NI 51-101 Form F1

Anterra Energy Inc.

Statement of reserves data

and other oil and gas information

as of December 31, 2013

Prepared by Deloitte

March 18, 2014

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Part 1: Date of statement

Date of statement:	**March 18, 2014**
Effective date:	**December 31, 2013**
Preparation date:	**March 18, 2014**

Anterra Energy Inc.'s (the "Company") oil and gas reserves were evaluated by Deloitte LLP (Deloitte), effective December 31, 2013. 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").*

The Company closed two separate deals prior to year-end, acquiring Terrex Energy Inc. (Terrex) which included the Strathmore, Two Creek-Jurassic A and Two Creek-Jurassic B properties, and the Nipisi property from Pengrowth Energy Corp. (Pengrowth). These acquisitions resulted in significant reserve additions at year-end, accounting for approximately 2,947 MBoe at the proved plus probable category, slightly more than 60 percent of the forecast net remaining reserves.

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 Deloitte Price Forecast December 31, 2013 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

	Oil		Natural Gas		NGLs	
	First attributed WI Mbbl	Cumulative WI Mbbl	First attributed WI MMcf	Cumulative WI MMcf	First attributed WI Mbbl	Cumulative WI Mbbl
Proved undeveloped						
***Prior to 2011**	1,020	214	1,337	449	29	27
2011	50	234	-	519	-	34
2012	-	197	-	247	-	20
2013	200	845	166	754	8	15
Probable undeveloped						
****Prior to 2011**	607	618	909	913	52	52
2011	90	515	308	493	21	21
2012	-	523	-	343	-	13
2013	716	1,973	93	1,150	4	15

*****Cumulative volumes were not reported prior to 2010.
******Probable undeveloped reserves were not reported prior to 2010.

Undeveloped reserves were assigned within seven properties: Breton, Matziwin, Minnehik-Buck Lake, Sakwatamau, Strathmore, Two Creek – Jurassic A, and Two Creek – Jurassic B.

Breton

No new undeveloped locations were assigned reserves this year.

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 has confirmed the estimated on-stream dates forecast.

Probable reserves have been assigned to the horizontal HZ/13-20-047-03W5/A Cardium location. In prior years, 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. The surrounding offset wells have continued along the expected production profile. 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 more shallow decline.

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. These locations are offsetting active water injectors and are a continuous downspacing of the pool. The Company has confirmed the expected on-stream date forecast.

Matziwin

One new undeveloped location was assigned reserves this year.

The Company plans to drill a short leg horizontal well at HZ/01-16-023-14W4/A to increase Pekisko recovery in section sixteen. The Company has also planned to drill an offsetting location at HZ/03-15-023-14W4/A. Proved undeveloped and proved plus probable reserves were assigned primarily by analogy to the 02/04-15-023-14W4/0 well. Deloitte confirmed estimated on-stream dates with the Company.

Minnehik-Buck Lake

In 2011, the Company added two successful horizontal wells in section 17-045-05W5, the 00/01-17-045-05W5/0, and 00/08-17-045-05W5/0 wells. These two wells have shown good production to date; however, the wells have only recently started the expected shallowing 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. The Company also drilled the 00/09-17-045-05W5/0 well which started producing in December 2012. The well has exhibited a similar production profile as the first two wells, but with a slightly lower initial production rate.

There are three horizontal Cardium locations accounted for in this property, with proved locations 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. These new locations are considered as infills, based on the estimated areal extent of the existing wells. Currently, spacing for the Cardium is limited to four wells per section; however operators in the area, such as Sinopec Daylight Energy to the north, have started downspacing to six or eight wells per section. Deloitte has assigned reserves assuming the Company would get the same approval for downspacing. Sinopec Daylight has also been experimenting with increasing the length of the wellbores of their Cardium horizontal wells. The Company has suggested they will apply similar completion methods as other operators in the area, with 16 fracture stages per well and utilizing a slick water fracturing procedure.

These infill locations were assigned reserves after a review of the original oil-in-place for section 17-045-05W5. The production to date and the assigned reserves were used to estimate the remaining oil-in-place. The remaining reserves were assigned to the two horizontal infill locations after confirming the recovery factor from the gross production and reserves assigned and compared to the pool ticket. One additional location to the north of the 00/09-17 well has been forecast with the same reserve volumes. The Company no longer plans to drill the previously assigned Cardium locations in section 08-045-05W5.

Sakwatamau

The Company has identified two horizontal drilling locations in the Belloy Formation in the north part of the pool. These locations are proposed to the north of the existing defined pool boundary. Probable undeveloped reserves have been assigned to both locations based on volumetric analysis and a review of the previously produced wells in the pool. Proved reserves were not assigned due to the lack of certainty regarding the oil water contact and the effect of areal extent of these locations. Additionally, there has not been a horizontal well drilled in this area targeting the Belloy Formation to date.

