STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

Dated 01 November 2006

In accordance with National Instrument 51-101 Statement of Reserves Data and Other Oil and Gas Information ("NI 51-101"), Gilbert Laustsen Jung Associates Ltd. ("GLJ") and Paul R. Clevenger P.E. ("Clevenger") (both entities hereafter referred to as "the Evaluators") prepared the Report on Reserves Data of Emerald Bay Energy Inc. ("Emerald") (the "Emerald Report") on April 6, 2006 and April 14, 2006 respectively, evaluating the proved and probable crude oil, natural gas and natural gas liquids reserves attributable to Emerald's interest in its properties and net present value of estimated future cash flow from such reserves, based on both forecasted and constant price and cost assumptions ("Emerald Properties"). The Emerald Report evaluated, effective as at December 31, 2005, the Emerald Properties' oil, natural gas and natural gas reserves. The tables below are a summary of the estimated share of Emerald's crude oil, natural gas liquids and natural gas reserves in its properties and the net present value of estimated future net revenue for these reserves, using constant and forecast prices and costs as indicated. The information set forth below is prepared in accordance with standards contained in the COGE Handbook and the reserves definitions contained in NI 51-101 and the COGE Handbook. The tables summarize the data contained in the Emerald Report and as a result may contain slightly different numbers than such report due to rounding. Also due to rounding, certain columns may not add exactly. The net present value of future net revenue attributable to the Emerald Properties reserves is stated without provision for interest costs and general and administrative costs, but after providing for estimated royalties, production costs, development costs, other income, future capital expenditures, and well abandonment costs for only those wells assigned reserves by the Evaluators. It should not be assumed that the undiscounted or discounted net present value of future net revenue attributable to the Emerald Properties' reserves estimated by the Evaluators represent the fair market value of those reserves. Other assumptions and qualifications relating to costs, prices for future production and other matters are summarized herein. The recovery and reserve estimates of the Emerald Properties' oil, natural gas liquids and natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual reserves may be greater than or less than the estimates provided herein.

Emerald is not bound by any forward selling contracts that will preclude it from fully realizing future market prices of oil and gas.

Summary of Oil and Gas Reserves using Constant Prices and Costs

Canadian Assets

	Light/Medium Oil		Natural Gas		NGL's		Oil Equivalent	
	Gross[(1)] (Mbbl)	Net[(2)] (Mbbl)	Gross[(1)] (MMcf)	Net[(2)] (MMcf)	Gross[(1)] (Mbbl)	Net[(2)] (Mbbl)	Gross[(1)] (Mbbl)	Net[(2)] (Mbbl)
Proved Developed Producing	3	3	1308	1090	39	26	259	210
Proved Developed Non-Producing	0	0		0	0	0	0	0
Proved Undeveloped	0	0	77	66	0	0	13	11
Total Proved	3	3	1,385	1,156	39	26	272	221

US Assets

	Light/Medium Oil		Natural Gas		NGL's		Oil Equivalent	
	Gross[(1)] (Mbbl)	Net[(2)] (Mbbl)	Gross[(1)] (MMcf)	Net[(2)] (MMcf)	Gross[(1)] (Mbbl)	Net[(2)] (Mbbl)	Gross[(1)] (Mbbl)	Net[(2)] (Mbbl)
Proved Developed Producing	11	8	0	0	0	0	11	8
Proved Developed Non-Producing	0	0	0	0	0	0	0	0
Proved Undeveloped	0	0	0	0	0	0	0	0
Total Proved	11	8	0	0	0	0	11	8

in Aggregate

	Light/Medium Oil		Natural Gas		NGL's		Oil Equivalent	
	Gross[(1)] (Mbbl)	Net[(2)] (Mbbl)	Gross[(1)] (MMcf)	Net[(2)] (MMcf)	Gross[(1)] (Mbbl)	Net[(2)] (Mbbl)	Gross[(1)] (Mbbl)	Net[(2)] (Mbbl)
Proved Developed Producing	14	11	1308	1090	39	26	270	218
Proved Developed Non-Producing	0	0	0	0	0	0	0	0
Proved Undeveloped	0	0	77	66	0	0	13	11
Total Proved	14	11	1,385	1,156	39	26	283	229

Notes:

(1) Gross Reserves means Emerald's working interest (operating and non-operating) share before deduction of royalties and income taxes.

(2) Net Reserves means Emerald's working interest (operating and non-operating) share after deduction of royalties but before deduction of income taxes.

Summary of Net Present Value of Future Net Reserves using Constant Prices and Costs (in CDN$ thousands, Before Tax)

Canadian Assets

	Before Tax Discounted At						
	0%	5%	8%	10%	12%	15%	20%
Proved Developed Producing	8,987	6,972	6,192	5,777	5,424	4,984	4,418
Proved Developed Non-Producing	0	0	0	0	0	0	0
Proved Undeveloped	186	143	122	109	97	80	57
Total Proved	9,173	7,115	6,314	5,886	5,521	5,064	4,475

US Assets

	Before Tax Discounted At						
	0%	5%	8%	10%	12%	15%	20%
Proved Developed Producing	244	213	197	189	180	170	155
Proved Developed Non-Producing	0	0	0	0	0	0	0
Proved Undeveloped	0	0	0	0	0	0	0
Total Proved	244	213	197	189	180	170	155

