

Reserves Summary

Oil and Natural Gas Reserves

Provident's reserves were evaluated by McDaniel & Associates Consultants Ltd. (McDaniel) and by AJM Petroleum Consultants (AJM) in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook (COGEH) and the Canadian Securities Administrators' National Instrument 51-101 Standards of Disclosure for Oil and Gas Activities (NI 51-101). McDaniel evaluated all of Provident's Canadian oil and natural gas properties, except the Northwest Alberta properties which were evaluated by AJM. McDaniel and AJM are independent qualified reserves evaluators appointed pursuant to NI 51-101. Additional information pertaining to NI 51-101 and some of the key reserves definitions are provided at the conclusion of the Reserves section. Additional details on Provident's reserves can be found in Form NI 51-101 F1 on Provident's website or at www.sedar.com.

During 2009 Provident repositioned the Upstream oil and gas portfolio for growth by monetizing non-core properties to focus financial and technical resources on assets with significant growth potential. This asset rationalization initiative included the sale of the Trust's Lloydminster and Southern Saskatchewan properties in 2009. An agreement to sell Provident's properties in West Central Alberta (WCA) was announced on December 23, 2009 and this sale closed March 1, 2010. Hence the year-end presentation of reserves and values include the WCA assets. Key information adjusted for the WCA divestiture is also presented for clarity. The Lloydminster and Saskatchewan assets are shown as divestitures in the reconciliation tables.

Provident's oil and natural gas reserves and present value of estimated future cash flows based on forecast prices and costs as of December 31, 2009 using the McDaniel January 1, 2010 price forecast are summarized in the following tables. Reserves volumes are presented on a Gross (working interest) and Net basis, except where otherwise noted (refer to the notes under the tables and to the Definitions at the end of the Reserves section for explanations of company share, working interest, gross and net). Provident Upstream reserves as presented herein are based on the Alberta New Royalty Framework including the Transitional Royalties that were announced in November 2008, the drilling royalty credit and the new well incentive program, which were both announced March 3, 2009.

Reserves as of December 31, 2009^{(a) (b)} Using McDaniel Price Forecast

	Oil		Natural Gas		NGL		Oil Equivalent	
	Gross (Mbbl)	Net (Mbbl)	Gross (MMcf)	Net (MMcf)	Gross (Mbbl)	Net (Mbbl)	Gross (Mboe)	Net (Mboe)
Proved Reserves								
Producing	12,022	9,598	128,507	110,680	1,751	1,232	35,190	29,277
Non-Producing	197	145	15,134	10,174	81	58	2,800	1,898
Undeveloped	1,998	1,429	21,455	17,917	195	135	5,769	4,550
Total Proved	14,217	11,171	165,096	138,771	2,026	1,425	43,759	35,725
Probable	12,839	9,522	72,832	60,980	803	558	25,781	20,244
Proved plus Probable	27,056	20,694	237,928	199,751	2,829	1,983	69,540	55,968

Notes:

- (a) Tables may not add due to rounding
- (b) Gross Reserves are Provident's working interest (operated or non-operated) share before deduction of Crown and Freehold royalties and without including any over-riding royalty interests of Provident. Net Reserves are Provident's working interest (operated or non-operated) share after deduction of royalty obligations, plus Provident's royalty interests in reserves.

Present Value of Reserves as of December 31, 2009^(a)

Using McDaniel Price Forecast

The present value of estimated future cash flows based on forecast prices and costs of Provident's oil and natural gas reserves are summarized in the following tables. The impact of Federal and Provincial income taxes has been incorporated in the table showing After Tax values. Tax pools held by Provident Upstream will mitigate the impact of Federal income tax changes that were enacted during 2007 under which the Trust is expected to be taxable beginning January 1, 2011.