Strathmore

This property was acquired by the Company during 2013.

Proved undeveloped reserves have been forecast based on the reactivations of following water injections wells: 00/16-01-022-26W4/00, 00/12-06-022-25W4/00, 00/05-07-022-25W4/00, 00/14-18-022-25W4/02, and 00/04-19-022-25W4/00, and conversions to injectors of the 00/06-18-022-25W4/02 and 00/10-18-022-25W4/00 wells. The 02/14-07-022-25W5/A proved location has been forecast in this entity and capital has been added for a new injector to be drilled at 02/03-18-022-25W4, scheduled for completion in the third quarter 2014. It is assumed that the workovers will increase overall productivity in the pool. Total proved reserves have been forecast by decline analysis based on the historical production performance of the group. The incremental producing rate forecast for November 2014 is based on simulations provided by Terrex demonstrating the expected performance of the pool based on the water flood re-alignment and the drilling of a new producer.

The assigned proved plus probable undeveloped reserves includes the re-alignment of the water flood, the drilling of the 02/14-07-022-25W5/A and 00/07-18-22-25W5/A producing locations and a water injection well drilled at 02/03-18-022-25W5/0. The incremental producing rate forecast for November 2014 is based on simulations provided by Terrex demonstrating the expected performance of the pool based on the water flood re-alignment and the drilling of two new producers. Deloitte has estimated these activities to occur in the second half of 2014 as the Company indicated this property to be one of its priority development opportunities.

Two Creek – Jurassic A

This property was acquired by the Company during 2013.

An assignment of probable undeveloped reserves includes the re-alignment of the waterflood and a water injection well drilled at 00/05-17-065-15W5/0. The forecast producing rates and incremental reserves were based on simulation data provided by Terrex and the performance of the pool to date. Based on confirmation from the Company, Deloitte has forecast this to occur in the second half of 2014.

The Company has identified two horizontal drilling locations, the H1/10-08-065-15W5/A and the H2/12-08-065-15W5/A wells. Proved undeveloped reserves were assigned to the H1/10-08-065-15W5/A oil location and probable undeveloped reserves were assigned to the H2/12-08-065-15W5/A oil well and were based on geological analysis of stepping out towards the edges of the pool. Reserves are based on volumetric analysis from geological parameters estimated from offset well logs by Deloitte. A drainage area of 80 acres was used and a recovery factor of 20 percent was based on the expected recovery of a waterflood in this pool and the offset production of the horizontal wells in the pool. The initial producing rate and forecast production trend were based on the 00/14-08-065-15W5/00, 102/02-17-065-15W5/00, and 100/06-17-065-15W5/00 wells producing from the pool. Based on confirmation from the Company, Deloitte has forecast the two locations to come on-stream in Q4 2014 and Q1 2015.

Two Creek – Jurassic B

This property was acquired by the Company during 2013.

Probable undeveloped (PBUD) reserves have been assigned based on a waterflood development plan proposed by the Company. As identified by the Company, the pressure in the Jurassic B Pool has been significantly depleted to approximately 13 percent of the original pressure, through the production of oil and water, but predominantly from the large volumes of gas produced. The Company identified both a gas cap and downdip water leg, each largely influencing the pool production. According to the plan proposed previously by Terrex, a reservoir re-pressurization to 40 percent of the original would be required in order to successfully develop the waterflood. Deloitte has estimated that this would require suspending production for approximately one year during injection, through three injector entities as identified by the Company. Injection would occur in the southern portion of the pool, near the migrated water-oil contact estimate. Once production is started again after the injection period, based on the expected increased reservoir pressure and reservoir fluid movement during that time, Deloitte has applied a 75 percent lower gas/oil ratio than is currently being exhibited. This would take into account the injected water pushing the oil column further up in the reservoir, potentially reducing further production from the gas cap, in addition to operationally trying to limit gas production in an attempt to keep the reservoir pressure level high.

Terrex previously identified the Killam North – Upper Mannville F2F pool as an analogous waterflood scenario. It should be noted that while both pools have seen pressure depletion, the Killam pool is not a direct analog. The Killam pool contains: a heavier oil (24 API) with less expected solution gas, a higher porosity, lower initial water saturation, and is approximately five times the size by volume of oil initially-in-place. The Killam pool pressure was depleted from an original six MPa to under one MPa before the waterflood was implemented, and according to public data, the pool has an estimated five percent incremental recovery factor due to the enhanced oil recovery from the waterflood. That incremental recovery factor is considered reasonable, and has been applied to in the Two Creek B pool. This is an additional 237 Mbbl of oil and total EUR of 1.03 MMbbl on the total proved plus probable case.

