NI Form 51-101 F1

Anterra Energy Inc.

Statement of reserves data

and other oil and gas information

as of December 31, 2011

Prepared by AJM Deloitte

March 28, 2012

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Part 1 Date of statement

Date of statement:	**March 28, 2012**
Effective date:	**December 31, 2011**
Preparation date:	**March 28, 2012**

Anterra Energy Inc. (the "Company") oil and gas reserves were evaluated by Deloitte & Touche LLP ("AJM Deloitte"), effective December 31, 2011. AJM Deloitte was engaged by the Company to evaluate proved and proved plus probable reserves: no valuation of possible reserves or resources was undertaken The AJM Deloitte evaluation was prepared in accordance with National Instrument 51-101 – *Standards of Disclosure for Oil and Gas Activities* and the *Canadian Oil and Gas Evaluation Handbook ("COGE Handbook").*

All of the Company's oil and gas reserves are located on-shore, in Canada.

The reserves on the properties described herein are estimates only. By nature, such forecasting of reserves and related economic parameters and analyses are forward-looking statements based on predictions of future events. Actual events or results may differ materially. Furthermore, the estimated future net revenue contained in the following tables does not necessarily represent the fair market value of the reserves.

In certain instances, numbers may not total due to computer-generated rounding.

Part 2 Disclosure of reserves data

Item 2.1 Reserves data (forecast prices and costs)

Item 2.1.1 Breakdown of proved reserves (forecast case)

Please refer to NI 51-101 Table 1 – Forecast – Summary of Oil and Gas Reserves in the Appendix.

Item 2.1.2 Net present value of future net revenue (forecast case)

Please refer to NI 51-101 Table 2 – Forecast – Summary of Net Present Values of Future Net Revenue in the Appendix.

Item 2.1.3 Additional information concerning future net revenue (forecast case)

Please refer to NI 51-101 Table 3 – Forecast – Total Future Net Revenue (Undiscounted), NI 51-101 Table 4 – Unit Value of Net Reserves by Production Group in the Appendix.

Item 2.2 Supplemental disclosure of reserves data (constant prices and costs)

Supplemental constant price estimates are not reported.

Item 2.3 Reserves disclosure varies with accounting

The Company has no subsidiaries and is not a subsidiary of another company.

Item 2.4 Future net revenue disclosure varies with accounting

The Company has no subsidiaries and is not a subsidiary of another company.

Part 3 Pricing assumptions

Item 3.1 Constant prices used in estimates

Supplemental constant price estimates are not reported.

Item 3.2 Forecast prices used in estimates

Forecast oil and gas prices are laid out in the AJM Deloitte Price Forecast December 31, 2011 Table (see Appendix). All prices are stated in Canadian dollars unless otherwise indicated. Adjustments for oil differential and gas heating values are applied to these prices, as appropriate for each entity. Capital and operating costs are inflated.

Part 4 Reconciliation of changes in reserves

Item 4.1 Reserves reconciliation

Please refer to Table 5 - Reserves Reconciliation Summary in the Appendix.

Part 5 Additional information relating to reserves data

Item 5.1 Undeveloped reserves

The undeveloped reserves are located within three properties: Matzwin, Minnehik-Buck Lake and Breton.

Matziwin

The Matziwin Pekisko A Pool consists of seven producing and one non-producing oil wells. The Company owns 40 to 100 percent working interest in six of these wells, 09-09, 02/09-09, 15-09, 05-15, 01-16, and 02/04-15-023-14W4. The remaining producing wells are 12-10-023-14W4/2 and 13-10-023-14W4/0, in which the Company holds no interests.

The 02/04-15-023-14W4/0 oil well has been on production since December 2009. Reserves have been estimated using volumetrics, area analogues, and performance evaluations. Volumetric parameters have been provided by the Company and audited by an AJM Deloitte geologist. For proved developed producing reserves, the reservoir height of 17.2 feet used was based on the Matziwin Pekisko A pool data to reflect the estimated ultimate recovery of the 100/13-10-023-14W4/0 analogue. For proved plus probable reserves a reservoir height of 54.1 feet was taken from the geological mapping provided by the Company to reflect the estimated ultimate recovery of the 100/12-10-023-14W4/0 analogue. Drainage area was based on the spacing of existing pool wells. API gravity, shrinkage, pressure, temperature, and recovery factor were taken from the Matziwin Pekisko A pool data. The Company plans to re-enter, repair and stimulate the well during 2012, as this horizontal well appears to be underachieving.

The Company plans to drill a short leg horizontal well at HZ/01-16-023-14W4/A to increase Pekisko recovery in the section. Proven undeveloped and proven plus probable reserves were assigned primarily by analogy to 02/04-15-023-14W4/0. A successful operation on the 02/04-15 well may improve this reserve assignment.

Minnehik-Buck Lake

In 2011, The Company has added two successful horizontal wells in section 17-045-05W5, the 00/01-17-045-05W5/00 well and the 00/08-17-045-05W5/00 well. Initial monthly rates were approximately 300 and 400 bbl/d respectively and the wells now appear to be at or near at steady state producing at about 60 and 85 bbl/d respectively in December 2011. A type well was generated based on the best horizontal wells in the area. A normalized plot was generated based on these surrounding Cardium horizontal wells. Eleven wells were considered as their peak rates were above 150 bbl/d. From this normalized plot, a new type well was created. The initial rate of the wells are based on the highest peak rate that was seen in the area.

Four horizontal Cardium locations were assigned to this property. Two proved undeveloped wells were assigned in Section 08-045-05W5, and one proved undeveloped and one probable location were assigned in Section 17-045-05W5. A type well generated from existing vertical and horizontal Cardium oil producers was used as the basis of assigning reserves.

The Company plans to drill the proved undeveloped horizontal well location at 00/09-17-045-05W5/00 later in 2012. The remaining locations in section 08-045-05W5 and section 17-045-05W5 will be drilled in late 2012 or 2013 depending upon success at 00/09-17-045-05W5/00 and capital priority.