Present Value (\$000's) Before Tax Discounted at					
	0%	8%	10%	15%	20%
Proved Reserves					
Producing	826,667	590,115	550,770	473,032	415,878
Non-Producing	34,961	34,146	30,515	23,098	17,921
Undeveloped	108,906	59,686	50,774	33,774	22,213
Total Proved	970,534	683,947	632,060	529,904	456,013
Probable	833,081	329,049	276,840	191,713	141,799
Proved plus Probable	1,803,615	1,012,996	908,900	721,617	597,811

Present Value (\$000's) After Tax^(b) Discounted at					
	0%	8%	10%	15%	20%
Proved Reserves					
Producing	799,151	578,867	541,613	467,407	412,306
Non-Producing	19,099	26,417	23,952	18,635	14,802
Undeveloped	79,087	44,289	37,477	24,331	15,315
Total Proved	897,337	649,573	603,041	510,374	442,422
Probable	638,215	250,996	211,424	147,210	109,706
Proved plus Probable	1,535,551	900,569	814,465	657,584	552,128

Notes:

(a) Tables may not add due to rounding

(b) After tax values include the impact of Canadian Federal and Provincial Income taxes beginning January 1, 2011.

Reserves Reconciliation

The following tables present the changes that occurred by reserve category during 2009 on the basis of Company Share (Working Interest plus Royalty Interest) reserves. Working Interest (Gross) reserves are provided at the bottom of each table to tie to the preceding reserves tables. Total proved reserves decreased from 59,596 Mboe as of December 31, 2008 to 43,982 Mboe as of December 31, 2009. Divestitures and production were the main contributing factors to this decrease. Proved plus probable reserves decreased from 97,763 Mboe as of December 31, 2008 to 69,866 Mboe as of December 31, 2009. Internal development activities were successful in replacing 31 percent of production. The Dixonville and Pekisko oil properties account for the majority of the negative technical revisions during 2009. The Dixonville Montney C pool reserves were revised downward based on results of technical studies which were completed during 2009. The reserves of the emerging Pekisko Oil resource play were revised downward based on early and limited performance data of the five wells that were drilled during 2008 and 2009. The negative technical revision to Pekisko Oil reserves was mitigated by reserve additions for wells that were drilled during 2009 and adjacent locations so that, after accounting for production, the net result is no change to the Pekisko Oil proved plus probable reserves at year-end 2009.

Reconciliation Summary^(a)
Proved Developed Producing

Company Share (WI +RI)^(b)	Light & Medium Oil^(d)	Heavy Oil^(d)	Total Oil	Natural Gas	NGL	Total Oil Equivalent
	Mbbl	Mbbl	Mbbl	MMcf	Mbbl	Mboe
Balance at December 31, 2008	18,117	3,759	21,875	155,514	2,019	49,813
Production	(2,723)	(516)	(3,240)	(25,395)	(409)	(7,881)
Drilling Activity						
Drilling Extensions	26	131	157	1,463	13	413
Recompletion	20	71	92	1,272	4	307
Transfer	34	259	293	1,529	10	558
Acquisition	8	0	8	11	(0)	9
Divestiture	(4,497)	(1,781)	(6,277)	(6,459)	(23)	(7,377)
Economic Factors	4	0	4	(2,087)	(12)	(356)
Technical Revisions	(494)	(371)	(866)	3,503	172	(110)
Balance at December 31, 2009	10,494	1,551	12,046	129,350	1,772	35,376
WI Share^(c)						
Balance at December 31, 2009	10,470	1,551	12,022	128,507	1,751	35,190

Reconciliation Summary^(a)
Total Proved

Company Share (WI +RI)^(b)	Light & Medium Oil^(d)	Heavy Oil^(d)	Total Oil	Natural Gas	NGL	Total Oil Equivalent
	Mbbl	Mbbl	Mbbl	MMcf	Mbbl	Mboe
Balance at December 31, 2008	19,905	5,099	25,004	193,792	2,293	59,596
Production	(2,723)	(516)	(3,240)	(25,395)	(409)	(7,881)
Drilling Activity						
Drilling Extensions	141	390	531	2,450	16	955
Recompletion	20	71	92	1,512	4	348
Transfer	20	259	279	95	0	295
Acquisition	8	0	8	11	(0)	9
Divestiture	(5,282)	(2,174)	(7,456)	(8,192)	(23)	(8,844)
Economic Factors	4	0	4	(2,159)	(12)	(368)
Technical Revisions	30	(1,011)	(981)	4,008	185	(128)
Balance at December 31, 2009	12,123	2,118	14,241	166,122	2,054	43,982
WI Share^(c)						
Balance at December 31, 2009	12,099	2,118	14,217	165,096	2,026	43,759

