

**MONTELLO RESOURCES LTD.  
STATEMENT OF RESERVES DATA  
AND OTHER OIL AND GAS INFORMATION  
(Form NI 51-101F1)**

***Part 1 – Date of Statement***

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

The Preparation Date is November 21, 2008.

## 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 Montello Resources Ltd. ("Montello" or the "Company") as evaluated by Chapman Petroleum Engineering Ltd. as at July 31, 2008 (the "Chapman Report"). The product pricing used in the evaluations is set forth in the notes to the tables.

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

### SUMMARY OF OIL AND GAS RESERVES BASED ON FORECAST PRICES AND COSTS<sup>(9)</sup>

Reserves Category	Company Reserves <sup>(1)</sup>							
	Light and Medium Oil		Heavy Oil		Natural Gas <sup>(10)</sup>		Natural Gas Liquids	
	Gross MSTB	Net MSTB	Gross MSTB	Net MSTB	Gross MMscf	Net MMscf	Gross Mbbbl	Net Mbbbl
<b>PROVED</b>								
Developed Producing <sup>(2)(6)</sup>	17	16	0	0	21	15	0	0
Developed Non-Producing <sup>(2)(7)</sup>	17	14	0	0	42	32	3	2
Undeveloped <sup>(2)(8)</sup>	0	0	0	0	0	0	0	0
<b>TOTAL PROVED<sup>(2)</sup></b>	<b>34</b>	<b>30</b>	<b>0</b>	<b>0</b>	<b>64</b>	<b>47</b>	<b>3</b>	<b>2</b>
<b>TOTAL PROBABLE<sup>(3)</sup></b>	<b>64</b>	<b>55</b>	<b>0</b>	<b>0</b>	<b>2,123</b>	<b>1,411</b>	<b>64</b>	<b>42</b>
<b>TOTAL PROVED + PROBABLE<sup>(2)(3)</sup></b>	<b>98</b>	<b>85</b>	<b>0</b>	<b>0</b>	<b>2,188</b>	<b>1,457</b>	<b>66</b>	<b>44</b>

### SUMMARY OF NET PRESENT VALUES BASED ON FORECAST PRICES AND COSTS<sup>(9)</sup>

Reserves Category	Net Present Values of Future Net Revenue									
	Before Income Tax					After Income Tax				
	Discounted at					Discounted at				
0%/yr	5%/yr.	10%/yr.	15%/yr.	20%/yr.	0%/yr	5%/yr.	10%/yr.	15%/yr.	20%/yr.	
\$M	\$M	\$M	\$M	\$M	\$M	\$M	\$M	\$M	\$M	
<b>PROVED</b>										
Developed Producing <sup>(2)(6)</sup>	1,104	1,015	939	875	819	1,104	1,015	939	875	819
Developed Non-Producing <sup>(2)(7)</sup>	1,673	1,544	1,435	1,340	1,258	1,673	1,544	1,435	1,340	1,258
Undeveloped <sup>(2)(8)</sup>	0	0	0	0	0	0	0	0	0	0
<b>TOTAL PROVED<sup>(2)</sup></b>	<b>2,777</b>	<b>2,560</b>	<b>2,375</b>	<b>2,215</b>	<b>2,077</b>	<b>2,777</b>	<b>2,560</b>	<b>2,375</b>	<b>2,215</b>	<b>2,077</b>
<b>TOTAL PROBABLE<sup>(3)</sup></b>	<b>19,332</b>	<b>13,967</b>	<b>10,921</b>	<b>8,963</b>	<b>7,593</b>	<b>17,039</b>	<b>12,538</b>	<b>9,947</b>	<b>8,260</b>	<b>7,064</b>
<b>TOTAL PROVED + PROBABLE<sup>(2)(3)</sup></b>	<b>22,109</b>	<b>16,527</b>	<b>13,296</b>	<b>11,177</b>	<b>9,670</b>	<b>19,817</b>	<b>15,098</b>	<b>12,322</b>	<b>10,474</b>	<b>9,141</b>

**TOTAL FUTURE NET REVENUE  
(UNDISCOUNTED)  
BASED ON FORECAST PRICES AND COSTS<sup>(9)</sup>**

	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 <sup>(2)</sup>	4,864	753	1,023	167	145	2,777	0	2,777
Total Proved Plus Probable <sup>(2)(3)</sup>	38,695	10,684	4,485	1,193	223	22,109	-2,293	19,817