Breton

The Breton property consists of six producing oil wells which are in the Norbuck Basal Belly River B Pool Unit, five producing Non-Unit oil wells, and seven oil well locations, five of which are horizontal wells. There are also three producing gas wells to which no reserves were assigned as they are producing below the economic limit. In addition, there are several service wells which are used to dispose of water and other produced fluids.

Proven undeveloped reserves of 17.9 and 19.3 Mbbl have been assigned volumetrically to two vertical locations at 15-23-047-04W5 and 11-24-047-07W5 respectively, based on offsetting wells.

Reserves were assigned to four horizontal Belly River wells that are to be drilled into the Norbuck Basal Belly River B Pool Unit. Each of the locations were assigned 90 Mbbl of probable reserves based on the successful 02/10-25-048-05W5/0 well drilled in the Basal Belly River H pool. The 02/10-25 well is located immediately beside the 00/10-25-048-05W5/0 oil well which has produced over 313 Mbbl of oil to date and is the largest well in the pool. Given that seven wells in the Norbuck Basal Belly River B Pool Unit have produced greater than 313 Mbbl it would be reasonable to assume that a horizontal location drilled in the unit could perform as well or better than one drilled in the Belly River H pool. Proved reserves were not assigned at this time due to the fact that there has not yet been a horizontal well drilled by the Company into this pool.

The Company expects to drill the first horizontal Belly River well in the middle of 2012. Depending upon success and capital priority, the remaining Belly River horizontal wells and/or the two vertical Belly River locations will be drilled in late 2012 or 2013.

Probable reserves were assigned to HZ/13-20-047-03W5/0. The proved undeveloped reserve entity based on proximity to existing Cardium producers was found to be uneconomic. A type well generated from existing vertical and horizontal Cardium oil producers was used as the basis of assigning reserves.

Vertical Cardium oil wells in the area of 044-03W5 to 048-06W5 which were put on production post-1995 were first analyzed. The peak production rate was recorded along with an estimated ultimate recoverable reserve (if one could be estimated); if the well was drilled too recently and did not have an obvious decline or trend, the well was removed from the data set. In cases where the well was no longer producing, the cumulative production volume was recorded. From the data, an average initial peak rate of 23.5 bbl/d was determined and an average ultimate recoverable reserve of 11.5 Mbbl was calculated. This 2:1 relationship between initial rate and ultimate recoverable was then applied to the nearby producing horizontal wells.

From the 02/01-18-046-03W5 and 00/01-25-047-03W5 wells, it was observed that, during a period of approximately seven months, the oil rate would drop rapidly before it would begin to level out and produce at a much shallower decline. Eighteen horizontal wells were assigned an ultimate recoverable reserve based on this methodology and most wells fitted to the type curve profile reasonably well. From these 18 wells, an average initial peak rate of 128 bbl/d was estimated with an average estimated ultimate recoverable reserve of 65 Mbbl (proved plus probable reserves). The average initial rate of wells immediately surrounding 13-20 was determined to be 105 bbl/d. The type well was adjusted to this rate for an estimated ultimate recoverable reserve of 50 Mbbl (proved undeveloped reserves).

	Light & Medium Oil		Heavy Oil		Natural Gas		NGLs		Coalbed Methane	
	First attributed	Cumulative	First attributed	Cumulative	First attributed	Cumulative	First attributed	Cumulative	First attributed	Cumulative
	WI Mbbl	WI Mbbl	WI Mbbl	WI Mbbl	WI MMcf	WI MMcf	WI Mbbl	WI Mbbl	WI MMcf	WI MMcf
Proved undeveloped										
Prior to 2009	545	-	-	-	329	-	2	-	-	-
2009	299	-	-	-	575	-	-	-	-	-
2010	176	214	-	-	433	449	27	27	-	-
2011	50	234	-	-	-	519	-	34	-	-
Probable undeveloped										
Prior to 2009	-	-	-	-	-	-	-	-	-	-
2009	-	-	-	-	-	-	-	-	-	-
2010	607	618	-	-	909	913	52	52	-	-
2011	90	515	-	-	308	493	21	21	-	-

Item 5.2 Significant factors or uncertainties

Reserve estimates are subject to change with such factors as updated production data, well performance and operational issues, ongoing development activities, price forecasts, and other economic conditions.

Item 5.3 Future development costs

	Undiscounted future costs net (M$)		Discounted (10%) future costs net (M$)	
Year	**Proved**	**Proved + probable**	**Proved**	**Proved + probable**
2012	6,557.5	16,327.5	6,214.2	15,345.8
2013	1,550.4	1,550.4	1,325.1	1,325.1
2014		3,537.4		2,842.1
2015				
2016				
2017+				
Total	8,107.9	21,415.3	7,539.3	19,513.0

Forecast capital expenditures will be funded by forecast cash flow and development lines of credit. The cost of funding is unlikely to make any projects uneconomic.

Part 6 Other oil and gas information

Item 6.1 Oil and gas properties and wells

Item 6.1.1 Major properties

Breton, Alberta

The Breton property is located near the town of Breton, Alberta approximately 50 miles southwest of Edmonton, Alberta in Townships 47 to 48, Ranges 3 and 4 W5M. The Company has working interests of 100 percent in the majority of their wells as well as a couple of royalty interest wells. Burdens on production include Crown royalties, freehold royalties, and gross overriding royalties on certain wells. Production is from the Belly River Formation; however, there is one location targeting the Cardium Formation. The Breton property consists of six producing oil wells which are in the Norbuck Basal Belly River B Pool Unit, five producing Non-Unit wells, and seven oil well locations, five of which are horizontal wells. There are also several service wells which are used to dispose of water and other produced fluids. The largest value entity in this property is the Norbuck Basal Belly River B Pool Unit. The company also processes third party production to separate water from emulsion and dispose of water and other produced fluids.