Reconciliation Summary^(a) Total Proved plus Probable

Company Share (WI +RI) ^(b)	Light & Medium Oil ^(d) Mbbbl	Heavy Oil ^(d) Mbbbl	Total Oil Mbbbl	Natural Gas MMcf	NGL Mbbbl	Total Oil Equivalent Mboe
Balance at December 31, 2008	39,324	9,083	48,407	276,771	3,228	97,763
Production	(2,723)	(516)	(3,240)	(25,395)	(409)	(7,881)
Drilling Activity						
Drilling Extensions	303	1,025	1,328	3,857	22	1,992
Recompletion	26	93	120	1,843	5	432
Transfer	0	0	0	0	0	0
Acquisition	10	0	10	14	0	12
Divestiture	(8,157)	(4,420)	(12,577)	(13,627)	(34)	(14,883)
Economic Factors	5	0	5	(2,821)	(18)	(483)
Technical Revisions	(5,809)	(1,153)	(6,962)	(1,192)	74	(7,087)
Balance at December 31, 2009	22,977	4,113	27,090	239,451	2,867	69,866
WI Share^(c)						
Balance at December 31, 2009	22,943	4,113	27,056	237,928	2,829	69,540

Notes:

- (a) Tables may not add due to rounding
(b) Company share includes working interest (WI) and royalty interest (RI) volumes.
(c) WI share includes the Company's working interests only, and excludes volumes associated with royalties.
(d) The definition of light, medium and heavy oil for Canada is consistent with the royalty regime of each province. Heavy Oil within the province of Alberta includes oil defined as heavy and ultra-heavy in accordance with the New Royalty Framework, which came into effect on January 1, 2009.

Price Forecast Summary

The following table summarizes the McDaniel January 1, 2010 price forecast used in evaluating Provident's reserves.

Year	WTI Crude at Cushing Oklahoma US\$/bbl	Light, Sweet Crude at Edmonton Cdn\$/bbl	Alberta Bow River Hardisty Cdn\$/bbl	Alberta AECO Gas Spot Price Cdn\$/MMbtu	Exchange Rate US\$/Cdn\$
2010	80.00	83.20	72.30	6.05	0.950
2011	83.60	87.00	73.80	6.75	0.950
2012	87.40	91.00	74.40	7.15	0.950
2013	91.30	95.00	75.80	7.45	0.950
2014	95.30	99.20	79.20	7.80	0.950

Finding, Development and Acquisition Costs

Finding and development costs (F&D) include all costs to develop reserves, including land and seismic costs. The methodology used to calculate F&D costs under NI 51-101 requires that F&D costs incorporate changes in future development capital (FDC) required to bring non-producing and undeveloped reserves to production. This capital, which is included in the reserves evaluations, is part of the ongoing development process necessary to bring production on stream and generate cash flow. To provide clarity in the true costs to find and develop reserves, Provident does not include the FDC associated with acquisitions and divestitures in the F&D costs. However, since FDC is a component of the cost of acquiring reserves Provident does include the FDC associated with acquisitions and divestitures in the finding, development and acquisition (FD&A) costs.

Provident's focus has been development and exploitation of reserves. As a result of capital expenditures during 2009, drilling and recompletion activity added total proved reserves of 1,303 Mboe and proved plus probable reserves of 2,425 Mboe. Drilling and tie-in activity promoted 558 Mboe of reserves into the proved developed producing category and 295 Mboe into total proved. Continued development of the Dixonville Montney C pool and the Pekisko Oil play in northwest Alberta were significant recipients of capital expenditures during 2009.

The aggregate of the development costs incurred in the most recent financial year and the change during that year in estimated future development costs generally will not reflect total finding and development costs related to reserve additions for that year. A three-year average of F&D costs is a better reflection of full cycle economics and is therefore a more appropriate view of the cost of reserve additions. The three-year average FD&A cost includes the change in FDC, including acquisitions and divestitures, over the three year period. Acquisition costs include the cash cost of acquiring reserves and the fair value of liabilities assumed. NI 51-101 does not contemplate nor define acquisition costs. Provident has included goodwill on corporate acquisitions as part of the purchase price allocation and therefore it is included in the cost of acquiring reserves.

