	-
Natural Gas (Mcf/d)	516	505	429	287
Natural Gas Liquids (bbl/d)	12	12	10	7
BOEs (boe/d)	148	149	132	97