Minnehik-Buck Lake, Alberta

The Minnehik Buck Lake property is located approximately 50 miles northwest of Red Deer, Alberta in Township 45, Range 5 W5M. The property contains five producing oil wells, and four drilling locations. The Company has working interests ranging from 50 to 93.7 percent before payout. Burdens on production include crown royalties, freehold royalties, and gross overriding royalties. Production is from the Cardium Formation. In 2011, the Company has added two successful horizontal wells in section 17-045-05W5, the 00/01-17-045-05W5/00 well and the 00/08-17-045-05W5/00 well. Initial monthly rates were approximately 300 and 400 bbl/d respectively and the wells now appear to be at or near at steady state producing at about 60 and 85 bbl/d respectively in December 2011.

Matziwin, Alberta

The Matziwin property is located approximately 75 miles east of Calgary, Alberta. The property consists of four producing oil wells, one non-producing well and one location. The Company holds a 100 percent working interest in all of these wells with exception of 02/04-15-023-14W4/0 which has a 45 percent working interest. Production is from the Pekisko and Banff Formations. Two producing wells, 00/15-09-023-14W4/0 and 02/04-15-023-14W4/0 represent over 40 percent of the total proved reserves and value in this property.

Item 6.1.2 Gross and net oil and gas wells

	Oil		Gas		Non-producing		Total	
Country/Province	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Canada								
Alberta	19.0	17.5	0.0	0.0	104	89.7	124	108.4
Saskatchewan	2.0	1.0	0.0	0.0	8.0	3.8	10.0	4.8
Total	21.0	18.5	0.0	0.0	112	93.7	134	113.2

The Company does not have any additional wells that were not evaluated by AJM Deloitte.

Item 6.2 Properties with no attributed reserves

The Company has 6,240 total hectares (6,240 ha net) of land in Abbott, Saskatchewan where no reserves have been assigned. The company acquired 3D seismic data over a portion of the lands in 2011 and has interpreted a drillable structure. A test well was initiated in 2011, but encountered mechanical difficulties prior to reaching the projected total depth. Any additional activity in this area is dependent on re-entering the test well or drilling another well to test the interpreted structure.

Item 6.3 Forward contracts

There are no forward contracts applicable to any produced product.

Item 6.4 Additional information concerning abandonment and reclamation costs

No. of net wells	
Included in evaluation	112.2
Not included in evaluation	0.0

Property	Gross cost of abandonment and reclamation
Breton	$40,000/well
Frontier	$30,000/well
July Creek	$45,000/well
Matziwin	$70,000/well
Minnehik-Buck Lake	$48,000/well
Sakwatamau	$50,000/well
Scots Lake	$70,000/well
Shadow	$50,000/well

The abandonment costs are based on area averages taken from the Energy Resources Conservation Board ("ERCB") Directive 011 called the "Alberta Regional Well Abandonment Cost Tables". Reclamation costs are taken from the ERCB Directive 011 section called "Alberta Regional Well Reclamation Cost Table".

Forecast abandonment costs	Proved		Proved plus probable	
	Undiscounted	Discounted at 10%	Undiscounted	Discounted at 10%
	M$	M$	M$	M$
Next 3 fiscal years	479.8	392.2	479.8	392.2
Following years	4,983.1	1,853.5	5,479.2	1,837.9
Total	**5,462.9**	**2,245.7**	**5,959.0**	**2,230.1**

Item 6.5 Tax Horizon

The Company is expected to begin paying income tax in 2014.

Item 6.6 Costs incurred

	M$
Proved property acquisition	0
Land acquisition (unproved)	354.8
Exploration	2,520.5
Development	4,713.0
Total	7,588.3

Item 6.7 Exploration and development activities

In 2011, the Company drilled 1 (0.6 net) development oil well in the Minnehik-Buck Lake property.

Item 6.8 Production estimates

Forecast production W.I. volume Jan 1 - Dec 31/12

	Proved	**Proved + probable**
Breton		
Oil NGLs(Mbbl)	31.2	42.5
Gas (MMcf)	19.3	24.1
Minnehik-Buck Lake		
Oil & NGLs(Mbbl)	43.5	49.3
Gas (MMcf)	116.5	132.7
Remaining properties		
Oil & NGLs(Mbbl)	16.9	17.2
Gas (MMcf)	0.0	0.0
Total		
Oil & NGLs(Mbbl)	91.6	109.0
Gas (MMcf)	135.9	156.7

Item 6.9 Production history

Total Company	Q1 2011	Q2 2011	Q3 2011	Q4 2011
Volumes				
oil, bbl	18,720	21,840	24,380	20,976
gas, Mcf	30,150	26,117	42,228	35,236
natural gas liquids, bbl	180	2,912	1,472	1,840
Boe	23,940	29,211	32,936	28,704
Production				
oil, bopd	208	240	265	228
gas, Mcf/d	335	287	459	383
natural gas liquids, bopd	2	32	16	20
Boe/d	266	321	358	312
Price				
averages, $/bbl				
oil	89.77	101.65	86.53	95.55
gas	3.92	4.22	4.32	3.51
natural gas liquids	47.47	62.14	56.00	66.61
Operating expenses, royalties, and netback				
averages, $/Boe				
royalties paid	8.08	15.02	21.20	15.74
operating cost	21.58	24.47	22.96	32.93
netback	44.20	41.59	28.78	29.78

Reserve definitions

Reserves are classified in accordance with the following definitions which meet the standards established by National Instrument 51-101, Standards of Disclosure for Oil and Gas Activities and found in Appendix 1 to Companion Policy 51-101 CP, Part 2 Definition of Reserves.

Reserve categories

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

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

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

Proved Reserves are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.

Probable Reserves are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

Possible Reserves are those additional reserves that are less certain to be recovered than probable reserves. It is unlikely that the actual remaining quantities recovered will exceed the sum of the estimated proved plus probable plus possible reserves.

