Serinus Energy Inc.

Management's Discussion and Analysis
For the year ended December 31, 2017
(US Dollars)

This Management's Discussion and Analysis ("MD&A") for Serinus Energy Inc. ("Serinus", or the "Company") is a review of the results of operations and the liquidity and capital resources of Serinus Energy Inc. and its subsidiaries (collectively "Serinus" or the "Company"). The MD&A should be read in conjunction with the December 31, 2017 audited Consolidated Financial Statements of Serinus and the accompanying notes. Readers should also read the "Forward-Looking Statements" legal advisory contained at the end of this document.

Management is responsible for preparing the MD&A, while the audit committee of the Company's Board of Directors ("the Board") reviews the MD&A and recommends its approval by the Board.

This MD&A uses United States dollars ("US Dollars" or "USD") which is the reporting currency of the Company. The accompanying financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS") also referred to as GAAP. This document is dated March 20, 2018.

In the Advisory section located at the end of this document, readers can find the definition of certain terms used in the disclosure regarding Oil and Gas Information, Non-IFRS Measures as well as information on "Critical Accounting Estimates". Additional information related to Serinus, including its Annual Information Form, is available on SEDAR at www.sedar.com or on Serinus' website at www.serinusenergy.com.

Highlights

- Production in 2017 has been severely impacted due to labour issues and social unrest in Tunisia. The Chouech Es Saida field has been shut-in in since February 28, 2017, initially due to labour issues. In addition, the Sabria field was shut-in from May 22, 2017 until early September 2017, due to social unrest in the southern part of the country. The Company has restarted production at Sabria resulting in average volumes of 396 boe/d in Q4 2017, a decrease of 65% from 1,131 boe/d in Q4 2016, primarily due to the shut in of the Chouech Es Saida field in Q4 2017 and the performance of the WIN-12 well in Sabria after being shut-in.
- During Q4 2017, Brent prices averaged $61.53 per bbl, as compared to $49.19 per bbl in the comparable period of 2016, an increase of 25%. Average realized crude oil prices were higher in 2017, at $51.48 per bbl, compared to $42.10 per bbl in 2016, reflecting the increase in average Brent prices from $43.55 per bbl in 2016 to $54.25 per bbl in 2017. Average realized crude oil prices were higher in Q4 2017, at $56.43 per bbl, compared to $47.40 per bbl in Q4 2016, reflecting improved benchmark crude pricing in 2017.
- For the three months ended December 31, 2017, funds from operations[a] was an outflow of $6.0 million compared to an outflow of $0.4 million in Q4 2016. The negative funds outflow was primarily attributable to one-time well incident cost of $4.0 million in Romania and lower operating cashflows of $1.5 million from the Tunisian assets. For 2017, funds from operations[a] for continuing operations (excluding Ukraine) was an outflow of $7.9 million, compared to an outflow of $4.7 million in 2016. The additional funds used of $3.2 million in 2017 was due to lower operating cash flows from Tunisia of $4.0 million in 2017 as compared to 2016, one-time well incident costs of $4.0 million, transaction costs of $0.7 million related to the Company's continuance and AIM listing transaction, partially offset by lower G&A of $5.3 million and lower foreign exchange loss of $0.2 million.
- Capital expenditures of $3.2 million and $8.9 million were incurred for the three and twelve months ended December 31, 2017, respectively. The majority of capital expenditures for 2017 were focused on the construction of the Moftinu gas facility in Romania and the reactivation and tie in of wells to this facility. On May 9, 2017, the Company entered into an EPCC contract with Confind S.R. L. for the construction of a 15 MMcf/d gas plant at the Moftinu 1001 well location, construction is ongoing with first production expected in late Q2 2018.
- On December 18, 2017, the Company suffered a well incident whereby during routine operations, to prepare the Moftinu 1001 well for future production, an unexpected gas release occurred and subsequently ignited. The well was subsequently brought back under control on January 6, 2018. Immediately following the capping operation, the Company performed a flow-kill operation and following a period of evaluation determined that the casing bowl assembly had been exposed to sufficient heat that its integrity was questionable. As such the Company has abandoned the Moftinu 1001 well. The costs associated with the above emergency operations are fully provided in the year end 2017 numbers in an amount of $4.0 million. The Company is in the process of completing its insurance coverage claim with its insurance broker. The impact of the well incident is that the construction of the gas facility, which is located on the wellsite of the Moftinu 1001 well, has been delayed with first production now expected late in Q2 2018. The Company has also initiated planning and tendering for the immediate drilling of a replacement well, Moftinu 1007, located approximately 300 metres from the Moftinu 1001 well site. The redrill will form part of the Company's insurance claim.
- As at December 31, 2017, the outstanding principal on the debt held with the European Bank for Reconstruction and Development ("EBRD") was $5.4 million under the Senior loan and $20.0 million under the Convertible loan. Effective October 2017, the terms of the loan facilities with the EBRD were restructured, which the Company believes provides the appropriate balance to be able to meet the debt servicing requirements while also being able to make the capital investments necessary to grow the Company. The restructured agreements provide for changes to specific terms of each loan facility as well as to the financial ratio covenants. The key points include a deferral of repayments under the Senior Loan until March 31, 2019, though a cash sweep provision remains in effect. The convertible loan maturity has been extended and repayments will be made over four years (2020 to 2023) rather than one bullet payment in June 2021. In addition, the restructuring provides for relief from all financial covenants for one year until September 2018, and all requirements for covenants at the Tunisia level have been removed permanently. The debt to EBITDA ratio has been increased to a maximum of 10.0 times as at September 30, 2018 and December 31, 2018 and reduced to 2.5 times thereafter. The debt service coverage ratio, which is effective as at December 31, 2018, is set at a minimum of 1.3 times and is now only applicable to the Senior Loan.

- On February 24, 2017 the Company closed an equity offering ("the Offering") for aggregate gross proceeds of CAD$25.2 million (net CAD$24.3 million, after agents' fees of CAD$0.9 million) by issuing 72 million common shares are a price of CAD$0.35 per share.
- The Company has announced its intent to continue to Jersey and seek admission to the AIM market to the London Stock Exchange. On March 7, 2018, the Company's shareholders voted in favour of the continuance to Jersey. The Company is therefore proceeding with the process to continue to Jersey and to list on AIM.

(a) Funds from (used in) operations is from cashflows from operations before changes in non-cash working capital.

Operational Overview

Serinus is an international oil and gas exploration and production company with operations in Tunisia and Romania. The Company has its management office in Calgary (Canada) and an investor relations office in Warsaw (Poland).

Included in the MD&A is an analysis of the above operations. The Company also had operations in Ukraine which were sold in February 2016. Operations in Ukraine, up to the date of sale, have been presented as discontinued operations in the Statement of Operations and Comprehensive Earnings (Loss) for the year ended December 31, 2016. For purposes of this MD&A, analysis of the results of Ukraine has been limited to the funds from operations in order to provide a reconciliation to cash flows for 2016.

Tunisia

As at December 31, 2017, the Company has the following interests in the concessions in Tunisia:

Concession	Working interest	Expiry date
Chouech Es Saida	100%	January 2028
Ech Chouech	100%	May 2022
Sabria	45%	November 2028
Sanrhar	100%	December 2021
Zinnia	100%	December 2020

The Tunisian state oil and gas company, Enterprise Tunisienne d'Activites Petroliere ("ETAP"), has the right to back into the Chouech Es Saida concession for up to a 50% interest, if and when the cumulative crude oil sales, net of royalties and shrinkage, from the concession exceed 6.5 million barrels. As at December 31, 2017, cumulatively 5.2 million barrels, net of royalties and shrinkage have been sold from the concession. The Company began to generate revenues in Tunisia with its acquisition in September 2013, and since that time has generated $113.5 million of revenue, net of royalties, in aggregate from these assets.

During the year ended December 31, 2017, production came from the Sabria and Chouech Es Saida fields. The Chouech Es Saida field has been shut-in since February 28, 2017 originally due to strike notices issued by Tunisia General Trade Union ("UGTT"), which represents the Company's employees at the Chouech Es Saida field. The Sabria field was on production from the start of the year until May 22, 2017, when it was shut-in due to social unrest in the southern part of the country. The Company initiated the restart of oil and gas production at the Sabria field in September, following the end of the protests and having determined that production at its oilfields could be restarted in a safe and secure environment. For the Chouech Es Saida field, the Company is continuing to evaluate the restart of the field. However, with the Company's need to focus its financial resources on the completion of the Moftinu Gas Development Project, it is expected that the Chouech Es Saida field will not be brought onto production until the latter half of 2018.

Romania

Serinus, through its wholly owned subsidiary, Serinus Energy Romania S.A. (formerly Winstar Satu Mare S.A.), currently holds a deemed 100% interest in the Satu Mare concession.

Serinus is concentrating on the development of the Moftinu gas discovery, which includes building surface facilities that are expected to begin producing from the gas discovery in late Q2 2018. Given the well incident involving the Moftinu 1001 well, which was subsequently plugged and abandoned, the Company is expediting the drilling of the Moftinu 1007 well to ready for production at the time the gas plant is ready to be commissioned. The Company entered into an EPCC contract with Confind S.R.L. on May 9, 2017 and the construction of the gas plant with 15 Mmcf/d of operational capacity is in progress. The Company is also progressing the drilling program to meet work commitments required for the three-year extension to October 28, 2019 on the concession agreement.

Given the success in Moftinu, the Company is also proceeding to refine and expand the exploration inventory within the concession. Based on older vintage 2D seismic data and existing wells, management has identified over 25 leads and prospects. The exploration program may include acquiring more seismic.

The defaulted partner, who held a 40% interest in the Satu Mare concession declined to participate in future exploration or development phases under the concession and as such has not contributed their share of expenditures to the joint venture. The Company therefore issued a notice of default to the partner in December 2016 under the terms of the joint operating agreement ("JOA"). The partner did not have the necessary means or intention to remedy the situation and as such the partner is not entitled to participate in joint venture operations and has no right to transfer their interest to a third party. The partner is currently in a tax dispute with the government of Romania, the results of which is that the Romanian fiscal authorities have placed a protective seizure order on an account of the partner relating to their past activities on the Satu Mare concession. The primary goal of this seizure order is to prevent the unauthorized flight of capital by the partner out of Romania whilst the tax dispute is adjudicated. The seizure order also has the effect of preventing the transfer of the partner's 40% interest in the Satu Mare concession without the approval of the Romanian fiscal authorities. Serinus is not involved in any manner with this tax dispute and the dispute only relates to the partner. However, the dispute means that any transfer of the partner's interest to the Company necessarily involves conversations with the Romanian fiscal authorities. In August 2017, the Company provided the partner with a Notice of Deemed Transfer pursuant to the JOA. This Notice of Deemed Transfer states that Serinus has claimed this interest without any obligation to the partner going forward and that the partner must without delay, do any act required to render the transfer of the participating interest legally valid, including obtaining all governmental consents and approvals, and shall execute any document and take such other actions as may be necessary in order to affect a prompt and valid transfer of the interest in the Satu Mare Concession. Serinus fully expects the Partner to fulfil this obligation to transfer its interest in the Satu Mare Concession to Serinus in an expedited manner, subject to the approval of the Romanian Fiscal Authorities.

