FORM 51-101F1
Statement of Reserve Data and
Other Oil and Gas Information
New Range Resources Ltd.
April 27, 2007

PART 1
RELEVANT DATES

The effective date of this Form 51-101F1 is December 31, 2006 and is dated April 27, 2007.

The reserve and economic evaluation of the oil and natural gas properties of New Range Resources Ltd. (the "**Company**") was prepared by Fekete Associates Inc. of Calgary, Alberta ("**Fekete**"), effective December 31, 2006 and dated March 12, 2007. Fekete are independent qualified reserves evaluators appointed by the Company pursuant to National Policy Instrument 51-101 "Standards for Disclosure for Oil and Gas Activities" ("**NI 51-101**").

All properties evaluated are located in the Province of Alberta.

For the purpose of reporting production information, reserves and calculating unit prices and costs, natural gas volumes have been converted to a barrel of oil equivalent ("**boe**") using six thousand cubic feet ("mcf") to one barrel of oil. A boe conversion ratio of 6:1 is based upon an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Boe's may be misleading, particularly if used in isolation.

PART 2
DISCLOSURE OF RESERVES DATA

2.1 Reserves Data (Constant Prices and Costs)

The estimated future net revenue figures contained in the following tables do not necessarily represent the fair market value for the Company's reserves. There is no assurance that the forecast price and costs assumptions contained in the Fekete report will be attained and variances could be material. Other assumptions relating to costs and other matters are included in the Fekete report. The recovery and reserves estimates attributed to the company's properties described herein are estimates only. The actual reserves attributable to the Company's properties may be greater or less than those calculated.

The crude oil, natural gas liquids and natural gas reserve estimates presented in the Fekete report are based on the definitions and guidelines contained in NI 51-101 and the Canadian Oil and Gas Evaluation Handbook ("**COGE Handbook**"). For a glossary of terminology and definitions relating to the information included in this report, readers are referred NI 51-101 and Schedule A attached hereto.

SUMMARY OF OIL AND GAS RESERVES (Constant Costs and Prices) as of December 31, 2006

	Light and Medium Oil		Heavy Oil		Natural Gas		Natural Gas Liquids	
Reserve Category	Gross (Mstb)	Net (Mstb)	Gross (Mstb)	Net (Mstb)	Gross (MMcf)	Net (MMcf)	Gross (Mstb)	Net (Mstb)
PROVED								
Producing	40.6	38.7	0	0	267	215	7.2	5.3
Developed - Non-producing	38.8	34.1	0	0	517	312	1.8	1.2
Undeveloped	0	0	0	0	0	0	0	0
TOTAL PROVED	**79.4**	**72.8**	**0**	**0**	**784**	**527**	**9.0**	**6.5**
TOTAL PROBABLE	**57.7**	**53.8**	**0**	**0**	**182**	**132**	**3.0**	**2.2**
TOTAL PROVED PLUS PROBABLE	**137.1**	**126.6**	**0**	**0**	**966**	**659**	**12**	**8.7**

(CONSTANT COSTS AND PRICES)
BEFORE TAX PRESENT VALUE (M$)
DISCOUNTED AT

	0%	5%	10%	12%	15%	20%
Proved Producing	2,454	1,953	1,623	1,521	1,392	1,223
Proved Developed (Non-producing)	2,629	2,207	1,906	1,809	1,682	1,508
Proved (Undeveloped)	0	0	0	0	0	0
Total Proved	**5,083**	**4,160**	**3,529**	**3,330**	**3,074**	**2,731**
Total Probable	**2,812**	**1,914**	**1,439**	**1,308**	**1,151**	**959**
Total Proved Plus Probable	**7,895**	**6,074**	**4,968**	**4,638**	**4,225**	**3,690**

(CONSTANT COSTS AND PRICES)
AFTER TAX PRESENT VALUE (M$)
DISCOUNTED AT

	0%	5%	10%	12%	15%	20%
Proved Producing	2,454	1,953	1,623	1,521	1,392	1,223
Proved Developed (Non-producing)	2,629	2,207	1,906	1,809	1,682	1,508
Proved (Undeveloped)	0	0	0	0	0	0
Total Proved	**5,083**	**4,160**	**3,529**	**3,330**	**3,074**	**2,731**
Total Probable	**2,812**	**1,914**	**1,439**	**1,308**	**1,151**	**959**
Total Proved Plus Probable	**7,895**	**6,074**	**4,968**	**4,638**	**4,225**	**3,690**

