MOUNT DAKOTA ENERGY CORP.

STATEMENT OF RESERVE DATA AND OTHER OIL AND GAS INFORMATION

EFFECTIVE JANUARY 31, 2014

ABBREVIATIONS AND CONVERSION

In this document, the abbreviations set forth below have the following meanings:

bbl barrel	Mcf thousand cubic feet
Mbbl thousand barrels	MMcf million cubic feet
MMbbl million barrels	Mcf/d thousand cubic feet per day
bbl/d barrels per day	MMBtu million British Thermal Units
NGLs natural gas liquids	Bcf billion cubic feet
boe/d barrels of oil equivalent per day	GJ gigajoule

AECO	EnCana Corp.'s natural gas storage facility located at Suffield, Alberta.
API	American Petroleum Institute
°API	an indication of the specific gravity of crude oil measured on the API gravity scale. Liquid petroleum with a specified gravity of 28° API or higher is generally referred to as light crude oil.
boe	barrel of oil equivalent on the basis of 1 boe to 6 Mcf of natural gas. Boe's may be misleading, particularly if used in isolation. A boe conversion ratio of 1 boe for 6 Mcf is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.
M$	thousands of dollars
MM$	millions of dollars
WTI	West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma for crude oil of standard grade

NOTES AND DEFINITIONS

The determination of oil and gas reserves involves the preparation of estimates that have an inherent degree of associated uncertainty. Categories of proved, probable and possible reserves have been established to reflect the level of these uncertainties and to provide an indication of the probability of recovery.

The estimation and classification of reserves requires the application of professional judgment combined with geological and engineering knowledge to assess whether or not specific reserves classification criteria have been satisfied. Knowledge of concepts including uncertainty and risk, probability and statistics, and deterministic and probabilistic estimation methods is required to properly use and apply reserves definitions.

"Reserves" are estimated remaining quantities of oil and natural gas and related substances anticipated to be economically recoverable from discovered resources, from a given date forward, based on (a) analysis of drilling, geological, geophysical, and engineering data; (b) the use of established technology; and (c) specified economic conditions, which are generally accepted as being reasonable and shall be 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.

"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 (e.g., 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. In multi-well pools, it may be appropriate to allocate total pool reserves between the developed and undeveloped categories or to sub-divide the developed reserves for the pool between developed producing and developed non-producing. This allocation should be based on the estimator's assessment as to the reserves that will be recorded from specific wells, facilities and completion intervals in the pool and their respective development and production status.

"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 + probable reserves. The following terms, used in the preparation of the Evaluator's Report (as defined herein) and this document have the following meanings:

"Associated gas" means the gas cap overlying a crude oil accumulation in a reservoir.

"**Constant prices and costs"** means prices and costs used in an estimate that are:

(a) the Company's prices and costs as at the effective date of the estimation, held constant throughout the estimated lives of the properties to which the estimate applies;
(b) if, and only to the extent that, there are fixed or presently determinable future prices or costs to which the Company is legally bound by a contractual or other obligation to supply a physical product, including those for an extension period of a contract that is likely to be extended, those prices or costs rather than the prices and costs referred to in paragraph (a).

For the purpose of paragraph (a), the reporting issuer's prices will be the posted price for oil and the spot price for gas, after historical adjustments for transportation, gravity and other factors.

"**Company"** or **"MDEC"** means MOUNT DAKOTA ENERGY CORP.

"Crude oil" or **"Oil"** means a mixture that consists mainly of pentanes and heavier hydrocarbons, which may contain sulphur and other non-hydrocarbon compounds, that is recoverable at a well from an underground reservoir and that is liquid at the conditions under which its volume is measured or estimated. It does not include solution gas or natural gas liquids.

"Development costs" means costs incurred to obtain access to reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas from the reserves. More specifically, development costs, including applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

(a) gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines and power lines, to the extent necessary in developing the reserves;

(b) drill and equip development wells, development type stratigraphic test wells and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment and the wellhead assembly;

(c) acquire, construct and install production facilities such as flow lines, separators, treaters, heaters, manifolds, measuring devices and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems; and

(d) provide improved recovery systems.

