STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

Disclosure of Reserves Data

In accordance with National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities ("NI 51-101"), Sproule Associates Limited ("Sproule") prepared a report (the "Sproule Report") dated March 19, 2008 and effective December 31, 2007. The Sproule Report evaluated the oil, natural gas liquids ("NGL") and natural gas reserves of Richards Oil & Gas Limited (the "Company") as at December 31, 2007. The preparation date of the information regarding the reserves in the Sproule Report is January to March 2008.

The tables below are a summary of the oil, NGL and natural gas reserves of the Company and the net present value of future net revenue attributable to such reserves as evaluated in the Sproule Report based on forecast price and cost assumptions. The tables summarize the data contained in the Sproule Report and as a result may contain slightly different numbers than such report due to rounding. Also due to rounding, certain columns may not add exactly.

The net present value of future net revenue attributable to the Company's reserves is stated without provision for interest costs and general and administrative costs, but after providing for estimated royalties, production costs, development costs, other income, future capital expenditures, and well abandonment costs for only those wells assigned reserves by Sproule. It should not be assumed that the undiscounted or discounted net present value of future net revenue attributable to the Company's reserves estimated by Sproule represent the fair market value of those reserves. Other assumptions and qualifications relating to costs, prices for future production and other matters are summarized herein. The recovery and reserve estimates of the Company's oil, NGL and natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual reserves may be greater than or less than the estimates provided herein.

The values shown for income taxes and future net revenue after income taxes were calculated on a stand-alone basis in the Sproule Report. The values shown may not be representative of future income tax obligations, applicable tax horizon or after tax valuation.

The Sproule Report is based on certain factual data supplied by the Company and Sproule's opinion of reasonable practice in the industry. The extent and character of ownership and all factual data pertaining to the Company's petroleum and natural gas properties and contracts (except for certain information residing in the public domain) were supplied by the Company to Sproule and accepted without any further investigation. Sproule accepted this data as presented and neither title searches nor field inspections were conducted.

All of the reserves held by the Company are located in Canada, and specifically, in the provinces of Alberta and Saskatchewan.

Reserves Data (Forecast Prices and Costs)

Summary of Oil and Gas Reserves
Forecast Prices and Costs

Reserve Category	Light & Medium Oil Gross (Mbbl)	Light & Medium Oil Net (Mbbl)	Heavy Oil Gross (Mbbl)	Heavy Oil Net (Mbbl)	Conventional Natural Gas Gross (MMcf)	Conventional Natural Gas Net (MMcf)	Coalbed Methane Gross (MMcf)	Coalbed Methane Net (MMcf)	Natural Gas Liquids Gross (Mbbl)	Natural Gas Liquids Net (Mbbl)
Proved										
Developed Producing	-	-	7	6	138	108	1,625	1,398	-	-
Developed Non-Producing	-	-	-	-	-	-	607	540	-	-
Undeveloped	-	-	-	-	-	-	4,553	3,853	-	-
Total Proved	-	-	7	6	138	108	6,785	5,791	-	-
Probable	-	-	3	3	38	30	3,807	3,208	-	-
Total Proved + Probable	**-**	**-**	**10**	**9**	**176**	**138**	**10,592**	**8,999**	**-**	**-**

Summary of Net Present Values of Future Net Revenue
Forecast Prices and Costs

Reserve Category	Before Income Taxes Discounted at (%/year) 0 (M$)	5 (M$)	10 (M$)	15 (M$)	20 (M$)	Unit Value Before Income Tax Discounted at 10% $/BOE
Proved						
Developed Producing	6,209	5,305	4,708	4,252	3,886	18.28
Developed Non-Producing	1,184	911	706	547	423	7.85
Undeveloped	4,168	2,052	547	-512	-1,260	0.85
Total Proved	**11,561**	**8,268**	**5,961**	**4,288**	**3,049**	**6.02**
Probable	8,131	4,898	2,975	1,767	986	5.48
Total Proved + Probable	**19,692**	**13,166**	**8,936**	**6,055**	**4,035**	**5.83**

Reserve Category	After Income Taxes Discounted at (%/year) 0 (M$)	5 (M$)	10 (M$)	15 (M$)	20 (M$)
Proved					
Developed Producing	6,209	5,305	4,708	4,252	3,886
Developed Non-Producing	1,184	911	706	547	423
Undeveloped	4,168	2,052	547	-512	-1,260
Total Proved	**11,561**	**8,268**	**5,961**	**4,288**	**3,049**
Probable	8,131	4,898	2,975	1,767	986
Total Proved + Probable	**19,692**	**13,166**	**8,936**	**6,055**	**4,035**