TOTAL FUTURE NET REVENUE (UNDISCOUNTED)

	Revenue M$	Royalties M$	Operating Costs M$	Capital Development Costs M$	Abandonment Costs M$	Future Net Revenue Before Income Taxes M$	Future Net Revenue After Income Taxes M$
Proved Producing	4,561	586	1,400	0	151	2,454	2,454
Proved Developed (Non-producing)	5,610	1,665	1,183	205	36	2,629	2,629
Proved (Undeveloped)	0	0	0	0	0	0	0
Total Proved	**10,171**	**2,251**	**2,583**	**205**	**187**	**5,083**	**5,083**
Total Probable	**4,929**	**619**	**1,369**	**118**	**36**	**2,812**	**2,812**
Total Proved Plus Probable	**15,100**	**2,870**	**3,952**	**323**	**223**	**7,895**	**7,895**

Future Net Revenue
By Production Group (Constant Prices and Costs)

Reserve Category	Production Group	Before Income Tax Discounted at 10% per year $M
Total Proved	Light and Medium Oil (including solution gas and other by-products)	2,217.1
	Natural Gas (including by-products by not solution gas)	1,311.8
Total Plus Probable	Light and Medium Oil (including solution gas and other by-products)	3,416.4
	Natural Gas (including by-products by not solution gas)	1,551.4

2.2 Reserves Data (Forecast Prices and Costs)

SUMMARY OF OIL AND GAS RESERVES (Forecast Costs and Prices) as at December 31, 2006

Reserve Category	Light and Medium Oil Gross (Mstb)	Light and Medium Oil Net (Mstb)	Heavy Oil Gross (Mstb)	Heavy Oil Net (Mstb)	Natural Gas Gross (MMcf)	Natural Gas Net (MMcf)	Natural Gas Liquids Gross (Mstb)	Natural Gas Liquids Net (Mstb)
PROVED								
Producing	40.6	38.7	0	0	267	214	7.2	5.3
Developed - Non-producing	38.8	34.1	0	0	517	308	1.8	1.2
Undeveloped	0	0	0	0	0	0	0	0
TOTAL PROVED	**79.4**	**72.8**	**0**	**0**	**784**	**522**	**9.0**	**6.5**
TOTAL PROBABLE	**57.7**	**53.8**	**0**	**0**	**181**	**131**	**3.0**	**2.2**
TOTAL PROVED PLUS PROBABLE	**137.1**	**126.6**	**0**	**0**	**965**	**653**	**12.0**	**8.7**

(FORECAST COSTS AND PRICES)
BEFORE TAX PRESENT VALUE (M$)
DISCOUNTED AT

	0%	5%	10%	15%	20%
Proved Producing	2,769	2,189	1,815	1,556	1,369
Proved Developed (Non-producing)	3,047	2,582	2,249	1,999	1,804
Proved (Undeveloped)	0	0	0	0	0
Total Proved	**5,816**	**4,771**	**4,064**	**3,555**	**3,173**
Total Probable	**3,133**	**2,082**	**1,544**	**1,227**	**1,018**
Total Proved Plus Probable	**8,949**	**6,853**	**5,608**	**4,782**	**4,191**

(FORECAST COSTS AND PRICES)
AFTER TAX PRESENT VALUE (M$)
DISCOUNTED AT

	0%	5%	10%	15%	20%
Proved Producing	2,769	2,189	1,815	1,556	1,369
Proved Developed (Non-producing)	3,047	2,582	2,249	1,999	1,804
Proved (Undeveloped)	0	0	0	0	0
Total Proved	**5,816**	**4,771**	**4,064**	**3,555**	**3,173**
Total Probable	**3,133**	**2,082**	**1,544**	**1,227**	**1,018**
Total Proved Plus Probable	**8,949**	**6,853**	**5,608**	**4,782**	**4,191**

TOTAL FUTURE NET REVENUE (UNDISCOUNTED)