Under the terms of the JOA and pursuant to the notice of default and notice of deemed transfer, Serinus has commercially assumed 100% of the joint venture. The Company has notified the National Agency for Mineral Resources ("NAMR") of the default of the partner and has provided the requisite guarantees to NAMR for 100% of the project. The Company has also communicated the position to the fiscal authorities in Romania. The Company continues to pursue the Partner's adherence to its obligation to transfer the interest, and should this not be forthcoming, pursue any and all legal remedies that would formally see the rightful transfer of the defaulting 40% working interest to Serinus. The Company maintains its right to 100% of the obligations and benefits of commercial activities conducted within the Satu Mare concession.

Given the defaulted partners legal dispute with fiscal authorities in Romania, it is yet unclear whether the Partner has the ability to transfer its interest in the Satu Mare Concession to Serinus. There is a risk with respect to the timing of the transfer as it is dependent on the Partner in resolving its legal dispute with the fiscal authorities.

The Satu Mare concession is on the border with Hungary and Ukraine within the Pannonian Basin and the term of the concession agreement expires in September 2034.

Other

Serinus has interests in a minor property at Sturgeon Lake in Alberta, Canada. This asset is not currently producing and has a future abandonment liability associated with it of US$1.1 million (CAD$1.4 million). No abandonment work was undertaken during 2017 (2016: $0.4 million).

In September 2017, the Company closed the sale of its indirect wholly-owned subsidiary that held an interest in Syria Block 9, for which Force Majeure had been declared on July 16, 2012 due to conditions arising from the instability in the country. The impact of this sale was that payables in the amount of $2.2 million relating to this asset have been reversed through the income statement and presented as a gain on sale.

Funds from Operations

The Company uses funds from operations as a key performance indicator to measure the ability of the Company to generate cash from operations to fund future exploration and development activities.

The following table is a reconciliation of funds from operations to cash flow from operating activities:

		Three months ended			Year ended	
For periods ended December 31,		2017	2016		2017	2016
Cashflows from (used in) operating activities	$	(3,574)	2,366		(4,336)	(1,435)
Changes in non-cash working capital		(2,398)	(2,734)		(3,518)	(205)
Funds used in operations	$	(5,972)	(368)		(7,854)	(1,640)
Funds used in operations per share	$	(0.04)	-	$	(0.06)	(0.02)
Funds from (used in) operations:						
Continuing operations	$	(5,972)	(368)	$	(7,854)	(4,652)
Discontinued operations [(a)]		-	-		-	3,012
	$	(5,972)	(368)	$	(7,854)	(1,640)

(a) Ukraine is reported as discontinued operations for the period ended December 31, 2016 in the Statement of Operations.

Funds from operations for the three months ended December 31, 2017 was an outflow of $6.0 million as compared to an outflow of $0.4 million in the comparable period of 2016. The additional funds used in operations for the comparative period of 2016 was primarily attributable to the one-time well incident costs of $4.0 million in 2017, lower operating cashflows of $1.5 million from the Tunisia assets, corporate transaction costs of $0.7 million, partially offset by lower G&A expenses of $0.4 million and foreign exchange loss of $0.2 million.

For 2017, excluding discontinued operations of Ukraine, funds from operations for continuing operations was an outflow of $7.9 million, compared to an outflow of $4.7 million in 2016. The additional funds used of $3.2 million in 2017 was due to lower operating cash flows from Tunisia of $4.0 million in 2017 as compared to 2016, the one-time well incident cost of $4.0 million, transaction costs of $0.7 million for the Company's continuance and AIM listing transaction, partially offset by lower G&A of $5.3 million and lower foreign exchange loss of $0.2 million.

The Company is in the process of completing its coverage claim with its insurance broker on the incident cost incurred on the Moftinu-1001 well in December 2017 and in January 2018. Subsequent to year end, the Company has submitted an interim insurance claim.

Net earnings (loss) and Funds from Operations

The Company uses funds from operations as a key performance indicator to measure the ability of the Company to generate cash from operations to fund future exploration activities. The following table presents a reconciliation of funds from operations to cash flow from operations and segmented net loss.

	Romania		Tunisia		Ukraine		Corporate		Total	
For three months ended December 31,	**2017**	**2016**	**2017**	**2016**	**2017**	**2016**	**2017**	**2016**	**2017**	**2016**
Net earnings (loss)	(4,134)	56	(2,929)	(12,137)	-	-	(2,618)	(2,338)	(9,681)	(14,419)
Adjustments for:										
Depletion and depreciation	1	1	455	1,343	-	-	31	41	487	1,385
Impairment	-	-	-	16,754	-	-	-	-	-	16,754
Change in ARO provision	-	-	1,155	-	-	-	-	-	1,155	-
Accretion	1	2	170	193	-	-	-	-	171	195
Gain (loss) on disposition of assets	-	-	-	-	-	-	-	12	-	12
Share-based compensation	-	-	-	-	-	-	235	49	235	49
Unrealized gain (loss) on investments	-	-	-	-	-	-	-	(13)	-	(13)
Decommissioning costs	-	-	-	-	-	-	-	-	-	-
Unrealized foreign exchange (gain) loss	9	11	25	86	-	-	32	36	66	133
Other provisions	-	-	599	-	-	-	-	-	599	-
Deferred income tax expense (recovery)	-	-	278	(5,167)	-	-	-	-	278	(5,167)
Non-cash equity issued	-	-	-	-	-	-	-	-	-	-
Interest expense	-	-	-	-	-	-	718	703	718	703
Funds (used in) from operations	(4,123)	23	(247)	1,072	-	-	(1,602)	(1,510)	(5,972)	(368)
Changes in non-cash working capital	2,679	-	(469)	2,496	-	-	188	238	2,398	2,734
Cashflows (used in) from operations	(1,444)	23	(716)	3,568	-	-	(1,414)	(1,272)	(3,574)	2,366

	Romania		Tunisia		Ukraine		Corporate		Total	
For year ended December 31,	**2017**	**2016**	**2017**	**2016**	**2017**	**2016**	**2017**	**2016**	**2017**	**2016**
Net earnings (loss)	(4,101)	6	(9,547)	(15,038)	-	(30,657)	(5,144)	(12,489)	(18,792)	(58,178)
Adjustments for:										
Depletion and depreciation	5	5	1,722	5,070	-	599	139	183	1,866	5,857
Impairment	-	-	4,981	16,754	-	-	-	-	4,981	16,754
Change in ARO provision	-	-	1,155	-	-	-	-	-	1,155	-
Accretion	5	5	679	770	-	2	-	-	684	777
Gain (loss) on disposition of assets	-	-	-	-	-	33,040	(2,179)	-	(2,179)	33,040
Share-based compensation	-	-	-	-	-	-	691	85	691	85
Unrealized gain (loss) on investments	-	-	-	-	-	-	13	8	13	8
Decommissioning costs	-	-	-	-	-	1	-	(407)	-	(406)
Unrealized foreign exchange (gain) loss	14	7	61	154	-	105	(63)	112	12	378
Other provisions	-	-	599	-	-	-	-	-	599	-
Deferred income tax expense (recovery)	-	-	190	(3,357)	-	-	-	-	190	(3,357)
Non-cash equity issued	-	-	-	-	-	-	7	-	7	-
Interest expense	-	-	-	-	-	(78)	2,919	3,480	2,919	3,402
Funds (used in) from operations	(4,077)	23	(160)	4,353	-	3,012	(3,617)	(9,028)	(7,854)	(1,640)
Changes in non-cash working capital	2,679	-	667	1,784	-	(2,143)	172	564	3,518	205
Cashflows from (used in) operations	(1,398)	23	507	6,137	-	869	(3,445)	(8,464)	(4,336)	(1,435)

Production

For the periods ended December 31,	Three months ended		Year ended	
$ thousands, except % and per boe	2017	2016	2017	2016
Production-crude oil (bbl/d)	287	842	279	853
Production-natural gas (mcf/d)	652	1,733	581	1,628
Production-total (boe/d)	396	1,131	376	1,124
% oil weighting	72%	74%	74%	76%
% gas weighting	28%	26%	26%	24%

Production volumes decreased by 65% in the fourth quarter 2017 to 396 boe/d, as compared to 1,131 boe/d in the fourth quarter of 2016. The decrease in production in Q4 2017 was attributable to the shut-in of the Chouech Es Saida field and lower volumes from the WIN-12 well in Sabria.

On a full year basis, production decreased by 67% to 376 boe/d, compared to 1,124 boe/d in the prior year. The decrease year over year was due to the shut-in of both the Chouech Es Saida and Sabria fields. The production volumes at Chouech Es Saida were additionally impacted in Q1 2017 by lower production due to the CS-3 and CS-1 wells which went down in the middle of December and remained off-line in the first quarter pending pump replacement and workovers.

The Chouech Es Saida field has been shut-in since February 28, 2017 due to strike notices issued by Tunisia General Trade Union ("UGTT"), which represents the Company's employees at the Chouech Es Saida field. The shut-in was a result of a strike notice and illegal sit-in at the field in response to the Company terminating the employment of 14 of the 52 field employees for economic reasons, even though these terminations were within the right of the Company and strictly followed the appropriate laws, work code and regulations. The terminated employees accepted their termination notices and this sit-in ended early in Q2, but due to social unrest in the south of Tunisia the field remained shut-in. The field was completely shut down during Q3 and all remaining employees terminated.

The Sabria field was on production from the start of the year until May 22, 2017 when it was shut-in temporarily due to continued social unrest in the southern part of the country. Production resumed at the Sabria field in early September when the social unrest in the southern part of the country had subsided and the Company had determined that that the facilities could be restarted in a safe and secure environment.