Total Future Net Revenues, Undiscounted
Forecast Prices and Costs

Reserve Category	Revenue (M$)	Royalties (M$)	Operating Costs (M$)	Development Costs (M$)	Well Abandonment/ Other Costs (M$)	Future Net Revenue Before Income Taxes (M$)	Income Taxes (M$)	Future Net Revenue After Income Taxes (M$)
Proved	52,991	7,642	20,155	12,281	1,352	11,561	nil	11,561
Proved + Probable	84,559	12,516	33,578	16,974	1,799	19,692	nil	19,692

Net Present Value of Future Net Revenues
by Production Group
Forecast Prices and Costs

Reserve Category	Production Group	Future Net Revenue Before Income Taxes Discounted at 10%/ Year (M$)	Unit Value Before Income Taxes Discounted at 10%/ Year $/BOE
Proved			
	Light and Medium Crude Oil (including solution gas and associated by-products)	-	-
	Heavy Oil (including solution gas and associated by-products)	220.3	34.42
	Coalbed Methane (including associated by-products)	5,287.6	5.48
	Natural Gas (including associated by-products)	142.2	7.86
	Other Revenue	311.2	
Total		**5,961.3**	
Proved plus Probable			
	Light and Medium Crude Oil (including solution gas and associated by-products)	-	-
	Heavy Oil (including solution gas and associated by-products)	303.3	32.16
	Coalbed Methane (including associated by-products)	8,035.1	5.36
	Natural Gas (including associated by-products)	196.0	8.48
	Other Revenue	401.9	
Total		**8,936.3**	

Pricing Assumptions

Sproule employed the following pricing, exchange rate and inflation rate assumptions as at December 31, 2007 in estimating the Company's reserves data using forecast prices and costs:

Summary of Pricing and Inflation Rate Assumptions
Forecast Prices and Costs

	Oil			Natural Gas & Natural Gas Liquids				
Year	**WTI Cushing Oklahoma ($US/bbl)**	**Edmonton Par Price 40° API ($Cdn/bbl)**	**Cromer Medium 29° API ($Cnd/bbl)**	**AECO Gas Prices ($Cdn/MmBtu)**	**Pentanes Plus FOB Field Gate ($Cdn/bbl)**	**Butanes FOB Field Gate ($Cdn/bbl)**	**Inflation Rate (%/Yr)**	**Exchange Rate ($US/$Cdn)**
2008	89.61	88.17	75.83	6.51	90.30	65.72	2.0	1.00
2009	86.01	84.54	72.71	7.22	86.58	63.01	2.0	1.00
2010	84.65	83.16	71.52	7.69	85.17	61.98	2.0	1.00
2011	82.77	81.26	69.89	7.70	83.23	60.57	2.0	1.00
2012	82.26	80.73	69.43	7.61	82.68	60.17	2.0	1.00
Thereafter	Various Escalation Rates							

The weighted average realized sales prices for Richards Oil & Gas Limited for the year ended December 31, 2007 were $6.34 per Mcf for natural gas and $43.01 per bbl for heavy oil.

Reconciliation of Company Reserves
By Principal Product Type
As at December 31, 2007
Forecast Prices and Costs

	Heavy Oil (Mbbls)			Conventional Natural Gas (MMcf)		
	Gross Proved	**Gross Probable**	**Gross Proved Plus Probable**	**Gross Proved**	**Gross Probable**	**Gross Proved Plus Probable**
December 31, 2006	7.2	4.1	11.3	995.3	107.2	1,102.6
Extensions and improved recovery	-	-	-	-	-	-
Transfer	-	-	-	-	-	-
Technical revisions	2.8	(0.6)	2.3	(945.0)	(95.0)	(1,040.0)
Economic factors	0.3	(0.4)	(0.1)	142.1	26.0	168.1
Production	(3.7)	-	(3.7)	(54.9)	-	(54.9)
December 31, 2007	6.6	3.1	9.7	137.5	38.2	175.7