In Aggregate

	Before Tax Discounted At						
	0%	5%	8%	10%	12%	15%	20%
Proved Developed Producing	9,231	7,185	6,389	5,966	5,604	5,154	4,573
Proved Developed Non-Producing	0	0	0	0	0	0	0
Proved Undeveloped	186	143	122	109	97	80	57
Total Proved	9,417	7,328	6,511	6,075	5,701	5,234	4,630

Summary of Net Present Value of Future Reserves using Constant Prices and Costs (in CDN$ thousands, After Tax)

Cdn Assets

	After Tax Discounted at						
	0%	5%	8%	10%	12%	15%	20%
Proved Developed Producing	8,987	6,972	6,192	5,777	5,424	4,984	4,418
Proved Developed Non-Producing	0	0	0	0	0	0	0
Proved Undeveloped	186	143	122	109	97	80	57
	9,173	7,115	6,314	5,886	5,521	5,064	4,475
Tax Pools Utilized	-3,346	-2,595	-2,303	-2,147	-2,014	-1,847	-1,632
Total Proved	5,827	4,520	4,011	3,739	3,507	3,217	2,843

US Assets

	After Tax Discounted at						
	0%	5%	8%	10%	12%	15%	20%
Proved Developed Producing	244	213	197	189	180	170	155
Proved Developed Non-Producing	0	0	0	0	0	0	0
Proved Undeveloped	0	0	0	0	0	0	0
	244	213	197	189	180	170	155
Tax Pools Utilized	0	0	0	0	0	0	0
Total Proved	244	213	197	189	180	170	155

In Aggregate

	After Tax Discounted at						
	0%	5%	8%	10%	12%	15%	20%
Proved Developed Producing	9,231	7,185	6,389	5,966	5,604	5,154	4,573
Proved Developed Non-Producing	0	0	0	0	0	0	0
Proved Undeveloped	186	143	122	109	97	80	57
	9,417	7,328	6,511	6,075	5,701	5,234	4,630
Tax Pools Utilized	-3,346	-2,595	-2,303	-2,147	-2,014	-1,847	-1,632
Total Taxable Proved	6,071	4,733	4,208	3,928	3,687	3,387	2,998
2006 Statutory Tax Rate	32.12%	32.12%	32.12%	32.12%	32.12%	32.12%	32.12%
Tax on Total Proved	1,950	1,520	1,352	1,262	1,184	1,088	963
Total Proved After Tax	7,467	5,808	5,159	4,813	4,517	4,146	3,667

TOTAL FUTURE NET REVENUE
(UNDISCOUNTED)
AS OF DECEMBER 31, 2005
CONSTANT PRICES AND COSTS
(CDN $Thousands)

Reserves Category	Revenue	Royalties	Operating Costs	Development Costs	Abandonment and Reclamations Costs	Future Net Revenue Before Income Tax	Tax Pools	Taxable Future Net Revenue Before Income Tax	Tax @ 32.12%	Future Net Revenue After Income Tax
Canadian Assets Proved	16,867	2,983	4,091	325	295	9,173	3,346	5,827	1,872	7,301
US Assets Proved	470	35	191	0	0	244	0	244	78	166
Aggregate	17,337	3,018	4,282	325	474	9,417	3,346	6,071	1,950	7,467

TOTAL FUTURE NET REVENUE
BY PRODUCTION GROUP
AS OF DECEMBER 31, 2005
CONSTANT PRICES AND COSTS (CDN $Thousands)

Reserves Category	Production Group	Future Net Revenue Before Income Taxes (disc @ 10%)	Tax Pools	Taxable Future Net Revenue Before Income Taxes	Tax@ 32.12%	Future Net Revenue After Income Taxes (disc @ 10%)
Canadian Assets						
Proved	Light and Medium Crude Oil[1]	0	0	0	0	0
Proved	Natural Gas[2]	5,886	2,147	3,739	1,201	4,685
US Assets						
Proved	Light and Medium Crude Oil	189	0	189	61	128
Aggregate						
Proved	Light and Medium Crude Oil	189	0	189	61	128
Proved	Natural Gas	5,886	2,147	3,739	1,201	4,685

[1] Light and Medium Crude Oil (Includes solution gas and other by-products)
[2] Natural Gas (Includes by-products but excludes solution gas from oil wells)

Summary of Oil and Gas Reserves using Forecast Prices and Costs

Canadian Assets

	Light/Medium Oil		Natural Gas		NGL's		Oil Equivalent	
	Gross[(1)] (Mbbl)	Net[(2)] (Mbbl)	Gross[(1)] (MMcf)	Net[(2)] (MMcf)	Gross[(1)] (Mbbl)	Net[(2)] (Mbbl)	Gross[(1)] (Mbbl)	Net[(2)] (Mbbl)
Proved Developed Producing	3	3	1268	1057	37	25	251	203
Proved Developed Non-Producing	0	0	0	0	0	0	0	0
Proved Undeveloped	0	0	76	64	0	0	13	11
Total Proved	3	3	1344	1121	37	25	264	214
Probable	5.6	5.6	426	367	9	6	86	73
Proved plus Probable	8.6	8.6	1770	1488	46	31	350	287