	Revenue M$	Royalties M$	Operating Costs M$	Capital Development Costs M$	Abandonment Costs M$	Future Net Revenue Before Income Taxes M$	Future Net Revenue After Income Taxes M$
Proved Producing	5,205	696	1,593	0	183	2,769	2,769
Proved Developed (Non-producing)	6,475	2,005	1,282	205	46	3,047	3,047
Proved (Undeveloped)	0	0	0	0	0	0	0
Total Proved	**11,680**	**2,701**	**2,875**	**205**	**229**	**5,816**	**5,816**
Total Probable	**5,830**	**760**	**1,779**	**120**	**69**	**3,133**	**3,133**
Total Proved Plus Probable	**17,510**	**3,461**	**4,654**	**325**	**298**	**8,949**	**8,949**

Future Net Revenue By Production Group (Forecast Prices and Costs)		
Reserve Category	Production Group	Before Income Tax Discounted at 10% per year $M
Total Proved	Light and Medium Oil (including solution gas and other by-products)	2,235.0
	Natural Gas (including by-products by not solution gas)	1,828.7
Total Plus Probable	Light and Medium Oil (including solution gas and other by-products)	3,431.0
	Natural Gas (including by-products by not solution gas)	2,176.8

2.3 **Reserves Disclosure Varies with Accounting**

The reserves disclosed are 100% attributable to the Company.

2.4 **Future Net Revenue Disclosure Varies with Accounting**

The future net revenues disclosed are 100% attributable to the Company.

PART 3
PRICING ASSUMPTIONS

The following pricing assumptions were provided by Fekete, a qualified reserves evaluator independent of the Company.

3.1 Constant Prices used in Estimates

Oil and Liquids Constant – December 31, 2006

W.T.I.:	\$61.05 U.S./STB
Exchange Rate:	0.8581 \$U.S./\$CDN
Edmonton Light (40^{O} API) Oil:	\$67.74 CDN/STB
Hardisty Medium (25^{O} API) Oil:	\$49.16 CDN/STB
Hardisty Heavy (12^{O} API) Oil:	\$35.93 CDN/STB
Cromer Medium (29^{O} API) Oil:	\$58.82 CDN/STB
Edmonton Condensate:	\$72.02 CDN/STB
Edmonton Propane:	\$42.13 CDN/STB
Edmonton Butane:	\$54.05 CDN/STB

Natural Gas Constant – December 31, 2006

Henry Hub Spot:	\$5.50 U.S./MMBTU
Sumas Spot:	\$5.60 U.S./MMBTU (\$6.53 CDN/MMBTU)
Alberta Gas Reference Price:	\$6.05 CDN/MMBTU
Alberta AECO Spot:	\$6.00 CDN/MMBTU
Alberta Plantgate Spot:	\$5.85 CDN/MMBTU
Alberta Aggregator Plantgate:	\$7.40 CDN/MMBTU
B.C. Plantgate Spot:	\$7.05 CDN/MMBTU
Saskatchewan Spot:	\$8.00 CDN/MMBTU

The base prices shown are the actual or estimated December 31, 2006 closing prices.

3.2 Forecast Prices used in Estimates

Oil and Liquids Forecast – December 31, 2006

Year	W.T.I.[1]	Edmonton Light[2]	Bow River Medium[3]	Hardisty Heavy[4]	Sask. Cromer[5]	Edmonton Propane	Edmonton Butane	Inflation	U.S./CDN Exchange Rate
	(U.S./STB)	($CDN/STB)	($CDN/STB)	($CDN/STB)	($CDN/STB)	($CDN/STB)	($CDN/STB)	(%)	($U.S./$CDN)
2007	63.00	70.55	50.55	40.55	60.55	42.35	52.90	2.0	0.880
2008	61.50	68.80	49.80	39.80	59.80	41.30	51.60	2.0	0.880
2009	60.00	67.10	49.10	39.10	58.60	40.25	50.35	2.0	0.880
2010	58.00	64.85	47.85	38.85	56.35	38.90	48.65	2.0	0.880
2011	58.00	64.85	47.85	38.85	56.35	38.90	48.65	2.0	0.880

… 0.88 thereafter …

… escalate at 2% per year thereafter …

1. at Cushing
2. 40^{O} API; 0.5% sulphur
3. 24.9^{O} API; 2.1% sulphur
4. 12^{O} API
5. 29^{O} API; 1.2% sulphur