**FUTURE NET REVENUE BY PRODUCTION GROUP  
BASED ON FORECAST PRICES AND COSTS<sup>(9)</sup>**

Reserve Category	Production Group	Future Net Revenue Before Income Taxes (Discounted at 10%/Year) (\$M)
Total Proved <sup>(2)</sup>	Light and Medium Oil ( including solution gas and other by-products)	2,275
	Heavy Oil (including solution gas and other by-products)	0
	Natural Gas (including by-products but not solution gas)	99
Total Proved Plus Probable <sup>(2)(3)</sup>	Light and Medium Oil ( including solution gas and other by-products)	6,062
	Heavy Oil (including solution gas and other by-products)	0
	Natural Gas (including by-products but not solution gas)	7,233

**OIL AND GAS RESERVES AND NET PRESENT VALUES BY PRODUCTION GROUP  
BASED ON FORECAST PRICES AND COSTS<sup>(9)</sup>**

Reserve Group by Category	Reserves						Net Present Value (BIT) 10% M\$	Unit Values @ 10%/yr
	Oil		Gas <sup>(10)</sup>		NGL			
	Gross MSTB	Net MSTB	Gross MMscf	Net MMscf	Gross Mbbl	Net Mbbl		
<b>Light and Medium Oil</b>								
<b>Proved</b>								
Developed Producing	17	16	18	13	0	0	931	58.67
Developed Non-Producing	17	14	25	18	3	2	1,344	96.00
Undeveloped	0	0	0	0	0	0	0	N/A
<b>Total Proved</b>	<b>34</b>	<b>30</b>	<b>42</b>	<b>30</b>	<b>3</b>	<b>2</b>	<b>2,275</b>	<b>76.16</b>
Probable	64	55	59	44	5	3	3,787	68.55
<b>Proved Plus Probable</b>	<b>98</b>	<b>85</b>	<b>102</b>	<b>73</b>	<b>7</b>	<b>5</b>	<b>6,062</b>	<b>71.22</b>
<b>Assoc &amp; Non-Assoc Gas</b>								
<b>Proved</b>								
Developed Producing	0	0	4	4	0	0	8	2.30
Developed Non-Producing	0	0	17	14	0	0	91	6.52
Undeveloped	0	0	0	0	0	0	0	0.00
<b>Total Proved</b>	<b>0</b>	<b>0</b>	<b>22</b>	<b>17</b>	<b>0</b>	<b>0</b>	<b>99</b>	<b>6.02</b>
Probable	0	0	2,064	1,369	59	39	7,133	5.21
<b>Proved Plus Probable</b>	<b>0</b>	<b>0</b>	<b>2,086</b>	<b>1,384</b>	<b>59</b>	<b>39</b>	<b>7,233</b>	<b>5.23</b>

**SUMMARY OF OIL AND GAS RESERVES  
BASED ON CONSTANT PRICES AND COSTS<sup>(9)</sup>**

Company Reserves<sup>(1)</sup>

Reserves Category	Light and Medium Oil		Heavy Oil		Natural Gas <sup>(10)</sup>		Natural Gas Liquids	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
	MSTB	MSTB	MSTB	MSTB	MMscf	MMscf	Mbbl	Mbbl
<b>PROVED</b>								
Developed Producing <sup>(2)(6)</sup>	18	17	0	0	24	17	0	0
Developed Non-Producing <sup>(2)(7)</sup>	17	14	0	0	42	32	3	2
Undeveloped <sup>(2)(8)</sup>	0	0	0	0	0	0	0	0
<b>TOTAL PROVED<sup>(2)</sup></b>	<b>35</b>	<b>31</b>	<b>0</b>	<b>0</b>	<b>66</b>	<b>49</b>	<b>3</b>	<b>2</b>
<b>TOTAL PROBABLE<sup>(3)</sup></b>	<b>65</b>	<b>56</b>	<b>0</b>	<b>0</b>	<b>2,125</b>	<b>1,403</b>	<b>64</b>	<b>42</b>
<b>TOTAL PROVED + PROBABLE<sup>(2)(3)</sup></b>	<b>100</b>	<b>87</b>	<b>0</b>	<b>0</b>	<b>2,191</b>	<b>1,452</b>	<b>66</b>	<b>44</b>