The following table presents 2009 and three-year average finding and development costs. The three-year average is calculated based on the total capital and total reserves over the three-year time period from 2007 through 2009. F&D costs including revisions and FDC were \$18.87 per boe of total proved reserves in 2009. The three-year average FD&A costs including revisions and FDC were \$32.68 per boe of proved plus probable reserves. FD&A costs in 2009 were skewed by the significant divestiture activity and therefore are not presented.

Finding and Development Costs^{(a) (b)} Including Future Development Costs

	F&D Costs per boe		FD&A Costs per boe
	2009	3-year Average ^(c)	3-year Average
<u>Total Proved</u>			
Including revisions	18.87	32.75	41.67
Excluding revisions	13.01	29.09	39.09
<u>Proved plus Probable</u>			
Including revisions	na (d)	79.80	32.68
Excluding revisions	12.71	23.28	23.06

Notes:

- (a) F&D costs are based on company share reserves.
- (b) BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 Mcf:1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.
- (c) Three year average is the average of 2007, 2008 and 2009 calculated based on the total capital and total reserves over the three-year time period.
- (d) Revisions exceed additions; therefore the calculation is not included in the table.

The following table presents the details of the 2009 F&D cost calculations and illustrates the impact of including the change in future development capital in the calculation.

2009 Finding and Development Cost Calculations

	Capital (\$000s)	Reserve Additions Mboe	F&D Costs \$/boe
Finding and Development Costs Including Reserve Revisions			
<u>Total Proved</u>			
Capital Expenditures ⁽¹⁾	\$ 76,831	1,102	\$ 69.71
Change in FDC ⁽²⁾	<u>(56,039)</u>		
Total F&D including change in FDC	\$ 20,792	1,102	\$ 18.87
Finding and Development Costs Excluding Reserve Revisions			
<u>Total Proved</u>			
Capital Expenditures ⁽¹⁾	\$ 76,831	1,598	\$ 48.08
Change in FDC ⁽²⁾	<u>(56,039)</u>		
Total F&D including change in FDC	\$ 20,792	1,598	\$ 13.01
<u>Proved plus Probable</u>			
Capital Expenditures ⁽¹⁾	\$ 76,831	2,425	\$ 31.69
Change in FDC ⁽²⁾	<u>(46,013)</u>		
Total F&D including change in FDC	\$ 30,818	2,425	\$ 12.71

Details of Capital and FDC

(1) Total F&D Costs (\$000s)			
2009 Oil and Gas Capital Expenditures	\$ 76,831		
Property Acquisitions (net of dispositions)	(309,635)		
Corporate Acquisitions	<u>-</u>		
Total Oil and Gas FD&A costs	\$ (232,804)		
(2) Change in Future Development Costs (\$000s)			
	Total Proved	Proved plus Probable	
FDC as of 2009-12-31	\$ 83,861	\$ 127,587	
FDC as of 2008-12-31	<u>165,400</u>	<u>221,800</u>	
Change in FDC for FD&A Calculation	\$ (81,539)	\$ (94,213)	
FDC of Acquired (Divested) Properties	<u>(25,500)</u>	<u>(48,200)</u>	
Change in FDC for F&D Calculation	\$ (56,039)	\$ (46,013)	

The following table presents the details of the three-year F&D cost calculations and illustrates the impact of including the change in future development capital in the calculation.