Natural Gas Forecast – December 31, 2006

			Alberta Plantgate[1]						B.C. Plantgate	Sask. Plantgate
Year	Henry Hub Spot	AECO-C Hub	Alberta Gas Reference Price	Pan Alberta	Cargill/ Progas	Spot	Sumas		Spot	Spot
	($U.S.)	($CDN)	($CDN)	($CDN)	($CDN)	($CDN)	($U.S.)	($CDN)	($CDN)	($CDN)
2007	7.50	7.35	7.25	7.25	7.25	7.15	6.80	7.75	7.20	7.35
2008	7.75	7.65	7.45	7.45	7.45	7.45	7.05	8.00	7.50	7.65
2009	7.80	7.80	7.45	7.60	7.60	7.60	7.15	8.15	7.65	7.80
2010	7.85	7.90	7.70	7.70	7.70	7.70	7.25	8.25	7.75	7.90
2011	7.90	7.95	7.75	7.75	7.75	7.75	7.30	8.30	7.80	7.95

… escalate at 2% per year thereafter …

1. Years 2002 – 2006 historical aggregator prices shown are prior to receipt transportation deduction. Forecast prices are plantgate assuming $0.20/MMBTU receipt transportation deduction.

3.3 **Summary of Operating Costs**

SUMMARY OF OPERATING COSTS
(2006 DOLLARS)

		Variable	
AREA	**Fixed ($/W/M)**	**Sales Gas ($/Mscf)**	**Oil/NGL ($/stb)**
Enchant			
100/07-02-14-16W4/00	1,000	1.30	-
100/10-03-14-16W4/00	1,000	0.75	-
Eymore			
All wells	2,800	0.10	-
Hays			
All wells	2,000	-	0.60
Herronton			
All wells	1,600	0.30	-
Knopcik			
All wells	4,000	1.40	-
Lodgepole			
All wells	3,900	0.60	2.60
Pembina			
All wells	3,000	0.90	2.00
Provost			
All wells	1,300	0.80	-

PART 4
RECONCILIATION OF CHANGES IN RESERVES

4.1 **Reserves Reconciliation**

A reserve reconciliation has not been prepared as this is the first year of production for the Company.

4.2 **Future Net Revenue Reconciliation**

Future net revenue reconciliation has not been prepared as this is the first year of net revenue for the Company.

PART 5
ADDITIONAL INFORMATION RELATING TO RESERVES DATA

5.1 **Undeveloped Reserves**

5.1.1 **Proved Non-Producing Reserves**

Proved non-producing reserves have been estimated in accordance with procedures and standards contained in the COGE Handbook. The significant majority of the non-producing reserves are scheduled to be on-stream by the second quarter of 2007.

5.1.2 **Proved Undeveloped Reserves**

There are no proved undeveloped reserves assigned to any non-producing wells.

5.1.3 **Probable Reserves**

Probable reserves are assigned to statistically feasible improved recoveries from the Company's current and future producing reserves. In accordance with the definitions in NI 51-101, it is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the reported proved plus probable reserves. Because these reserves additional are primarily the result of improved recoveries from existing wells, no capital is required or planned by the Company for the future recovery of these reserves.

5.2 **Significant Factors or Uncertainties**

The evaluated oil and gas properties of the Company have no material extraordinary risks or uncertainties beyond those which are inherent of an oil and gas producing company as discussed in Section 9 of the COGE Handbook.

5.3 **Future Development Costs**

The development cost deduction in the estimation of the future net revenue attributable to the Company's reserves is summarized as follows:

Company Annual Capital Development Expenditures (M$)
Constant Pricing as of December 31, 2006

YEAR	PROVED PRODUCING	TOTAL PROVED	TOTAL PROVED PLUS PROBABLE
2007	0	205	323
2008	0	0	0
2009	0	0	0
2010	0	0	0
2011	0	0	0
SUBTOTAL	0	205	323
REMAINDER	0	0	0
TOTAL	0	205	323
10% DISCOUNTED	0	184	291

Company Annual Capital Development Expenditures (M$)
Forecast Pricing as at December 31, 2006

YEAR	PROVED PRODUCING	TOTAL PROVED	TOTAL PROVED PLUS PROBABLE
2007	0	205	325
2008	0	0	0
2009	0	0	0
2010	0	0	0
2011	0	0	0
SUBTOTAL	0	205	325
REMAINDER	0	0	0
TOTAL	0	205	325
10% DISCOUNTED	0	184	292

PART 6
OTHER OIL AND GAS INFORMATION

6.1 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, 2006, all of which were in Alberta.