Development and production status

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

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 (for example, when compared to the cost of drilling a well) to put the reserves on production. The developed category may be subdivided into producing and non-producing.

Developed Producing Reserves are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing, or if shut-in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.

Developed Non-Producing Reserves are those reserves that either have not been on production, or have previously been on production, but are shut-in, and the date of resumption of production is unknown.

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

Use of Barrels of Oil Equivalent (boe)

Disclosure provided herein in respect of boe units may be misleading, particularly if used in isolation. A boe conversion ratio of 6 Mcf of natural gas to 1 bbl of crude oil is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

Abbreviations

Certain terms and abbreviations used in this document are defined below:

"bbl"	barrel of oil or NGL;
"bcf"	billion cubic feet of natural gas;
"bpd"	barrel of oil or NGL per day;
"boe"	barrel of oil equivalent determined by converting a volume of natural gas to barrels using the ratio of 6 Mcf to one barrel;
"boe/d"	barrel of oil equivalent per day;
"Mbbl"	thousand barrels;
"Mboe"	thousand barrels of oil equivalent;
"Mcf"	thousand cubic feet of natural gas;
"Mcfe"	Mcf of gas equivalent determined by converting a volume of oil or NGL to Mcf using the ratio of 0.1667 barrels to 1 Mcf;
"Mcf/d"	thousand cubic feet of natural gas per day;
"MMcf"	million cubic feet of natural gas;
"MMcf/d"	million cubic feet of natural gas per day;
"NGLs"	natural gas liquids;
"$US"	United States dollar;
"$Cdn"	Canadian dollar.

Conversion

In this document measurements are given in standard Imperial or metric units only. The following table sets forth certain standard conversions.

To convert from:	To:	Multiply by:
Mcf	cubic metres	28.174
Cubic metres	cubic feet	35.494
bbls	cubic metres	0.159
cubic metres	bbls	6.290
feet	metres	0.305
metres	feet	3.281
miles	kilometres	1.609
kilometres	miles	0.621
acres	hectares	0.405
hectares	acres	2.471

Appendix

NI 51-101 Forecast – Oil and Gas Reserves Summary
NI 51-101 Forecast – Summary of Net Present Values of Future Net Revenue
NI 51-101 Forecast – Total Future Net Revenue
NI 51-101 Forecast – Unit Value of Net Reserves by Production Group
NI 51-101 Forecast – Reconciliation of Company Gross Reserves
AJM Deloitte Price Forecast December 31, 2011

Form 51-101 F2

Anterra Energy Inc.
NI 51-101 FORECAST CASE
OIL AND GAS RESERVES SUMMARY
AJM Deloitte December 31, 2011 Forecast Pricing

Effective: December 31, 2011 Canada

VOLUMES IN IMPERIAL UNITS

	Oil						Natural gas											
	Light, medium and shale		Heavy		Bitumen		Solution		Associated and non-associated		Coalbed methane		Natural gas liquids		Sulphur		Total Boe	
Category	WI Gross Mbbl	Co. Share Net Mbbl	WI Gross Mbbl	Co. Share Net Mbbl	WI Gross Mbbl	Co. Share Net Mbbl	WI Gross MMcf	Co. Share Net MMcf	WI Gross MMcf	Co. Share Net MMcf	WI Gross MMcf	Co. Share Net MMcf	WI Gross Mbbl	Co. Share Net Mbbl	WI Gross Mlt	Co. Share Gross Mlt	WI Gross MBoe	Co. Share Net MBoe
PDP	538.9	445.3	40.2	35.9	0	0	655.7	512.2	0	0	0	0	29.0	17.8	0	0	717.4	584.4
PDNP	9.1	8.4	1.6	1.6	0	0	0	0	0	0	0	0	0	0	0	0	10.7	10.0
PUD	455.5	336.4	0	0	0	0	701.5	521.2	0	0	0	0	34.4	24.8	0	0	606.8	448.1
TP	1003.5	790.1	41.8	37.5	0	0	1357.3	1033.4	0	0	0	0	63.4	42.6	0	0	1335.0	1042.4
PB	980.3	772.4	19.7	17.3	0	0	1171.0	875.6	0	0	0	0	53.4	34.9	0	0	1248.6	970.6
P+P	1983.8	1562.6	61.5	54.8	0	0	2528.3	1909.1	0	0	0	0	116.8	77.5	0	0	2583.6	2013.0

VOLUMES IN METRIC UNITS

	Oil						Natural gas											
	Light, medium and shale		Heavy		Bitumen		Solution		Associated and non-associated		Coalbed methane		Natural gas liquids		Sulphur		Total Boe	
Category	WI Gross E3m3	Co. Share Net E3m3	WI Gross E3m3	Co. Share Net E3m3	WI Gross E3m3	Co. Share Net E3m3	WI Gross E6m3	Co. Share Net E6m3	WI Gross E6m3	Co. Share Net E6m3	WI Gross E6m3	Co. Share Net E6m3	WI Gross E3m3	Co. Share Net E3m3	WI Gross E3t	Co. Share Gross E3t	WI Gross E3m3e	Co. Share Net E3m3e
PDP	85.6	70.8	6.4	5.7	0	0	18.5	14.4	0	0	0	0	4.6	2.8	0	0	114.0	92.9
PDNP	1.4	1.3	0.3	0.3	0	0	0	0	0	0	0	0	0	0	0	0	1.7	1.6
PUD	72.4	53.5	0	0	0	0	19.8	14.7	0	0	0	0	5.5	3.9	0	0	96.4	71.2
TP	159.5	125.6	6.6	6.0	0	0	38.2	29.1	0	0	0	0	10.1	6.8	0	0	212.1	165.6
PB	155.8	122.7	3.1	2.8	0	0	33.0	24.7	0	0	0	0	8.5	5.5	0	0	198.4	154.2
P+P	315.3	248.3	9.8	8.7	0	0	71.2	53.8	0	0	0	0	18.6	12.3	0	0	410.6	319.9