**SUMMARY OF NET PRESENT VALUES  
BASED ON CONSTANT PRICES AND COSTS<sup>(9)</sup>**

Net Present Values of Future Net Revenue

Reserves Category	Before Income Tax					After Income Tax				
	Discounted at					Discounted at				
	0%/yr	5%/yr.	10%/yr.	15%/yr.	20%/yr.	0%/yr	5%/yr.	10%/yr.	15%/yr.	20%/yr.
	\$M	\$M	\$M	\$M	\$M	\$M	\$M	\$M	\$M	\$M
<b>PROVED</b>										
Developed Producing <sup>(2)(6)</sup>	1,520	1,360	1,230	1,124	1,035	1,520	1,360	1,230	1,124	1,035
Developed Non-Producing <sup>(2)(7)</sup>	1,934	1,777	1,643	1,529	1,431	1,934	1,777	1,643	1,529	1,431
Undeveloped <sup>(2)(8)</sup>	0	0	0	0	0	0	0	0	0	0
<b>TOTAL PROVED<sup>(2)</sup></b>	<b>3,454</b>	<b>3,137</b>	<b>2,874</b>	<b>2,653</b>	<b>2,466</b>	<b>3,454</b>	<b>3,137</b>	<b>2,874</b>	<b>2,653</b>	<b>2,466</b>
<b>TOTAL PROBABLE<sup>(3)</sup></b>	<b>22,241</b>	<b>16,174</b>	<b>12,674</b>	<b>10,393</b>	<b>8,789</b>	<b>19,036</b>	<b>14,046</b>	<b>11,146</b>	<b>9,239</b>	<b>7,887</b>
<b>TOTAL PROVED + PROBABLE<sup>(2)(3)</sup></b>	<b>25,696</b>	<b>19,311</b>	<b>15,547</b>	<b>13,047</b>	<b>11,255</b>	<b>22,491</b>	<b>17,183</b>	<b>14,018</b>	<b>11,893</b>	<b>10,354</b>

**TOTAL FUTURE NET REVENUE  
(UNDISCOUNTED)  
BASED ON CONSTANT PRICES AND COSTS<sup>(9)</sup>**

	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 <sup>(2)</sup>	5,681	825	1,106	167	128	3,454	0	3,454
Total Proved Plus Probable <sup>(2)(3)</sup>	42,906	11,752	4,102	1,173	183	25,696	(3,206)	22,491

**FUTURE NET REVENUE BY PRODUCTION GROUP  
BASED ON CONSTANT PRICES AND COSTS<sup>(9)</sup>**

Reserve Category	Production Group	Future Net Revenue Before Income Taxes (Discounted at 10%/Year)
		(\$M)
Total Proved <sup>(2)</sup>	Light and Medium Oil ( including solution gas and other by-products)	2,764
	Heavy Oil (including solution gas and other by-products)	0
	Natural Gas (including by-products but not solution gas)	110
Total Proved Plus Probable <sup>(2)(3)</sup>	Light and Medium Oil ( including solution gas and other by-products)	7,437
	Heavy Oil (including solution gas and other by-products)	0
	Natural Gas (including by-products but not solution gas)	8,110

**OIL AND GAS RESERVES AND NET PRESENT VALUES BY PRODUCTION GROUP  
BASED ON CONSTANT PRICES AND COSTS<sup>(9)</sup>**

Reserve Group by Category	Reserves						Net Present Value (BIT) 10% M\$	Unit Values @ 10%/yr
	Oil		Gas <sup>(10)</sup>		NGL			
	Gross MSTB	Net MSTB	Gross MMscf	Net MMscf	Gross Mbbbl	Net Mbbbl		
<b>Light and Medium Oil</b>								
<b>Proved</b>								
Developed Producing	18	17	18	12	0	0	1,220	71.38
Developed Non-Producing	17	14	25	18	3	2	1,543	111.82
Undeveloped	0	0	0	0	0	0	0	N/A
<b>Total Proved</b>	<b>35</b>	<b>31</b>	<b>44</b>	<b>31</b>	<b>3</b>	<b>2</b>	<b>2,764</b>	<b>89.48</b>
Probable	65	56	61	45	5	3	4,673	83.52
<b>Proved Plus Probable</b>	<b>100</b>	<b>875</b>	<b>105</b>	<b>76</b>	<b>7</b>	<b>5</b>	<b>4,437</b>	<b>85.64</b>
<b>Assoc &amp; Non-Assoc Gas</b>								
<b>Proved</b>								
Developed Producing	0	0	5	4	0	0	10	2.61
Developed Non-Producing	0	0	17	14	0	0	100	7.14
Undeveloped	0	0	0	0	0	0	0	N/A
<b>Total Proved</b>	<b>0</b>	<b>0</b>	<b>22</b>	<b>18</b>	<b>0</b>	<b>0</b>	<b>110</b>	<b>6.13</b>
Probable	0	0	2,064	1,359	59	39	8,000	5.89
<b>Proved Plus Probable</b>	<b>0</b>	<b>0</b>	<b>2,086</b>	<b>1,376</b>	<b>59</b>	<b>39</b>	<b>8,110</b>	<b>5.89</b>

**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. The pricing assumptions used in the Chapman Report with respect to net values of future net revenue (forecast) as well as the inflation rates used for operating and capital costs are set forth below along with the product prices used in the constant price and cost evaluations. Chapman Petroleum Engineering Ltd. is an independent qualified reserves evaluator appointed pursuant to NI 51-101.
10. Includes associated, non-associated and solution gas where applicable.