	Oil		Natural Gas	
	Gross[(1)]	**Net[(1)]**	**Gross[(1)]**	**Net[(1)]**
Producing	16.0	4.0	24.0	3.0
Non-producing	14.0	0.5	4.0	1.5
	30.0	4.5	28	4.5

The following is a description of the important properties, plants, facilities and installations of the Company:

Knopcik, Alberta

In August 2006, the Company participated in earning a 30% working interest in the completion of an existing well bore at 14-09-74-11W6 ("14-9 well") in the Halfway zone at 2,398-2,410 metres. The zone was perforated, fraced with a 30 tonne oil based gel frac and then production tested. This discovery well was flow tested over a 63-hour period at a stabilized rate of 3.0 mmcf per day of slightly sour (7.5%) natural gas from the Halfway zone. The 14-9 well flowed through a 6.35 mm choke with a final flowing pressure of 17,350 kPa. The 14-9 well remained shut-in for 17 days with pressure recorders down hole. Final bottom hole pressure was 23,376 Kpa.

In the fall of 2006, the Company and its working interest partners completed the construction of a 4" (114.3 mm) 1.8-mile (2.875 Km) pipeline and related well site facilities.

The Knopcik 14-9 well was initially put on production in December, 2006. Due to hydrate blockage in a non-operated section of pipeline, production was limited in December, 2006. Once the hydrate blockage was resolved, Knopcik re-commenced production in early January, 2007, producing a total of 57,475 mmcf (17,242 mmcf net), averaging 1,854 mcf/day (556 mcf/day net) of gas during January, with production during the last week of January averaging 3.55 mmcf/day (1.065 mmcf/day net). The Knopcik 14-9 well was shut-in on February 1, 2007 as the H2S level had increased from 6.3% to 7.8% which was in excess of the pipeline specifications.

In February, 2007 design and construction began on a sour gas dilution facility to bring the H2S level back in line with pipeline specifications. The facility should be completed and installed by early May, 2007. At that time, Knopcik 14-9 well is expected to be put on production at a restricted rate of 3 mmscf/day (900 mcf/day net).

Pembina, Alberta

The Company has interests in the following wells in the Pembina property:

Well	Status
100/02-12-047-09W5/00	Completed and waiting tie-in
100/08-12-047-09W5/00	Pumping oil

The Pembina 100/2-12-47-9W5/00 ("2-12 well") was drilled in November 2006 as an infill well in the SE/4 of Section 12. The well was perforated over the intervals of 1,653 – 1,657 m and 1,664.2 – 1666.2 m to evaluate the Cardium formation for oil production. The 2-12 well was cased, perforated and fractured and tested. A final extendd production test was initiated on February 15, 2007 at a rate of 25m3/d (157 BOPD) with reates declining to 11 m3/d (69 BOPD) by February 20, 2007. The 2-12 well is anticipated to stabilize and commence production at a rate of 40 BOPD. Design and construction of a single well oil battery and a 400 metre natural gas pipeline has commenced with an expected completion date of May, 2007. New Range is the operator of the Pembina 2-12 well and holds a 64% working interest.

The Company holds a 64% working interest in the producing Pembina 100/08-12-047-09W5/00 well.

Lodgepole, Alberta

The Company has various interests (between 33.50% and 36.625%) in the following wells in the Lodgepole property.

Well	Status
100/09-17-047-08W5/00	Pumping OIL
100/10-17-047-08W5/00	Susp OIL
100/11-17-047-08W5/00	Pumping OIL
100/12-17-047-08W5/00	Pumping OIL
100/13-17-047-08W5/00	Pumping OIL
100/14-17-047-08W5/00	WTR Injection
100/15-17-047-08W5/00	Pumping OIL
100/16-17-047-08W5/00	WTR Injection
102/10-18-047-08W5/00	Pumping OIL
102/11-18-047-08W5/00	Pumping OIL

The 102/10-18-047-08W5/00 well was re-completed in the summer of 2005 to suspend the Belley Rive 'B' sand and to perf and frac the Belly River 'E' and 'F' zones. A second work-over to evaluate these zones is planned.

Niton, Alberta

The Company has small (between 0.41663% and 3.33%) working interests in the following wells on its Niton property.