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
2014	4,755.0	11,525.0	4,434.2	10,738.2
2015	8,516.0	27,080.0	7,541.9	23,846.6
2016				
2017				
2018				
2019+				
Total	13,271.0	38,605.0	11,976.1	34,584.8

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 five producing oil wells, one producing oil Unit containing six wells, and seven drilling locations. The Company holds a working interest of 100 percent in the majority of their wells, as well as two royalty interest only 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 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 five Non-Unit producing wells in the property have been assigned proved developed producing and proved plus probable reserves, based on decline analysis with consideration towards 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.

Nipisi, Alberta

The Nipisi property is located approximately 40 miles northwest of Slave Lake, Alberta in Townships 78 and 79, Ranges 8 and 9 W5M. The Company acquired the property from Pengrowth effective December 18, 2013 and holds working interests ranging from 22.5 to 100 percent in 68 entities, of which 18 have been assigned reserves. Wells are producing oil out of the Gilwood Formation. The Company is the main operator in the property.

Reserves have been assigned to 18 entities in the property. Proved developed producing reserves have been assigned to 16 producing entities based on decline analysis with consideration towards performance history of the wells and the area. Based on received operating statements gas has been conserved on all of the wells in the property. Gas-oil ratios have been estimated based on the performance of the wells. The wells included in this property are located primarily to the west of the Nipisi Gilwood Unit 1. The Gilwood A pool was first produced from in 1965, and water injection was implemented in 1969. The western flank of the pool, where these wells produce from, was first brought on-stream in the early 1980s.

The 00/11-29-078-08W5/0 well was shut-in just before Christmas. The Company has indicated this was to replace the electric submersible pump and 34 joints of tubing. These operations have been completed and Deloitte has assumed the well to be back on-stream in January 2014; proved developed producing reserves have been assigned.

The 00/09-21-078-08W5/0 well stopped producing in July 2013; however, the drop in producing rates coincided with a reduction in producing hours. The 00/06-29-078-08W5/0 well has been suspended since January 2013. The Company has indicated this was due to a broken jack and bottom-hole pump. Deloitte has assumed these wells will come back on-stream in the first quarter of 2014 at previously seen producing rates and production trends; proved developed non-producing reserves have been assigned.

Several wells have not produced at full hours since various periods in 2012, and Deloitte has assumed these wells will not be brought back on-stream; no reserves have been assigned to these entities.

Strathmore, Alberta

The Strathmore property is located 40 miles southeast of Calgary, Alberta in Townships 21 to 23, Ranges 25 to 26 W4M. Terrex was acquired by The Company in January of 2013. The Company has acquired 100 percent working interest in the Strathmore property which contains 25 non-producing wells, three producing gas wells, one producing oil well, and the oil producing Lower Mannville B Pool group. The Lower Manville B Pool group consists of eight producing oil wells and 31 non-producing oil wells. The wells in this property are producing from the Ellerslie Formation. The Company is now the operator of this property.

The producing wells in the Lower Mannville B Pool have been evaluated as a group. There have been seven to ten producing wells in the group over the past two years, and more than 30 non-producing oil wells. Deloitte has started the proved developed producing forecast with eight wells and declining over the life. Proved developed producing and proved plus probable developed producing reserves have been assigned by decline analysis, based on the pools current performance.

The gas wells 00/16-06-022-25W4/2 and 00/05-19-022-26W4/3 are currently uneconomic to produce due to high operating costs and low gas prices. Reserves have not been assigned to these wells until such time they are proved economic.

Item 6.1.2 Gross and net oil and gas wells

Country/Province	Oil		Gas		Non-producing		Total	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Canada								
Alberta	51.0	48.1	1.0	1.0	171.0	160.9	223.0	210.1
Saskatchewan	2.0	1.0	-	-	5.0	2.3	7.0	3.3
Total	53.0	49.1	1.0	1.0	176.0	163.2	230	213.4

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 4,883 total hectares (3,662 ha net) of land in Abbott, Saskatchewan where no reserves have been assigned. The Company farmed-out a 25% interest in the lands, the proceeds from which were used to drill a second exploration test well. The well was drilled, logged, and abandoned.

