NI Form 51-101 F1

Anterra Energy Inc.

Statement of reserves data

and other oil and gas information

as of December 31, 2012

Prepared by Deloitte

April 19, 2013

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Part 1: Date of statement

Date of statement: **April 19, 2013**
Effective date: **December 31, 2012**
Preparation date: **April 19, 2013**

Anterra Energy Inc. (the "Company") oil and gas reserves were evaluated by Deloitte LLP ("Deloitte"), effective December 31, 2012. Deloitte was engaged by the Company to evaluate proved and proved plus probable reserves: no valuation of possible reserves or resources was undertaken. The 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 Forecast Case – 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 Forecast Case – 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 Forecast Case – Total Future Net Revenue (Undiscounted), and NI 51-101 Forecast Case – 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, 2012 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 NI 51-101 Forecast Case - 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: Matziwin, Minnehik-Buck Lake and Breton.

Matziwin

The Matziwin property includes three wells to which proved developed producing and proved plus probable reserves have been assigned. Reserves have been assigned to these entities based on decline analysis with consideration to well performance.

Anterra plans to drill a short leg horizontal well at HZ/01-16-023-14W4/A to increase Pekisko recovery in the section. Proved undeveloped and proved plus probable reserves were assigned primarily by analogy to the 02/04-15-023-14W4/0 well.

Reserves have not been assigned to five entities in the property based on recent production rates being under the estimated economic rate or if they have been suspended.

Minnehik-Buck Lake

Two vertical wells in the area have established production and have been assigned proved developed producing reserves, which are based on decline analysis with consideration to the previous performance of the entities.

In 2011, Anterra added two successful horizontal wells in section 17-045-05W5, the 00/01-17-045-05W5/00 and 00/08-17-045-05W5/00 wells. These two wells have shown good production to date; however, the wells have yet to reach a steady production trend. Reserves have been assigned to the well based on the type curve profile estimated for the property, offsetting wells, and these wells' production to date.

Anterra drilled a third horizontal Cardium well in section 17-045-05W5, in November 2012, which is expected to be on-stream immediately prior to the effective date. Proved undeveloped reserves had previously been assigned. Additionally, three locations were assigned to this property. Two proved undeveloped wells were assigned in Section 08-045-05W5, and one proved location was 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.

All other wells in the property were either uneconomic or have not produced for a reasonable amount of time in which it was assumed they would not come back on-stream. No reserves have been assigned to these entities.

Breton

The Breton property consists of six producing oil wells which are in the Norbuck Basal Belly River B Pool Unit, four producing Non-Unit oil wells, and seven oil well locations, five of which are horizontal wells. There are also two 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. The four Non-Unit producing wells in the Unit have been assigned proved developed producing and proved plus probable reserves; based on decline analysis with consideration towards well performance.

The six remaining Norbuck Basal Belly River B Pool Unit wells have been assigned proved developed producing reserves based on decline analysis with consideration towards individual well performance. The wells were evaluated individually to determine the well count trend for the remaining life of the pool. Anterra has indicated that they plan to install a water injector to the Unit to increase the recovery of the remaining wells. Deloitte has assumed that this will occur sometime in mid-2013, and increased total proved and proved plus probable reserves have been assigned to the Unit through a combination of well performance, decline analysis, and analogy to other wells Anterra has previously installed waterfloods on.

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 Anterra into this pool.

Probable reserves have been assigned to the horizontal HZ/13-20-047-03W5/A Cardium location. A type well generated from existing horizontal Cardium oil producers was used as the basis of assigning reserves. Wells in the surrounding area were examined to determine the profile and initial rate of the type curve assigned. Deloitte reviewed 37 horizontal wells located in Township 47, Range 3W5. An ultimate recoverable volume was estimated for all wells that had established production trends, which was used to estimate an ultimate recoverable for the type well. From these wells a two part profile was established with an initial rate of 130 bbl/d and an EUR of 65 Mbbl. It was observed from these horizontal wells that they experienced a sharp drop-off during the first seven months of production before leveling off to a shallower decline. The start date for this location has been pushed to January 2015 where oil prices are forecast to be higher.