US Assets

	Light/Medium Oil		Natural Gas		NGL's		Oil Equivalent	
	Gross[(1)] (Mbbl)	Net[(2)] (Mbbl)	Gross[(1)] (MMcf)	Net[(2)] (MMcf)	Gross[(1)] (Mbbl)	Net[(2)] (Mbbl)	Gross[(1)] (Mbbl)	Net[(2)] (Mbbl)
Proved Developed Producing	11	8	0	0	0	0	11	8
Proved Developed Non-Producing	0	0	0	0	0	0	0	0
Proved Undeveloped	0	0	0	0	0	0	0	0
Total Proved	11	8	0	0	0	0	11	8

In Aggregate

	Light/Medium Oil		Natural Gas		NGL's		Oil Equivalent	
	Gross[(1)] (Mbbl)	Net[(2)] (Mbbl)	Gross[(1)] (MMcf)	Net[(2)] (MMcf)	Gross[(1)] (Mbbl)	Net[(2)] (Mbbl)	Gross[(1)] (Mbbl)	Net[(2)] (Mbbl)
Proved Developed Producing	14	11	1268	1057	37	25	262	211
Proved Developed Non-Producing	0	0	0	0	0	0	0	0
Proved Undeveloped	0	0	76	64	0	0	13	11
Total Proved	14	11	1344	1121	37	25	275	222
Probable	5.6	5.6	426	367	9	6	86	73
Proved plus Probable	19.6	16.6	1770	1488	46	31	361	295

Notes:

(1) Gross Reserves means Emerald's working interest (operating and non-operating) share before deduction of royalties and income taxes.

(2) Net Reserves means Emerald's working interest (operating and non-operating) share after deduction of royalties but before deduction of income taxes.

Summary of Net Present Value of Future Net Reserves using Forecast Prices and Costs (in CDN$ thousands, Before Tax)

Canadian Assets

	Before Tax Discounted At						
	0%	5%	8%	10%	12%	15%	20%
Proved Developed Producing	6,554	5,382	4,913	4,660	4,441	4,162	3,793
Proved Developed Non-Producing	0	0	0	0	0	0	0
Proved Undeveloped	95	69	55	47	39	29	14
Total Proved	6,649	5,451	4,968	4,707	4,480	4,191	3,807
Probable	2,007	1,400	1,178	1,064	969	853	709
Proved plus Probable	8,656	6,851	6,146	5,771	5,449	5,044	4,516

US Assets

	Before Tax Discounted At						
	0%	5%	8%	10%	12%	15%	20%
Proved Developed Producing	244	213	197	189	180	170	155
Proved Developed Non-Producing	0	0	0	0	0	0	0
Proved Undeveloped	0	0	0	0	0	0	0
Total Proved	244	213	197	189	180	170	155

In Aggregate

	Before Tax Discounted At						
	0%	5%	8%	10%	12%	15%	20%
Proved Developed Producing	6,798	5,595	5,110	4,849	4,621	4,332	3,948
Proved Developed Non-Producing	0	0	0	0	0	0	0
Proved Undeveloped	95	69	55	47	39	29	14
Total Proved	6,893	5,664	5,165	4,896	4,660	4,361	3,962
Probable	2,007	1,400	1,178	1,064	969	853	709
Proved plus Probable	8,900	7,064	6,343	5,960	5,629	5,214	4,671

Summary of Net Present Value of Future Reserves using Forecast Prices and Costs (in CDN$ thousands, After Tax)

Cdn Assets

	After Tax Discounted at						
	0%	5%	8%	10%	12%	15%	20%
Proved Developed Producing	6,554	5,382	4,913	4,660	4,441	4,162	3,793
Proved Developed Non-Producing	0	0	0	0	0	0	0
Proved Undeveloped	95	69	55	47	39	29	14
	6,649	5,451	4,968	4,707	4,480	4,191	3,807
Tax Pools Utilized	-3,346	-2,743	-2,500	-2,369	-2,254	-2,109	-1,916
Total Proved	3,303	2,708	2,468	2,338	2,226	2,082	1,891

US Assets

	After Tax Discounted at						
	0%	5%	8%	10%	12%	15%	20%
Proved Developed Producing	244	213	197	189	180	170	155
Proved Developed Non-Producing	0	0	0	0	0	0	0
Proved Undeveloped	0	0	0	0	0	0	0
	244	213	197	189	180	170	155
Tax Pools Utilized	0	0	0	0	0	0	0
Total Proved	244	213	197	189	180	170	155

In Aggregate

	After Tax Discounted at						
	0%	5%	8%	10%	12%	15%	20%
Proved Developed Producing	6,798	5,595	5,110	4,849	4,621	4,332	3,948
Proved Developed Non-Producing	0	0	0	0	0	0	0
Proved Undeveloped	95	69	55	47	39	29	14
	6,893	5,664	5,165	4,896	4,660	4,361	3,962
Tax Pools Utilized	-3,346	-2,743	-2,500	-2,369	-2,254	-2,109	-1,916
Total Taxable Proved	3,547	2,921	2,665	2,527	2,406	2,252	2,046
2006 Statutory Tax Rate	32.12%	32.12%	32.12%	32.12%	32.12%	32.12%	32.12%
Tax on Total Proved	1,139	938	856	812	773	723	657
Total Proved After Tax	5,754	4,726	4,309	4,084	3,887	3,638	3,305