### Part 3 - Pricing Assumptions

The following tables detail the benchmark reference prices for the regions in which the Company operated, as at July 31, 2008, reflected in the reserves data disclosed above under "Statement of Reserves Data and Other oil & Gas Information". There will be adjustments to field prices from the benchmarks below

#### CRUDE OIL HISTORICAL, CONSTANT, CURRENT AND FUTURE PRICES

August 1, 2008

Date	WTI [1]	Alberta Par Price [2]	Alberta Heavy [3]	Sask. Light [4]	Sask. Heavy [5]	B.C. Light [6]
	\$US/STB	\$CDN/STB	\$CDN/STB	\$CDN/STB	\$CDN/STB	\$CDN/STB
	WTI	A L	AH	SL	SH	
<b>HISTORICAL PRICES</b>						
1994	17.16	22.27	18.19	20.76	19.16	21.12
1995	18.41	25.11	19.76	22.77	20.57	23.85
1996	21.98	29.39	25.09	28.41	26.07	27.99
1997	20.59	27.90	21.15	26.52	23.73	26.32
1998	14.46	20.39	14.68	19.31	17.01	19.38
1999	19.21	27.88	23.71	27.23	25.65	27.42
2000	30.39	44.90	34.51	43.37	40.12	n/a
2001	25.98	39.66	25.41	35.57	31.84	n/a
2002	26.09	40.63	32.20	37.67	34.57	n/a
2003	30.84	43.57	32.65	40.13	37.64	n/a
2004	41.48	52.89	37.52	48.96	45.74	n/a
2005	56.62	69.16	43.25	62.04	56.53	n/a
2006	65.91	72.88	50.40	66.77	61.23	n/a
2007	72.35	75.57	53.17	71.42	64.55	n/a
2008(7 month)	114.27	115.66	93.99	105.85	100.63	n/a
<b>CONSTANT PRICES</b>						
August 1, 2012 [8]	124.08	131.05	110.18	122.10	117.17	127.77
<b>CURRENT YEAR FORECAST</b>						
2008 (5 months)	<b>130.00</b>	127.50	102.00	118.58	111.46	124.31
<b>FUTURE FORECAST</b>						
2009	<b>125.00</b>	129.08	103.26	120.04	112.84	125.85
2010	<b>120.00</b>	127.93	102.35	118.98	111.84	124.74
2011	<b>110.00</b>	119.72	95.78	111.34	104.66	116.73
2012	<b>100.00</b>	108.61	86.89	101.01	94.95	105.90
2013	<b>100.00</b>	108.61	86.89	101.01	94.95	105.90
2014	<b>100.00</b>	108.61	86.89	101.01	94.95	105.90
2015	<b>102.00</b>	110.83	88.67	103.08	96.89	108.06
2016	<b>104.04</b>	113.10	90.48	105.18	98.87	110.27
2017	<b>106.12</b>	115.41	92.33	107.33	100.89	112.53
2018	<b>108.24</b>	117.77	94.22	109.53	102.95	114.83
2019	<b>110.41</b>	120.18	96.14	111.76	105.06	117.17
2020	<b>112.62</b>	122.63	98.10	114.05	107.20	119.56
2021	<b>114.87</b>	125.13	100.11	116.37	109.39	122.00
2022	<b>117.17</b>	127.68	102.15	118.75	111.62	124.49
2023	<b>119.51</b>	130.29	104.23	121.17	113.90	127.03
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 1.00US\$/CDN\$ in 2008, 0.95US\$/CDN\$ in 2009, 0.92US\$/CDN\$ in 2010 and thereafter 0.90US\$/CDN\$ and transportation differential of \$2.50 CDN/STB.
- [3] Bow River at Hardisty, Alberta (905 kg/m<sup>3</sup>, 2.1% sulphur).
- [4] Light Sour Blend at Cromer, Saskatchewan (850 kg/m<sup>3</sup>, 1.2% sulphur).
- [5] Midale at Cromer, Saskatchewan (880 kg/m<sup>3</sup>, 2.0% sulphur).
- [6] B.C. Light at Taylor, British Columbia (825 kg/m<sup>3</sup>, 0.5% sulphur).
- [7] The Alberta Energy Minister confirmed end of Alberta Royalty Tax Credits as of January 1, 2007, <http://www.gov.ab.ca/acn/200609/20527D0EDD3BF-A8A0-2F29-960D7A45197E3999.html>
- [8] July 31, 2008 is the last trading day of July 2008.
- [9] Capital expenditures and operating costs are escalated at 2.0% per year until 2023.