"Development well" means a well drilled inside the established limits of an oil or gas reservoir, or in close proximity to the edge of the reservoir, to the depth of a stratigraphic horizon known to be productive.

"Exploration costs" means costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects that may contain oil and gas reserves, including costs of drilling exploratory wells and exploratory type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property (sometimes referred to in part as "prospecting costs") and after acquiring the property. Exploration costs, which include applicable operating costs of support equipment and facilities and other costs of exploration activities, are:

(a) costs of topographical, geochemical, geological and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews and others conducting those studies (collectively sometimes referred to as "geological and geophysical costs");

(b) costs of carrying and retaining unproved properties, such as delay rentals, taxes (other than income and capital taxes) on properties, legal costs for title defense, and the maintenance of land and lease records;

(c) dry hole contributions and bottom hole contributions;

(d) costs of drilling and equipping exploratory wells; and

(e) costs of drilling exploratory type stratigraphic test wells.

"Exploratory well" means a well that is not a development well, a service well or a stratigraphic test well.

"Field" means an area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field that are separated vertically by intervening impervious strata or laterally by local geologic barriers, or both. Reservoirs that are associated by being in overlapping or adjacent fields may be treated as a single or common operational field. The geological terms "structural feature" and "stratigraphic condition" are intended to denote localized geological features, in contrast to broader terms such as "basin", "trend", "province", "play" or "area of interest".

"Future prices and costs" means future prices and costs that are:

(a) generally accepted as being a reasonable outlook of the future;

(b) if, and only to the extent that, there are fixed or presently determinable future prices or costs to which the Company issuer is legally bound by a contractual or other obligation to supply a physical product, including those for an extension period of a contract that is likely to be extended, those prices or costs rather than the prices and costs referred to in paragraph (a).

"Future income tax expenses" means future income tax expenses estimated (generally, year-by year):

(a) making appropriate allocations of estimated unclaimed costs and losses carried forward for tax purposes, between oil and gas activities and other business activities;

(b) without deducting estimated future costs (for example, Crown royalties) that are not deductible in computing taxable income;

(c) taking into account estimated tax credits and allowances (for example, royalty tax credits); and

(d) applying to the future pre-tax net cash flows relating to the reporting issuer's oil and gas activities the appropriate year-end statutory tax rates, taking into account future tax rates already legislated.

"Future net revenue" means the estimated net amount to be received with respect to the development and production of reserves (including synthetic oil, coal bed methane and other non-conventional reserves) estimated using constant prices and costs or forecast prices and costs.

"Gross" means:

(a) in relation to the Company's interest in production or reserves, its "Company gross reserves", which are its working interest (operating or non-operating) share before deduction of royalties and without including any royalty interests of the Company;

(b) in relation to wells, the total number of wells in which the Company has an interest, and

(c) in relation to properties, the total area of properties in which the Company has an interest.

"Natural gas" means the lighter hydrocarbons and associated non-hydrocarbon substances occurring naturally in an underground reservoir, which under atmospheric conditions are essentially gases but which may contain natural gas liquids. Natural gas can exist in a reservoir either dissolved in crude oil (solution gas) or in a gaseous phase (associated gas or non-associated gas). Non-hydrocarbon substances may include hydrogen sulphide, carbon dioxide and nitrogen.

"Natural gas liquids" means those hydrocarbon components that can be recovered from natural gas as liquids including, but not limited to, ethane, propane, butanes, pentanes plus, condensate and small quantities of non-hydrocarbons.

“Net” means:

(a) in relation to the Company’s interest in production or reserves its working interest (operating or non operating) share after deduction of royalty obligations, plus its royalty interests in production or reserves;

(b) in relation to the Company’s interest in wells, the number of wells obtained by aggregating the Company’s working interest in each of its gross wells; and

(c) in relation to the Company’s interest in a property, the total area in which the Company has an interest multiplied by the working interest owned by the Company.

“Non-associated gas” means an accumulation of natural gas in a reservoir where there is no crude oil.

“Operating costs” or “production costs” means costs incurred to operate and maintain wells and related equipment and facilities, including applicable operating costs of support equipment and facilities and other costs of operating and maintaining those wells and related equipment and facilities.