Reserves have also been assigned to two proved undeveloped vertical well locations targeting the Belly River Formation. Proved undeveloped and proved plus probable reserves have been assigned to these entities based on volumetric analysis. Reservoir parameters have been estimated by Deloitte based on a review of well logs for nearby producers. The reservoir pressure and temperature have been estimated from the public pool ticket for the Pembina Commingled Pool 003. The recovery factor and drainage area were estimated from surrounding well performance.

All other wells in the property were either uneconomic or have not produced for a reasonable amount of time in which it was assumed they would not come back on-stream. No reserves have been assigned to these entities.

	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 2010	844	-	-	-	904	-	2	-	-	-
2010	176	214	-	-	433	449	27	27	-	-
2011	50	234	-	-	-	519	-	34	-	-
2012	-	197	-	-	-	247	-	20	-	-
Probable undeveloped										
Prior to 2010	-	-	-	-	-	-	-	-	-	-
2010	607-	618	-	-	909	913	52	52	-	-
2011	90	515	-	-	308	493	21	21	-	-
2012	-	523	-	-	-	343	-	13	-	-

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
2013	6,699.91	15,399.91	6,317.38	14,640.79
2014	1,058.76	4,526.76	898.27	3,794.71
2015				
2016				
2017				
2018+				
Total	7,758.67	19,926.67	7,215.64	18,435.51

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 and 48, Ranges 3 and 4 W5M. The property contains four producing oil wells, one producing oil Unit containing six wells, and seven drilling locations. The Company has working interests of 100 percent in the majority of their wells, as well as two 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 company 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 seven producing oil wells, and three 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. The Company operates all of the wells in the property.

Matziwin, Alberta

The Matziwin property is located approximately 75 miles east of Calgary, Alberta. The Company holds a 100 percent working interest in four producing oil wells, one proved location, four non-producing oil wells, and one non-producing gas well. Production is from the Pekisko Formation. The Company operates all of the wells in the 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	17	15.1	19	14.2	59	55.5	95	84.8
Saskatchewan	1	0.5	-	-	7	3.3	8	3.8
Total	18	15.6	19	14.2	66	58.8	103	88.6

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

Item 6.2 Properties with no attributed reserves

The Company has 4,818 total hectares (4,818 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	88.6
Not included in evaluation	0.0

Property	Gross cost of abandonment and reclamation
Breton	$45,000/well
Frontier	$30,000/well
July Creek	$45,000/well
Matziwin	$35,000/well
Minnehik-Buck Lake	$45,000/well
Sakwatamau	$50,000/well
Scots Lake	$35,000/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	547.47	445.41	538.11	438.06
Following years	4,394.05	1,939.83	5,025.93	1,916.52
Total	**4,941.52**	**2,385.24**	**5,564.04**	**2,354.58**

Item 6.5 Tax Horizon

The Company is expected to begin paying income tax in 2016.

Item 6.6 Costs incurred

	$
Proved property acquisition	675,000
Land acquisition (unproved)	
Exploration	102,031
Development	3,545,107
Total	4,322,138

Item 6.7 Exploration and development activities

In 2012 the Company drilled one horizontal well in Minnehik-Buck Lake.

Item 6.8 Production estimates

Forecast production W.I. volume Jan 1 - Dec 31/13

	Proved	Proved + probable
Breton		
Oil NGLs(Mbbl)	27.5	50.5
Gas (MMcf)	20.9	30.5
Minnehik-Buck Lake		
Oil & NGLs(Mbbl)	40.6	41.3
Gas (MMcf)	88.5	90.5
Remaining properties		
Oil & NGLs(Mbbl)	15.1	15.3
Gas (MMcf)	0.0	0.0
Total		
Oil & NGLs(Mbbl)	83.2	107.2
Gas (MMcf)	109.4	121.0

Item 6.9 Production history

	Total Company			
	Q1 2012	Q2 2012	Q3 2012	Q4 2012
Volumes				
oil, bbl	16,198	21,840	12,103	20,976
gas, Mcf	33,670	26,117	30,758	35,236
natural gas liquids, bbl	1,092	1,183	910	1,840
Boe	22,602	22,767	17,907	28,749
Production				
oil, bopd	178	175	133	228
gas, Mcf/d	370	378	338	383
natural gas liquids, bopd	12	13	10	20
Boe/d	248	250	199	312
Price				
averages, $/bbl				
oil	89.58	78.62	83.06	95.55
gas	2.69	2.04	2.58	3.51
natural gas liquids	72.00	50.10	50.59	66.61
Operating expenses, royalties, and netback				
averages, $/Boe				
royalties paid	15.09	11.27	8.64	15.74
operating cost	29.85	32.56	32.84	34.28
netback	25.78	16.86	20.96	38.43