Anterra Energy Inc.
NI 51-101 FORECAST CASE
SUMMARY OF NET PRESENT VALUES OF FUTURE NET REVENUE – WITH CORPORATE TAX POOLS
AJM Deloitte December 31, 2011 Forecast Pricing

Effective: December 31, 2011 Canada

	Before Income Taxes					After Income Taxes					Unit Value Before Income Tax Discounted at 10%
	0%	5%	10%	15%	20%	0%	5%	10%	15%	20%	
Reserves category	**M$**	**M$**	**M$**	**M$**	**M$**	**M$**	**M$**	**M$**	**M$**	**M$**	**$/boe**
Proved developed producing	52,654.2	34,418.9	26,380.2	21,811.7	18,805.3	43,735.1	29,573.3	23,152.2	19,435.7	16,956.6	45.14
Proved developed non-producing	526.8	393.4	305.6	245.2	201.9	394.5	294.1	228.1	182.8	150.4	30.59
Proved undeveloped	26,928.2	14,428.7	8,950.7	5,881.5	3,919.4	20,212.3	10,621.2	6,370.9	3,968.3	2,423.0	19.98
Proved	80,109.3	49,240.9	35,636.5	27,938.5	22,926.7	64,341.9	40,488.5	29,751.3	23,586.8	19,530.0	34.19
Probable	64,785.3	33,499.0	20,661.8	13,865.1	9,712.3	48,740.5	24,796.0	14,932.1	9,681.7	6,461.9	21.29
Proved plus probable	144,894.5	82,739.9	56,298.3	41,803.4	32,639.0	113,082.4	65,284.5	44,683.4	33,268.5	25,992.0	27.97

Values may not add due to rounding
Unit Value calculation based on Net Boe reserves.

Anterra Energy Inc.
NI 51-101 FORECAST CASE
TOTAL FUTURE NET REVENUE – WITH CORPORATE TAX POOLS
AJM Deloitte December 31, 2011 Forecast Pricing

Effective: December 31, 2011

Canada

Category	Revenue*	Royalties	Operating Costs	Development Costs	Well Abandonment Costs	Future Net Revenue Before Income Taxes	Income Tax Expenses	Future Net Revenue After Income Taxes
	M$	M$	M$	M$	M$	M$	M$	M$
Proved developed producing	93,934.5	13,175.5	23,082.2	0.0	5,022.5	52,654.2	8,919.1	43,735.1
Proved developed non-producing	1,126.9	79.2	505.9	15.0	0.0	526.8	132.3	394.5
Proved undeveloped	64,137.5	17,185.6	11,490.5	8,092.9	440.4	26,928.2	6,715.9	20,212.3
Proved	159,199.0	30,440.3	35,078.6	8,107.9	5,462.9	80,109.3	15,767.4	64,341.9
Probable	140,920.6	31,614.2	30,717.6	13,307.4	496.1	64,785.3	16,044.8	48,740.5
Proved plus probable	300,119.5	62,054.5	65,796.2	21,415.3	5,959.0	144,894.5	31,812.2	113,082.4

*Revenue includes product revenue and other income from facilities, wells and corporate if specified.

Anterra Energy Inc.
NI 51-101 FORECAST CASE
UNIT VALUE OF NET RESERVES BY PRODUCTION GROUP
AJM Deloitte December 31, 2011 Forecast Pricing

Effective: December 31, 2011 Canada

	Reserves					
	Oil	**Gas**	**NGL**	**BOE**	**NPV**	**Unit Value**
	Net	Net	Net	Net	10%	
	Mbbl	MMcf	Mbbl	boe	M$	$/boe
Light & Medium Crude Oil						
Proved developed producing	445.3	512.2	17.8	548,477.9	25,574.2	46.63
Proved developed non-producing	8.4	0.0	0.0	8,408.5	256.8	30.54
Proved undeveloped	336.4	521.2	24.8	448,063.8	8,950.7	19.98
Proved	790.1	1,033.4	42.6	1,004,950.1	34,781.7	34.61
Probable	772.4	875.6	34.9	953,274.0	20,305.6	21.30
Proved plus probable	1,562.6	1,909.1	77.5	1,958,224.2	55,087.3	28.13
Heavy Oil						
Proved developed producing	35.9	0.0	0.0	35,879.7	806.0	22.46
Proved developed non-producing	1.6	0.0	0.0	1,581.4	48.8	30.83
Proved undeveloped	0.0	0.0	0.0	0.0	0.0	0.0
Proved	37.5	0.0	0.0	37,461.1	854.8	22.82
Probable	17.3	0.0	0.0	17,326.5	356.2	20.56
Proved plus probable	54.8	0.0	0.0	54,787.6	1,211.0	22.10
Total						
Proved developed producing	481.2	512.2	17.8	584,357.6	26,380.2	45.14
Proved developed non-producing	10.0	0.0	0.0	9,989.8	305.6	30.59
Proved undeveloped	336.4	521.2	24.8	448,063.8	8,950.7	19.98
Proved	827.6	1,033.4	42.6	1,042,411.2	35,636.5	34.19
Probable	789.8	875.6	34.9	970,600.5	20,661.8	21.29
Proved plus probable	1,617.4	1,909.1	77.5	2,013,011.7	56,298.3	27.97

Anterra Energy Inc.
NI 51-101 FORECAST CASE
RECONCILIATION OF COMPANY GROSS RESERVES BY PRINCIPAL PRODUCT

Opening Case: AJM December 31, 2010 Forecast Pricing
Closing Case: AJM Deloitte December 31, 2011 Forecast Pricing