The Company brought back on production the producing wells in Sabria in early September 2017, all of which, except for the Win-12bis well, have come back on at pre-shut in levels. The Win-12bis well has a history of producing at high water cuts after being shut-in, the production from Win-12bis initially decreased by 60% from pre-shut in levels. The well continued to improve steadily through Q4, 2017, but has in Q1, 2018 produced at a more stable rate of approximately 162 boe/d, net. The Company continues to monitor the Win-12bis well, though it is likely that the Win-12bis well will require a well intervention to improve performance. Production from Sabria in January and February 2018 averaged 393 boe/d. The Company is evaluating the restart of the Chouech Es Saida field in the latter part of 2018.

During the year ended December 31, 2017, only the Sabria and Chouech Es Saida fields produced oil and gas.

Oil and gas revenue and change in oil inventory

For the periods ended December 31,	Three months ended		Year ended	
$ thousands, except % and per boe	2017	2016	2017	2016
Oil revenue & change in oil inventory	$ 1,491	3,673	$ 5,242	13,143
Gas revenue	404	783	1,327	2,804
Total revenue	$ 1,895	4,456	$ 6,569	15,947
Oil revenue & change in oil inventory (%)	79%	82%	80%	82%
Gas revenue (%)	21%	18%	20%	18%
Oil ($/bbl)	$ 56.43	47.40	$ 51.48	42.10
Gas ($/mcf)	6.73	4.91	6.25	4.70
Average realized price ($/boe)	$ 52.03	42.82	$ 47.88	38.75

Revenue is currently generated in Tunisia. The Company is required to sell 20% of its annual crude oil production from the Sabria concession into the local market, which is sold at an approximate 10% discount to the price obtained on its other crude sales. The remaining crude oil production is sold to the international market, through which the Company has a marketing agreement with Shell International Trading and Shipping Company Limited ("Shell agreement")

In Q2 2016, the Company, through its Tunisian subsidiary, entered into the Shell agreement for the sale of its oil production. The term of the agreement is for five years and the pricing mechanism is competitive. This benefits the Company by getting regular crude oil liftings from a large and highly reputable purchaser.

During 2016, there were two tanker liftings prior to the Shell contract being finalized. Since the Shell contract has been in place, there was one lifting in Q4 2016 and one lifting in Q2 2017 with no further liftings to date.

As the crude oil accumulates the Company records inventory at its net realizable value and the change in inventory is recorded in the income statement as change in oil inventory. The cash that is received monthly from Shell is presented on the balance sheet as advances for crude oil sales. Once the crude oil is physically lifted onto tankers and title passes, the inventory and advances are reversed and an Accounts Receivable is set up for the remaining amount due from Shell, and the change in oil inventory in the income statement is reclassified as revenue.

As at December 31, 2017, the Company was in an under-lift position of 27,241 bbls of which 6,476 bbls were reserved for local oil sales (Q4 2016: inventory of 23,421 bbls of which 5,534 bbls were reserved for local oil sales). As a result, the Company has crude oil inventory of $1.5 million at December 31, 2017 (December 31, 2016: $1.2 million).

For the three and twelve months ended December 31, 2017, Brent prices averaged $61.53 and $54.25 per bbl, respectively, as compared to $49.19 and $43.55 per bbl in the comparable periods of 2016, reflecting a 25% increase in both periods from 2016. The Company realized 92% of the Brent price during Q4 2017 (Q4 2016: 96%) and 95% for full year 2017 (97% for the year ended December 31, 2016). The realized price of $51.48 per bbl in 2017 increased 22% from $42.10 per bbl in 2016, and increased 19% to $56.43 per bbl, from $47.40 per bbl in Q4 2017. The increase in realized price year over year is slightly lower than the increase in Brent due to the effect of the shut-in and committed volumes at time of lifting in Q2, 2017, which resulted in such committed volumes being produced after shut-in but at a pre-shut in commodity price.

Natural gas prices are nationally regulated and are tied to the twelve-month trailing average of low sulphur heating oil (benchmarked to Brent).

Oil and gas revenues and change in oil inventory totaled $1.9 million for Q4 2017, compared to $4.5 million in Q4 2016. The decrease of 57% is reflective of the 65% decrease in production, offset by the increase in pricing. Similar trends are noted on a year to date basis.

Royalties

		Three months ended			Year ended	
For the periods ended December 31,		2017	2016		2017	2016
Royalties	$	196	735	$	680	1,972
Royalties ($/boe)	$	5.38	7.06	$	4.96	4.79
Royalties (% of revenue)		10.3%	16.5%		10.4%	12.4%

Tunisian royalties are based on individual concession agreements, none of which exceed 15%. In two concessions, Sabria and Zinnia, the royalty rate varies depending on a calculation of cumulative revenues, net of taxes, as compared to cumulative investment in the concession, known as the "R factor". As the R factor increases, so does the royalty percentage to a maximum rate of 15%. During 2017, the royalty rate in Sabria was 10% for oil and 8% for gas, this reflected an increase in the R factor, in Q4 2016, when the rates increased from 7% for oil and 6% for gas. In Chouech Es Saida, royalty rates are flat at 15%.

Royalties decreased by 73% in Q4 2017 as compared to Q4 2016, due to a decrease in revenue of 57% and a decrease in the effective royalty rate to 10.3% in Q4 2017 from 16.5% in Q4 2016. The royalty rate in Q4 2016 was exceptionally high at 16.5% due to Q4 2016 including Chouech Es Saida royalties at 15% and the retroactive adjustment to full year 2016 for the increase in the R factor in Q4, 2016 for Sabria. In Q4 2017 royalties only included the Sabria field.

On a year to date basis, royalties decreased by 66% to $0.7 million from $2.0 million in 2016. The decrease was attributable to a 59% decrease in revenue and a two percentage rate decrease in royalty rates. The decrease in royalty rates is attributable to Chouech Es Saida being shut in for the majority of the year and so the royalty rate reflecting the lower rates applicable in Sabria.

The increase in the per boe metric for the three months ended December 31, 2017 is attributable to higher commodity prices as compared to the Q4 2016.

Production Expenses

For the periods ended December 31,		Three months ended			Year ended	
($ thousands except for per boe)		2017	2016		2017	2016
Production expense-Tunisia	$	1,764	2,674	$	5,207	9,279
Production expense-Canada		8	(65)		43	79
Production expense-Total		1,772	2,609		5,250	9,358
Production expense-Tunisia ($/boe)	$	48.43	25.70	$	37.96	22.55

Production expenses for Q4 2017 decreased by 32% to $1.8 million as compared to Q4 2016. The decrease reflects the shut-in of the Chouech Es Saida field in Tunisia, resulting in lower operating costs and transportation charges, partially offset by a severance provision of $0.6 million relating to the termination of employees from the Chouech Es Saida field in Q3 2017. The severance provision reflects the Company's best estimate of the probable outcome of the settlements.

On a per boe basis, the costs in Q4 2017 increased to $48.43 per boe as compared to $25.70 per boe in the comparable period of 2016. Excluding the severance provision of $16.44 per boe, the production expense would have been $31.99 per boe for Q4 2017, reflecting lower production in 2017.

For the year ended December 31, 2017, total production expenses decreased by 44% to $5.3 million, from $9.4 million in 2016, due to the reasons discussed above. Excluding the severance provision accrued in 2017, production expense would have decreased by 49% due to the shut-in periods in 2017. On a per boe basis, production expense in Tunisia increased to $37.96 per boe from $22.55 per boe in the prior year. Excluding the $4.37 per boe impact of the severance provision, the production expense for 2017 would be $33.59 per boe as compared to $22.55 per boe in 2016, reflecting that production volumes declined by 67% but production expenses only decreased by 50%.

During the shut-in period, the Company incurred operating costs related to field personnel, security, insurance and other miscellaneous expenses in addition to the Tunis office costs. The Company continues to review the ongoing running costs of the Tunisian operations to reduce costs where possible.

Canadian production expenses relate to the Sturgeon Lake assets and totaled $43 thousand for the year ended December 31, 2017. The asset is not producing and is incurring minimal operating costs to maintain the property.

Operating Netback

Serinus uses netback as a key performance indicator to measure the Company's revenue less the direct costs consisting of royalties and production expenses to assist management in understanding Serinus' profitability relative to current market conditions and as an analytical tool to benchmark changes in operational performance against prior periods. Netback is not a standard measure under IFRS and therefore may not be comparable to similar measures reported by other entities.

The following table shows the reconciliation of netback to its most closely related IFRS measure revenue:

Operating netback by commodity	Three months ended December 31, 2017			Three months ended December 31, 2016		
($ per boe except for volume)	Oil (bbl/d)	Gas (mcf/d)	Total (boe/d)	Oil (bbl/d)	Gas (mcf/d)	Total (boe/d)
Production volume	287	652	396	842	1,733	1,131
Realized price	$ 56.43	$ 6.73	$ 52.03	$ 47.40	$ 4.91	$ 42.82
Royalties	(6.21)	(0.53)	(5.38)	(8.08)	(0.68)	(7.06)
Production expense	(52.67)	(6.20)	(48.43)	(28.46)	(2.94)	(25.70)
Operating netback [(a)]	$ (2.45)	$ -	$ (1.78)	$ 10.86	$ 1.29	$ 10.06

Operating netback by commodity	Year ended December 31, 2017			Year ended December 31, 2016		
($ per boe except for volume)	Oil (bbl/d)	Gas (mcf/d)	Total (boe/d)	Oil (bbl/d)	Gas (mcf/d)	Total (boe/d)
Production volume	279	581	376	853	1,628	1,124
Realized price	$ 51.48	$ 6.25	$ 47.88	$ 42.10	$ 4.71	$ 38.75
Royalties	(5.67)	(0.49)	(4.96)	(5.37)	(0.49)	(4.79)
Production expense	(40.81)	(4.96)	(37.96)	(24.50)	(2.74)	(22.55)
Operating netback [(a)]	$ 5.00	$ 0.80	$ 4.96	$ 12.23	$ 1.48	$ 11.41

(a) *Netback is defined as revenue and change in inventory less direct expenses and is calculated as oil and gas revenue net of royalties, less production expense. Netback is not a standard measure under IFRS; see section titled "Non-IFRS Financial Measures" for advisory over the use of non-IFRS financial measures.*

Realized price per boe increased by 22% in Q4 2017 as compared to Q4 2016. However, the high production expenses per boe resulted in a negative operating netback on a per boe basis.