“Production” means recovering, gathering, treating, field or plant processing (for example, processing gas to extract natural gas liquids) and field storage of oil and gas.

“Property” includes:

(a) fee ownership or a lease, concession, agreement, permit, licence or other interest representing the right to extract oil or gas subject to such terms as may be imposed by the conveyance of that interest;

(b) royalty interests, production payments payable in oil or gas, and other non-operating interests in properties operated by others; and

(c) an agreement with a foreign government or authority under which a reporting issuer participates in the operation of properties or otherwise serves as “producer” of the underlying reserves (in contrast to being an independent purchaser, broker, dealer or importer).

A property does not include supply agreements, or contracts that represent a right to purchase, rather than extract, oil or gas.

“Property acquisition costs” means costs incurred to acquire a property (directly by purchase or lease or indirectly by acquiring another corporate entity with an interest in the property), including:

(a) costs of lease bonuses and options to purchase or lease a property;

(b) the portion of the costs applicable to hydrocarbons when land including rights to hydrocarbons is purchased in fee;

(c) brokers’ fees, recording and registration fees, legal costs and other costs incurred in acquiring properties.

“Proved property” means a property or part of a property to which reserves have been specifically attributed.

“Reservoir” means a porous and permeable underground formation containing a natural accumulation of producible oil or gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

“Service well” means a well drilled or completed for the purpose of supporting production in an existing field. Wells in this class are drilled for the following specific purposes: gas injection (natural gas, propane, butane or flue gas), water injection, steam injection, air injection, salt-water disposal, water supply for injection, observation, or injection for combustion.

“Solution gas” means natural gas dissolved in crude oil.

“Stratigraphic test well” means a drilling effort, geologically directed, to obtain information pertaining to a specific geologic condition. Ordinarily, such wells are drilled without the intention of being completed for hydrocarbon production. They include wells for the purpose of core tests and all types of expendable holes related to hydrocarbon exploration. Stratigraphic test wells are classified as (a) exploratory type” if not drilled into a proved property; or (b) "development type", if drilled into a proved property. Development type stratigraphic wells are also referred to as "evaluation wells".

"Support equipment and facilities" means equipment and facilities used in oil and gas activities, including seismic equipment, drilling equipment, construction and grading equipment, vehicles, repair shops, warehouses, supply points, camps, and division, district or field offices.

"Unproved property" means a property or part of a property to which no reserves have been specifically attributed.

"Well abandonment costs" means costs of abandoning a well and preparing the surface lease to commence reclamation.

"Well abandonment and reclamation costs" means costs of abandoning a well and surface lease reclamation. They do not include costs of abandoning the gathering system, suspended wells, batteries, plants, or processing facilities.

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

In accordance with National Instrument 51-101 Standards of Disclosure for Oil and Gas Activities, Sproule Associates Limited (the "Evaluators") prepared a report (the "Report") dated January 31, 2014. The Report evaluated, as at January 31, 2014, MOUNT DAKOTA ENERGY CORP.'s (the "Company") oil reserves in Alsike, Alberta. The tables below are a summary of the oil, reserves of the Company and the net present value of future net revenue attributable to such reserves as evaluated in the Evaluators' Reports based on forecast price and cost assumptions. The tables summarize the data contained in the Evaluators' Report and as a result may contain slightly different numbers than such report due to rounding. Also due to rounding, certain columns may not add exactly.

The net present value of future net revenue attributable to the Company's reserves is stated without provision for interest costs and general and administrative costs, but after providing for estimated royalties, production costs, development costs, other income, future capital expenditures, and well abandonment costs for only those wells assigned reserves by Evaluators. It should not be assumed that the undiscounted or discounted net present value of future net revenue attributable to the Company's reserves estimated by Evaluators represent the fair market value of those reserves. Other assumptions and qualifications relating to costs, prices for future production and other matters are summarized herein. The recovery and reserve estimates of the Company's oil reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual reserves may be greater than or less than the estimates provided herein.