TOTAL FUTURE NET REVENUE
(UNDISCOUNTED)
AS OF DECEMBER 31, 2005
FORECAST PRICES AND COSTS
(CDN $Thousands)

Reserves Category	Revenue	Royalties	Operating Costs	Development Costs	Abandonment and Reclamations Costs	Future Net Revenue Before Income Tax	Tax Pools	Taxable Future Net Revenue Before Income Tax	Tax @ 32.12%	Future Net Revenue After Income Tax
Canadian Assets Proved	14,359	2,611	4,428	325	345	6,649	3,346	3,303	1,061	5,588
Canadian Assets Proved plus Probable	18,852	3,243	6,135	399	418	8,656	3,346	5,310	1706	6,950
US Assets Proved	470	35	191	0	0	244	0	244	78	166
US Assets Proved Plus Probable	470	35	191	0	0	244	0	244	78	166
Aggregate Proved	14,829	2,646	4,619	325	345	6,893	3,346	3,547	1,139	5,754
Aggregate Proved plus Probable	19,322	3,278	6,326	399	418	8,900	3,346	5,554	1,783	7,117

TOTAL FUTURE NET REVENUE
BY PRODUCTION GROUP
AS OF DECEMBER 31, 2005
FORECAST PRICES AND COSTS (CDN $Thousands)

Reserves Category	Production Group	Future Net Revenue Before Income Taxes (disc @ 10%)	Tax Pools	Taxable Future Net Revenue Before Income Taxes	Tax@ 32.12%	Future Net Revenue After Income Taxes (disc @ 10%)
Canadian Assets						
Proved	Light and Medium Crude Oil[3]	0	0	0	0	0
Proved	Natural Gas[4]	4,707	2,369	2,338	751	3,956
Proved Plus Probable	Light and Medium Crude Oil	0	0	0	0	0
Proved Plus Probable	Natural Gas	5,771	2,241	3,530	1,134	4,637
US Assets						
Proved	Light and Medium Crude Oil	189	0	189	61	128
Proved Plus Probable	Light and Medium Crude Oil	189	0	189	61	128
Aggregate						
Proved	Light and Medium Crude Oil	189	0	189	61	128
Proved	Natural Gas	4,707	2,369	2,338	751	3,956
Proved Plus Probable	Light and Medium Crude Oil	189	0	189	61	128
Proved Plus Probable	Natural Gas	5,771	2,241	3,530	1,134	4,637

[3] Light and Medium Crude Oil (Includes solution gas and other by-products)
[4] Natural Gas (Includes by-products but excludes solution gas from oil wells)

Summary of Pricing Assumptions for Oil and Gas Reserves

The Evaluators employed the following price and exchange rate and inflation rate assumptions as of December 31, 2005 in estimating Emerald's reserves data using constant prices and costs.

Constant Prices and Costs Used in Estimates

Inflation Rate Percent	0.00
Crude Oil $CND/BBL	
Light Sweet Crude @ Edmonton	68.27
Medium Hardisty	39.00
LLB @ Hardisty	39.20
Medium @ Cromer	51.84
WTI @ Cushing, Oklahoma ($US/BBL)	61.04
Somerset Oil @ Somerset ($US/BBL)	n/a
NGLs $CDN/BBL at Edmonton	
Propane	43.69
Butane	50.52
Condensate	71.67
NGLs $CND/MMBTU	
AECO Spot	9.71
Alberta Spot Plant-gate	9.46
Alberta Government Reference Plant-gate	9.46
Alberta Aggregator Plant-gate	9.36
Saskatchewan Spot Plant-gate	9.61
B.C. Spot Plant-gate	8.64
Canwest Plant-gate	7.77
Exchange Rate	
$US/$CND	0.85

Forecast Prices and Costs Used in Estimates

The Evaluators employed the following price and exchange rate and inflation rate assumptions as of December 31, 2005 in estimating Emerald's reserves data using forecast prices and costs.

			West Texas Intermediate Crude Oil at Cushing Oklahoma		Sommerset Texas Oil	Brent Blend Crude Oil FOB North Sea		Light Sweet Crude Oil (40 API, 0.3% S) at Edmonton	
Year	Inflation (%)	Bank of Canada Average Noon Exchange Rate	Constant 2006 $ $US/bbl	Then Current $US/bbl	Then Current $US/bbl	Constant 2006 $ $US/bbl	Then Current $US/bbl	Constant 2006 $ $US/bbl	Then Current $US/bbl
2006	2.0	0.850	57.00	57.00	n/a	55.50	55.50	66.25	66.25
2007	2.0	0.850	54.00	55.00	n/a	52.50	53.50	62.75	64.00
2008	2.0	0.850	49.00	51.00	n/a	47.50	49.50	57.00	59.25
2009	2.0	0.850	45.25	48.00	n/a	43.75	46.50	52.50	55.75
2010	2.0	0.850	43.00	46.50	n/a	41.50	45.00	50.00	54.00
2011	2.0	0.850	40.75	45.00	n/a	39.50	43.50	47.25	52.25
2012	2.0	0.850	40.00	45.00	n/a	38.75	43.50	46.50	52.25
2013	2.0	0.850	40.00	46.00	n/a	38.75	44.50	46.25	53.25
2014	2.0	0.850	40.00	46.75	n/a	38.50	45.25	46.25	54.25
2015	2.0	0.850	40.00	47.75	n/a	38.75	46.25	46.50	55.50
2016	2.0	0.850	40.00	48.75	n/a	38.75	47.25	46.25	56.50
2017	2.0	0.850	40.00	2%/yr	n/a	38.75	2%/yr	46.25	2%/yr