The negative netback of $1.78 per boe in Q4 2017 was $11.84 per boe less than the netback of $10.06 per boe in the comparable period of 2016. The increase in realized prices was more than offset by substantially higher production expenses per boe, due to the severance provision impact of $16.44 per boe on a quarter basis. Excluding the severance provision, total production expense per boe for Q4 2017 would have been $31.99, resulting in a positive an operating netback of $14.66 per boe.

On an annual basis, the netback was $4.96 per boe as compared to $11.41 per boe in 2016 for reasons as noted above. Excluding the severance provision of $4.37 per boe, the netback for 2017 would be $9.33 per boe. The decrease in netback is due to a proportionally smaller decrease in production expenses as compared to production volumes, partially offset by improved realized prices.

General and Administrative

For the periods ended December 31,	Three months ended		Year ended	
($ thousands except for per boe)	2017	2016	2017	2016
G&A expense	$ 915	1,361	$ 3,005	8,320
G&A expense ($/boe)	$ 25.12	13.08	$ 21.91	20.22

General and administrative ("G&A") costs incurred by the Company are expensed, with certain costs directly related to exploration and development assets being capitalized or reported as production costs. The G&A costs reported are on a net basis, representing gross G&A costs incurred less recoveries.

General and administrative ("G&A") costs decreased by $0.4 million, or 33%, from $1.4 million in Q4 2016 to $0.9 million in Q4 2017. The decrease is the direct result of significant cost savings measures taken by the Company. For full year 2017, G&A decreased 64% to $3.0 million, from $8.3 million in 2016. The decrease was attributable to cost saving measures taken by the Company and the inclusion in 2016 of one-time termination costs of $2.4 million related to the closure of the Dubai office.

On a per boe basis, the decrease in G&A expenses was negatively impacted by the decrease in production volumes year over year. For the fourth quarter, G&A per boe increased by 92% to $25.12 per boe in 2017, as compared to $13.08 per boe in Q4 2016, due to the 65% decrease in production volumes more than offsetting the 33% decrease in G&A expenses. For 2017, G&A expenses on a per boe basis increased minimally to $21.91 per boe in 2017 from $20.22 per boe in 2016, resulting from the decrease in production volumes of 67% more than offsetting the impact of the cost savings measures taken by the Company.

Well Incident Costs

Well incident costs reflect the costs associated with dealing with the emergency situation in Romania. On December 18, 2017, the Company suffered a well incident whereby during routine operations, to prepare the Moftinu 1001 well for future production, an unexpected gas release occurred and subsequently ignited. The well was subsequently brought back under control on January 6, 2018. Immediately following the capping operation, the Company performed a flow-kill operation and following a period of evaluation determined that the casing bowl assembly had been exposed to sufficient heat that its integrity was questionable. As such the Company has plugged and abandoned the Moftinu 1001 well. The costs associated with the above emergency operations have been provided in the year end 2017 financial statements in an amount of $4.0 million. Subsequent to year-end, the Company has submitted an interim insurance claim. The Company has also initiated planning and tendering for the immediate drilling of a replacement well, Moftinu 1007, located approximately 300 metres from the Moftinu 1001 well site. The redrill will form part of the Company's insurance claim.

Transaction costs

Transaction costs of $0.7 million in 2017 relate to the proposed continuance of the Company from Alberta to Jersey, Channel Islands and the plans to seek admission to be traded on the Alternative Investment Market ("AIM") of the London Stock Exchange in 2018.

Stock-based Compensation

For the periods ended December 31,	Three months ended		Year ended	
($ thousands except for per boe)	2017	2016	2017	2016
Stock-based compensation	$ 235	49	$ 691	$ 85
Stock-based compensation expense ($/boe)	$ 6.45	$ 0.47	$ 5.04	$ 0.21

The Company has granted common share purchase options to officers, directors, and employees with exercise prices equal to or greater than the fair value of the common shares on the grant date. Upon exercise, the options are settled in common shares issued from treasury. For options issued prior to 2016, each tranche of the share purchase options has a five-year term and vest one-third immediately with the remaining two-thirds at one-third per year each on the anniversary of the grant date. In Q4 2016, options were granted with a seven-year term and which vest one-third per year on the anniversary of the grant date for the three subsequent years. In 2017, options were granted with a five-year term, which vest one-third per year on the anniversary date for the three subsequent years. All options are to be settled by physical delivery of shares.

Stock-based compensation was $235 thousand in Q4 2017 compared to $49 thousand in Q4 2016. The increase in the expense recognized in Q4 2017 as compared to Q4 2016 reflects the issuance of 6,680,000 options in the second quarter of 2017 compared to 3,500,000 options issued in Q4 2016. The Q4 2016 expense also reflected that no options were granted between late 2014 until Q4 2016 and therefore the amortization of expense was declining.

On a year to date basis, stock-based compensation expense was $691 thousand compared to $85 thousand in 2016, for reasons as noted above.

Depletion, Depreciation and Impairment

For the periods ended December 31,	Three months ended		Year ended	
($ thousands except for per boe)	2017	2016	2017	2016
Depletion and depreciation-Tunisia	$ 455	$ 1,343	$ 1,722	$ 5,070
Depletion and depreciation-Corporate	32	42	144	188
Impairment expense-Tunisia	-	-	4,981	16,754
	487	1,385	6,847	22,012
Depletion and depreciation-Tunisia ($/boe)	$ 12.49	$ 12.91	$ 12.55	$ 12.32

Depletion and depreciation expense is computed on a concession by concession basis considering the net book value of the concession, future development costs associated with the reserves as well as the proved and probable reserves of the concession.

In Q4 2017, Tunisia depletion and depreciation expense decreased by 66% to $0.5 million from $1.3 million in Q4 2016, correlating with the 65% lower production between the two periods.

On a per boe basis, the depletion rate was $12.49 per boe for the three months ended December 31, 2017, compared to $12.91 per boe in the comparable period of 2016.

At December 31, 2017, there were no impairment indicators to trigger an impairment test or a reversal, as such, no impairment or reversals have been recorded in Q4 2017. At September 30, 2017, as a result of negative technical revisions, due to prolonged shut-ins and decreased performance, and sustained low oil prices which are impairment indicators, the Company performed impairment tests on its Tunisian assets by concession using a fair value less costs to sell methodology, using reserves updated at that time. The fair value was based on the September 30, 2017 proved plus probable reserves and 2C contingent resources data, a risk-adjusted discount rates of 20%-27%, and a price forecast adjusted for quality differentials specific to the Company. The calculation resulted in a $5.0 million impairment expense in Q3 2017 ($16.8 million for the three months and year ended December 31, 2016).

Interest and accretion expense

For the periods ended December 31,	Three months ended		Year ended	
($ thousands except for per boe)	2017	2016	2017	2016
Interest expense	$ 718	703	$ 2,919	3,478
Accretion expense on ARO	171	195	684	777
	$ 889	898	$ 3,603	4,255

Interest expense and accretion for Q4 2017 was comparable to the same quarter in 2016, at $0.9 million, and consistent with the debt balances of $30.7 million at the end of September 2016 and $30.8 million at September 2017.

On a full year basis, interest and accretion decreased by $0.7 million to $3.6 million. Interest expense on debt decreased to $2.9 million in 2017 from $3.5 million in 2016. The decrease was attributable to higher debt levels in the first quarter of 2016 which were subsequently reduced when, in conjunction with the disposition of the Ukrainian operations in Q1 2016, the Romania EBRD debt of $11.3 million was repaid and $7.4 million of the Tunisia debt was repaid. These repayments were in addition to the regular scheduled repayments in March and September 2016 and a cash sweep repayment of $3.4 million in May 2016. The interest in 2016 therefore reflected higher interest charges due to higher debt balances as well as the accelerated amortization of deferred financing costs on the Romania EBRD debt.

Accretion represents the increase in the asset retirement obligation ("ARO") from the previous year end to reflect the passage of time. Accretion expense in 2017 remains consistent with 2016 as there was minimal change in the estimate made as at December 31, 2016. As at December 31, 2017, an increase was determined necessary for the Tunisian estimate of ARO due to an increase in applicable future inflation rates. This increase, plus the addition of new assets in Romania in 2018, will result in an increase in accretion expense in 2018.

Foreign exchange

Fluctuations in foreign currency exchange rates are an economic factor that affects the Company's cash flow required for operations and for investments. The financial statements are presented in US dollars, which is the reporting currency of the Company.

The foreign currency loss was $0.2 million and $0.1 million for the three and twelve months ended December 31, 2017, compared to a loss of $0.2 million and $0.7 million for the comparable periods in 2016, due to fluctuations in various currencies against the U.S. dollar. Please see the foreign currency exchange risk against the US dollar in the Risk Section.

Income tax expense

Current income tax expense was $0.8 million and $1.3 million for the three months and twelve months ended December 31, 2017, respectively (nil for Q4 and full year 2016). The income tax expense in 2017 includes current tax expense for the Sabria concession and an estimated expense of $1.6 million for a tax incentive previously taken in Tunisia for a planned capital project in Chouech Es Saida that has not yet been completed.

Capital Expenditures

	For three months ended December 31, 2017				For three months ended December 31, 2016			
		Tunisia	Romania	Total		Tunisia	Romania	Total
Property, plant and equipment	$	(18)	4	(14)	$	399	(1)	398
Exploration and evaluation		-	3,217	3,217		-	577	577
Total exploration and development	$	(18)	3,221	3,203	$	399	576	975

	For year ended December 31, 2017				For year ended December 31, 2016			
		Tunisia	Romania	Total		Tunisia	Romania	Total
Property, plant and equipment	$	402	19	421	$	1,911	3	1,914
Exploration and evaluation		-	8,431	8,431		-	1,737	1,737
Total exploration and development	$	402	8,450	8,852	$	1,911	1,740	3,651

In Tunisia, the Company incurred capital expenditures of $0.4 million for the year ended December 31, 2017, which primarily included costs for pumps and parts in preparation of workovers on the CS-1 and CS-3 wells in Chouech Es Saida.

In Romania, the Company incurred expenditures of $3.2 million and $8.5 million for the three and twelve months ended December 31, 2017, respectively. The expenses consisted of the construction of the Moftinu gas facilities, reactivation of two wells and costs associated with the Bucharest office. The majority of the costs in Q4 2017 relate to the procurement of major components of the gas plant and flowlines and well testing.