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	213.4
Not included in evaluation	0.0

Property	Gross cost of abandonment and reclamation
Breton	$50,000/well
Breton-Cardium	$60,000/well
Frontier	$50,000/well
July Creek	$55,000/well
Matziwin	$40,000/well
Minnehik-Buck Lake	$60,000/well
Nipisi	$55,000/well
Sakwatamau	$60,000/well
Scots Lake	$40,000/well
Shadow	$65,000/well
Strathmore	$65,000/well
Two Creek – Jurassic A	$60,000/well
Two Creek – Jurassic B	$60,000/well

The abandonment costs are based on area averages taken from the Alberta Energy Regulator (AER) Directive 011 called the “Alberta Regional Well Abandonment Cost Tables”. Reclamation costs are taken from the AER 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	1,716.4	1,397.7	1,785.1	1,447.5
Following years	13,161.9	5,573.1	14,660.8	5,336.0
Total	**14,878.3**	**6,970.8**	**16,445.9**	**6,783.5**

Item 6.5 Tax Horizon

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

Item 6.6 Costs incurred

	$
Proved property acquisition	12,133,750
Land acquisition (unproved)	-
Exploration	-
Development	1,759,309
Total	13,968,309

Item 6.7 Exploration and development activities

In 2013, the Company drilled an exploration test well at Abbott, SK. 100% of the well costs were paid by the Farm-in partner. The well was abandoned.

The Company did no development drilling in 2014.

Item 6.8 Production estimates

Forecast production working interest January 1, 2014 - December 31, 2014			
		Proved	Proved + probable
Breton			
	Oil (Mbbl)	22.8	23.5
	Gas (MMcf)	17.1	17.7
	NGL (Mbbl)	0.1	0.1
Nipisi			
	Oil (Mbbl)	123.3	125.4
	Gas (MMcf)	29.3	29.8
	NGL (Mbbl)	8.7	8.9
Strathmore			
	Oil (Mbbl)	46.9	65.0
	Gas (MMcf)	77.7	102.1
	NGL (Mbbl)	0.5	0.7
Remaining properties			
	Oil (Mbbl)	68.2	57.1
	Gas (MMcf)	88.3	91.9
	NGL (Mbbl)	2.7	2.9
Total			
	Oil (Mbbl)	261.2	271.0
	Gas (MMcf)	212.5	241.5
	NGL (Mbbl)	12.1	12.6

Item 6.9 Production history

Total Company	Q1 2013	Q2 2013	Q3 2013	Q4 2013
Volumes				
oil, bbl	18,000	26,390	26,036	27,534
gas, Mcf	51,660	66,066	59,984	50,610
natural gas liquids, bbl	1,980	1,456	1,288	1,281
Boe	28,617	38,857	37,327	37,241
Production				
oil, bopd	200	290	283	299
gas, Mcf/d	574	726	652	550
natural gas liquids, bopd	22	16	14	14
Boe/d	318	432	406	405
Price				
oil, $/bbl	84.31	81.94	94.83	76.87
gas, $/Mcf	3.45	3.91	3.53	3.81
natural gas liquids, $/bbl	50.65	60.13	62.73	67.84
Total, $/Boe	61.63	63.8	73.49	64.34
Operating expenses, royalties, and netback				
averages, $/Boe				
royalties paid	8.50	9.56	14.44	12.93
operating cost	38.48	53.25	51.10	52.75
netback	14.65	1.03	7.94	-1.34

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, 2013

Anterra Energy Inc.
NI 51-101 FORECAST CASE
OIL AND GAS RESERVES SUMMARY
Deloitte December 31, 2013 Forecast Pricing

Effective: December 31, 2013 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	1,199.5	1,005.5	379.1	338.2	0.0	0.0	1,009.5	881.5	11.8	11.4	0.0	0.0	60.6	38.4	0.0	0.0	1,809.4	1,530.9
PDNP	61.2	44.5	10.9	9.4	0.0	0.0	11.9	9.2	0.0	0.0	0.0	0.0	3.5	2.2	0.0	0.0	77.6	57.7
PUD	742.4	660.3	103.0	87.7	0.0	0.0	753.5	665.4	0.0	0.0	0.0	0.0	15.4	9.9	0.0	0.0	986.4	868.8
TP	2,003.1	1,710.3	493.0	435.3	0.0	0.0	1,774.8	1,556.2	11.8	11.4	0.0	0.0	79.6	50.5	0.0	0.0	2.873.4	2,457.4
PB	1,972.3	1,628.2	533.6	453.7	0.0	0.0	1,643.0	1,452.4	3.0	2.9	0.0	0.0	42.2	27.8	0.0	0.0	2,822.5	2,352.3
P+P	3,975.4	3,338.5	1,026.6	889.0	0.0	0.0	3,417.8	3,008.6	14.8	14.4	0.0	0.0	121.8	78.4	0.0	0.0	5,695.9	4,809.7