	Bow River Crude Oil Stream Quality at Hardisty		Heavy Crude Oil Proxy (12 API) at Hardisty		Medium Crude Oil (29 API, 2.0%S) at Cromer		Alberta Natural Gas Liquids (Then Current Dollars)			
Year	Constant 2006 $ $US/bbl	Then Current $US/bbl	Constant 2006 $ $US/bbl	Then Current $US/bbl	Constant 2006 $ $US/bbl	Then Current $US/bbl	Spec Ethane $CDN/bbl	Edmonton Propane $CDN/bbl	Edmonton Butane $CDN/bbl	Edmonton Pentanes Plus $CDN/bbl
2006	43.00	43.00	33.25	33.25	55.75	55.75	36.00	42.50	49.00	67.00
2007	41.75	42.50	32.00	32.75	54.25	55.25	31.25	41.00	47.25	65.25
2008	39.50	41.00	31.25	32.50	49.25	51.25	27.00	38.00	43.75	60.50
2009	37.25	39.50	30.25	32.00	45.50	48.25	25.25	35.75	41.25	56.75
2010	36.50	39.50	29.50	32.00	43.25	46.75	24.25	34.50	40.00	55.00
2011	36.00	39.75	30.25	33.50	41.00	45.25	23.25	33.50	38.75	53.25
2012	35.25	39.75	29.75	33.50	40.25	45.25	23.25	33.50	38.75	53.25
2013	35.25	40.50	29.50	34.00	40.00	46.00	23.75	34.00	39.50	54.25
2014	35.25	41.25	29.75	34.75	40.00	47.00	24.25	34.75	40.25	55.25
2015	35.25	42.25	29.50	35.25	40.25	48.00	25.00	35.50	41.00	56.50
2016	35.25	43.00	29.50	36.00	40.00	48.75	25.50	36.25	41.75	57.75
2017	35.25	2%/yr	29.50	2%/yr	40.00	2%/yr		2%/yr	2%/yr	2%/yr

Year	US Gulf Coast Gas Price @ Henry Hub		Midwes Price @ Chicago	AECO-C Spot	Alberta Plant Gate				
					Spot				
	Constant 2006$ $US/mmbtu	Current $US/mmbtu	Then Current $US/mmbtu	Then Current $CDN/mmbtu	Constant 2006 $ $/mmbtu	Then Current $/mmbtu	ARP $/mmbtu	Aggregator $/mmbtu	Alliance $/mmbtu
2006	10.50	10.50	10.30	10.60	10.35	10.35	10.35	10.25	10.50
2007	8.60	8.75	8.90	9.25	8.80	9.00	9.00	9.00	8.90
2008	7.20	7.50	7.65	8.00	7.45	7.75	7.75	7.75	7.45
2009	6.60	7.00	7.15	7.50	6.85	7.25	7.25	7.25	6.90
2010	6.25	6.75	6.90	7.20	6.40	6.95	6.95	6.95	6.65
2011	5.90	6.50	6.65	6.90	6.05	6.65	6.65	6.65	6.35
2012	5.75	6.50	6.65	6.90	5.90	6.65	6.65	6.65	6.35
2013	5.75	6.65	6.80	7.05	5.95	6.80	6.80	6.80	6.50
2014	5.75	6.75	6.90	7.20	5.95	6.95	6.95	6.95	6.65
2015	5.75	6.90	7.05	7.40	6.00	7.15	7.15	7.15	6.80
2016	5.75	7.05	7.20	7.55	6.00	7.30	7.30	7.30	6.95
2017	5.75	2%/yr	2%/yr	2%/yr	6.00	2%/yr			

	Sasktchewan Plant Gate			British Columbia			
	SaskEnergy $/mmbtu	Spot $/mmbtu	Sumas Spot $US/mmbtu	CanWest Plant Gate $/mmbtu	Spot Plant Gate $/mmbtu	Sulphur FOB Vancouver $US/LT	Alberta Sulphur at Plant Gate $CDN/LT
2006	10.50	10.50	9.40	8.50	10.40	63.50	31.00
2007	9.15	9.15	8.15	8.60	9.00	55.00	21.00
2008	7.90	7.90	7.00	7.65	7.65	45.00	9.50
2009	7.40	7.40	6.55	7.15	7.15	45.00	9.50
2010	7.10	7.10	6.30	6.85	6.85	46.00	10.50
2011	6.80	6.80	6.05	6.55	6.55	47.00	12.00
2012	6.80	6.80	6.05	6.55	6.55	48.00	13.00
2013	6.95	6.95	6.20	6.70	6.70	49.00	14.00
2014	7.10	7.10	6.30	6.85	6.85	50.00	15.50
2015	7.30	7.30	6.45	7.00	7.00	51.00	17.00
2016	7.45	7.45	6.45	7.15	7.15	52.00	18.00
2017	2%/yr	2%/yr	2%/yr	2%/yr	2%/yr	2%/yr	2%/yr