	Coalbed Methane (MMcf)			Total Company BOE		
	Gross Proved	**Gross Probable**	**Gross Proved Plus Probable**	**Gross Proved**	**Gross Probable**	**Gross Proved Plus Probable**
December 31, 2006	4,793.4	3,641.6	8,435.0	972.3	629.0	1,601.3
Extensions and improved recovery	3,315.1	2,075.5	5,390.6	552.5	345.9	898.4
Transfer	(182.4)	(239.2)	(421.5)	(30.4)	(39.9)	(70.3)
Technical revisions	(922.0)	(1,669.7)	(2,591.6)	(308.2)	(294.7)	(602.9)
Economic factors	(48.1)	(1.3)	(49.4)	15.9	3.7	19.6
Production	(170.9)	-	(170.9)	(41.5)	-	(41.5)
December 31, 2007	6,785.1	3,807.0	10,592.2	1,160.6	644.1	1,804.7

Undeveloped Reserves

Product Type	Units	Company Gross Reserves First Attributed By Year				
		Prior	2005	2006	2007	Total
Proved Undeveloped						
Heavy Oil	Mbbl	-	-	-	-	-
Conventional Natural Gas	Mmcf	-	-	-	-	-
Coalbed Methane	Mmcf	-	843.0	2,922.0	788.3	4,553.3
Total: Oil Equivalent	**Mboe**	**-**	**140.5**	**498.7**	**131.4**	**758.9**
Probable Undeveloped						
Heavy Oil	Mbbl	-	11.0	(11.0)	-	-
Conventional Natural Gas	Mmcf	-	-	-	-	-
Coalbed Methane	Mmcf	-	765.0	2,533	(2,471.8)	826.2
Total: Oil Equivalent	**Mboe**	**-**	**138.5**	**422.2**	**(412.0)**	**137.7**

The Company has an active development program underway in all its Coalbed Methane reserves areas. All undeveloped Coalbed Methane reserves have resulted from discoveries in the period 2005 though to 2007. The remaining undeveloped reserves are downspacing locations primarily at the Company's Lacombe and Thorsby properties. These wells are in the budget to be drilled and tied-in over the next three years and are economic under current conditions.

Significant Factors or Uncertainties

Other than the various risks and uncertainties that participants in the oil and gas industry are exposed to generally, the Company is unable to identify any important economic factors or significant uncertainties that will affect any particular components of the reserves data disclosed herein.

Future Development Costs

FUTURE DEVELOPMENT COSTS BY RESERVES CATEGORIES
FORECAST PRICES AND COSTS

Reserve Category	Total (undiscounted)	Total (NPV 10%)	2008	2009	2010	2011 and 2012
Proved Reserves (Forecast Prices and Costs)	12,282	10,718	2,936	6,850	2,496	-
Proved Plus Probable Reserves (Forecast Prices and Costs)	16,975	14,450	2,960	6,953	7,062	-

The Company expects to finance the identified development costs from a combination of cash flow, available working capital, debt and equity. The Company does not expect that the costs of funding the development costs will make the development of the properties uneconomic. Of further note, the development costs discussed here represent a fraction of the overall development costs which could be incurred on the Company's lands if exploration and testing is successful.

Principal Properties

Morningside/Lacombe Area, Alberta

The Morningside property is located between the cities of Red Deer and Edmonton and is approximately 10 kilometers northwest of the town of Lacombe. The Company holds four sections of land (1,280 net acres) in this property. During 2005 through to the end of 2007 the Company drilled and completed 15 wells on the Morningside lands. At the end of December 2007, 13 of the 15 wells that have been drilled and completed to date have been tied into a sales pipeline. Current average per well production from the 13 wells are at rates of over 100 Mcf per day from the Horseshoe Canyon coals and the comingled Belly River and Edmonton sands. The Company intends to tie in the remaining two wells in the first quarter of 2008. This will effectively complete the development of this property.

The Lacombe property was acquired effective July 1, 2005 from Drumlin Energy Corp. This non-operated property sits adjacent to the Company's Morningside lands. The assets acquired comprise an average 36% Working Interest in 19 sections of land, and a 42% Working Interest in a gas gathering pipeline and approximately 120 Mcf per day (net) of conventional gas production. Since the acquisition of the assets, the operator has drilled an additional seven (gross) Horseshoe Canyon CBM wells in early 2006 and an additional six (gross) Horseshoe Canyon CBM wells in mid 2007. These additional wells have added approximately 280 mcf per day (net) of CBM production from these new wells. The Company is in discussion with the operator regarding the additional development drilling opportunities on this property.