The Evaluators' Reports are based on certain factual data supplied by the Company and Evaluator's opinion of reasonable practice in the industry. The extent and character of ownership and all factual data pertaining to the Company's petroleum properties and contracts (except for certain information residing in the public domain) were supplied by the Company to the Evaluators and accepted without any further investigation. The Evaluators accepted this data as presented and neither title searches nor field inspections were conducted.

All properties are in Canada.

All monetary values are expressed in Canadian dollars unless stated otherwise.

Table 1
NI 51-101
Summary of Oil and Gas Reserves
as of January 31, 2014
Forecast Prices and Costs

Reserves

	Light and Medium Oil		Heavy Oil		Bitumen		Synthetic Oil		Shale Oil		Non Associated Gas		Coal Bed Methane		Shale Gas		Solution Gas		Natural Gas Liquids	
Reserve Category	Gross (Mbbl)	Net (Mbbl)	Gross (Mbbl)	Net (Mbbl)	Gross (Mbbl)	Net (Mbbl)	Gross (Mbbl)	Net (Mbbl)	Gross (Mbbl)	Net (Mbbl)	Gross (MMcf)	Net (MMcf)	Gross (MMcf)	Net (MMcf)	Gross (MMcf)	Net (MMcf)	Gross (MMcf)	Net (MMcf)	Gross (Mbbl)	Net (Mbbl)
Proved																				
Developed Producing	8.6	8.5																		
Developed Non-Producing																				
Undeveloped																				
Total Proved	**8.6**	**8.5**																		
Probable	5.4	5.2																		
Total Proved Plus Probable	**14.0**	**13.7**																		

Reference: Item 2.1(1) of Form 51-101F1

Table 2 NI 51-101 Summary of Net Present Values of Future Net Revenue as of January 31, 2014 Forecast Prices and Costs											
	Net Present Values of Future Net Revenue										
	Before Income Taxes Discounted at (%/Year)					**After Income Taxes Discounted at (%/Year)**					**Bef Tax Net Val**
Reserves Category	**0 (M$)**	**5 (M$)**	**10 (M$)**	**15 (M$)**	**20 (M$)**	**0 (M$)**	**5 (M$)**	**10 (M$)**	**15 (M$)**	**20 (M$)**	**10%/yr ($/boe)**
Proved											
Developed Producing	296	265	238	216	197	296	265	238	216	197	28.07
Developed Non-Producing											
Undeveloped											
Total Proved	**296**	**265**	**238**	**216**	**197**	**296**	**265**	**238**	**216**	**197**	**28.07**
Probable	221	157	114	86	66	221	157	114	86	66	22.14
Total Proved Plus Probable	**517**	**422**	**353**	**302**	**263**	**517**	**422**	**353**	**302**	**263**	**25.83**

Reference: Item 2.1(2) of Form 51-101F1

Notes: NPV of FNR includes all resource income:

- Sale of oil, gas, by-product reserves
- Processing third party reserves
- Other income

Unit Values are based on net reserve volumes

Barrel of Oil Equivalent (BOE): 6 Mcf = 1 BOE

Table 3
NI 51-101
Total Future Net Revenue
(Undiscounted)
as of January 31, 2014
Forecast Prices and Costs

Reserves Category	Revenue (M$)	Royalties (M$)	Operat-ing Costs (M$)	Develop-ment Costs (M$)	Well Abandon-ment / Other Costs (M$)	Future Net Revenue Before Income Taxes (M$)	Income Taxes (M$)	Future Net Revenue After Income Taxes (M$)
Proved	790	12	447		35	296	0	296
Proved Plus Probable	1,339	30	752		39	517	0	517

Reference: Item 2.1(3)(b) of Form 51-101F1

Royalties include Saskatchewan Capital Surtax, if applicable

Table 4
NI 51-101
Net Present Value of Future Net Revenue
By Production Group
as of January 31, 2014
Forecast Prices and Costs