Effective: December 31, 2011

Canada

	Light & Medium Oil			Heavy Oil			Associated & Non-Associated Gas			Natural Gas Liquids		
	Proved	Probable	Proved +probable	Proved	Probable	Proved +probable	Proved	Probable	Proved +probable	Proved	Probable	Proved +probable
	Mbbl	Mbbl	Mbbl	Mbbl	Mbbl	Mbbl	Mbbl	Mbbl	Mbbl	Mbbl	Mbbl	Mbbl
Opening balance	951.0	985.2	1,936.1	26.3	14.6	40.9	1,155.1	1,263.0	2,418.1	56.6	66.9	123.5
Production	-75.3	0.0	-75.3	-5.3	0.0	-5.3	-123.9	0.0	-123.9	-7.1	0.0	-7.1
Technical revisions	82.8	-107.4	-24.5	21.4	6.2	27.5	330.5	-393.2	-62.8	14.2	-33.6	-19.4
Extensions & improved recovery	50.0	105.0	155.0	0.0	0.0	0.0	0.0	307.8	307.8	0.0	20.5	20.5
Discoveries												
Acquisitions												
Dispositions												
Economic Factors	-5.0	-2.5	-7.5	-0.6	-1.1	-1.7	-4.4	-6.5	-11.0	-0.3	-0.4	-0.7
Infill Drilling												
Closing balance	1,003.5	980.3	1,983.8	41.8	19.7	61.5	1,357.3	1,171.0	2,528.3	63.4	53.4	116.8

AJM Deloitte
Canadian Domestic Price Forecast
Base Case Forecast Effective December 31, 2011