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	190.6	159.8	60.2	53.7	0.0	0.0	28.4	24.8	0.3	0.3	0.0	0.0	9.6	6.1	0.0	0.0	287.5	243.3
PDNP	9.7	7.1	1.7	1.5	0.0	0.0	0.3	0.3	0.0	0.0	0.0	0.0	0.6	0.4	0.0	0.0	12.3	9.2
PUD	118.0	104.9	16.4	13.9	0.0	0.0	21.2	18.7	0.0	0.0	0.0	0.0	2.4	1.6	0.0	0.0	156.8	138.1
TP	318.3	271.8	78.3	69.2	0.0	0.0	50.0	43.8	0.3	0.3	0.0	0.0	12.6	8.0	0.0	0.0	456.6	390.5
PB	313.4	258.7	84.8	72.1	0.0	0.0	46.3	40.9	0.1	0.1	0.0	0.0	6.7	4.4	0.0	0.0	448.5	373.8
P+P	631.7	530.5	163.1	141.3	0.0	0.0	96.3	84.8	0.4	0.4	0.0	0.0	19.4	12.5	0.0	0.0	905.1	764.3

Anterra Energy Inc.
NI 51-101 FORECAST CASE
SUMMARY OF NET PRESENT VALUES OF FUTURE NET REVENUE – WITH CORPORATE TAX POOLS
Deloitte December 31, 2013 Forecast Pricing

Effective: December 31, 2013 Canada

	Before Income Taxes					After Income Taxes					Unit Value Before Income Tax
	0%	5%	10%	15%	20%	0%	5%	10%	15%	20%	Discounted at 10%
Reserves category	M$	M$	M$	M$	M$	M$	M$	M$	M$	M$	$/boe
Proved developed producing	43,681.8	33,541.0	28,069.2	24,495.4	21,924.0	43,681.8	33,541.0	28,069.2	24,495.4	21,924.0	18.33
Proved developed non-producing	1,773.7	1,542.4	1,361.0	1,215.9	1,098.0	1,773.7	1,542.4	1,361.0	1,215.9	1,098.0	23.60
Proved undeveloped	42,769.7	26,438.8	18,460.1	13,694.7	10,507.7	36,097.0	23,241.2	16,629.7	12,539.7	9,734.2	21.25
Proved	88,225.2	61,522.2	47,890.3	39,406.1	33,529.7	81,552.5	58,324.5	46,059.9	38,251.1	32,756.1	19.49
Probable	90,327.2	54,291.0	36,735.3	26,250.5	19,315.4	67,684.5	40,298.8	26,878.2	18,845.2	13,528.4	15.62
Proved plus probable	178,552.4	115,813.2	84,625.6	65,656.6	52,845.1	149,237.0	98,623.4	72,938.1	57,096.3	46,284.5	17.59

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
Deloitte December 31, 2013 Forecast Pricing

Effective: December 31, 2013 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$
PDP	171,058.5	23,989.5	89,202.1	0.0	14,185.1	43,681.8	0.0	43,681.8
PDNP	7,096.8	1,967.1	3,305.7	50.3	0.0	1,773.7	0.0	1,773.7
PUD	91,028.8	11,639.5	22,705.7	13,220.7	693.2	42,769.7	6,672.7	36,097.0
TP	269,184.1	37,596.1	115,213.5	13,271.0	14,878.3	88,225.2	6,672.7	81,552.5
PB	266,021.8	45,877.5	102,915.6	25,334.0	1,567.6	90,327.2	22,642.7	67,684.5
P+P	535,206.0	83,473.6	218,129.1	38,605.0	16,445.9	178,552.4	29,315.4	149,237.0

*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
Deloitte December 31, 2013 Forecast Pricing

Effective: December 31, 2013 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	1,004.1	881.5	38.4	1,189.3	22,665.8	19.06
Proved developed non-producing	44.5	9.2	2.2	48.2	1,195.2	24.80
Proved undeveloped	660.3	665.4	9.9	781.1	17,300.1	22.15
Proved	1,708.8	1,556.2	50.5	2,081.7	41,161.1	19.77
Probable	1,627.8	1,452.4	27.8	1,897.7	32,404.5	17.08
Proved plus probable	3,336.6	3,008.6	78.3	3,916.4	73,565.7	18.78
Heavy Oil						
Proved developed producing	338.2	0.0	0.0	338.2	6,165.2	18.23
Proved developed non-producing	9.4	0.0	0.0	9.4	165.8	17.64
Proved undeveloped	87.7	0.0	0.0	87.7	1,160.0	13.23
Proved	435.3	0.0	0.0	435.3	7,491.0	17.21
Probable	453.7	0.0	0.0	453.7	4,325.4	9.53
Proved plus probable	889.0	0.0	0.0	889.0	11,816.4	13.29
Associated & Non-Associated Gas						
Proved developed producing	1.5	11.4	0.1	3.5	-761.8	-217.66
Proved developed non-producing	0.0	0.0	0.0	0.0	0.0	0.0
Proved undeveloped	0.0	0.0	0.0	0.0	0.0	0.0
Proved	1.5	11.4	0.1	3.5	-761.8	-217.66
Probable	0.4	2.9	0.0	0.9	5.4	6.00
Proved plus probable	1.8	14.4	0.1	4.3	-756.5	-175.93
Total						
Proved developed producing	1,343.7	893.0	38.4	1,530.9	28,069.2	18.33
Proved developed non-producing	53.9	9.2	2.2	57.7	1,361.0	23.60
Proved undeveloped	748.0	665.4	9.9	868.8	18,460.1	21.25
Proved	2,145.6	1,567.6	50.5	2,457.4	47,890.3	19.49
Probable	2,081.9	1,455.3	27.8	2,352.3	36,735.3	15.62
Proved plus probable	4,227.5	3,022.9	78.4	4,809.7	84,625.6	17.59