Three-year Finding, Development and Acquisition Cost Calculations

	Capital (\$000s)	Reserve Additions including Revisions Mboe	F&D Costs \$/boe
Finding and Development Costs			
<u>Total Proved</u>			
Capital Expenditures ⁽¹⁾	\$ 369,109	9,591	\$ 38.48
Change in FDC ⁽²⁾	<u>(55,004)</u>		
Total F&D including change in FDC	\$ 314,106	9,591	\$ 32.75
<u>Proved plus Probable</u>			
Capital Expenditures ⁽¹⁾	\$ 369,109	4,023	\$ 91.74
Change in FDC ⁽²⁾	<u>(48,048)</u>		
Total F&D including change in FDC	\$ 321,062	4,023	\$ 79.80
Finding, Development and Acquisition Costs			
<u>Total Proved</u>			
Capital Expenditures and Acquisition Costs ⁽¹⁾	\$ 738,970	18,293	\$ 40.40
Change in FDC ⁽²⁾	<u>23,297</u>		
Total FD&A including change in FDC	\$ 762,267	18,293	\$ 41.67
<u>Proved plus Probable</u>			
Capital Expenditures and Acquisition Costs ⁽¹⁾	\$ 738,970	23,418	\$ 31.56
Change in FDC ⁽²⁾	<u>26,222</u>		
Total FD&A including change in FDC	\$ 765,192	23,418	\$ 32.68
<u>Details of Capital and FDC</u>			
(1) Total F&D Costs (\$000s)			
Oil and Gas Capital Expenditures	\$ 369,109		
Property Acquisitions (net of dispositions)	(226,383)		
Corporate Acquisitions	<u>596,243</u>		
Total Oil and Gas FD&A costs	<u>\$ 738,970</u>		
(2) Change in Future Development Costs (\$000s)			
	Total Proved	Proved plus Probable	
FDC as of 2009-12-31	\$ 83,861	\$ 127,587	
FDC as of 2006-12-31	60,565	101,365	
Change in FDC for FD&A Calculation	<u>23,297</u>	<u>26,222</u>	
FDC of Acquired and Divested Properties	78,301	74,270	
Change in FDC for F&D Calculation	\$ (55,004)	\$ (48,048)	

Reserves after West Central Alberta Divestiture

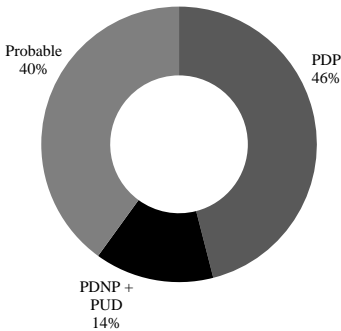
On December 23, 2009 Provident announced an agreement had been reached to sell the Trust's oil and natural gas assets in West Central Alberta (WCA). This divestiture closed March 1, 2010. The following tables present the Trust's reserves and values as of December 31, 2009 without the WCA assets.

Reserves as of December 31, 2009 without WCA^{(a) (b)}

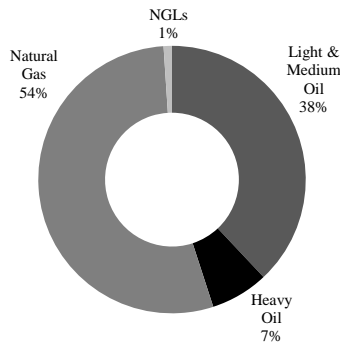
Using McDaniel Price Forecast

	Oil		Natural Gas		NGL		Oil Equivalent	
	Gross (Mbbbl)	Net (Mbbbl)	Gross (MMcf)	Net (MMcf)	Gross (Mbbbl)	Net (Mbbbl)	Gross (Mboe)	Net (Mboe)
Proved Reserves								
Producing	10,508	8,310	88,149	78,067	375	230	25,575	21,551
Non-Producing	197	145	13,616	8,922	50	32	2,517	1,664
Undeveloped	1,998	1,429	20,172	16,848	107	68	5,467	4,305
Total Proved	12,704	9,884	121,937	103,837	533	330	33,559	27,520
Probable	12,272	9,069	56,749	48,265	245	151	21,975	17,264
Proved plus Probable	24,975	18,953	178,686	152,102	777	480	55,534	44,784