Reserves Category	Production Group	Future Net Revenue Before Income Taxes (Discounted at 10%/Year) (M$)	Unit Value Before Income Taxes (Discounted at 10%/Year) ($/boe)
Proved	Light and Medium Crude Oil (including solution gas and associated by-products)	238	28.07
	Heavy Oil (including solution gas and associated by-products)		
	Bitumen (including solution gas and associated by-products)		
	Synthetic Oil (including solution gas and associated by-products)		
	Shale Oil (including solution gas and associated by-products)		
	Natural Gas (including associated by-products)		
	Coal Bed Methane (including associated by-products)		
	Shale Gas (including associated by-products)		
	Other Income		
Proved Plus Probable	Light and Medium Crude Oil (including solution gas and associated by-products)	353	25.83
	Heavy Oil (including solution gas and associated by-products)		
	Bitumen (including solution gas and associated by-products)		
	Synthetic Oil (including solution gas and associated by-products)		
	Shale Oil (including solution gas and associated by-products)		
	Natural Gas (including associated by-products)		
	Coal Bed Methane (including associated by-products)		
	Shale Gas (including associated by-products)		
	Other Income		

Reference: Item 2.1(3)(c) of Form 51-101F1

Notes: Unit Values are based on net reserve volumes

Barrel of Oil Equivalent (BOE): 6 Mcf = 1 BOE

Table 5
NI 51-101
Summary of Pricing and Inflation Rate Assumptions as of January 31, 2014
Forecast Prices and Costs

Year	WTI Cushing Oklahoma ($US/bbl)	Edmonton Par Price 40° API ($Cdn/bbl)	Cromer LSB 35° API ($Cdn/bbl)	Natural Gas[1] AECO Gas Prices ($Cdn/MMBtu)	Pentanes Plus FOB Edmonton ($Cdn/bbl)	Butanes F.O.B. Edmonton ($Cdn/bbl)	Inflation Rate[2] (%/Yr)	Exchange Rate[3] ($US/$Cdn)
Historical								
2009	61.63	66.20	63.86	4.19	68.13	49.34	2.0	0.880
2010	79.43	77.80	76.57	4.16	84.21	57.99	1.2	0.971
2011	95.00	95.16	89.68	3.72	104.12	70.93	1.6	1.012
2012	94.19	86.57	84.42	2.43	100.76	64.48	1.3	1.001
2013	97.98	93.24	91.59	3.13	104.86	70.29	0.8	0.971
Forecast								
2014	93.31	92.81	90.81	4.16	103.69	69.17	1.5	0.925
2015	86.38	85.91	83.91	4.03	95.99	64.03	1.5	0.925
2016	81.87	84.08	82.08	4.02	93.94	62.67	1.5	0.925
2017	92.81	100.33	98.33	4.88	112.10	74.78	1.5	0.925
2018	95.52	103.27	101.27	5.01	115.38	76.97	1.5	0.925
2019	96.96	104.82	102.82	5.09	117.11	78.12	1.5	0.925
2020	98.41	106.39	104.39	5.18	118.86	79.30	1.5	0.925
2021	99.89	107.98	105.98	5.26	120.65	80.49	1.5	0.925
2022	101.38	109.60	107.60	5.35	122.45	81.69	1.5	0.925
2023	102.91	111.25	109.25	5.43	124.29	82.92	1.5	0.925
2024	104.45	112.92	110.92	5.52	126.16	84.16	1.5	0.925
Thereafter				Escalation Rate of 1.5%				

(1) This summary table identifies benchmark reference pricing schedules that might apply to a *reporting issuer*.
(2) Inflation rates for forecasting prices and costs.
(3) Exchange rates used to generate the benchmark reference prices in this table.

Notes:

Product sale prices will reflect these reference prices with further adjustments for quality and transportation to point of sale.