During 2017, the Romania assets were classified as exploration and evaluation assets ("E&E"). E&E assets are not subject to depletion and depreciation, but are tested for impairment if there are triggers identified. As at December 31, 2017, it was determined that these assets met the conditions of technical feasibility and commercial viability to transfer them to property, plant and equipment ("PP&E"). On transfer to PP&E, an impairment test was required to be undertaken, which resulted in no impairment charge on reclassification from E&E assets to PP&E based on the proved plus probable reserves associated with the Moftinu development as at December 31, 2017, using a risk adjusted discount rate of 13.5%.

Total capitalized costs of the exploration and evaluation assets, including the asset retirement obligation provision, in Romania totaled $29.3 million as at December 31, 2017 (December 31, 2016: $20.3 million) which were transferred to PP&E.

Liquidity, Debt and Capital Resources

For the periods ended December 31,	Three months ended			Year ended		
		2017	2016		2017	2016
Operating activities	$	(3,574)	2,366	$	(4,336)	(1,435)
Financing activities		(160)	(13)		15,738	(27,408)
Investing activities		(2,400)	(588)		(8,433)	21,677
Effect of foreign currency translation on cash		(65)	(107)		(14)	(354)
Change in cash	$	(6,199)	1,658	$	2,955	(7,520)

For the three months ended December 31, 2017, the net change in cash was an outflow of $6.2 million, as compared to an inflow of $1.7 million in the three months ended December 31, 2016. The negative change in cash use of $7.9 million was primarily attributable to a decline in cashflow from operating activities of $5.9 million, combined with finance costs of $0.2 million, and higher capital investment of $1.8 million, as compared to Q4 2016. The majority of the decrease in cashflow from operating activities was a result of the shut-in in Tunisia, thereby reducing cash flows generated, the one-time well incident costs in Romania of $4.0 million, the provision for severance costs of

$0.6 million for Chouech Es Saida employees and an estimated repayment of a Tunisia tax incentive provision on a previously planned capital project of $1.6 million, partially offset by lower corporate G&A costs.

For the year ended December 31, 2017, the net change in cash was a positive inflow of $3.0 million, as compared to an outflow of $7.5 million in 2016. The change year over year is attributable to lower G&A expense in 2017, the equity offering in 2017 and lower debt repayments than in 2016, partially offset by lower operating cash flow from Tunisia. In Q1 2016, the proceeds on disposition of Ukraine less the debt repayments totaled $6.8 million.

During 2017, the Company realized negative funds from operations of $7.9 million, before changes in working capital, and cashflows used in operating activities of $4.3 million (after changes in non-cash working capital). The cash flows used in operating activities reflected the social issues in Tunisia, which necessitated the shut-in of the operating fields for certain periods of 2017. This combined with the well incident in Romania and corporate costs relating to G&A meant that the Company did not generate sufficient cash flows to cover its operating cash requirements.

As a result of the shut-in of the fields in Tunisia during 2017, the cash flow generated from the Tunisian assets was not sufficient to cover the capital expenditures incurred in Tunisia in the year of $0.4 million.

During 2017, the Company made a scheduled debt repayment of $1.7 million, interest payments of $0.6 million and incurred capital expenditures in Romania of $8.0 million associated with the Moftinu gas development project.

To improve its liquidity position the Company closed an equity offering of $18 million net of costs in February 2017. The Company issued 72 million common shares at CAD$0.35 per share for aggregate gross proceeds of CAD$25.2 million (net CAD$24.3 million, after agents' fees of CAD$0.9 million) ("the Offering"), such proceeds to fund the construction of the gas plant in Romania, to achieve first gas in Romania and to enable Romania to become a cash flow generating business unit.

In addition, effective October 2017, the Company renegotiated its loan agreements with the EBRD, to provide, amongst other, a deferral on principal repayments until 2019 for the Senior Loan and relief from financial covenants until September 2018, providing the Company with the appropriate balance between meeting debt servicing obligations and being to make the necessary capital expenditures to grow the business (see EBRD – Tunisia Loan Facility section).

The construction of the Moftinu gas development project was delayed due to the Moftinu 1001 well incident. The plant is now slated to bring on gas production from the Moftinu-1000 well and the currently planned Moftinu 1007 well, through the construction of a 15 Mmcf/d gas plant, connecting well flowlines and a sales gas pipeline to the Transgaz national gas transmission system in late Q2 2018. The Company was negatively impacted in 2017 by the $4.0 million of well incident costs incurred in response to the emergency situation, which are anticipated to be recoverable through insurance.

The near term liquidity needs of the Company are dependent on the receipt of insurance proceeds from the recent well incident, the timely completion of the Moftinu gas plant and the successful execution of the drilling of the Moftinu 1007 well to provide a further cash flow source for the Company.

Cash flow generation in Tunisia remains challenging given the current production level, though with stability of production and cost cutting measures, Tunisia should be a positive cash flow generating business unit at current commodity prices.

There can be no assurance that internally generated cash flows will be adequate for the Company's future financial obligations, including the future capital expenditure program, or that the Company will be able to obtain additional funds.

The Company is actively considering alternatives to finance the Company and provide the necessary liquidity and capital. The Company monitors its liquidity position constantly to assess whether it has the funds necessary to meet ongoing cash requirements. The Company's debt is fully drawn and the period for drawdowns expired, therefore there is no access to further debt amounts under the EBRD loan agreements. Alternatives available to Serinus to manage liquidity include farm-out arrangements and securing new equity, as well as minimizing costs by cutting operating and administrative costs and deferring capital expenditures. There are no restrictions on the use of the Company's capital resources that could materially affect, directly or indirectly, its operations or activities.

The Company is seeking a listing on the AIM market of the London Stock Exchange, which it believes will increase its access to equity in the capital markets.

To ensure security and the preservation of capital, the Company's investment policy for cash that is surplus to immediate requirements is to invest such funds in instruments issued by major chartered banks that are rated "triple A", or its equivalent by independent rating agencies.

Working Capital

Serinus uses working capital as a key performance indicator to measure the Company's current assets less current liabilities to assist management in understanding Serinus' liquidity relative to current market conditions and as an analytical tool to benchmark changes against prior periods. Working capital is not a standard measure under IFRS and therefore may not be comparable to similar measures reported by other entities. The following table shows the reconciliation of working capital to its most closely related IFRS measure current assets and liabilities:

Working capital as at:		December 31, 2017		December 31, 2016
Current assets	$	15,393	$	10,728
Current liabilities		(21,960)		(49,203)
Working capital (deficit)	$	(6,567)	$	(38,475)
Debt classified as current		-		(30,699)
Working capital (deficit) excluding debt	$	(6,567)	$	(7,776)

(a) *Working capital is defined as current assets less current liabilities. Working capital is not a standard measure under IFRS; see section titled "Non-IFRS Financial Measures" for advisory over the use of non-IFRS financial measures.*

At December 31, 2017, Serinus has a working capital deficit of $6.6 million, as compared to $38.5 million at December 31, 2016. At December 31, 2016, all of the debt balance was presented as a current liability due to the violation of bank covenants, excluding the debt balance, the working capital deficit was $7.8 million at December 31, 2016. At December 31, 2017, the current liabilities of $22.0 million increased by $3.5 million compared to the current liabilities balance (excluding reclassified long-term debt) of $18.5 million at December 31, 2016. The increase in current liabilities was the result of accounts payables for the well incident costs, and a provision for income tax payable of $1.6 million, related to a tax incentive repayment.

The improvement in the working capital deficit (excluding the debt balances) of $1.2 million since December 2016 was mainly due to the proceeds from the equity offering held as cash and the disposition of the entity holding the Syrian asset, which released $2.2 million of accounts payable to the income statement as a gain on disposition.

Included in accounts payable was $8.2 million relating to Brunei at December 31, 2017 and 2016. Of this amount, $2.2 million relates to a dispute with a drilling company dating back to 2013 on Block L. The remaining $6.0 million relates to the Brunei Block M production sharing agreement which expired August 2012.

EBRD-Tunisia Loan Facility

On November 20, 2013, Serinus finalized two loan agreements aggregating USD $60 million with EBRD. The Senior Loan is in the amount of USD$40 million, has a term of seven years, and was available in two tranches of USD$20 million each. The second tranche was subsequently reduced from $20 million to $8.72 million upon placement of the EBRD Romanian Facility in Q1 2015. Both loan agreements contain a number of affirmative covenants, including maintaining the specified security, environmental and social compliance, and maintenance of specified financial ratios. Refer to "Covenants" section for details of the associated covenants of the EBRD-Tunisia Loan Facility.

Effective October 31, the Company entered into Agreements, relating to the Senior Loan and Convertible loans, to amend certain terms of the original agreements. The new Agreements provide for changes to specific terms of each of the loan facilities as well as to the financial covenants.

The Senior Loan interest is payable semi-annually at a variable rate equal to LIBOR plus 6%. At the Company's option, the interest rate may be fixed at the sum of 6% and the forward rate available to EBRD on the interest rate swap market. The Company had locked in the interest rate on the $20.0 million Senior Loan at a rate of 6.9% for a two-year period from December 31, 2014 to December 31, 2016 at which time interest reverted back to LIBOR plus 6%.

The Senior Loan was repayable in twelve equal semi-annual installments with the first repayment made on March 31, 2015. Subsequent repayments, on March 31 and December 31 of each year, have followed the repayment schedule. In the first quarter of 2016, $7.6 million, including interest, of the Senior Loan was repaid using the proceeds from the sale of the Ukrainian operations, resulting in tranche 2 of the Senior Loan being fully repaid. In the year ended 2017, a scheduled semi-annual installment of $1.7 million was made in March along with $0.2 million of interest in March and $0.3 million in September. As at December 31, 2017, the principal outstanding under the Senior Loan was $5.4 million (December 31, 2016: $7.1 million). Under the terms of the restructuring there is a deferral of principal repayments, the original agreement required that there were scheduled repayments of $1.7 million in each September and March. Under the restructured terms no principal repayment is due until 2019, with the remaining principal to be repaid in two equal amounts of $2.7 million each on March 31, 2019 and December 31, 2019.

Under the restructured terms, the cash sweep is now computed at the corporate level. Previously, the Company had to apply 40% of its Excess Cash from Tunisia toward early repayment of the Senior Loan facility outstanding with EBRD. Under the restructured terms, the cash sweep is calculated semi-annually on December 31 and June 30 of each year as long as balances remain outstanding on the Senior Loan. Any cash balance in excess of $7 million is to be used to prepay the senior loan in inverse order of maturity until the outstanding loan balance is no greater than that under the original amortization schedule. No pre-payment fees are applicable to the accelerated payments described above.