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

Opening Case: AJM Deloitte December 31, 2012 Forecast Pricing
Closing Case: Deloitte December 31, 2013 Forecast Pricing

Effective: December 31, 2013

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	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
Production	-70.7	0.0	-70.7	-39.6	0.0	-39.6	-192.7	0.0	-192.7	-5.6	0.0	-5.6
Technical revisions	-136.7	-362.2	-499.0	2.9	0.7	3.7	-235.1	-433.3	-668.4	-19.8	-15.0	-34.9
Extensions & improved recovery	48.8	385.9	434.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	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	1,197.2	832.0	2,029.2	510.8	523.8	1,034.6	1,100.4	1,084.6	2,185.0	56.1	27.1	83.2
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	2.7	0.5	3.2	0.8	0.1	0.9	0.2	-0.5	-0.2	0.0	0.0	0.0
Infill Drilling	48.0	18.0	66.0	0.0	0.0	0.0	166.2	93.4	259.6	7.9	4.4	12.3
Closing balance	2,003.1	1,972.3	3,975.4	493.0	533.6	1,026.6	1,786.6	1,646.0	3,432.6	79.6	42.2	121.8

Deloitte
Canadian Domestic Price Forecast
Base Case Forecast Effective December 31, 2013

					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	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	$28.28	$20.60	$37.83	$27.98	$23.71	$21.26	$14.35	n/a	$19.41	$19.02	$30.85	$1.87	$2.35	$1.71	$1.98	$1.74	$3.55	$2.59	$11.50
i	1998	0.7%	0.7%	0.675	$19.43	$14.38	$26.72	$20.08	$16.94	$14.63	$9.43	n/a	$11.97	$12.92	$22.35	$1.94	$2.80	$2.07	$2.00	$2.13	$2.85	$2.11	($6.51)
s	1999	1.8%	1.8%	0.648	$25.89	$19.29	$36.22	$27.41	$21.72	$20.29	$17.62	$8.09	$13.21	$14.39	$20.94	$2.48	$3.69	$2.75	$2.64	$2.61	$2.81	$2.10	$6.93
t	2000	2.6%	2.6%	0.674	$39.83	$30.22	$57.56	$44.33	$39.89	$34.46	$28.57	$14.10	$32.59	$36.51	$46.30	$4.51	$7.41	$5.62	$4.73	$5.05	$5.69	$4.32	$13.59
o	2001	2.5%	2.5%	0.646	$33.21	$25.87	$49.51	$39.17	$31.54	$25.12	$18.07	$17.20	$30.62	$30.49	$43.03	$5.39	$6.96	$5.42	$6.34	$6.10	$5.04	$3.93	($14.50)
r	2002	2.3%	2.3%	0.637	$32.66	$26.11	$49.69	$40.33	$35.52	$31.89	$27.63	$11.21	$20.92	$27.78	$41.22	$3.88	$5.24	$4.19	$4.09	$4.08	$4.20	$3.36	$12.74
i	2003	2.8%	2.8%	0.716	$37.92	$31.01	$52.40	$43.51	$37.47	$32.96	$27.35	$18.43	$32.31	$36.03	$45.18	$6.12	$8.17	$6.68	$6.42	$6.67	$6.70	$5.48	$40.99
c	2004	1.8%	1.8%	0.770	$49.27	$41.45	$62.00	$52.96	$45.76	$38.01	$30.44	$19.04	$35.20	$44.07	$55.49	$6.31	$7.79	$6.55	$6.52	$6.84	$7.43	$6.25	$40.82
a	2005	2.2%	2.2%	0.826	$66.06	$56.61	$79.67	$69.33	$57.39	$45.68	$33.77	$23.80	$43.23	$51.91	$74.67	$8.31	$10.25	$8.78	$8.22	$8.51	$10.40	$8.91	$40.99
l	2006	2.0%	2.0%	0.882	$75.35	$66.06	$82.39	$73.34	$62.42	$52.04	$39.68	$19.81	$44.11	$58.16	$78.19	$6.56	$7.46	$6.54	$6.57	$7.11	$7.70	$6.75	$19.51
	2007	2.1%	2.1%	0.935	$80.91	$72.38	$84.87	$77.09	$65.18	$53.86	$39.75	$18.41	$49.77	$59.40	$81.67	$6.20	$7.20	$6.44	$6.40	$6.54	$7.79	$6.97	$38.32
	2008	2.4%	2.4%	0.943	$108.93	$99.58	$110.78	$102.83	$93.26	$83.97	$73.17	$22.61	$56.94	$83.56	$109.80	$7.88	$8.92	$8.15	$8.21	$8.19	$9.71	$8.88	$304.51
	2009	0.3%	0.3%	0.880	$65.98	$61.78	$69.63	$66.21	$62.77	$59.90	$54.49	$11.60	$34.56	$56.29	$69.59	$3.84	$4.23	$3.96	$4.16	$4.14	$4.17	$3.90	($4.97)
	2010	1.8%	1.8%	0.971	$84.55	$79.42	$81.56	$77.79	$73.48	$68.16	$60.59	$11.52	$45.13	$68.78	$84.00	$3.76	$4.26	$4.00	$4.00	$3.90	$4.67	$4.38	$57.81
	2011	2.9%	2.9%	1.012	$99.27	$94.91	$98.45	$95.58	$88.21	$78.50	$69.56	$10.30	$52.44	$87.06	$105.31	$3.46	$3.80	$3.63	$3.34	$3.33	$4.17	$3.99	$79.49
	2012	1.5%	1.5%	1.001	$95.52	$94.07	$87.84	$86.51	$80.83	$74.34	$63.99	$6.73	$30.75	$75.44	$99.63	$2.25	$2.43	$2.39	$2.30	$2.15	$2.80	$2.76	$77.95