**NATURAL GAS & BY-PRODUCTS**  
**HISTORICAL, CONSTANT, CURRENT AND FUTURE PRICES**  
 August 1, 2008

Date	GRP [1]		AECO Spot	Henry Hub	Sask.	B.C.	Propane [4]	Butane [4]	Pentane	NGL
	\$/MMBTU	\$/GJ	Gas [NIT] \$/MMBTU	Gas[7] \$/MMBTU	Gas [2] \$/MMBTU	Gas [3] \$/MMBTU	\$/BBL	\$/BBL	Plus [4] \$/BBL	Mix [5] \$/BBL
<b>HISTORICAL PRICES</b>	<b>GRP</b>		<b>AECO</b>	<b>CAD</b>			<b>C3</b>	<b>C4</b>	<b>C5+</b>	
1994	1.82	1.73	1.78	N/A	1.88	1.81	12.72	13.44	21.67	15.62
1995	1.31	1.24	1.08	N/A	1.35	1.29	14.38	13.97	24.11	17.18
1996	1.63	1.55	1.33	N/A	1.52	1.50	22.95	17.19	30.05	23.35
1997	1.97	1.87	1.67	N/A	1.84	1.80	17.73	19.07	30.90	22.08
1998	1.94	1.84	1.94	N/A	2.05	1.94	11.13	12.06	21.86	14.63
1999	2.48	2.35	2.82	N/A	2.83	2.51	15.93	18.01	27.73	20.09
2000	4.50	4.27	5.56	N/A	4.85	4.00	31.38	35.01	46.35	36.96
2001	5.78	5.48	5.44	N/A	5.48	6.12	31.27	30.27	44.98	35.08
2002	3.86	3.66	4.13	N/A	4.17	3.85	19.14	25.11	40.72	27.41
2003	6.45	6.11	7.03	N/A	6.47	6.45	28.85	32.15	44.23	34.46
2004	6.25	5.92	6.60	5.91	6.50	6.25	31.95	38.40	54.06	40.52
2005	8.30	7.87	8.82	8.92	8.55	8.30	38.03	46.31	69.32	49.90
2006	6.57	6.23	6.55	6.75	6.82	6.57	38.97	50.42	76.08	53.54
2007	6.21	5.88	6.47	6.97	6.46	6.21	40.47	49.76	75.96	53.90
2008 (7 month)	8.55	est. 8.10	9.15	9.99	8.80	8.55	51.85	68.95	115.66	76.12
<b>CONSTANT PRICES</b>										
August 1, 2012 [6]	9.46	est. 8.97	7.90	9.26	9.71	9.46	58.55	79.48	126.87	85.32
<b>CURRENT YEAR FORECAST</b>										
2008 (5 months)	11.00	10.43	12.10	14.04	11.25	11.00	62.54	79.49	121.63	85.35
<b>FUTURE FORECAST</b>										
2009	<b>10.00</b>	9.48	11.00	12.76	10.25	10.00	63.23	80.44	123.07	86.35
2010	<b>9.30</b>	8.82	10.23	11.87	9.55	9.30	62.73	79.75	122.02	85.63
2011	<b>8.90</b>	8.44	9.79	11.36	9.15	8.90	59.12	74.84	114.51	80.45
2012	<b>8.70</b>	8.25	9.57	11.10	8.95	8.70	54.23	68.19	104.33	73.45
2013	<b>8.80</b>	8.34	9.68	11.23	9.05	8.80	54.23	68.19	104.33	73.45
2014	<b>8.90</b>	8.44	9.79	11.36	9.15	8.90	54.23	68.19	104.33	73.45
2015	<b>9.10</b>	8.63	10.01	11.61	9.35	9.10	55.21	69.52	106.37	74.85
2016	<b>9.28</b>	8.80	10.21	11.84	9.53	9.28	56.20	70.88	108.44	76.28
2017	<b>9.47</b>	8.97	10.41	12.08	9.72	9.47	57.22	72.26	110.56	77.73
2018	<b>9.65</b>	9.15	10.62	12.32	9.90	9.65	58.26	73.67	112.72	79.22
2019	<b>9.85</b>	9.33	10.83	12.57	10.10	9.85	59.32	75.11	114.92	80.74
2020	<b>10.04</b>	9.52	11.05	12.82	10.29	10.04	60.40	76.58	117.17	82.28
2021	<b>10.25</b>	9.71	11.27	13.07	10.50	10.25	61.50	78.08	119.46	83.86
2022	<b>10.45</b>	9.91	11.50	13.34	10.70	10.45	62.62	79.60	121.80	85.47
2023	<b>10.66</b>	10.10	11.73	13.60	10.91	10.66	63.77	81.16	124.18	87.11