Reference Item 3.2 of Form 51-101F1

Table 5 **NI 51-101** **Summary of Pricing and Inflation Rate Assumptions as of January 31, 2014** ***Forecast Prices and Costs***								
Year	**WTI Cushing Oklahoma ($US/bbl)**	**Edmonton Par Price 40° API ($Cdn/bbl)**	**Cromer LSB 35° API ($Cdn/bbl)**	**Natural Gas[1] AECO Gas Prices ($Cdn/MMBtu)**	**Pentanes Plus FOB Edmonton ($Cdn/bbl)**	**Butanes F.O.B. Edmonton ($Cdn/bbl)**	**Inflation Rate[2] (%/Yr)**	**Exchange Rate[3] ($US/$Cdn)**
Historical								
2009	61.63	66.20	63.86	4.19	68.13	49.34	2.0	0.880
2010	79.43	77.80	76.57	4.16	84.21	57.99	1.2	0.971
2011	95.00	95.16	89.68	3.72	104.12	70.93	1.6	1.012
2012	94.19	86.57	84.42	2.43	100.76	64.48	1.3	1.001
2013	97.98	93.24	91.59	3.13	104.86	70.29	0.8	0.971
Forecast								
2014	93.31	92.81	90.81	4.16	103.69	69.17	1.5	0.925
2015	86.38	85.91	83.91	4.03	95.99	64.03	1.5	0.925
2016	81.87	84.08	82.08	4.02	93.94	62.67	1.5	0.925
2017	92.81	100.33	98.33	4.88	112.10	74.78	1.5	0.925
2018	95.52	103.27	101.27	5.01	115.38	76.97	1.5	0.925
2019	96.96	104.82	102.82	5.09	117.11	78.12	1.5	0.925
2020	98.41	106.39	104.39	5.18	118.86	79.30	1.5	0.925
2021	99.89	107.98	105.98	5.26	120.65	80.49	1.5	0.925
2022	101.38	109.60	107.60	5.35	122.45	81.69	1.5	0.925
2023	102.91	111.25	109.25	5.43	124.29	82.92	1.5	0.925
2024	104.45	112.92	110.92	5.52	126.16	84.16	1.5	0.925
Thereafter	Escalation Rate of 1.5%							

(1) This summary table identifies benchmark reference pricing schedules that might apply to a *reporting issuer*.
(2) Inflation rates for forecasting prices and costs.
(3) Exchange rates used to generate the benchmark reference prices in this table.

Notes:

Product sale prices will reflect these reference prices with further adjustments for quality and transportation to point of sale.

Reference Item 3.2 of Form 51-101F1

5.1 UNDEVELOPED RESERVES

The following discussion generally describes the basis on which the Company attributes Proved and Probable Undeveloped Reserves and its plans for developing those Undeveloped Reserves.

	L&M Oil		Heavy Oil		A&NA Gas	
Proved	1st Attributed	Booked	1st Attributed	Booked	1st Attributed	Booked
Undeveloped	Mbbl	Mbbl	Mbbl	Mbbl	MMcf	MMcf
Prior to 2014	nil	nil	nil	nil	nil	nil
2014	nil	nil	nil	nil	nil	nil
Probable	1st Attributed	Booked	1st Attributed	Booked	1st Attributed	Booked
Undeveloped	Mbbl	Mbbl	Mbbl	Mbbl	MMcf	MMcf
Prior to 2014	nil	nil	nil	nil	nil	nil
2014	nil	nil	nil	nil	nil	nil

Proved undeveloped reserves are assigned in accordance with COGE and are predominantly those reserves tested or indicated by analogy to be productive.

The Company has no proved undeveloped and probable undeveloped reserves allocated to the Alsike field.

Probable undeveloped reserves are generally those reserves tested or indicated by analogy to be productive, infill drilling locations and lands contiguous to production.

The Company currently has no plans for further development in the Alsike field.

5.2 SIGNIFICANT FACTORS OR UNCERTAINTIES AFFECTING RESERVES DATA

The estimation of reserves requires significant judgment and decisions based on available geological, geophysical, engineering, and economic data. These estimates can change substantially as additional information from ongoing development activities and production performance becomes available and as economic and political conditions impact oil and gas prices and costs change. The Company's estimates are based on current production forecasts, prices and economic conditions. All of the Company's reserves in Alberta are evaluated by an independent engineering firm, Sproule Associates Limited., an independent engineering firm. As circumstances change and additional data becomes available, reserve estimates also change. Based on new information, reserve estimates are reviewed and revised, either upward or downward, as warranted. Although every reasonable effort has been made by the Company to ensure that reserve estimates are accurate, revisions arises as new information becomes available. As new geological, production and economic information is incorporated into the process of estimating reserves the accuracy of the reserve estimates improves.

5.3 FUTURE DEVELOPMENT COSTS

There are no future development costs allocated for the Alsike field at this time.