Thorsby, Alberta

The Thorsby Horseshoe Canyon CBM properties were purchased from Mazzerado Resources Ltd. effective July 1, 2005. The Company purchased a 30% working interest in seven sections of land plus a 30% working interest in the gas gathering pipeline in the area. One Horseshoe Canyon coalbed methane well was drilled in February 2007 and was brought on production in September 2007. The performance of this well was encouraging enough that the Company acquired two sections of adjacent Crown land in November 2007 at 100% working interest. In late 2007 the Company also increased its working interest in its original seven sections of land from 30% to 48%. Subsequent to December 31, 2007, the Company further increased its opportunity to expand in Thorsby when it entered into a farmin agreement representing a five well drilling commitment to earn a 100% working interest on five sections that are adjacent with the Company's current landholdings. Under the terms of the agreement, the Company has the option to earn up to nine additional surrounding sections with the drilling of additional wells.

Crossfield, Alberta

The Crossfield property consists of five sections of land purchased at a Crown land sale in March 2006. The Company holds a 60% working interest in all rights in the five sections. The Crossfield property is primarily a Horseshoe Canyon CBM play with additional upside from the conventional Edmonton, Belly River, Viking and Crossfield formations. The Company shot and owns a proprietary 3D seismic over the entire five section block. Two wells have been drilled to date. In the first well the Viking formation was initially tested and abandoned. Testing in this well now is currently focused on the Edmonton sand and Horseshoe Canyon CBM potential. The second well was drilled in 2007 and the drill focused specifically on Horseshoe Canyon CBM. Both of these wells show strong potential from the current zones of interest. The Company is at present reviewing options for getting the natural gas to market and evaluating additional land opportunities. Up to 18 additional wells could be drilled in this area.

Gadsby, Alberta

The Corporation entered into a deal with one of its partners to drill to earn Mannville conventional and CBM rights in their lands in the Gadsby area, which is located approximately 15 kilomtres south of the town of Stettler. To date, four sections of land have been earned through the drilling of three wells. Negotiations are ongoing for the earning of an additional four sections.

Two wells were drilled in December 2005 in which the Glauconite zone was subsequently completed and tied in, and a third well was drilled in June 2006 in which the Viking zone was completed and tied in. Preliminary testing of the Mannville coals was done while drilling these wells. During 2007 conventional gas production declined from the Glauconite wells significantly due to natural reservoir depletion and water production issues. Currently the Company is only producing from two of the three original wells at Gadsby and the combined production rate is currently approximately 140 mcf per day (net). These wells also provided base line information on the Mannville CBM resource potential. Further work is planned for mid to late 2008 to evaluate the CBM opportunities and identify horizontal drill locations to test the Mannville coals. The Company's after pay out working interest at Gadsby will be 50%.

Saskatchewan Heavy Oil Properties

The Company has 720 net acres of property in the province of Saskatchewan. Current production from these non-operated properties is approximately 10 bbl/d.

Greater Berland Area, Alberta

The Company holds approximately 27 gross sections of land (10,800 net acres) in the Greater Berland area, 13 earned sections at Marsh and 14 at earned sections at Lambert. The Company has assembled a significant land position in this area and is currently evaluating the Ardley coal zone. The Ardley is largest CBM opportunity in Alberta that to date has not produced commercial levels of CBM.

From the last quarter of 2005 to the third quarter of 2007 the Company has drilled seven vertical wells targeting the Ardley coal zone on its Greater Berland Area property. In 2005 and 2006 five vertical wells were drilled. On these wells zone by zone testing (of the Ardley coals) on these wells took place throughout 2006. Testing of the wells resulted in dry gas flows of up to 50 mcf/d per well in four of these five wells. Although this does not represent an economic flow rate for the Ardley coals it represents a significant advancement in the project by demonstrating dry gas flow from Ardley coals. The Company drilled two vertical wells in July 2007 on the Lambert property. Testing of the wells resulted in dry gas flows of up to 40 mcf/d per well, consistent with the Company’s 2006 testing results from earlier vertical wells. Unique stimulation techniques were applied in one of these wells and due to technical difficulties the Company was not yet able to demonstrate the viability of this new technique. The Company is continuing to apply various completion and stimulation techniques to the two additional vertical CBM wells that were drilled in mid 2007.

A large, six section, three dimensional seismic survey was completed at Marsh to support a multi-horizontal test well program. A horizontal well was drilled fourth quarter of 2006 and the Company is continuing to apply various completion and stimulation techniques to enhance permeability and flow rates.