RECONCILIATION OF COMPANY NET RESERVES
BY PRINCIPAL PRODUCT TYPE
FORECAST PRICES AND COSTS
DECEMBER 31, 2005

Canadian Assets

	Light/Medium Oil			Conventional Natural Gas			NGL's			Oil Equivalent		
Factors	Net Proved (Mbbl)	Net Probable (Mbbl)	Net Proved Plus Probable (Mbbl)	Net Proved (MMcf)	Net Probable (MMcf)	Net Proved Plus Probable (MMcf)	Net Proved (Mbbl)	Net Probable (Mbbl)	Net Proved Plus Probable (Mbbl)	Net Proved (MBoe)	Net Probable (MBoe)	Net Proved Plus Probable (MBoe)
December 31, 2004	3	1	4	1,014	465	1,479	31	7	38	203	86	289
Extensions	0	0	0	0	0	0	0	0	0	0	0	0
Improved Recovery	0	0	0	0	0	0	0	0	0	0	0	0
Technical Revisions	2	4	6	291	-41	250	-3	-1	-4	48	-4	44
Discoveries	0	0	0	0	0	0	0	0	0	0	0	0
Acquisitions	0	0	0	0	0	0	0	0	0	0	0	0
Dispositions	0	0	0	-24	-57	-81	0	0	0	-4	-10	-14
Economic Factors	0	0	0	0	0	0	0	0	0	0	0	0
Production	-2		-2	-160		-160	-3		-3	-32		-32
December 31, 2005	3	5	8	1,121	367	1,488	25	6	31	215	72	287

US Assets

Light/ Medium Oil	
Factors	Net Proved (Mbbl)
January 1, 2005	11
Technical Revisions	-1
Production	-2
January 1, 2006	8

Future Net Revenue Reconciliation

RECONCILIATION OF CHANGES IN NET PRESENT VALUES OF FUTURE NET REVENUE DISCOUNTED AT 10%

TOTAL PROVED RESERVES CONSTANT PRICES AND COSTS

Canadian Assets

Period and Factor	After Tax 2005 (M$)
Estimated Net Present Value at December 31, 2004	**3,532**
Oil and Gas Sales During the Period Net of Production Costs and Royalties (1)	(1,341)
Changes due to Prices and Royalties Related to Forecast Production (2)	1,344
Development Costs During the Period (3)	413
Changes In Forecast Development Costs (4)	(413)
Changes Resulting from Extensions and Improved Recovery (5)	666
Changes Resulting from Discoveries (5)	533
Changes Resulting from Acquisitions of Reserves (5)	-
Changes Resulting from Dispositions of Reserves (5)	-
Accretion of Discount (6)	353
Net Change in Income Taxes (7)	
Changes Resulting from Technical Reserves Revisions	772
All Other Changes (8)	27
Estimated Net Present Value at at December 31, 2005	**5,886**

TOTAL PROVED RESERVES
CONSTANT PRICES AND COSTS

US Assets ($Cdn)

Period and Factor	After Tax 2005 (M$)
Estimated Net Present Value at December 31, 2004	**211.7**
Oil and Gas Sales During the Period Net of Production Costs and Royalties (1)	(29.1)
Changes due to Prices and Royalties Related to Forecast Production (2)	32.4
Development Costs During the Period (3)	---
Changes In Forecast Development Costs (4)	---
Changes Resulting from Extensions and Improved Recovery (5)	---
Changes Resulting from Discoveries (5)	---
Changes Resulting from Acquisitions of Reserves (5)	---
Changes Resulting from Dispositions of Reserves (5)	---
Accretion of Discount (6)	---
Net Change in Income Taxes (7)	---
Changes Resulting from Technical Reserves Revisions	(26.0)
All Other Changes (8)	---
Estimated Net Present Value at at December 31, 2005	**189.0**

(1) Company actual before income taxes, excluding G&A.

(2) The impact of changes in prices and other economic factors on future net revenue.

(3) Actual capital expenditures relating to the exploration, development and production of oil and gas reserves.

(4) The change in forecast development costs.

(5) End of period net present value of the related reserves.

(6) Estimated as 10% of the beginning of period net present value.

(7) The difference between forecast income taxes at beginning of period and the actual taxes for the period plus forecast income taxes at the end of period.

(8) Includes changes due to revised production profiles, development timing, operating costs, royalty rates, actual price received in 2003 versus forecast, etc.

Additional Information Relating to Reserves Data

Undeveloped Proved, Undeveloped Probable and Probable Reserves

Proved Undeveloped reserves can be categorised as proved through reserves assessment but not producing or developed due to production operations or multi-zone development plans. The company anticipates the Undeveloped Canadian reserves will become partially developed within two years.

Proved Undeveloped gas reserves have been assigned to the Pekisko and Viking formations within the Twining 00/16-18-031-23W4 well. Initial production from the Pekisko is scheduled to occur in 2006. The Viking formation is scheduled to begin production after depletion of the Ostracod and Pekisko zones in approximately 2010.

No specific Undeveloped Probable reserves have been assigned to the Canadian properties by the evaluator, only on a Probable reserves basis. Probable reserves are attributed to an increased recovery factor incremental to current proved producing or total proved recoverable reserves. An incremental recovery factor may be due to a changing price environment, multi-zone developments or changing technical conditions. Incremental Probable reserves are forecast to be recovered over the remaining economic life of the producing properties.