The Convertible Loan in the amount of $20 million had a term of seven years and was repayable on June 30, 2021. Under the restructured terms, the maturity is now extended to June 2023, with accrued interest accumulation until June 2020. In June 2020, the total outstanding principal plus accumulated accrued interest will be determined and this amount will constitute the new balance to be equally amortized over the four annual payments to be made each month of June for the years 2020 to 2023. The Convertible loan bears interest at a variable rate that is the LIBOR and a percentage calculated on the basis of incremental net revenues earned, with a floor of 8% per annum and a ceiling of 17% per annum. This margin was previously based on the net revenues of the Tunisian assets, but has under the restructured terms been expanded to include the Romanian assets. Serinus can elect, subject to certain conditions, to convert all or any portion of the Convertible Loan principal and accrued interest outstanding for newly issued shares of the Company at the then current market price of the shares on the TSX or WSE, as required by the exchange rules. The EBRD can also at any time, and on multiple occasions elect to convert all or any portion of the Convertible Loan principal and accrued interest outstanding for newly issued shares of the Company at the then current market price of the shares on the TSX or WSE.

The conversion feature of the loan is based on market price, which would result in the issuance of a variable number of shares of the Company, and as a result, no value was allocated to the conversion option. The Convertible Loan was recorded as debt and classified as financial liabilities at amortized costs.

The Company can also repay the Convertible Loan at maturity in cash or in-kind, subject to certain conditions, by issuing new common shares valued at the then current market price of the shares on the TSX or WSE. The repayment amount is subject to a discount of approximately 10% if the requirement for substantially all of the Company's assets and operations to be located and carried out in the EBRD countries of operations is not met at the date of repayment.

The loans were available to be drawn for a period of three years, such period has now expired.

The loans are secured by the Tunisian assets, pledges of certain bank accounts, shares of the Company's subsidiaries through which the concessions are owned, benefits arising from the Company's interests in insurance policies, and on-lending arrangements within the Serinus group of companies. In addition, under the restructured terms there is an additional security pledge of the shares of Serinus Energy Romania S.A., the holder of the Romanian assets.

In addition, under the terms of the restructuring the financial covenants have been amended. The restructured agreements provide relief from covenants until September 2018. All covenant requirements at the Tunisia level have been removed and the debt service coverage ratio at the consolidated level is now only applicable to the Senior Loan. The debt service coverage ratio changed to a minimum of 1.3 times from 1.5 times previously at the consolidated level and is effective from December 2018. The debt to EBITDA ratio has been increased from a maximum of 2.75 times to 10.0 times at September 2018 and December 2018 and then to 2.5 times thereafter.

	Senior Loan		Convertible loan	
Covenants	Original	Restructured	Original	Restructured
Corporate level-DSCR	1.5x	1.3x	1.5x	n/a
Corporate level-Debt-EBITDA	2.75x	Max 10.0x Sept & Dec 2018; max 2.5x 2019+	2.75x	Max 10.0x Sept & Dec 2018; max 2.5x 2019+
Tunisia level-DSCR	1.3x	n/a	1.3x	n/a
Tunisia level-Debt-EBITDA	2.5x	n/a	2.5x	n/a

Covenants

Both loan agreements as part of the EBRD-Tunisia Loan Facility contain a number of affirmative covenants, including maintaining the specified security, environmental and social compliance, and maintenance of specified financial ratios. The covenants use non-GAAP financial measures which are not standard measures under IFRS and may not be comparable to similar measures reported by other entities.

The covenants, as noted above, have been amended as follows:

- The financial debt to EBITDA ratio has been increased to a maximum of 10.0 times as at September 30 and December 31, 2018 and reduced to 2.5 times thereafter. The debt to EBITDA ratio is applicable to both the Senior Loan and the Convertible Loan.
- The debt service coverage ratio, which is effective as at December 31, 2018, is set at a minimum of 1.3 times and is now only applicable to the Senior Loan.

The definitions of the covenants remained the same on the restructured loan agreement and are as follows:

- Financial debt is defined as the principal amount of the loan and other borrowings and obligations identified in the Loan Agreements.
- EBITDA is calculated based on the terms and definitions as set out in the Loan Agreement, which adjusts earnings for interest expense, income tax, and non-cash transactions (including depletion, depreciation, exploration and evaluation expenses, impairment losses or provisions, unrealized gains and losses from foreign exchange, and share-based compensation) and is calculated based on a trailing twelve-month basis.
- The debt service coverage ratio is calculated as the ratio of (i) cashflows arising from operating activities for the trailing twelve months as per the statement of cash flows, minus the sum of those cashflows used for acquiring long-term assets or other capital expenditures, excluding those capital expenditures funded by equity, referred by Serinus as "adjusted cashflows, to (ii) the sum of scheduled principal repayments and interest payments on the financial debt on a trailing twelve-month basis.

At December 31, 2017, the Company was not subject to any financial covenants.

At December 31, 2016, the Company was not in compliance with the consolidated debt to EBITDA ratio covenant at the Serinus level in effect at that time, resulting in the reclassification of its long-term debt to current as required under accounting standards. The ratios as at December 31, 2016 were as follows:

- The financial debt to EBITDA for Tunisia should not be more than 2.5 to 1. The ratio for Tunisia was 1.6 at December 31, 2016 which was in compliance. Tunisia financial debt totaled $7.1 million as at December 31, 2016 and the EBITDA of Tunisia totaled $4.4 million.
- The financial debt to EBITDA for Serinus should not be more than 2.75 to 1. The ratio for Serinus was 98.4 at December 31, 2016 which was not in compliance. Serinus financial debt totaled $27.1 million at December 31, 2016 and the EBITDA of Serinus was a negative $0.3 million.
- The debt service coverage ratio for Tunisia should not be less than 1.3. The debt service coverage ratio for Tunisia was 1.4 at December 31, 2016 which was in compliance. Tunisia's adjusted cash flow was $5.8 million for the 12-month period ended December 31, 2016 and the debt service costs for the same period was $4.2 million.
- The debt service coverage ratio for Serinus should not be less than 1.5. The debt service coverage ratio was 2.4 at December 31, 2016 which was in compliance. Serinus' adjusted cash flow was $11.6 million for the 12-month period ended December 31, 2016 and the debt service costs for the same period was $4.8 million.

Share Data

The Company is authorized to issue an unlimited number of common shares, of which 150,652,138 common shares and 67,000 options, with a USD exercise price, and 9,993,000 options, with a Canadian Dollar ("CAD") exercise price, to purchase common shares, were outstanding as at December 31, 2017. Subsequent to year end 2017, 828,000 CAD options were forfeited.

	Number of common shares	Amount
Balance, December 31, 2015 and 2016	78,629,941	$ 344,479
Issued for cash	72,000,000	19,105
Issued for non-cash	22,197	7
Issuance costs, net of tax		(1,057)
Balance, December 31, 2017	150,652,138	$ 362,534

The change in common shares in 2017 is as a result of the Offering, whereby the Company issued 72,000,000 common shares resulting in 150,629,941 common shares outstanding as at February 24, 2017. During Q2 2017, a further 22,197 common shares were issued to Mr. Jeffrey Auld, the President and Chief Executive Officer of the Company, as part of his compensation, resulting in 150,652,138 shares outstanding.

The Company is also authorized to issue an unlimited number of preferred shares. No preferred shares are issued or outstanding.

The Company has the following options outstanding:

	USD denominated options		CAD denominated options	
	Number of options	Weighted average exercise price (USD)	Number of options	WA exercise price (CAD)
Balance, December 31, 2016	79,000	$ 3.90	$ 3,611,000	$ 0.38
Granted	-	-	6,995,000	0.37
Expired and cancelled	(12,000)	5.10	(58,000)	2.43
Forfeited	-	-	(615,000)	0.37
Balance, December 31, 2017	67,000	$ 3.68	$ 9,933,000	$ 0.36

The following tables summarize information about the USD and CAD options outstanding as at December 31, 2017:

USD denominated options				CAD denominated options			
Exercise price (USD)	Options outstanding	Options exercisable	Weighted average contractual life (years)	Exercise price (CAD)	Options outstanding	Options exercisable	Weighted average contractual life (years)
$3.01 - $4.00	32,000	32,000	0.7	$0.30 - $1.00	9,880,000	1,166,667	5.7
$4.01 - $5.00	35,000	35,000	0.9	$1.01 - $2.50	50,000	50,000	1.9
$5.01 - $5.10	-	-	-	$2.51 - $3.22	3,000	3,000	1.2
	67,000	67,000	0.8		$ 9,933,000	1,219,667	5.6

At the date of issuing this report, the following are the options outstanding and changes to directors, executives and officers shares owned since December 31, 2017, up to the date of this report:

	Changes to Ownership			
Name of Director/Executive Officer/ Key Person	Options held as at March 20, 2018	Shares held at December 31, 2017	Change in share ownership	Shares held at March 20, 2018
Evgenij Iorich [(a)]	100,000	3,415	-	3,415
Jeffrey Auld	4,500,000	22,197	-	22,197
Helmut Langanger [(d)]	-	-	-	-
Sebastian Kulczyk [(b)(e)]	-	-	-	-
Lukasz Redziniak	-	-	-	-
Dominik Libicki	-	-	-	-
Eleanor Barker	100,000	-	-	-
Tracy Heck	2,750,000	-	-	-
Calvin Brackman	750,000	-	-	-
Trevor Rath [(c)]	-	-	-	-
Jim Causgrove	100,000	-	-	-
	8,300,000	25,612	-	25,612

(a) Mr. Iorich holds a position with Pala Investments, which is related to Pala Assets Holdings Limited ("Pala"). Pala owned 11,266,084 Shares as at December 31, 2017 which included 5,385,600 shares issued relating to the Offering. By virtue of his position with Pala Investments, Mr. Iorich is deemed to have direction over such Shares in addition to those Shares that are shown above.
(b) Mr. Kulczyk holds a senior executive position with Kulczyk Investments ("KI"). KI owned 78,602,655 Shares as at December 31, 2017, which included 38,693,049 shares issued relating to the Offering. By virtue of his position with KI, Mr. Kulczyk is deemed to have direction over such Shares.
(c) Mr. Rath, resigned effective January 19, 2018, thus 650,000 options held were forfeited as they had not vested.
(d) Mr. Langanger, resigned effective March 7, 2018, thus 150,000 options held were forfeited as they had not vested.
(e) Mr. Kulczyk, resigned effective March 7, 2018. Mr. Kulczyk has been replaced by Mr. Dawid Jakubiwicz.