Banshee (Ansell and Shaw) / Coal Valley, Alberta

The Banshee / Coal Valley property comprises some 28 gross section (8,600 net acres), 9 at Shaw (3 earned and an additional 6 under option), 16 at Ansell (8 earned and an additional 8 under option) and 3 at Coal Valley (all of which are earned). Similar to the Company’s efforts in the Greater Berland Area, the Company has also assembled a significant land position in this area and is also currently evaluating the Ardley coal zone.

Two earning wells, one at Ansell and one at Shaw were drilled and cased in April 2006. Testing of the Ardley coal zones in the first well commenced in December 2005. Zone by zone testing (of the Ardley coals) was ongoing on these wells throughout the remainder of 2006. Testing of the wells resulted in dry gas flows of up to 30 mcf/d in the Ansell well and tested wet saline CBM at Shaw. Although this does not represent an economic flow rate for the Ardley coals it represents a significant advancement in the project by demonstrating dry gas flow from one well and wet but non-fresh water (Saline) Ardley potential from the second.

At Ansell a horizontal well was drilled in the third quarter of 2007 using an experimental "dry" in-balanced drilling process. In November 2007 the Company re-entered the well and extended the original horizontal single leg well into a multi-lateral well with an additional two horizontal legs drilled into the Ardley coals. These extensions were achieved by using a different drilling process than what was used in the third quarter of 2007. This new system was designed to provide effective drill bit lubrication and clearing of drill cuttings while not saturating the coal formation with water or other fluids that could adversely impact the future gas productivity from the Ardley coals. The Company is currently completing, cleaning and testing this multi-lateral well.

At Coal Valley, the Company drilled an earning well (28% Working Interest) with two industry partners in the second quarter of 2005 to test the CBM potential of the Ardley coal seams. An extensive completion and test program was abandoned as non-commercial due to formation damage across the main zones of interest, brought on by difficult drilling conditions experienced at this location.

Oil and Gas Wells

The following table sets forth the number and status of wells in which the Company has a working interest as at December 31, 2007.

	Number of Producing Wells [1]		Number of Non-Producing Wells [1]	
Property	**(Gross)**	**(Net)**	**(Gross)**	**(Net)**
Morningside	13	8.5	2	0.7
Lacombe	17	6.6	5	1.9
Thorsby	1	0.5	5	3.0
Gadsby	2	2.0	1	1.0
Lone Rock & Marsden	4	0.6	0	0
Manitou Lake	1	0.2	0	0

(1) The above well description and well count data refers only to wells which reserves are reported, exploratory test wells drilled to investigate resource assets are not included.

The following table sets forth the status of the producing wells in which the Company has a working interest as at December 31, 2007.

Property	Location	Status	Facilities
Morningside	Alberta	Producing CBM	On Pipe
Thorsby	Alberta	Producing CBM	On Pipe
Lacombe	Alberta	Producing CBM and Natural Gas	On Pipe
Gadsby	Alberta	Producing Natural Gas	On Pipe
Lone Rock, Marsden and Manitou Lake	Saskatchewan	Producing Heavy Oil	Trucked to sales

Properties With No Attributed Reserves (interest of the Company in terms of net area)

Canadian Property	Unproven Acreage(1) (Gross)	Unproven Acreage(1) (Net)	Wells Drilled(2) (Gross)
Banshee / Coal Valley	17,920	8,600	4
Greater Berland	17,280	10,800	8
Crossfield	3,200	1,920	2

Notes:

(1) Includes acreage which is subject to further earning requirements.

(2) Exploratory test wells drilled to investigate resource assets.

Forward Contracts

As at December 31, 2007, the Company is not bound by any agreements (including a transportation agreement), directly or through an aggregator, under which it may be precluded from fully realizing, or may be protected from the full effect of, future market prices for oil or gas.

Additional Information Concerning Abandonment and Reclamation Costs

In deriving estimates for abandonment and restoration costs, the Company considered the geographic location of the wells and facilities in place, the nature of the facilities and actual field experience. Using this methodology, the Company's total undiscounted, un-escalated abandonment and restoration costs, net of estimated salvage value, is estimated at $1,257,652 ($316,583 discounted at 10%). It is estimated that these costs are expected to be incurred for approximately 33.1 net wells in Canada, along with similar costs for the Company's facilities and pipelines interests. All of the estimated abandonment and restoration costs were deducted in computing future net revenue. The portion of the Company's undiscounted total abandonment and reclamation costs expected to be paid in the next three financial years is estimated to be $249,659.