Well	Status	Well	Status
100/14-07-055-11W5/00	Flowing GAS	100/10-18-055-12W5/00	Suspended OIL
100/12-19-055-11W5/00	Flowing GAS	100/10-18-055-12W5/02	Suspended GAS
100/16-01-055-12W5/00	Flowing GAS	100/10-22-055-12W5/00	Flowing GAS
100/14-11-055-12W5/00	Flowing GAS	100/06-23-055-12W5/00	Flowing GAS
100/07-12-055-12W5/00	Flowing GAS	100/11-24-055-12W5/00	Flowing GAS
100/13-13-055-12W5/00	Pumping OIL	100/02-25-055-12W5/00	Flowing GAS
100/07-14-055-12W5/00	Flowing GAS	100/09-36-055-12W5/00	Flowing GAS

The Company also has a 0.043% working interest in the natural gas associated with the Rock Creek H pool.

The Company also has interests in the following facilities at Niton:

West Paddle River Gas Plan (11-10-056-11W5)	0.01%
Niton Gas Compression and Gathering (07-12-055-12W5)	3.33%
North Niton Gas Gathering	0.07%
Niton Gas Gathering – 3 laterals	1.53%
Gas Gathering 12-19-055-11W5	0.46%

6.2 **Properties with no Attributed Reserves**

The Company had an interest in 768 gross (298 net) acres of undeveloped lands, all located in Alberta, as at December 31, 2006.

6.3 Forward Contracts

The Company does not have any forward sales contracts.

6.4 Additional Information Concerning Abandonment and Reclamation Costs

The Company performs an annual review of its forecast abandonment and site reclamation ("Abandonment") costs. These costs are estimated utilizing the Alberta Energy and Utilities Board's Abandonment and liability calculation spreadsheet as a basis, but the Company's review is further augmented with adjustments on an individual well and facility basis. The review considers the following factors in assessing liability: well depth, nature of the production stream, the nature, location and condition of the surface lease, age of the well and/or facility, number of zones to be abandoned, and presence of salvageable equipment such as tanks, tubing, and rods. The Abandonment cost determined is net of salvage. Total abandonment costs are included in the reserves data summarized as follows:

Company Annual Abandonment Expenditures (M$)
Constant Pricing as of December 31, 2006

YEAR	PROVED PRODUCING	TOTAL PROVED	TOTAL PROVED PLUS PROBABLE
2007	1	1	1
2008	19	19	19
2009	2	2	0
2010	19	19	0
2011	0	0	3
2012	9	21	18
2013	0	0	12
2014	20	20	0
2015	1	1	18
2016	0	0	0
2017	20	20	10
2018	0	0	0
2019	22	22	20
2020	4	4	38
2021	1	1	0
SUBTOTAL	117	129	139
REMAINDER	34	58	84
TOTAL	151	187	223
10% DISCOUNTED	136	168	202

Company Annual Abandonment Expenditures (M$)
Forecast Pricing as of December 31, 2006

YEAR	PROVED PRODUCING	TOTAL PROVED	TOTAL PROVED PLUS PROBABLE
2007	1	1	1
2008	19	19	19
2009	2	2	0
2010	20	20	0
2011	0	0	3
2012	10	23	20
2013	0	0	14
2014	23	23	0
2015	2	2	21
2016	0	0	0
2017	24	24	13
2018	0	0	0
2019	27	27	25
2020	5	5	50
2021	1	1	0
SUBTOTAL	135	149	166
REMAINDER	48	80	132
TOTAL	183	229	298
10% DISCOUNTED	165	206	268

6.5 Tax Horizon

Although its current tax horizon depends on product prices, production levels, and the nature, magnitude, and timing of capital expenditures, the Company believes that no cash income tax will be payable for several years. Fekete were not requested by the Company to prepare and after income tax economic analysis with respect to the reserve report.

6.6 Costs Incurred

The following table summarizes the capital expenditures related to the Company's activities for the year ended December 31, 2006:

	Exploration ($M)	Development ($M)	Total ($M)
Land	0	(23,250)	(23,250)
Seismic	0	0	0
Drilling	0	1,219,718	1,219,718
Facilities	0	379,146	379,146
Corporate Acquisitions	0	3,171,804	3,171,804
TOTAL	0	4,747,418	4,747,418

6.7 Exploration and Development Activities

The following table sets out the gross and net exploratory and developments wells in which the Company participated during the year ended December 31, 2006:

	Year Ended December 2006	
	Gross	**Net**
Natural gas	1.0	0.30
Crude oil	1.0	0.64
Suspended	0.0	0.00
Dry and abandoned	0.0	0.00
TOTAL	2.0	0.94

6.8 Production Estimates

The following tables summarize the Company's estimate future average daily production volumes for 2007 for each product type. Production for properties which individually account for 20% or more of the Company's forecast production (total proved plus probable reserves, boe basis) in the first year of forecast has been identified separately in these tables.