2	12 Mths H	1.1%	1.1%	0.971	$97.83	$97.83	$93.21	$93.21	$87.36	$76.23	$65.43	$8.63	$34.59	$76.64	$104.86	$2.89	$3.20	$3.20	$3.04	$3.01	$3.71	$3.71	$70.22
0	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
1																							
3	Avg.	n/a	n/a	0.971	$97.83	$97.83	$93.21	$93.21	$87.36	$76.23	$65.43	$8.63	$34.59	$76.64	$104.86	$2.89	$3.20	$3.20	$3.04	$3.01	$3.71	$3.71	$70.22
F	2014	0.0%	0.0%	0.940	$95.00	$95.00	$95.75	$95.75	$88.75	$80.00	$68.75	$10.20	$33.50	$76.60	$105.35	$3.45	$3.70	$3.70	$3.40	$3.65	$4.10	$4.10	$80.00
o	2015	2.0%	2.0%	0.940	$90.00	$91.80	$90.45	$92.30	$84.85	$76.30	$66.30	$10.95	$32.30	$73.85	$101.55	$3.70	$3.85	$3.95	$3.65	$3.90	$4.15	$4.25	$81.60
r	2016	2.0%	2.0%	0.940	$88.00	$91.55	$91.45	$95.20	$86.80	$77.35	$68.20	$11.40	$52.35	$76.15	$104.70	$3.85	$3.95	$4.10	$3.80	$4.05	$4.25	$4.40	$83.25
e	2017	2.0%	2.0%	0.940	$86.00	$91.25	$89.35	$94.80	$86.00	$76.80	$68.80	$12.00	$52.15	$75.85	$104.30	$4.05	$4.05	$4.30	$4.00	$4.25	$4.35	$4.60	$84.90
c	2018	2.0%	2.0%	0.940	$85.00	$92.00	$88.30	$95.60	$85.80	$75.65	$68.60	$12.75	$52.60	$76.50	$105.15	$4.30	$4.20	$4.55	$4.25	$4.50	$4.50	$4.85	$86.60
a	2019	2.0%	2.0%	0.940	$85.00	$93.85	$88.30	$97.50	$87.00	$76.50	$70.50	$13.65	$53.65	$78.00	$107.25	$4.60	$4.40	$4.85	$4.55	$4.80	$4.70	$5.20	$88.35
s	2020	2.0%	2.0%	0.940	$85.00	$95.70	$88.30	$99.45	$88.25	$78.45	$72.45	$14.85	$54.70	$79.55	$109.40	$5.00	$4.65	$5.25	$4.95	$5.20	$4.95	$5.55	$90.10
t	2021	2.0%	2.0%	0.940	$85.00	$97.65	$88.30	$101.45	$87.95	$79.45	$73.45	$16.20	$55.80	$81.15	$111.60	$5.45	$4.95	$5.70	$5.40	$5.65	$5.25	$6.05	$91.90
	2022	2.0%	2.0%	0.940	$85.00	$99.60	$88.30	$103.45	$88.45	$81.45	$75.45	$17.40	$56.90	$82.75	$113.80	$5.85	$5.20	$6.10	$5.80	$6.05	$5.50	$6.45	$93.75
	2023	2.0%	2.0%	0.940	$85.00	$101.60	$88.30	$105.55	$90.55	$83.55	$77.55	$18.45	$58.05	$84.45	$116.10	$6.20	$5.40	$6.45	$6.15	$6.40	$5.70	$6.80	$95.65
	2024	2.0%	2.0%	0.940	$85.00	$103.60	$88.30	$107.65	$92.65	$85.65	$79.65	$19.95	$59.20	$86.10	$118.40	$6.70	$5.70	$6.95	$6.65	$6.90	$6.00	$7.30	$97.55
	2025	2.0%	2.0%	0.940	$85.00	$105.70	$88.30	$109.80	$94.80	$87.80	$81.80	$20.40	$60.40	$87.85	$120.80	$6.85	$5.70	$7.10	$6.80	$7.05	$6.00	$7.45	$99.50
	2026	2.0%	2.0%	0.940	$85.00	$107.80	$88.30	$112.00	$97.00	$90.00	$84.00	$20.85	$61.60	$89.60	$123.20	$7.00	$5.70	$7.25	$6.95	$7.20	$6.00	$7.60	$101.50
	2027	2.0%	2.0%	0.940	$85.00	$109.95	$88.30	$114.25	$99.25	$92.25	$86.25	$21.15	$62.85	$91.40	$125.70	$7.10	$5.70	$7.35	$7.05	$7.30	$6.00	$7.75	$103.55
	2028	2.0%	2.0%	0.940	$85.00	$112.15	$88.30	$116.50	$101.50	$94.50	$88.50	$21.60	$64.10	$93.20	$128.15	$7.25	$5.70	$7.50	$7.20	$7.45	$6.00	$7.90	$105.60
	2029	2.0%	2.0%	0.940	$85.00	$114.40	$88.30	$118.85	$103.85	$96.85	$90.85	$22.05	$65.35	$95.10	$130.75	$7.40	$5.70	$7.65	$7.35	$7.60	$6.00	$8.10	$107.70
	2030	2.0%	2.0%	0.940	$85.00	$116.70	$88.30	$121.20	$106.20	$99.20	$93.20	$22.50	$66.65	$96.95	$133.30	$7.55	$5.70	$7.80	$7.50	$7.75	$6.00	$8.25	$109.85
	2031	2.0%	2.0%	0.940	$85.00	$119.00	$88.30	$123.65	$108.65	$101.65	$95.65	$23.10	$68.00	$98.90	$136.00	$7.75	$5.70	$8.00	$7.70	$7.95	$6.00	$8.40	$112.05
	2032	2.0%	2.0%	0.940	$85.00	$121.40	$88.30	$126.10	$111.10	$104.10	$98.10	$23.55	$69.35	$100.90	$138.70	$7.90	$5.70	$8.15	$7.85	$8.10	$6.00	$8.55	$114.30
	2033	2.0%	2.0%	0.940	$85.00	$123.85	$88.30	$128.65	$113.65	$106.65	$100.65	$24.00	$70.75	$102.90	$141.50	$8.05	$5.70	$8.30	$8.00	$8.25	$6.00	$8.75	$116.60
	2032+	2.0%	2.0%	0.940	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%	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.