There is no Proved Undeveloped, Probable Undeveloped or Probable reserves assigned to the U.S. properties.

Significant Factors and Uncertainties

Oil and natural gas exploration involves a high degree of risk and there is no assurance that expenditures made on future exploration by the Corporation will result in new discoveries of oil or natural gas in commercial quantities. It is difficult to project the costs of implementing an exploratory drilling program due to the inherent uncertainties of drilling in unknown formations, the costs associated with encountering various drilling conditions such as over pressured zones and tools lost in the hole, and changes in drilling plans and locations as a result of prior exploratory wells or additional seismic data and interpretations thereof.

The Corporation currently has a limited number of specific identified exploration or development prospects. Management will continue to evaluate prospects on an ongoing basis in a manner consistent with industry standards and their past practices. The long-term commercial success of the Corporation depends on its ability to find, acquire, develop and commercially produce oil and natural gas reserves. No assurance can be given that the Corporation will be able to locate satisfactory properties for acquisition or participation. Moreover, if such acquisitions or participations are identified, the Corporation may determine that current markets, terms of acquisition and participation or pricing conditions make such acquisitions or participations uneconomic.

Future oil and gas exploration may involve unprofitable efforts, not only from dry wells, but from wells that are productive but do not produce sufficient net revenues to return a profit after drilling, operating and other costs. Completion of a well does not assure a profit on the investment or recovery of drilling, completion and operating costs. In addition, drilling hazards or environmental damage could greatly increase the cost of operations, and various field operating conditions may adversely affect the production from successful wells. These conditions include delays in obtaining governmental approvals or consents, shut-ins of connected wells resulting from extreme weather conditions, insufficient storage or transportation capacity or other geological and mechanical conditions. While close well supervision and effective maintenance operations can contribute to maximizing production rates over time, production delays and declines from normal field operating conditions cannot be eliminated and can be expected to adversely affect revenue and cash flow levels to varying degrees.

In addition, oil and gas operations are subject to the risks of exploration, development and production of oil and natural gas properties, including encountering unexpected formations or pressures, premature declines of reservoirs, blow-outs, cratering, sour gas releases, fires and spills. Losses resulting from the occurrence of any of these risks could have a materially adverse effect on future results of operations, liquidity and financial condition.

Future Development Costs (in CDN$ thousands)

Canadian Assets

	Forecast Prices and Costs		Constant Prices and Costs
Year	Proved Reserves	Proved and Probable Reserves	Proved Reserves
2006	325	325	325
2007	0	0	0
2008	0	0	0
2009	0	74	0
2010	0	0	0
Thereafter	0	0	0
Total Undiscounted	325	399	325
Total Discounted @ 10%	310	363	310

The Corporation intends to fund these future development costs from cash flow. No Future Capital is required for US Assets.

Oil and Gas Properties and Wells

The Corporation has high working interest in many wells in Alberta and Texas.
The Corporation's Canadian assets are all located onshore in Alberta. The Corporation's US assets are all located onshore in Sommerset County, Texas. The Corporation's processing assets include single well oil and gas batteries.

	Oil wells				Gas wells			
	Producing		Non-Producing		Producing		Non-Producing	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
U.S.	42	42	0	0	0	0	0	0
Alberta	13	4.4	0	0	5	2.4	1	0.2
Total	55	46.4	0	0	5	2.4	1	0.2

Two gas-wells commenced production in 2005. Production commenced in October from the Twining 00/16-18-031-23W4/0 well, and in May from the Clive 00/10-16-039-24W4/0 well. Both of these were drilled in 2004.

Properties with no Attributable Reserves

The Corporation owns 1400 hectares (gross and net) in the Clive and Lottie Lake areas of Alberta to which no attributable reserves have been assigned. No land expiries are expected in 2006.

Abandonment costs

The Emerald Report details future abandonment and reclamation costs for the oil and gas properties. The Evaluators estimate abandonment and reclamation costs based on similar costs experienced in the area and reduce the amount by expected salvage value of facilities. The Corporation is not responsible for abandonment costs for wells that it owns net profits interests. In total, the Corporation expects to be responsible for abandonment and reclamation costs for 48 net wells. At forecast prices, total abandonment costs are expected to be $345 thousand before discounting or $188 thousand discounted at 10%. The Corporation expects to pay about $133 thousand of these in the next three fiscal years. All these costs are in Canadian dollars and are included in the future net revenues in this report.

Abandonment Costs Estimate ($Cdn Thousands)
Total Proved

Year	Forecast Prices and Costs	Constant Prices and Costs
2006	58	58
2007	30	0
2008	45	58
2009	31	14
2010	0	29
Thereafter	181	136
Total Undiscounted	345	295
Total Discounted @ 10%	188	164

Tax Horizon

Based on the Company's current levels of general & administration, investment in R&D and exploration, the company does not expect to become cash taxable within the foreseeable future.

The Company has approximately $3.3 million of tax pools at December 31, 2005, which can be utilized to reduce taxable income for federal and provincial tax purposes. The Summaries of Net Present Value of Future Net Revenues on pages 4 and 8 reflect the future taxes expected on net reserves at each discount rate after utilizing available tax pools.