Constant thereafter

Notes:

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

[2] Price paid at field delivery point.

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

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

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

[6] July 31, 2008 is the last trading day of July 2008

[7] Henry Hub USD price changed to Canadian dollars by exchange rate 1.0,0.95,0.92,0.90 thereafter since 2008

[8] Capital expenditures and operating costs are escalated at 2.0% per year until 2023.

The Company's weighted average prices received this fiscal year are: \$8.21/Mscf for natural gas and \$93.01/MSTB.

## Part 4 – Reconciliation of Changes in Reserves

The following table sets forth a reconciliation of the changes in the Company's gross reserves as at July 31, 2008 against such reserves as at July 31, 2007 based on the forecast price and cost assumptions set forth in note 9:

	Light and Medium Oil			Heavy Oil			Associated and Non-Associated Gas		
	Gross Proved (Mbbbl)	Gross Probable (Mbbbl)	Gross Proved Plus Probable (Mbbbl)	Gross Proved (Mbbbl)	Gross Probable (Mbbbl)	Gross Proved Plus Probable (Mbbbl)	Gross Proved (Mbbbl)	Gross Probable (Mbbbl)	Gross Proved Plus Probable (Mbbbl)
<b>At July 31, 2007</b>	10.1	61.9	72.0	0	0	0	19.0	692.0	711.0
Production(Sales)	(6.0)	0	(6.0)	0	0	0	(1.8)	0	(1.8)
Acquisitions	15	38.5	53.5	0	0	0	0	1,450	1,450
Dispositions	0	0	0	0	0	0	0	0	0
Discoveries	0	0	0	0	0	0	0	0	0
Extensions	0	0	0	0	0	0	0	0	0
Revisions to Previous Estimate									
Economic Factors	0	0	0	0	0	0	0	0	0
Technical	16.5	(36.5)	(20.0)	0	0	0	3.8	(78.0)	(74.3)
Improved Recovery	0	0	0	0	0	0	0	0	0
<b>At July 31, 2008</b>	35.6	63.9	99.5	0	0	0	21.0	2,064.0	2085.0

## Part 5 – Additional Information Relating to Reserves Data

### Undeveloped Reserves

The Company had no proved undeveloped reserves as at July 31, 2008 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 (Mbbbl)	Heavy Oil (Mbbbl)	Natural Gas (MMscf)	Natural Gas Liquids (Mbbbl)
Aggregate prior to 2005	0	0	0	0
2006	31	0	190	5
2007	33	0	190	5
2008	0	0	587	17

### Probable Undeveloped Reserves

The Company's Probable Undeveloped reserves are located in the Sarcee, Alberta gas field and are attributed to a location scheduled to be drilled in March 2009 to develop the Rundle formation. Reserves are based on geological mapping and logs and test analyses on other wells in the structure.

### **Significant Factors or Uncertainties**

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

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

In mid 2007, the Alberta government announced plans to change Crown royalty calculations, effective January 1, 2009. Since the exact nature of the changes have not been finalized, this evaluation has been prepared utilizing the existing regulations, in accordance with advice from the ASC and as recommended by the SPEE.

For comparison purposes, this evaluation has been rerun using the assumption that the proposed new Alberta Royalty Framework comes into effect January 1, 2009. Under the proposed royalties, the net present value of the Company will be reduced by 21 percent, from \$13,296,000 to \$10,453,000 before income tax discounted at 10% using forecast prices and costs.