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
Deloitte Price Forecast December 31, 2012

Form 51-101 F2

Anterra Energy Inc.
NI 51-101 FORECAST CASE
OIL AND GAS RESERVES SUMMARY
AJM Deloitte December 31, 2012 Forecast Pricing

Effective: December 31, 2012 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	459.6	419.2	16.8	15.0	0.0	0.0	489.2	403.6	0.0	0.0	0.0	0.0	21.3	14.2	0.0	0.0	579.2	515.8
PDNP	0.0	0.0	1.3	1.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.3	1.3
PUD	454.2	378.7	0.0	0.0	0.0	0.0	458.5	394.9	0.0	0.0	0.0	0.0	19.7	14.6	0.0	0.0	550.3	459.1
TP	913.8	797.9	18.1	16.3	0.0	0.0	947.7	798.5	0.0	0.0	0.0	0.0	41.0	28.9	0.0	0.0	1,130.8	976.1
PB	1,098.1	911.2	9.0	8.0	0.0	0.0	901.7	795.4	0.0	0.0	0.0	0.0	25.7	18.2	0.0	0.0	1,283.1	1,069.9
P+P	2,012.0	1,709.0	27.0	24.3	0.0	0.0	1,849.4	1,593.9	0.0	0.0	0.0	0.0	66.8	47.1	0.0	0.0	2,414.0	2,046.1

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	73.0	66.6	2.7	2.4	0.0	0.0	13.8	11.4	0.0	0.0	0.0	0.0	3.4	2.3	0.0	0.0	92.0	82.0
PDNP	0.0	0.0	0.2	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.2
PUD	72.2	60.2	0.0	0.0	0.0	0.0	12.9	11.1	0.0	0.0	0.0	0.0	3.1	2.3	0.0	0.0	87.5	73.0
TP	145.2	126.8	2.9	2.6	0.0	0.0	26.7	22.5	0.0	0.0	0.0	0.0	6.5	4.6	0.0	0.0	179.7	155.1
PB	174.5	144.8	1.4	1.3	0.0	0.0	25.4	22.4	0.0	0.0	0.0	0.0	4.1	2.9	0.0	0.0	203.9	170.0
P+P	319.7	271.6	4.3	3.9	0.0	0.0	52.1	44.9	0.0	0.0	0.0	0.0	10.6	7.5	0.0	0.0	383.6	325.1

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, 2012 Forecast Pricing

Effective: December 31, 2012 Canada

	Before Income Taxes					After Income Taxes					Unit Value
	0%	5%	10%	15%	20%	0%	5%	10%	15%	20%	Before Income Tax Discounted at 10%
Reserves category	**M$**	**M$**	**M$**	**M$**	**M$**	**M$**	**M$**	**M$**	**M$**	**M$**	**$/boe**
Proved developed producing	30,290.1	21,858.8	17,445.5	14,745.2	12,910.4	27,987.1	20,790.1	16,887.3	14,428.0	12,718.7	33.83
Proved developed non-producing	11.0	10.2	9.5	8.9	8.4	8.2	8.2	8.1	7.9	7.6	7.61
Proved undeveloped	19,867.8	8,990.9	4,523.6	2,183.5	767.1	14,900.6	6,587.1	3,118.2	1,272.2	138.4	9.85
Proved	50,168.8	30,859.9	21,978.7	16,937.6	13,685.8	42,896.0	27,385.4	20,013.6	15,708.1	12,864.7	22.52
Probable	56,713.2	25,844.4	14,123.3	8,238.6	4,772.9	42,535.9	19,100.5	10,115.5	5,562.8	2,860.3	13.20
Proved plus probable	106,882.0	56,704.3	36,101.9	25,176.2	18,458.7	85,431.9	46,486.0	30,129.1	21,270.9	15,725.0	17.64