As at the date of issuing this report, management is aware of three shareholders holding more than 5% of the common shares of the Company. KI owns 52.17%, Pala owns 7.48%, and Quercus Towarzystwo Funduszy Investycyjych SA owns 5.24% of the common shares issued.

Commitments

Contractual obligations as at December 31, 2017 are as follows:

	Within 1 Year	2-3 Years	4-5 Years	Beyond 5 Years	**Total**
Operating leases	$ 653	$ 1,037	$ 7	$ -	$ 1,697
Gas plant-Romania [(1)]	1,983	-	-	-	1,983
Long-term debt [(2)]	-	11,991	13,181	6,591	31,763
Total	$ 2,636	$ 13,028	$ 13,188	$ 6,591	$ 35,443

[(1)] Contractual obligation on the construction of the gas processing facility.

[(1)] Long-term debt obligations presented exclude deferred financing costs and include only current accrued interest.

The Company's commitments are all in the ordinary course of business and include the work commitments for Tunisia and Romania.

Tunisia
The Tunisian state oil and gas company, ETAP, has the right to back into up to a 50% working interest in the Chouech Es Saida concession if, and when, the cumulative crude oil sales, net of royalties and shrinkage, from the concession exceeds 6.5 million barrels. As at December 31, 2017, cumulative liquid hydrocarbon sales net of royalties and shrinkage was 5.2 million barrels.

Romania
The work obligations pursuant to the Phase 3 extension, approved on October 28, 2016, include the drilling of two wells, and, at the Company's option, either the acquisition of 120 km^2 of new 3D seismic data or to drill a third well. The two firm wells must be drilled to minimum depths of 1,000 and 1,600 metres respectively, and if so elected, the third well to a depth of 2,000 metres. The term of the Phase 3 extension is for three years, expiring on October 28, 2019. On May 5, 2017, the Company signed a letter of guarantee for up to $12 million to cover the necessary expenses for the fulfillment of the minimal commitments for the Phase 3 extension. This guarantee was made net of any amounts already spent by the Company since the time of the extension's approval.

The Company signed an engineering, procurement, construction and commissioning contract ("EPCC") with Confind S.R.L., a Romanian company, for the construction of a gas processing facility and associated flowlines and pipelines on the Satu Mare concession. As at December 31, 2017, a balance of $2.0 million is remaining on this contract.

Office Space
The Company has a lease agreement for office space in Calgary, Canada which expires on November 30, 2020 and an office lease agreement in Bucharest, Romania, which expires on August 27, 2020.

Off Balance Sheet Arrangements

The Tunisian state oil and gas company, ETAP, has the right to back into up to a 50% working interest in the Chouech Es Saida concession.

Related Party Transactions

Loon Energy Corporation ("Loon Energy") is a publicly traded Canadian corporation. Serinus and Loon Energy are related as they have the same principal shareholder with control over Serinus and significant influence over Loon Energy. Management and administrative services were provided to Loon Energy by the management and staff of Serinus until August 31, 2016 when the services agreement was terminated and an office lease rental agreement was entered into. The office lease rental agreement was terminated effective February 15, 2017. For the year ended December 31, 2017, these fees totaled $2 thousand (2016: $9 thousand). As at December 31, 2017, Loon Energy owed $nil (December 31, 2016: $nil) to Serinus for these services. All related party transactions were at exchange amounts agreed to by both parties.

2018 Outlook

The Company is focusing on Romania as the impetus for growth over the next several years. The Moftinu gas development project is a near-term project that is expected to begin producing from the gas discovery well Moftinu-1000 and the planned Moftinu 1007 in late Q2 2018. The Company signed an engineering, procurement and construction and commissioning contract on May 9, 2017 and construction of a gas plant with 15 Mmcf/d of operational capacity is progressing with expected first gas production late Q2 2018.

The Company is also progressing the drilling program to meet work commitments for the extension to October 2019 and plans to drill three additional development wells (Moftinu-1003 and Moftinu-1004 and Moftinu-1007) The Corporation sees potential production from these wells being able to bring the gas plant to full capacity by late 2018.

In Tunisia, the Company is currently focusing on improving production from Sabria following the shut-in and plans to focus on carrying out low cost incremental work programs to increase production from existing wells, including the Sabria N-2 re-entry and installing artificial lift on another Sabria well, having determined that production at its oil field can be restarted in a safe and secure environment with sufficient comfort that there will be no further production disruptions for the foreseeable future. The Corporation views Sabria as a large development opportunity longer term.

For the Chouech Es Saida field, the Company is evaluating the restart of the field including timing and costs to replace the electric submersible pump for the CS-3 well. The Company views the level of activity pursued in Tunisia as dependent on the following thresholds being achieved and maintained. In terms of oil prices, incremental vertical wells become economic at Brent oil prices of ~$45/bbl, with potential multi-leg horizontal wells lowering the threshold to below $30/bbl in Sabria. The current capacity of surface facilities would only allow for 1 to 3 incremental wells for each of Sabria and Chouech Es Saida/Ech Chouech. As well for Chouech Es Saida/Ech Chouech, the STEG El Borma gas plant is nearly at its effective capacity. Further gas developments from this concession may have to be delayed until the completion of the Nawara Pipeline for material gas pipeline capacity to come online.

Dividends

To date, the Company has not paid dividends and does not anticipate paying dividends in the foreseeable future. Should the Company decide to pay dividends in the future, the Company would be required to satisfy certain liquidity tests as established in the Alberta Business Corporations Act.

Selected Annual Information

The following table sets out selected annual information extracted from the audited consolidated financial statements.

		As at December 31,	
	2017	2016	2015
Total assets	114,971	$ 104,836	185,187
Total long-term liabilities	89,307	51,883	54,832
		As at December 31,	
	2017	2016	2015
Oil & gas revenue & change in oil inventory, net of royalties[(a)]	$ 5,889	$ 13,975	$ 22,986
Net loss from continuing operations attributable to:			
Common shareholders	$ (18,792)	$ (27,521)	$ (52,150)
Net loss per share			
Basic and diluted	$ (0.13)	$ (0.35)	$ (0.66)
Net loss attributable to:			
Common shareholders	$ (18,792)	$ (58,899)	$ (49,104)
Non-controlling interest	-	721	1,306
Net loss per share			
Basic and diluted	$ (0.13)	$ (0.75)	$ (0.62)
Weighted average number of shares	139,796,985	78,629,941	78,629,941

(a) Amounts have been presented net as a result of the reclassification of Ukraine to discontinued operations, see note 21 to the December 31, 2017 Audited Consolidated Annual Financial Statements.

Total assets

Total assets as at December 31, 2017 were $115.0 million compared to $104.8 million as at December 31, 2016. The increase is primarily due to capital additions of $8.9 million, an increase in property, plant, and equipment of $3.5 million related to the increase in the estimate of the asset retirement obligations, an increase in cash of $3.0 million and an increase in accounts receivable of $1.6 million, prepaids and crude oil inventory increase of $0.4 million, partially offset by a tax receivable decrease of $0.4 million, $1.9 million in depletion and depreciation and $5.0 million in impairment during the year.

Total long-term liabilities

Total long-term liabilities as at December 31, 2017 were $89.3 million compared to $51.9 million as at December 31, 2016. The change is primarily due to $31.2 million in debt being classified as long-term in the current year compared to current as at December 31, 2016, as well as an increase in long-term ARO liabilities of $5.4 million primarily due to an increase in the inflation rate and increase in estimates attributable to Tunisia.

Summary of Quarterly Results

Certain crude oil and natural gas liquids volumes have been converted to mcf or mmcf on the basis of one bbl to six mcf. Also, certain natural gas volumes have been converted to boe or mboe on the same basis. Any figure presented in mcf.

	Q4 2017	Q3 2017	Q2 2017	Q1 2017	Q4 2016	Q3 2016	Q2 2016	Q1 2016
Oil and gas revenues & change in oil inventory, net of royalties [(a)]	1,895	382	1,342	2,950	4,456	3,632	4,080	3,779
Net earnings (loss) attributed to:								
Common shares	(9,681)	(7,043)	31	(2,099)	(14,419)	(4,971)	(3,994)	(4,137)
Earning (loss) per share:								
-basic and diluted	$ (0.06)	$ (0.05)	$ -	$ (0.02)	$ (0.19)	$ (0.06)	$ (0.05)	$ (0.05)
Net earnings (loss) attributed to:								
Common shares	(9,681)	(7,043)	31	(2,099)	(14,419)	(4,971)	(3,994)	(35,515)
Non-controlling interest	-	-	-	-	-	-	-	721
Earning (loss) per share:								
-basic and diluted	$ (0.06)	$ (0.05)	$ -	$ (0.02)	$ (0.19)	$ (0.06)	$ (0.05)	$ (0.45)

[(a)] *Amounts have been restated as a result of the reclassification of Ukrainian operations to discontinued operations, see note 20 to the December 31, 2017 Audited Consolidated Financial Statements.*

- In Q1 2016, revenues were impacted by lower production and commodity prices in Tunisia. In addition, total income was negatively impacted by the loss on the sale of Ukraine operations.
- In Q2 2016, total income was impacted by low commodity prices in Tunisia.
- In Q4 2016, total income was impacted by low commodity prices in Tunisia and an increase in G&A due to one-time senior executives' termination payments incurred in the quarter.
- In Q4 2016, total income was impacted by recovering commodity prices in Tunisia and decreased corporate G&A, offset by a decrease in production. In addition, total income was negatively impacted by an impairment charge of $16.8 million for Tunisia.
- In Q1 2017, total income was impacted by a decrease in production due to the shut-in of the Chouech Es Saida field, offset by recovering commodity prices, decreased production expenses and corporate G&A.
- In Q2 2017, total income was negatively impacted by the shut-in in Tunisia, with Chouech Es Saida being shut-in for the full quarter and Sabria being shut-in from May 22, 2017. In addition, Q2 2017, was impacted by a gain on of $2.2 million resulting from the sale of the subsidiary holding the Syrian asset.
- In Q3 2017, oil and gas revenues were negatively impacted by the shut-in in Tunisia, with Chouech Es Saida being shut-in for the full quarter (since end of February 2017) and Sabria being shut-in from May 22, 2017 to the start of September 2017. Sabria came back on production with an average rate of 286 bbl/d in September 2017. During this period, 100% of the production is from the Sabria concession. Net earnings was negatively impacted by an impairment expense of $5.0 million for Tunisia assets.
- In Q4 2017, oil and gas revenues were negatively impacted by the shut-in in Tunisia, with Chouech Es Saida being shut-in for the full quarter. All production is from the Sabria concession with an average production rate of 396 boed in Q4 2017. Net earnings were negatively impacted by the one-time well incident expense of $4.0 million and a provision for $0.6 million for potential severance costs for termination of employees in the Chouech Es Saida field in Tunisia.