### **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.

	<b>Total Proved Estimated Using Forecast Prices and Costs (Undiscounted) (\$M)</b>	<b>Total Proved Plus Probable Estimated Using Forecast Prices and Costs (Undiscounted) (\$M)</b>
2008	156	156
2009	11	1,030
2010	0	0
2011	0	0
2012	0	0
Total for five years	167	1,186
Remainder	0	0
Total for all years	167	1,186

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 July 31, 2008

	Oil		Natural Gas	
	Gross <sup>(1)</sup>	Net <sup>(1)</sup>	Gross <sup>(1)</sup>	Net <sup>(1)</sup>
CANADA				
Mulligan, AB				
Producing	4	0.54	1	0.12
Non-producing	4	0.63	1	0.01
Sarcee, AB				
Producing	-	-	-	-
Non-producing	-	-	1	0.09
Pincher Creek, AB				
Producing	-	-	-	-
Non-producing	1	0.25	-	-
Grouard, AB				
Producing	-	-	-	-
Non-producing	-	-	2	0.7
USA				
Morgan County, Tennessee				
Producing	-	-	-	-
Non-producing	2	1.1	3	1.05
<b>Total Wells:</b>	<b>11</b>	<b>2.52</b>	<b>8</b>	<b>1.97</b>

#### *Mulligan, Alberta*

Montello Resources owns various working interests in 6,080 acres of land in the Mulligan area in Northern Alberta. At present this area contains four producing oil wells, one producing gas well, one shut-in gas well, three shut-in oil wells, and one water disposal well. The production is subject to new Crown royalties and various gross overriding royalties. The Company's lands in this area have oil production from Triassic (Charlie Lake member) and natural gas production from the Upper Mississippian Stoddart Group (Kiskatinaw).

#### *Pincher Creek, Alberta*

The Company owns a 25 percent working interest in 640 acres of land containing one non-producing oil well which is expected to produce from the Cadomin and Brown sands. The Company also has options to acquire rights to seven sections in this area.

The Company also has an interest in 960 acres with prospective resources in the Rundle.

#### *Sarcee, Alberta*

The Company owns an 8.50 percent working interest in 2,560 acres of land in this area. These lands contain one non producing gas well and one identified development drilling location. Production will be subject to Indian Royalties which are equivalent to Alberta New Crown royalties plus a 6.5 percent gross overriding royalty. The unit of interest is the Mississippian (Visean) age Turner Valley Formation of the Rundle Group.

### **Properties with No Attributed Reserves**

#### *Grouard, Alberta*

Montello holds a 35.00% working interest in two shut-in gas wells in an area operated by another Company, which has experienced financial difficulties. In order to place these wells on production a pipeline and other facilities will be required at an estimated cost of \$1.6 million. Montello does not plan to make further expenditures on this project until the operator's financial difficulties are resolved.

#### *Morgan County, Tennessee*

Montello holds interests varying from 35.00 to 55.00% in five wells located in Morgan County, Tennessee. Each of the wells have potential in the Chattanooga shale formation. In addition two of the wells have oil potential that has been inhibited from flowing due to paraffin buildup. The Company plans to attempt to rectify the paraffin problems in the spring of 2009.

### **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 4.49 net wells. Costs have been included in the Chapman report for the Mulligan, Pincher Creek and Sarcee area to which reserves have been assigned. Additional abandonment costs of \$154,500 are anticipated for Company wells in Tennessee and Grouard / Little Horse areas for which reserves have not been assigned.

### **FUTURE ABANDONMENT AND RESTORATION COSTS**

	<b>Total Proved Estimated Using Forecast Prices and Costs (Undiscounted) (\$M)</b>	<b>Total Proved Estimated Using Forecast Prices and Costs (10% Discounted) (\$M)</b>	<b>Total Proved Plus Probable Estimated Using Forecast Prices and Costs (Undiscounted) (\$M)</b>	<b>Total Proved Plus Probable Estimated Using Forecast Prices and Costs (10% Discounted) (\$M)</b>
2008	0	0	0	0
2009	0	0	0	0
2010	5	5	0	0
Total for three years	5	5	0	0
Remainder	140	102	223	90
Total for all years	145	107	223	90

### **Tax Horizon**

The Company is not expected to become taxable in the Total Proved Case, but will become taxable in 2011 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 July 31, 2008

Property Acquisition Costs (\$M)		Exploration Costs (\$M)	Development Costs (\$M)
Proved Properties	Unproved Properties		
272	3,499	1,516	499

### Exploration and Development Activities

The following table sets forth the number of exploratory and development wells which the Company completed during its 2008 financial year:

	Exploratory Wells		Development Wells	
	Gross <sup>(1)</sup>	Net <sup>(1)</sup>	Gross <sup>(1)</sup>	Net <sup>(1)</sup>
Oil Wells	2	1.1	-	-
Gas Wells	3	1.05	-	-
Service Wells	-	-	-	-
Dry Holes	-	-	-	-
Total Completed Wells	5	2.15	-	-

The Company did not drill or develop any additional reserves in the fiscal year. The Company drilled five wells in Morgan County, Tennessee, USA that are shut in, waiting for further testing.