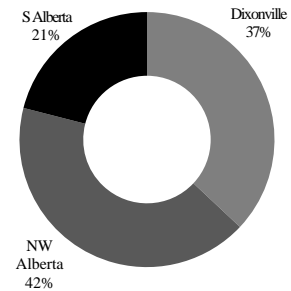
Reserves by Category Excluding WCA



P+P Reserves by Product Excluding WCA



P+P Reserves by Core Area Excluding WCA



**Present Value of Reserves as of December 31, 2009 without WCA^(a)
Using McDaniel Price Forecast**

	Present Value (\$000's) Before Tax Discounted at				
	0%	8%	10%	15%	20%
Proved Reserves					
Producing	608,031	427,502	398,040	340,284	298,197
Non-Producing	35,306	30,900	27,517	20,737	16,043
Undeveloped	99,673	52,587	44,073	27,908	17,006
Total Proved	743,011	510,990	469,630	388,929	331,247
Probable	719,285	269,790	224,993	153,036	111,552
Proved plus Probable	1,462,295	780,780	694,623	541,965	442,799

	Present Value (\$000's) After Tax^(b) Discounted at				
	0%	8%	10%	15%	20%
Proved Reserves					
Producing	578,455	414,310	387,050	333,128	293,377
Non-Producing	20,978	23,587	21,221	16,303	12,826
Undeveloped	71,469	37,802	31,228	18,625	10,086
Total Proved	670,902	475,698	439,499	368,055	316,289
Probable	549,854	204,936	170,862	116,357	85,061
Proved plus Probable	1,220,757	680,634	610,361	484,412	401,350

Notes:

- (a) Tables may not add due to rounding
- (b) Gross Reserves are Provident's working interest (operated or non-operated) share before deduction of Crown and Freehold royalties and without including any over-riding royalty interests of Provident. Net Reserves are Provident's working interest (operated or non-operated) share after deduction of royalty obligations, plus Provident's royalty interests in reserves.
- (c) After tax values include the impact of Canadian Federal and Provincial Income taxes beginning January 1, 2011.

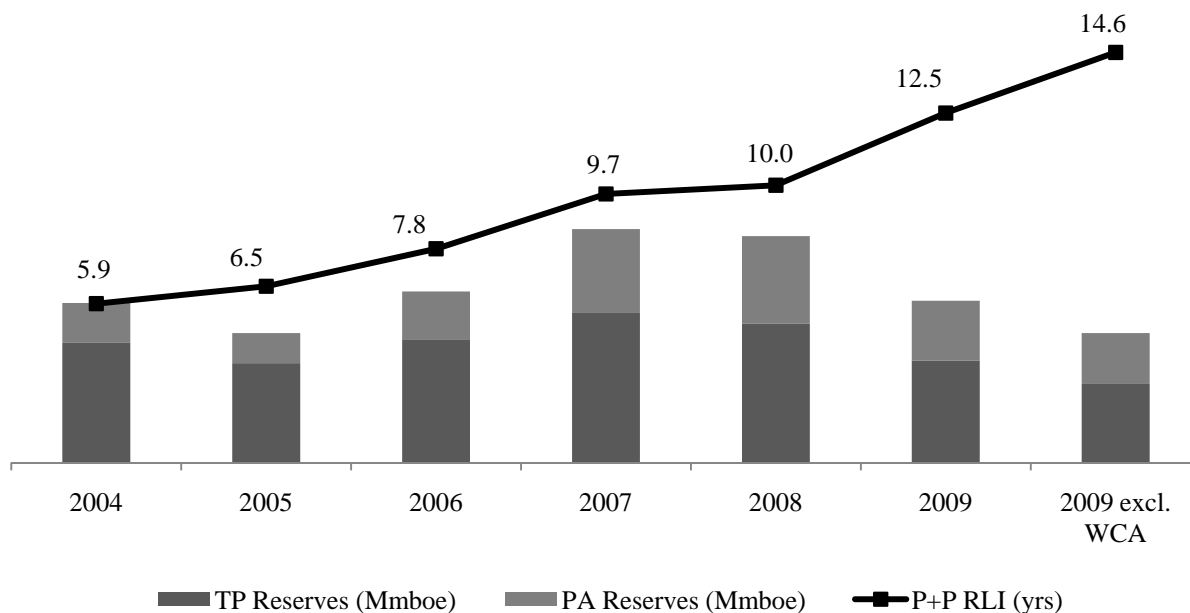
Reserve Life Index (RLI) without WCA

The success of Provident's divestment of non-core assets is illustrated by the increase in Provident's RLI., which was determined by applying the average actual production rate for the last quarter of 2009 (excluding production from the Lloydminster operating area that was sold during the quarter) to reserve volumes for each reserve category. Provident's proved plus probable RLI increased to 12.5 years as of December 31, 2009 and to 14.6 years excluding the WCA assets.