6.1 OIL AND GAS PROPERTIES AND WELLS

Alsike, Alberta

The Company has 1 well (*Alsike 1*) producing oil from the Banff formation. The Company is also test producing a well (*Alsike 2*) also in the Banff formation. The Alsike 2 is located a section away from the Alsike 1. The Company has a 100% interest in the Alsike 1 and a 75% working interest in the Alsike 2.

6.2 PROPERTIES WITH NO ATTRIBUTED RESERVES

The Company holds three quarter sections in the Alsike field contiguous with the Alsike 1 well. The Alsike 2 test well is on one of the three quarter sections. No reserves have been attributed to the three quarter sections.

6.3 FORWARD CONTRACTS

The Company may, from time to time, enter into fixed price contracts and derivative financial instruments with respect to oil and gas sales, in order to secure a certain amount of cash flow to protect a level of capital spending. The Company has not entered into any forward contracts.

6.4 ADDITIONAL INFORMATION CONCERNING ABANDONMENT & RECLAMATION COSTS

Mount Dakota estimates well abandonment costs on an area-by-area basis. The estimated total abandonment costs included in the Evaluator Report for the properties included under the proved reserves category is $30,000.

6.5 TAX HORIZON

The Company was not required to pay income taxes for the period ended January 31, 2014. Taxes payable beyond 2014 will become a function of commodity prices, production volumes, capital expenditures and current tax pools available to offset taxable income. Based on a strategy of reinvesting internally generated cash flow in an exploration and development program and based on commodity prices used in the evaluators reports, combined with its current tax pools, the Company estimates that it will not be required to pay income taxes in the forecasted period.

6.6 COSTS INCURRED

There were no capital expenditures made by the Company on oil and natural gas properties for the period ended January 31, 2014. All of the capital expenditures on the Company's properties occurred in previous years. The Company is test producing the Alsike 2 to determine the economic viability of the well.

6.7 EXPLORATION AND DEVELOPMENT ACTIVITIES

The Company had no exploration or development activities during the period ending January 31, 2014.

6.8 PRODUCTION ESTIMATES

	L&M Oil bbl/d		**Heavy Oil bbl/d**		**Natural Gas Mcf/d**		**NGL's bbl/d**		**Net boe/d**
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	
Total Proved	5	5	-	-	-	-	-	-	5
Probable	-	-	-	-	-	-	-	-	-
Proved Plus Probable	-	-	-	-	-	-	-	-	5

The Alsike, Alberta field accounts for 100% of the estimated production.

6.9 PRODUCTION HISTORY

The following table sets forth certain information in respect of production, product prices received, royalties, production costs and netbacks received by Mount Dakota for each quarter of its most recently completed financial period:

	2013			2014
	Quarter 1 April 30	Quarter 2 July 31	Quarter 3 October 31	Quarter 4 January 31
Average Production				
L&M Oil (bbl/d)	3	5	5	5
Heavy Oil (bbl/d)	-	-	-	-
Natural Gas (Mcf/d)	-	-	-	-
NGL's (bbl/d)	-	-	-	-
Selling Prices				
L&M Oil ($/bbl)	70	81	85	64
Heavy Oil (bbl/d)	-	-	-	-
Natural Gas ($/Mcf)	-	-	-	-
NGL's ($/bbl)	-	-	-	-
Royalties*				
L&M Oil ($/bbl)	-	-	-	-
Heavy Oil (bbl/d)	-	-	-	-
Natural Gas ($/Mcf)	-	-	-	-
NGL's ($/bbl)	-	-	-	-
Production Costs				
L&M Oil ($/bbl)	67	39	34	35
Heavy Oil (bbl/d)	-	-	-	-
Natural Gas ($/Mcf)	-	-	-	-
NGL's ($/bbl)	-	-	-	-
Netbacks				
L&M Oil ($/bbl)	3	42	51	29
Heavy Oil (bbl/d)	-	-	-	-
Natural Gas ($/Mcf)	-	-	-	-
NGL's ($/bbl)	-	-	-	-

*There are no royalties due on the Alsike because it is categorized as a low producer