					Crude Oil Pricing							Natural Gas Liquids Pricing				Natural Gas Pricing									Sulphur
												Edmonton Par Prices													
		Price Inflation Rate	Cost Inflation Rate	CAD to USD Exchange Rate	WTI at Cushing Oklahoma US$/bbl Real	WTI at Cushing Oklahoma US$/bbl Current	Edmonton City Gate C$/bbl Real	Edmonton City Gate C$/bbl Current	Med. Oil 29 Deg. API Cromer, Sk. C$/bbl Current	Bow River 25 Deg. API Hardisty C$/bbl Current	Heavy Oil 12 Deg. API Hardisty C$/bbl Current	Ethane C$/bbl Current	Propane C$/bbl Current	Butane C$/bbl Current	Pentanes + Condensate C$/bbl Current	Alberta Reference Average Price C$/mcf Current	Alberta AECO Average Price C$/mcf Real	Alberta AECO Average Price C$/mcf Current	Alberta System Plant Gate Sales C$/mcf Current	Alberta Direct Plant Gate Sales C$/mcf Current	B.C. Direct Stn. 2 Sales C$/mcf Current	Sask. Direct Plant Gate Sales C$/mcf Current	NYMEX US$/Mcf Real	NYMEX US$/Mcf Current	Alberta Plant Gate C$/lt Current
H	1997	1.6%	1.6%	0.722	$26.56	$20.60	$36.08	$27.98	$23.71	$21.26	$14.35	n/a	$19.41	$19.02	$30.85	$1.87	$2.21	$1.71	$1.78	$1.69	$1.98	$1.74	$3.34	$2.59	$11.50
i	1998	0.7%	0.7%	0.675	$18.25	$14.38	$25.49	$20.08	$16.94	$14.63	$9.43	n/a	$11.97	$12.92	$22.35	$1.94	$2.63	$2.07	$1.90	$1.95	$2.00	$2.13	$2.68	$2.11	($6.51)
s	1999	1.8%	1.8%	0.648	$24.32	$19.29	$34.54	$27.41	$21.72	$20.29	$17.62	$8.09	$13.21	$14.39	$20.94	$2.48	$3.47	$2.75	$2.22	$2.50	$2.64	$2.61	$2.64	$2.10	$6.93
t	2000	2.6%	2.6%	0.674	$37.41	$30.22	$54.89	$44.33	$39.89	$34.46	$28.57	$14.10	$32.59	$36.51	$46.30	$4.51	$6.96	$5.62	$4.84	$5.47	$4.73	$5.05	$5.35	$4.32	$13.59
o	2001	2.5%	2.5%	0.646	$31.19	$25.87	$47.22	$39.17	$31.54	$25.12	$18.07	$17.20	$30.62	$30.49	$43.03	$5.39	$6.54	$5.42	$5.42	$5.26	$6.34	$6.10	$4.74	$3.93	($14.50)
r	2002	2.3%	2.3%	0.637	$30.68	$26.11	$47.39	$40.33	$35.52	$31.89	$27.63	$11.21	$20.92	$27.78	$41.22	$3.88	$4.92	$4.19	$3.85	$4.03	$4.09	$4.08	$3.94	$3.36	$12.74
i	2003	2.8%	2.8%	0.716	$35.62	$31.01	$49.97	$43.51	$37.47	$32.96	$27.35	$18.43	$32.31	$36.03	$45.18	$6.12	$7.67	$6.68	$6.11	$6.51	$6.42	$6.67	$6.29	$5.48	$40.99
c	2004	1.8%	1.8%	0.770	$46.28	$41.45	$59.13	$52.96	$45.76	$38.01	$30.44	$19.04	$35.20	$44.07	$55.49	$6.31	$7.32	$6.55	$6.32	$6.38	$6.52	$6.84	$6.98	$6.25	$40.82
a	2005	2.2%	2.2%	0.826	$62.05	$56.61	$75.99	$69.33	$57.39	$45.68	$33.77	$23.80	$43.23	$51.91	$74.67	$8.31	$9.63	$8.78	$8.56	$8.61	$8.22	$8.51	$9.77	$8.91	$40.99
l	2006	2.0%	2.0%	0.882	$70.78	$66.06	$78.58	$73.34	$62.42	$52.04	$39.68	$19.81	$44.11	$58.16	$78.19	$6.56	$7.01	$6.54	$6.63	$6.35	$6.57	$7.11	$7.23	$6.75	$19.51
	2007	2.1%	2.1%	0.935	$76.00	$72.38	$80.94	$77.09	$65.18	$53.86	$39.75	$18.41	$49.77	$59.40	$81.67	$6.20	$6.76	$6.44	$6.31	$6.22	$6.40	$6.54	$7.32	$6.97	$38.32
	2008	2.4%	2.4%	0.943	$102.32	$99.58	$105.66	$102.83	$93.26	$83.97	$73.17	$22.61	$56.94	$83.56	$109.80	$7.88	$8.38	$8.15	$8.13	$7.92	$8.21	$8.19	$9.12	$8.88	$304.51
	2009	0.3%	0.3%	0.880	$61.98	$61.78	$66.41	$66.21	$62.77	$59.90	$54.49	$11.60	$34.56	$56.29	$69.59	$3.84	$3.97	$3.96	$3.94	$3.74	$4.16	$4.14	$3.92	$3.90	($4.97)
	2010	1.8%	1.8%	0.971	$79.42	$79.42	$77.79	$77.79	$73.48	$68.16	$60.59	$11.52	$45.60	$69.02	$84.68	$3.76	$4.00	$4.00	$4.07	$3.76	$4.00	$3.90	$4.38	$4.38	$57.81
2																									
0	12 Mths H	2.8%	2.8%	1.013	$94.99	$94.99	$95.77	$95.77	$88.29	$78.60	$69.75	$10.46	$53.34	$83.62	$104.70	$3.48	$3.65	$3.65	$3.83	$3.46	$3.37	$3.38	$4.00	$4.00	$80.69
1	0 Mths F	0.0%	0.0%	0.000	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
1	Avg.	n/a	n/a	1.013	$94.99	$94.99	$95.77	$95.77	$88.29	$78.60	$69.75	$10.46	$53.34	$83.62	$104.70	$3.48	$3.65	$3.65	$3.83	$3.46	$3.37	$3.38	$4.00	$4.00	$80.69
F	2012	0.0%	0.0%	1.000	$100.00	$100.00	$98.00	$98.00	$91.00	$81.20	$76.40	$9.60	$53.90	$83.30	$102.90	$3.25	$3.50	$3.50	$3.20	$3.30	$3.20	$3.45	$3.80	$3.80	$80.00
o	2013	2.0%	2.0%	1.000	$100.00	$102.00	$98.00	$100.00	$92.30	$81.10	$75.70	$11.40	$55.00	$85.00	$105.00	$3.85	$4.00	$4.10	$3.80	$3.90	$3.80	$4.05	$4.40	$4.50	$81.60
r	2014	2.0%	2.0%	1.000	$100.00	$104.05	$98.00	$102.00	$93.00	$80.00	$74.00	$13.20	$56.10	$86.70	$107.10	$4.45	$4.50	$4.70	$4.40	$4.50	$4.40	$4.65	$4.80	$5.00	$83.25
e	2015	2.0%	2.0%	1.000	$100.00	$106.10	$98.00	$104.00	$94.25	$82.00	$76.00	$14.55	$57.20	$88.40	$109.20	$4.90	$4.85	$5.15	$4.85	$4.95	$4.85	$5.10	$5.15	$5.45	$84.90
c	2016	2.0%	2.0%	1.000	$100.00	$108.25	$98.00	$106.10	$95.60	$84.10	$78.10	$15.75	$58.35	$90.20	$111.40	$5.30	$5.15	$5.55	$5.25	$5.35	$5.25	$5.50	$5.45	$5.90	$86.60
a	2017	2.0%	2.0%	1.000	$100.00	$110.40	$98.00	$108.20	$96.95	$86.20	$80.20	$17.10	$59.50	$91.95	$113.60	$5.75	$5.45	$6.00	$5.70	$5.80	$5.70	$5.95	$5.75	$6.35	$88.35
s	2018	2.0%	2.0%	1.000	$100.00	$112.60	$98.00	$110.35	$98.35	$88.35	$82.35	$18.30	$60.70	$93.80	$115.85	$6.15	$5.70	$6.40	$6.10	$6.20	$6.10	$6.35	$6.00	$6.75	$90.10
t	2019	2.0%	2.0%	1.000	$100.00	$114.85	$98.00	$112.55	$99.05	$90.55	$84.55	$19.80	$61.90	$95.65	$118.20	$6.65	$6.00	$6.90	$6.60	$6.70	$6.60	$6.85	$6.35	$7.30	$91.90
	2020	2.0%	2.0%	1.000	$100.00	$117.15	$98.00	$114.80	$99.80	$92.80	$86.80	$21.30	$63.15	$97.60	$120.55	$7.15	$6.30	$7.40	$7.10	$7.20	$7.10	$7.35	$6.60	$7.75	$93.75
	2021	2.0%	2.0%	1.000	$100.00	$119.50	$98.00	$117.10	$102.10	$95.10	$89.10	$22.35	$64.40	$99.55	$122.95	$7.50	$6.50	$7.75	$7.45	$7.55	$7.45	$7.70	$6.85	$8.20	$95.65
	2022	2.0%	2.0%	1.000	$100.00	$121.90	$98.00	$119.45	$104.45	$97.45	$91.45	$22.80	$65.70	$101.55	$125.40	$7.65	$6.50	$7.90	$7.60	$7.70	$7.60	$7.85	$7.00	$8.55	$97.55
	2023	2.0%	2.0%	1.000	$100.00	$124.35	$98.00	$121.85	$106.85	$99.85	$93.85	$23.40	$67.00	$103.55	$127.95	$7.85	$6.50	$8.10	$7.80	$7.90	$7.80	$8.05	$7.00	$8.70	$99.50
	2024	2.0%	2.0%	1.000	$100.00	$126.80	$98.00	$124.30	$109.30	$102.30	$96.30	$23.85	$68.35	$105.65	$130.50	$8.00	$6.50	$8.25	$7.95	$8.05	$7.95	$8.20	$7.00	$8.90	$101.50
	2025	2.0%	2.0%	1.000	$100.00	$129.35	$98.00	$126.75	$111.75	$104.75	$98.75	$24.30	$69.70	$107.75	$133.10	$8.15	$6.50	$8.40	$8.10	$8.20	$8.10	$8.35	$7.00	$9.05	$103.55
	2026	2.0%	2.0%	1.000	$100.00	$131.95	$98.00	$129.30	$114.30	$107.30	$101.30	$24.90	$71.10	$109.90	$135.75	$8.35	$6.50	$8.60	$8.30	$8.40	$8.30	$8.55	$7.00	$9.25	$105.60
	2027	2.0%	2.0%	1.000	$100.00	$134.60	$98.00	$131.90	$116.90	$109.90	$103.90	$25.35	$72.55	$112.10	$138.50	$8.50	$6.50	$8.75	$8.45	$8.55	$8.45	$8.70	$7.00	$9.40	$107.70
	2028	2.0%	2.0%	1.000	$100.00	$137.30	$98.00	$134.55	$119.55	$112.55	$106.55	$25.80	$74.00	$114.35	$141.30	$8.65	$6.50	$8.90	$8.60	$8.70	$8.60	$8.85	$7.00	$9.60	$109.85
	2029	2.0%	2.0%	1.000	$100.00	$140.00	$98.00	$137.20	$122.20	$115.20	$109.20	$26.40	$75.45	$116.60	$144.05	$8.85	$6.50	$9.10	$8.80	$8.90	$8.80	$9.05	$7.00	$9.80	$112.05
	2030	2.0%	2.0%	1.000	$100.00	$142.80	$98.00	$139.95	$124.95	$117.95	$111.95	$27.00	$76.95	$118.95	$146.95	$9.05	$6.50	$9.30	$9.00	$9.10	$9.00	$9.25	$7.00	$10.00	$114.30
	2031	2.0%	2.0%	1.000	$100.00	$145.70	$98.00	$142.75	$127.75	$120.75	$114.75	$27.45	$78.50	$121.35	$149.90	$9.20	$6.50	$9.45	$9.15	$9.25	$9.15	$9.40	$7.00	$10.20	$116.60
	2029+	2.0%	2.0%	1.000	0.0%	2.0%	0.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	0.0%	2.0%	2.0%	2.0%	2.0%	2.0%	0.0%	2.0%	2.0%