The following table illustrates the reserve life index for the various product and reserve categories as of December 31, 2009 and prior years.

	RLI (years) as of December 31						
	2009	2008	2007	2006	2005	2004	2003
Total Crude Oil							
Proved Producing	8.2	4.9	4.6	4.4	3.9	3.3	3.0
Total Proved	9.9	5.6	6.2	4.8	4.3	4.0	3.9
Proved plus Probable	19.5	10.8	11.2	6.8	5.8	5.4	5.4
Natural Gas & NGL							
Proved Producing	6.0	5.3	5.2	5.0	4.4	4.1	4.4
Total Proved	8.3	6.5	6.3	6.0	5.4	4.9	4.9
Proved plus Probable	12.1	9.3	8.7	8.3	7.1	6.4	6.1
Oil Equivalent (6:1)							
Proved Producing	6.7	5.1	4.9	4.8	4.2	3.7	3.7
Total Proved	8.8	6.1	6.2	5.6	5.0	4.5	4.4
Proved plus Probable	14.6	10.0	9.7	7.8	6.5	5.9	5.7

Reserves and Reserve Life Index (RLI)



Undeveloped Land

The following table presents Provident's undeveloped land and expiries within one year of December 31, 2009, excluding the WCA properties.

UNDEVELOPED LAND

Gross Area	Net Area	Expiries Within One Year
Acres	Acres	Net Acres
315,581	239,451	39,201

National Instrument 51-101

All aspects of oil and gas reserves disclosure in Canada are governed by the Canadian Securities Administrators under National Instrument 51-101 (NI 51-101) which was implemented effective September 2003 and updated effective December 28, 2007. NI 51-101 establishes prescribed disclosures regarding oil and natural gas information and requires that reserves information be prepared in accordance with the Canadian Oil and Gas Evaluation Handbook ("COGEH"). NI 51-101 also enhances corporate governance by mandating the involvement of independent reserves evaluators in the preparation of reserves data and assigning responsibility for the content of reserves data directly to management and the board of directors. Provident's reserves have been evaluated in accordance with COGEH and comply with NI 51-101. Under NI 51-101, proved reserves are defined as having a high degree of certainty to be recoverable. Probable reserves are defined as those reserves that are less certain to be recovered than proved reserves. The targeted levels of certainty, in aggregate, are at least 90 percent probability that the quantities actually recovered will equal or exceed the estimated proved reserves and at least 50 percent probability that the quantities recovered will equal or exceed the sum of the estimated proved plus probable reserves. Under NI 51-101 standards proved plus probable are considered a "best estimate" of future recoverable reserves. The following outlines some of the key reserves definitions according to NI 51-101.

Reserve Definitions

Acquisition and Divestiture: Positive or negative changes to the reserves as a result of purchasing or selling all or a portion of an interest in oil and gas properties.

Closing Balance: Reserves assigned at the end of the period.

Company Share: Includes working interest volumes before the deduction of Crown and Freehold royalties plus volumes equivalent to over-riding royalty interests received from others.

Drilling Extensions: Additions to reserves resulting from capital expenditures for step-out drilling in previously discovered reservoirs.

Economic Factors: Changes to reserves between the current and previous reporting periods resulting from different price forecasts, inflation rates, operating and capital cost escalation and regulatory changes.

Net Reserves: Includes the company's share of gross reserves after the deduction of royalties plus volumes equivalent to royalty interests received from others and excludes volumes equivalent to royalties paid to others.

Opening Balance: Reserves assigned at the end of the last reporting period.

Production: Reductions in reserves due to production during the reporting period.

Recompletions: Additions to reserves resulting from capital expenditures for recompletions or workovers.

Technical Revisions: Positive or negative revisions resulting from new technical data or revised interpretations on previously assigned reserves.

Transfers: Changes to the classification of reserves from Probable to Proved or from Proved Undeveloped to Proved Developed Producing resulting from capital expenditures.

Working Interest: The Company's interest before royalties paid to or received from others.