ESTIMATED 2007 PRODUCTION BY PRODUCT TYPE
CONSTANT PRICES AND COSTS

Property	Light and Medium Oil (stb/d)	Natural Gas (Mcf/d)	Natural Gas Liquids Stb/d	BOE (BOE/d)
Knopcik Proved	0	482	0	80
Pembina Proved	22	33	0	28
Other Total Proved	9	118	4	33
Probable	9	16	1	12
Proved plus probable	40	649	5	153

ESTIMATED 2007 PRODUCTION BY PRODUCT TYPE
FORECAST PRICES AND COSTS

Property	Light and Medium Oil (stb/d)	Natural Gas (Mcf/d)	Natural Gas Liquids Stb/d	BOE (BOE/d)
Knopcik Proved	0	482	0	80
Pembina Proved	22	33	0	28
Other Total Proved	9	118	4	33
Probable	9	16	1	12
Proved plus probable	40	649	5	153

6.9 Production History

The Company's historical production and netback data for the first year of operation is shown in the following table:

ACTUAL AVERAGE DAILY PRODUCTION VOLUMES AND NETBACKS
FOR THE YEAR ENDING DECEMBER 31, 2006
BY QUARTER

	2006	Q1	Q2	Q3	Q4
Average Daily Production					
Oil (stb per day)	16	22	22	13	12
Gas (Mscf per day)	180	194	194	213	162
NGLs (stb per day)	2	2	2	2	2
BOE's per day	48	56	56	50	42
Average Sales Price					
Oil ($ per stb)	68.00	60.36	60.36	68.75	77.37
Gas ($ per Mscf)	6.78	7.93	7.93	5.23	7.27
NGLs ($ per stb)	45.63	50.12	50.12	43.53	39.19
$ per BOE	49.99	52.62	52.62	42.29	53.03
Average Royalties					
Oil ($ per stb)	2.37	2.25	2.25	2.52	2.72
Gas ($ per Mscf)	1.40	1.70	1.70	1.03	1.34
NGLs ($ per stb)	12.64	16.48	16.48	10.94	10.89
$ per BOE	6.58	7.36	7.36	5.47	6.48
Average Production Costs					
Oil ($ per stb)	25.92	17.50	17.50	26.60	43.37
Gas ($ per Mscf)	1.59	1.37	1.37	1.12	2.22
NGLs ($ per stb)	26.39	24.49	24.49	22.01	33.12
$ per BOE	15.38	12.50	12.50	12.58	22.53
Netback Received					
Oil ($ per stb)	39.71	40.62	45.62	39.62	31.28
Gas ($ per Mscf)	3.78	4.86	3.52	3.08	3.71
NGLs ($ per stb)	6.60	9.14	12.44	10.58	-4.82
$ per BOE	28.03	32.76	30.93	24.24	24.02

SCHEDULE A

RESERVE DEFINITIONS

The following reserve definitions were prepared by the Standing Committee on Reserve Definitions of the Petroleum Society of CIM.

Reserve Categories

Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, from a given date forward, based on:

- analysis of drilling, geological, geophysical and engineering data,
- the use of established technology, and
- specified economic conditions, which are generally accepted as being reasonable and must be disclosed.

Reserves are classified according to the degree of certainty associated with the estimates.

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.

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.

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.

Development and Production Status

Each of the reserves classifications (proved, probable and possible) may be divided into developed and undeveloped categories.

Developed reserves are those 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. The developed category may be subdivided into producing or non-producing:

> ***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.
>
> ***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.

Undeveloped reserves are those reserves expected to be recovered from known accumulations where a significant expenditure (e.g. 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.

Levels of Certainty

The qualitative certainty levels contained in the definitions are applicable to individual ***Reserves Entities***, which refers to the lowest level at which reserves calculations are performed, and to ***Reported Reserves***, which refers to the highest level sum, or aggregate, of individual entity estimates for which reserves estimates are presented. ***Reported Reserves*** should target the following levels of certainty under a specific set of economic conditions:

- At least a 90 percent probability that the quantities actually recovered will equal or exceed the estimated proved reserves.
- At least a 50 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable reserves.
- At least a 10 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable plus possible reserves.