Costs Incurred in 2005

The following table shows gross capital expenditures for the Corporation in the categories and for the periods indicated:

	Year Ended December 31, 2005	Year Ended December 31, 2004
Land & Acquisition	$0	$21,000
Geological & Geophysical	(48,854)	461,000
Drilling and Exploration	799,242	1,117,000
Total	$750,388	$1,599,000

A positive value ($48,854) is shown for Geological and Geophysical expenses in 2005. This is due to a credit received by the company from geological and geophysical expenses that were not fully utilized.

Exploration and Development Drilling Activity

Emerald Bay did not drill or participate in the drilling of any wells in 2005.

Planned Area Activity

Clive –The Company is working to maximize current production by reducing capacity constraints on transmission lines. Increased activity in the area continues to make operators look for cost-effective tie-in options to optimize production. The Company is currently working to route three wells into the pipeline infrastructure. We expect one well will be flowing by the end of March, with the other two wells anticipated to begin production in the second quarter.

One of the key's for development in Clive relies on the success of the CBM production after tie-in. When the Corporation begins producing economic volumes of Coalbed Methane in the 2 wells in section 14 – it opens-up numerous opportunities such as:

From 3 to 6 additional locations on section 14.

Provides a good business model for a small-cap company like the Corporation that would focus on smaller blocks of CBM farm-in land in the Horseshoe Canyon field.

Holding for down-spacing has been acquired in section 14.

Belly River down-spacing could provide at least 2 additional locations in sections 14 and 16.

Edson – At Edson, the Company is moving forward with a plan to re-complete a Cardium well, drilled with Tom Brown Resources (now part of Encana Corporation) and Devon Energy. Completion options are being reviewed with anticipation of this work to begin after road bans have been lifted sometime in April or May.

Twinning – Emerald Bay Energy Inc. is pleased to confirm the approval of a well license for its Twining drilling program from the Energy and Utilities Board of Alberta. The Twining 10-18-31-23 W4 well (40% Working Interest

and operated by Emerald Bay) is a direct offset to the Company's vertical well drilled in 2004. The well will evaluate the Pekisko formation at an approximate vertical depth of 1620 metres and a total measured depth of 1765 metres. Estimated drilling time is 11 days. Drilling will commence as soon as road and surface conditions allow.

At Twining, the Company has recently completed an extensive geological and seismic review. While this process took longer than anticipated, it is a valuable resource to the Company in identifying drilling targets in the Twining area. Additionally, the Company is currently negotiating multiple farm-in opportunities in the Twining/Three Hills area for further exploration this year.

Somerset-Von Ormy – Exploration in the U.S. and Western Canada can most often be "counter-cyclical" in terms of exploration opportunities. Currently in Western Canada small-cap companies like the Corporation are competing at land sales with larger companies with large land budgets. This leaves the smaller companies aggressively competing for farm-in opportunities. In certain areas of South Texas leases and drilling locations can still be acquired by smaller companies. Justification points for exploration in South Texas include:

Management has been active in the region since 1980 – drilling over 200 wells.

The Corporation already has operations in the region.

Minimal barriers to entry.

Land owners are typically the mineral owners – making it much easier to negotiate surface issues.

Drilling and completion costs are comparable to Western Canada – when considering exchange rate.

More production dollars make it to the bottom line. For example; if the Corporation farms-in and drills a 10 BOPD well in Western Canada – the Corporation nets about 6.5 BOPD before pay-out – after a GORR and Crown Royalty. After payout that number drops to about 3 BOPD after the GORR converts to a 50% WI and Crown Royalty. That same well drilled in South Texas nets us about 8 BOPD before AND after payout. This makes for very compelling economics.

Currently the Corporation has identified 27 drilling locations with 80 to 84% net revenue interests – ready for drilling. An additional 50+ locations are currently under review.

Production Estimates for 2006

The daily production volumes for 2006 are unchanged under both the Forecast and Constant price scenarios.

2006 Production Estimate

	Light/Medium Oil		Natural Gas		NGL's		Oil Equivalent	
	Gross (Bbls/d)	Net (Bbls/d)	Gross (Mcf/d)	Net (Mcf/d)	Gross (Bbls/d)	Net (Bbls/d)	Gross (Boe/d)	Net (Boe/d)
PROVED								
Alberta	0	0	772	540	18	11	148	101
U.S.	6	4	0	0	0	0	6	4
Total Proved	6	4	772	540	18	11	154	105
PROVED & PROBABLE								
Alberta	0	0	823	567	19	11	157	107
U.S.	6	4	0	0	0	0	6	4
Total Proved & Probable	6	4	823	567	19	11	163	111

Production and Net Back Results for 2005

Production	2005 Q1	2005 Q2	2005 Q3	2005 Q4
Crude (bbl/d)	7	8	1	13
Gas (mcf/d)	368	463	402	927
NGL (bbl/d)	9	9	7	27
BOE (boe/d)	78	94	76	195
Elements of Historic Cash Flow ($/Boe)				
Revenue	46.44	47.18	54.35	66.94
Royalty	9.92	10.03	13.33	20.45
Production Costs	8.88	7.59	8.46	9.75
Net back	27.64	29.56	32.56	36.74