Tax Horizon

The Company is currently not required to pay taxes in Canada for its most recently completed financial year. Based on after tax economic forecasts (constant price case), income taxes are payable by the Company beginning in 2020.

Costs Incurred

The following table summarizes in Canadian dollars certain expenditures of the Company during the financial year ended December 31, 2007:

Country	Property Acquisition Costs ($) Unproved Properties	Property Acquisition Costs ($) Proved Properties	Exploration Costs ($)	Development Costs ($)	Total ($)
Canada	30,290	170,335	4,612,457	5,132,922	9,946,004

(1) The definitions of the various categories of properties and expenses are those set out in NI 51-101.

Drilling Activity

The following table sets forth the gross and net exploratory and development wells in which the Company participated during the year ended December 31, 2007.

	Exploration Wells		Development Wells	
	(Gross)	(Net)	(Gross)	(Net)
Oil	0	0	0	0
Gas	3	3.0	19	9.4
D&A	0	0	0	0
Total	3	3.0	19	9.4

The Company plans to continue with development of its Horseshoe Canyon CBM properties in the Lacombe and Thorsby areas, to expand it land base and explore options for getting its natural gas to market in the Crossfield area, to continue exploration of the CBM potential in Ardley coals in the Greater Berland, the Banshee and the Coal Valley areas.

The Company spent $9,728,601 on capital expenditures during the 2007 year excluding any purchases acquired for non-cash consideration. The following table summarized the Company's investment activities by types*:*

	Amount $
Land and carrying costs	253,125
Geological and geophysical	201,231
Drilling and completion	7,970,922
Well equipment and facilities	1,558,726
Acquisition of oil and gas properties	(38,000)
	9,946,004

Production Estimates for 2008

The following table discloses, by product type, the total volume of production estimated by Sproule for 2008 in the estimates of future net revenue from proved and probable reserves disclosed under "Petroleum and Natural Gas Reserves":

	Heavy Oil (Bbls/d)	Natural Gas [(1)] (Mcf/d)	NGLs (Bbls/d)	BOE (BOE/d)	%
Morningside	-	678	-	113	46
Thorsby	-	266	-	44	18
Lacombe	-	400	1	68	27
Gadsby	-	86	-	14	6
Lone Rock, Marsden and Manitou Lake	7	-	-	7	3
Estimated Total Production	7	1,430	1	246	100

(1) Natural Gas production includes Conventional Natural Gas production and production of Coalbed Methane including associated by-products

Production and Netback History

	2007				
	First Quarter	**Second Quarter**	**Third Quarter**	**Fourth Quarter**	**Year Ended December 31, 2007**
Total Sales Volumes					
Natural Gas (Mcf/d)	1,065	609	655	946	818
Oil (Bbls/d)	13	12	12	10	12
NGLs (Bbls/d)	3	1	1	1	1
Combined (Bopd)	193	114	122	169	149
Average price received					
Natural Gas ($/Mcf)	7.13	7.10	4.92	5.96	6.34
Oil ($/Bbl)	41.02	40.60	46.71	44.06	43.01
NGLs ($/Bbl)	46.75	50.13	54.67	63.05	52.19
Combined ($/Bopd)	42.74	42.47	31.43	36.44	38.56
Royalties paid					
Natural Gas ($/Mcf)	2.09	0.71	0.68	0.91	1.21
Oil ($/Bbl)	3.71	4.14	5.89	7.35	5.15
NGLs ($/Bbl)	10.43	21.17	14.26	37.20	18.09
Combined ($/Bopd)	11.94	4.43	4.34	6.02	7.16
Operating expenses (1)					
Natural Gas ($/Mcf)	2.10	3.54	3.26	3.63	3.05
Oil ($/Bbl)	12.66	24.08	19.57	22.47	19.44
NGLs ($/Bbl)	12.51	22.90	18.44	22.05	17.14
Combined ($/Bopd)	12.59	21.53	19.57	21.82	18.36
Netback					
Natural Gas ($/Mcf)	2.94	2.85	0.98	1.42	2.08
Oil ($/Bbl)	24.65	12.38	21.25	14.24	18.42
NGLs ($/Bbl)	23.81	6.06	21.97	3.80	16.96
Combined ($/Bopd)	18.21	16.51	7.52	8.60	13.04

Note:

(1) Operating expenses includes costs of field contractors, compression, transportation, chemicals and treating supplies, operating overhead and minor well workovers.