FORM 51-101F2

REPORT ON RESERVES DATA
BY
INDEPENDENT QUALIFIED RESERVES
EVALUATOR

April 23, 2007

To: The Board of Directors of New Range Resources Ltd.

1. We have evaluated the Company's reserves data as at December 31, 2006. The reserves data consist of the following:

   a) i) proved and proved plus probable oil and gas reserves estimated as at December 31, 2006 using forecast prices and costs; and

      ii) the related estimated future net revenue; and

   b) i) proved and proved plus probable oil and gas reserves estimated as at December 31, 2006 using constant prices and costs; and

      ii) the related estimated future net revenue.

2. The reserves data are the responsibility of the Company's management. Our responsibility is to express an opinion on the reserves data based on our evaluation.

   We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook (the "COGE Handbook") prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society).

3. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation also includes assessing whether the reserves data are in accordance with principles and definitions presented in the COGE Handbook.

4. The following table sets forth the estimated future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of

the Company evaluated by us for the year ended December 31, 2006, and identifies the respective portions thereof that we have evaluated and reported on to the Company's board of directors:

Independent Qualified Evaluator	Evaluation/Report Date	Country	Net Present Value of Future Net Revenue (M$, CDN) (before income taxes, 10% discount rate) Evaluated	Total
Fekete Associates Inc.	December 31, 2006	Canada	$5,607.82	$5,607.82

5. In our opinion, the reserves data respectively evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook. We express no opinion on the reserves data that we reviewed but did not audit or evaluate.

6. We have no responsibility to update our reports referred to in paragraph 4 for events and circumstances occurring after their respective preparation dates.

7. Because the reserves data are based on judgements regarding future events, actual results will vary and the variations may be material.

Executed as to our report referred to above:

Fekete Associates Inc., Calgary, Alberta, Canada, Dated April 23, 2007

Gary D. Metcalfe, P. Eng.
Vice-President

PERMIT TO PRACTICE
FEKETE ASSOCIATES INC.
Signature
Date April 23, 2007
PERMIT NUMBER: P 4676
The Association of Professional Engineers, Geologists and Geophysicists of Alberta.

FORM 51-101F3

REPORT OF
MANAGEMENT AND DIRECTORS
ON OIL AND GAS DISCLOSURE

REPORT OF MANAGEMENT AND DIRECTORS
On Reserve Data and Other Information

Management of New Range Resources Ltd. (the "Company") are responsible for the preparation and disclosure of information with respect to the Company's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data, which consist of the following:

a) i) proved and proved plus probable oil and gas reserves estimated as at December 31, 2006 using forecast prices and costs; and

ii) the related estimated future net revenue; and

b) i) proved and proved plus probable oil and gas reserves estimated as at December 31, 2006 using constant prices and costs; and

ii) the related estimated future net revenue.

An independent qualified reserves evaluator has evaluated and reviewed the Company's reserve data. The report of the independent qualified reserves evaluator will be filed with securities regulatory authorities concurrently with this report.

The reserves Committee of the board of directors of the Company has:

a) reviewed the Company's procedures for providing information to the independent qualified reserves evaluator;

b) met with the independent qualified reserves evaluator to determine whether any restrictions affected the ability of the independent qualified reserve evaluator to report without reservation;

c) reviewed the reserves data with management and the independent qualified reserves evaluator.

The Reserve Committee of the board of directors has reviewed the Company's procedures for assembling and reporting other information associated with oil and gas activities and has reviewed that information with management. The board of directors has on the recommendation of the Reserves Committee, approved:

a) the content and filing with securities regulatory authorities of the reserves data and other oil and gas information;

b) the filing of the report of the independent qualified reserves evaluator on the reserves data; and

c) the content and filing of this report.

Because the reserves data are based on judgments regarding future events, actual results will vary and the variations may be material.

(signed)

Hugh M. Thomson
President and Chief Executive Officer

(signed)

Leigh D. Stewart
Vice-President, Finance
and Chief Financial Officer

(signed)
William C. Macdonald, Director

(signed)
Geoffrey S. Paskuski, Director

Dated April 27, 2007