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, 2012 Forecast Pricing

Effective: December 31, 2012 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	62,554.7	4,855.1	22,826.4	0.0	4,583.1	30,290.1	2,302.9	27,987.1
Proved developed non-producing	80.5	2.9	51.6	15.0	0.0	11.0	2.7	8.2
Proved undeveloped	52,416.9	8,834.5	15,612.5	7,743.7	358.4	19,867.8	4,967.2	14,900.6
Proved	115,052.0	13,692.5	38,490.6	7,758.7	4,941.5	50,168.8	7,272.8	42,896.0
Probable	130,246.0	22,007.8	38,734.5	12,168.0	622.5	56,713.2	14,177.3	42,535.9
Proved plus probable	245,298.0	35,700.2	77,225.1	19,926.7	5,564.0	106,882.0	21,450.1	85,431.9

*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, 2012 Forecast Pricing

Effective: December 31, 2012 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	419.2	403.6	14.2	500,719.0	17,355.8	34.66
Proved developed non-producing	0.0	0.0	0.0	0.0	0.0	0.0
Proved undeveloped	378.7	394.9	14.6	459,105.6	4,523.6	9.85
Proved	797.9	798.5	28.9	959,824.6	21,879.4	22.80
Probable	911.2	795.4	18.2	1,061,938.3	14,023.6	13.21
Proved plus probable	1,709.0	1,593.9	47.1	2,021,762.9	35,903.0	17.76
Heavy Oil						
Proved developed producing	15.0	0.0	0.0	15,038.0	89.7	5.97
Proved developed non-producing	1.3	0.0	0.0	1,252.4	9.5	7.61
Proved undeveloped	0.0	0.0	0.0	0.0	0.0	0.0
Proved	16.3	0.0	0.0	16,290.4	99.3	6.09
Probable	8.0	0.0	0.0	8,004.9	99.7	12.45
Proved plus probable	24.3	0.0	0.0	24,295.2	198.9	8.19
Total						
Proved developed producing	434.3	403.6	14.2	515,756.9	17,445.5	33.83
Proved developed non-producing	1.3	0.0	0.0	1,252.4	9.5	7.61
Proved undeveloped	378.7	394.9	14.6	459,105.6	4,523.6	9.85
Proved	814.2	798.5	28.9	976,115.0	21,978.7	22.52
Probable	919.2	795.4	18.2	1,069,943.2	14,123.3	13.20
Proved plus probable	1,733.3	1,593.9	47.1	2,046,058.2	36,101.9	17.64

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

Opening Case: AJM Deloitte December 31, 2011 Forecast Pricing
Closing Case: AJM Deloitte December 31, 2012 Forecast Pricing

Effective: December 31, 2012 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	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
Production	-47.1	0.0	-47.1	-4.5	0.0	-4.5	-71.8	0.0	-71.8	-4.3	0.0	-4.3
Technical revisions	-101.1	162.5	61.4	-14.1	-7.0	-21.1	-429.7	-172.5	-602.1	-26.1	-19.6	-45.7
Extensions & improved recovery	45.0	-45.0	0.0	0.0	0.0	0.0	94.1	-94.1	0.0	8.0	-8.0	0.0
Discoveries	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Acquisitions	18.6	7.3	25.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Dispositions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Economic Factors	-5.1	-6.9	-12.0	-5.1	-3.7	-8.8	-2.1	-2.8	-5.0	0.0	0.0	0.0
Infill Drilling	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Closing balance	913.8	1,098.1	2,012.0	18.1	9.0	27.0	947.7	901.7	1,849.4	41.0	25.7	66.8

Deloitte.

NI 51-101 Form 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, 2012. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2012, 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, 2012, 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 $M	Evaluated $M	Reviewed $M	Total $M
Deloitte	Anterra Energy Inc. Reserve estimation and economic evaluation December 31, 2012	Canada	-	$36,101.90	-	$36,101.90

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:

Deloitte
700, 850 – 2nd Street S.W.
Calgary, Alberta
T2P 0R8

Original signed by: "Douglas S. Ashton"
Douglas S. Ashton, P. Eng.
Partner

Execution date: March 5, 2013

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, 2012, 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 evaluators 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 Corporation'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 evaluators 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 Form 51-101F2, which is the report of the independent qualified reserves evaluators 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)	(signed)
Dr. Gang Fang President, CEO and Director	Robert D. McCuaig, P.Eng. Executive Vice President
(signed)	(signed)
Owen C. Pinnell, P.Eng. Chairman and Director	Ross O. Drysdale Director

Dated: April 19, 2013