Notes:
- All prices are in Canadian dollars except WTI and NYMEX gas which are in U.S. dollars.
- Edmonton city gate prices based on light sweet crude posted at major Canadian refineries. (40 Deg. API < 0.5% Sulphur)
- Natural Gas Liquid prices are forecasted at Edmonton therefore an additional transportation cost must be included to plant gate sales point.
- 1 Mcf is equivalent to 1 mmbtu.
- System gas prices includes TCGSL, Progas, Pan Alberta and Alliance.
- Real dollars listed include future growth in prices with no escalation considered.
- Alberta gas prices, except AECO, include an Average cost of service to the plant gate.

ajm Deloitte.

Form 51-101 F2
Report on reserves data
by
independent qualified reserves
evaluator or auditor

To the Board of Directors of Anterra Energy Inc. (the "Company"):

1. We have evaluated the Company's reserves data as at December 31, 2011. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2011, estimated using forecast prices and costs.
2. The reserves data are the responsibility of the Company's management. Our responsibility is to express an opinion on the reserves data based on our evaluation.
   We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook (the "COGE Handbook") prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society).
3. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation also includes assessing whether the reserves data are in accordance with principles and definitions presented in the COGE Handbook.
4. The following table sets forth the estimated future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated by us for the year end December 31, 2011, and identifies the respective portions thereof that we have evaluated and reported on to the Company's management/Board of Directors:

Independent Qualified Reserves Evaluator or Auditor	Description and Preparation Date of Evaluation Report	Location of Reserves (Country or Foreign Geographic Area)	Net Present Value of Future Net Revenue (before income taxes, 10% discount rate)			
			Audited	Evaluated	Reviewed	Total
			$M	$M	$M	$M
AJM Deloitte	Anterra Energy Inc. Reserve estimation and economic evaluation December 31, 2011	Canada	-	$56,298.30	-	$56,298.30

5. In our opinion, the reserves data respectively evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook, consistently applied. We express no opinion on the reserves data that we reviewed but did not audit or evaluate.
6. We have no responsibility to update our reports referred to in paragraph 4 for events and circumstances occurring after their respective preparation dates.
7. Because the reserves data are based on judgments regarding future events, actual events will vary and the variations may be material.

Executed as to our report referred to above:

AJM Deloitte
Fifth Avenue Place, East Tower
6th Floor, 425 – 1st Street S.W.
Calgary, Alberta
T2P 3P8

*Original signed by: "**R**obin G. Bertram"*
Robin G. Bertram, P. Eng.
Associate Partner

Execution date: March 6, 2012

FORM 51-101F3

REPORT OF MANAGEMENT AND DIRECTORS ON OIL AND GAS DISCLOSURE

The management of Anterra Energy Inc. (the "Company") is 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 December 31, 2011, estimated using forecast prices and costs.

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

The Audit and Reserves Committee of the board of directors of the Company has:

(a) Reviewed the Company's procedures for providing information to the independent qualified reserves evaluator;
(b) Met with the independent qualified reserves evaluator to determine whether any restrictions affected the ability of the independent qualified reserves evaluator to report without reservation; and
(c) Reviewed the reserves data with management and the independent qualified reserves evaluator.

The Audit and Reserves Committee of the board of directors has reviewed the Company's procedures for assembling and reporting other information associated with oil and gas activities and has reviewed that information with management. The board of directors has, on the recommendation of the Audit and Reserves Committee: 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 the Form 51-101F2 of the independent qualified reserves evaluator on the reserves data; and (c) the content and filing of this report.

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

(signed)
Dr. Gang Fang, CEO

(signed)
Qiping Men, CFO

(signed)
James H. Coleman, Director

(signed)
Ross O. Drysdale, Director

Dated: April 23, 2012