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, 2013. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2013, 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, 2013 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 LLP	Anterra Energy Inc. Reserve estimation and economic evaluation December 31, 2013	Canada	-	$84,625.60	-	$84,625.60

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 LLP
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 10, 2014

NI 51-101 FORM F3

REPORT OF MANAGEMENT AND DORECTORS ON RESERVE DATA AND OTHER INFORMATION

Terms to which a meaning is ascribed in National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities have the same meaning herein.

Management of Anterra Energy Inc. (the **"Corporation"**) is responsible for the preparation and disclosure of information with respect to the Corporation's oil and gas activities in accordance with securities regulatory requirements. This information include reserves data, which are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2013, estimated using forecast prices and costs.

An independent qualified reserves evaluator has evaluated the Corporation'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 Corporation has:

a) reviewed the Corporation's procedures for providing information to the independent qualified reserve 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 reserves evaluator.

The Audit and reserves Committee of the Board of Directors has reviewed the Corporation'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 evaluator on the reserves data; and
c) The content and filing of this report.

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

(signed) ***"Gang Fang"***
Dr. Gang Fang
President, CEO and Director

(signed) ***"Robert D. McCuaig"***
Robert D. McCuaig, P.Eng.
Executive Vice President

(signed) ***"Owen C. Pinnell"***
Owen C. Pinnell, P.Eng.
Chairman and Director

(signed) ***"Ross O. Drysdale"***
Ross O. Drysdale
Director

Dated: April 7, 2014