### Production Estimates

The following table sets forth the volume of production estimated by Chapman for August 2008 to July 2009:

TOTAL PROVED RESERVES				
AREA	Light and Medium Oil (Mbbbl)	Heavy Oil (Mbbbl)	Natural Gas (MMscf)	Natural Gas Liquids (Mbbbl)
Mulligan	4.0	-	11.0	0.0
Pincher Creek	6.1	-	10.0	1.0
<b>Total for all areas</b>	<b>10.1</b>	<b>-</b>	<b>21.0</b>	<b>1.0</b>

TOTAL PROVED PLUS PROBABLE RESERVES				
AREA	Light and Medium Oil (Mbbbl)	Heavy Oil (Mbbbl)	Natural Gas (MMscf)	Natural Gas Liquids (Mbbbl)
Mulligan	5.3	-	13.0	0.0
Pincher Creek	10.5	-	15.0	1.5
Sarcee	0.0	-	90.0	2.6
<b>Total for all areas</b>	<b>15.8</b>	<b>-</b>	<b>118.0</b>	<b>4.1</b>

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 October 31, 2008	Three Months Ended January 31, 2008	Three Months Ended April 30, 2008	Three Months Ended July 31, 2008
<b>Average Daily Production</b>				
Light and Medium Oil (Mbb/d)	16	18	1	16
Natural Gas (MMscf/d)	27	26	16	16
<b>Average Net Prices Received</b>				
Light and Medium Oil (\$/Mbb)	\$73.23	\$80.80	\$97.91	\$124.22
Natural Gas (\$/MMscf)	\$5.99	\$7.41	\$9.63	\$11.87
<b>Royalties</b>				
Light and Medium Oil (\$/Mbb)	\$8.71	\$6.10	\$6.95	\$8.22
Natural Gas (\$/MMscf)	\$1.52	(\$4.12) *	\$4.27	\$7.27
<b>Production Costs</b>				
Per BOE	\$22.23	\$26.39	\$59.78	\$39.29
<b>Netback Received</b>				
Per BOE	\$33.88	\$47.58	\$16.41	\$63.51

\* Includes royalty refund from APMC December, 2007.

## ABBREVIATIONS AND CONVERSION

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

<b>Oil and Natural Gas Liquids</b>		<b>Natural Gas</b>	
Bbl	barrel	Mscf	thousand standard cubic feet
Bbls	barrels	MMscf	million standard cubic feet
Mbbls	thousand barrels	Mscf/d	thousand standard cubic feet per day
MMbbls	million barrels	MMscf/d	million standard cubic feet per day
MSTB	1,000 stock tank barrels	MMBTU	million British Thermal Units
Bbls/d	barrels per day	Bcf	billion cubic feet
BOPD	barrels of oil per day	GJ	gigajoule
NGLs	natural gas liquids		
STB	stock tank barrels		
<b>Other</b>			
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 <sup>3</sup>	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		

**FORM 51-101F3  
REPORT OF  
MANAGEMENT AND DIRECTORS  
ON OIL AND GAS DISCLOSURE**

**This is the form referred to in item 3 of section 2.1 of National Instrument 51-101 Standards of Disclosure for oil and Gas activities (“NI 51-101”).**

1. Terms to which a meaning is ascribed in NI 51-101 have the same meaning in this form.
2. The report referred to in item 3 of section 2.1 of NI 51-101 must in all material aspects be as follows:

**Report of Management and Directors  
On Reserves Data and Other Information**

Management of Montello 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 are estimates of proved reserves and probable reserves and related future net revenue as at July 31, 2008, using estimated forecast prices and costs.

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

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 reserve evaluator to determine whether any restrictions affected the ability of the independent reserves evaluator to report without reservation; and
- (c) reviewed the reserves data with management and the independent qualified reserves evaluator.

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 the information with management. The Board of directors has approved:

- (a) the content and filing with securities regulatory authorities of Form 51-101F1 containing reserves data and other oil and gas information;
- (b) the filing of Form 51-101F2 which is the report of the independent qualified reserves evaluator; and
- (c) the content and filing of this report.

Because the reserves data are based on judgements regarding future events, actual results will vary and the variations may be material. However, any variations should be consistent with the fact that the reserves are categorized according to the probability of their recovery.

“SIGNED”

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Peter C. Brown, President and Chief Executive Officer

“SIGNED”

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Michael A. Williams, Chief Financial Officer

“SIGNED”

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William R. Cawker, Chairman and Director

“SIGNED”

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Phil Emrich, Director