Risk Factors

The Company takes a proactive approach to identifying inherent risks to its business and operations through the consistent identification of risks in day to day operations enabling the appropriate decision making. Below is a list of what the Company has identified as its principal risks. A principal risk is an exposure that has the potential to materially impact the ability of the Company to meet objectives. Some risks are common to operations in the oil and gas industry, while others are specific to the Company and its operations in emerging markets. The risks below are not meant to be an exhaustive or a static list, nor should they be taken as a complete summary of all the risks associated with our business. If any of these risks or other risks occur, our business, financial condition, results of operations and cash flows could be adversely affected in a material way.

Commodity Price Risk

The Company's financial performance is impacted by prices obtained for crude oil, natural gas and natural gas liquids. The prices of these commodities are influenced by global and regional supply and demand which can result in price volatility. Prices are also affected by factors such as economic growth, transportation constraints, political developments, decisions made by the Organization of Petroleum Exporting Countries (OPEC) members and weather. These dynamics can affect different types of products differently.

Specifically, the Company is exposed to risks due to fluctuations in the market price of Brent crude oil. Oil prices are based on the market price of Brent crude oil. Natural gas prices are nationally regulated and are tied to the twelve-month trailing average of low sulphur heating oil (benchmarked to Brent). The Company has no commodity hedge program in place which could potentially mitigate the price risk.

Given recent global economic conditions, there has been volatility and continued uncertainty in prices in the near time is expected. A prolonged period of low prices could affect the value of assets and the level of capital expenditure, thus having a material adverse effect on operations.

Financial Risks

Financial risks include interest rate risk, credit risk, foreign currency exchange risk and liquidity risks.

Foreign currency exchange risk

The Company is exposed to risks arising from fluctuations in currency exchange rates between the Canadian dollar, Polish zloty, Romanian leu, Tunisian dinar, the Euro and the United States dollar. At December 31, 2017, the Company's primary currency exposure related to Canadian dollar ("CAD"), Romanian leu ("LEU"), and Tunisian dinar ("TND") balances. The following table summarizes the Company's foreign currency exchange risk for each of the currencies indicated:

As at December 31, 2017		CAD	LEU	TND
Cash and cash equivalents	$	4,130	1,591	12
Accounts receivable		82	5,814	2,704
Income tax receivable		-	3	2,852
Restricted cash		1,378	-	-
Prepaid expense		43	171	328
Accounts payable and accrued liabilities		(153)	(10,371)	(6,956)
Net foreign exchange exposure	$	5,480	(2,792)	(1,060)
Translation to USD		0.7971	0.2570	0.4026
USD equivalent at period end exchange rate	$	4,368	(718)	(427)

Based on the net foreign exchange exposure at the end of the period, if these currencies had strengthened or weakened by 10% compared to the U.S. dollar and all other variables were held constant, the after tax net earnings would have decreased or increased by approximately the following amounts:

Impact on net earnings (loss)		December 31, 2017		December 31, 2016
Canadian dollar (CAD)	$	437	$	109
Romanian leu (LEU)		(72)		10
Tunisian dinar (TND)		(43)		146
Total	$	322	$	265

Interest rate risk

The Company maintains its cash and cash equivalents in instruments that are redeemable at any time without penalty, thereby reducing its exposure to interest rate fluctuations thereon.

The primary exposure to interest rate risk is related to the Tunisia debt, being the only debt outstanding. The interest rate on the senior loan is LIBOR plus 6%. The convertible loan interest is linked to LIBOR with a portion based on incremental revenue with a floor of 8% and ceiling of 17%.

A 1% change in the LIBOR, assuming the amount of debt remains unchanged, would affect the senior loan interest expense by $14 thousand and $59 thousand for three and year ended December 31, 2017, respectively (Q4 2016

– $18 thousand), and the convertible loan by $64 thousand and $244 thousand for the three and year ended December 31, 2017, respectively ($59 thousand and $224 thousand for the comparative periods in 2016).

Credit risk

The Company's cash and cash equivalents and restricted cash are held with major financial institutions. Management monitors credit risk by reviewing the credit quality of the financial institutions that hold the cash, cash equivalents and restricted cash.

The Company's accounts receivable consisted primarily of receivables for revenue and from joint venture partners.

The Company is exposed to credit risk in relation to balances receivable from joint venture partners as collection of outstanding balances is not assured. The Company attempts to mitigate the risk from joint venture receivables by obtaining partner approval of significant capital expenditures prior to expenditure and issuing cash calls to its partners on projects before they commence.

Management believes that the Company's exposure to credit risk is manageable, as commodities sold are under contract or payment within 30 days. Production is sold with reputable parties and collection is prompt based on the individual terms with the parties. At December 31, 2017, the Company had $nil (December 31, 2016-$nil) of receivables that were considered past due (over 90 days outstanding). For the year ended December 31, 2017, excluding change in oil inventory and royalties taken-in-kind, the Company had three customers with sales representing 54%, 24% and 22% of total sales (for year ended December 2016 – four customers representing 51%, 19%, 22%, and 8%).

Management has no formal credit policy in place and the exposure to credit risk is approved and monitored on an ongoing basis individually for all significant customers. The maximum exposure to credit risk is represented by the carrying amount of each financial asset in the statement of financial position. The Company does not require collateral in respect of financial assets.

Liquidity risk

Liquidity risk is the risk that the Company will not be able to pay financial obligations when due. There are inherent liquidity risks, including the possibility that additional financing may not be available to the Company, or that actual exploration and development expenditures may exceed those planned. The Company mitigates this risk through monitoring its liquidity position regularly to assess whether it has the resources necessary to fund planned exploration commitments on its petroleum and natural gas properties or that viable options are available to fund such commitments. Alternatives available to the Company to manage its liquidity risk include deferring planned capital expenditures that exceed amounts required to retain concession licenses, farm-out arrangements and securing new equity or debt capital.

There can be no assurance that our internally generated cash flows will be adequate for our future financial obligations, including our future capital expenditure program, or that we will be able to obtain additional funds.

At December 31, 2017, the covenants on the debt were not in effect, as the terms of the financial debt and financial covenants were renegotiated in October 2017, see EBRD Tunisia Loan Facility. In Q4 2017, the Company financed cash outflows including working capital and capital expenditures from cash generated from Tunisian operations and proceeds of the equity offering.

Operational, Environmental and Safety Risks

The Company's operations require significant investment in both the exploration and evaluation and operation and maintenance of facilities. Associated are the risks relating to environmental and safety. Keeping employees and worksites safe and secure and to preserving and protecting the environment, is of paramount importance. Operational hazards include fires, explosions, blow-outs, power outages, severe weather conditions and the release of harmful substances such as oil spills, gas leaks. Any of these hazards can interrupt operations, cause injury or death, damage property, equipment or/and the environment. Losses resulting from the occurrence of any of these risks could have a material adverse effect on operations.

To mitigate these risks, the Company evaluates projects for financial, geological and engineering risk and mitigation plans are developed, including a comprehensive insurance program. There is the risk that insurance may not provide adequate coverage in all circumstances, nor are all risks insurable.

Project Risk

There are risks associated with exploration, evaluation and execution of oil and gas projects.

Risks in exploration include failure to acquire or find additional reserves which will, at minimum, result in erosion of the Company's existing reserves as these reserves are depleted through ongoing production, and may negatively impact the Company's ability to grow its asset base in the future. There is no assurance that the Company will be able to find suitable properties to acquire or participate in the future. The company uses proactive project planning on existing licenses and performs extensive business development dedicated to identifying and pursuing potential opportunities. Further, all investment opportunities are reviewed using careful consideration and technical analysis.

Risks in the evaluation of future oil and natural gas properties may involve unprofitable efforts from dry wells as well as from wells that are productive but do not produce sufficient production to return a profit after drilling, completing, operating and other costs. Completion of a well does not assure a profit on the investment or recovery of costs spent. To mitigate this, the Company uses reputable industry specialists and monitors field performance on a daily basis.

Risks involved in the execution of projects relate primarily to engineering and a failure in the specification, design or technology of a project; the construction and a failure in the ability to build the project in the time and cost budgeted; and lastly the commissioning and start up a failure of the facility to meet performance targets. To mitigate these risks, the Company estimates costs and an expectation for all projects and at each stage evaluates the project to ensure financial viability. There are numerous factors beyond our control such as commodity prices, weather, availability of equipment, unexpected cost increases, accidental events, regulatory changes which could have a negative impact on the company ability to execute projects on time and budget.

The oil and natural gas industry in emerging markets where the company operates is not as developed as the oil and natural gas industry in developed nations such as Canada. As a result, drilling and development operations may take longer to complete and may cost more than similar operations in a developed nation. As well, the availability of technical expertise, specific equipment and supplies may be more limited. Such factors subject operations in emerging markets to unique risks not experienced by others.

Partners and Joint Ventures

The Company has and will in the future, benefit from partnerships or joint ventures with local and international companies through which exploration, development, and operating activities for particular assets are conducted. Benefits include the ability to source and secure new opportunities, capitalizing on the local partner's market knowledge and relationships (in particular in countries or regions where the Company has no or limited prior operations), mitigation of some of the financial risk inherent in the exploration and development of oil and gas assets through farm-out and similar arrangements, and the alignment of interests. A deterioration in relationships or disagreements with existing partners, a failure to identify suitable partners, or a change in circumstances relating to a partner may have an adverse impact on its existing operations or affect its ability to grow its business.

Political and Economic Risks

The Company operates in an emerging market that is subject to political and economic risks. Political stability and the uncertainty regarding political decisions may result in: the possibility of war/revolution, border disputes, expropriation, renegotiation or modification of existing contracts, import, export and transportation restrictions, change in regulations and tariffs, tax increases, loss of subsidy, change of market policy and laws regarding resource extraction, social unrest and protests. As a result of political instability, economic challenges that may ensue include slow growth, high inflation and unfavorable fluctuations in exchange rates.

Regulatory Risks

The Company is subject to a range of laws and regulations imposed by a number of and various levels of government and regulatory bodies. The Company believes it fully complies with or exceeds all government laws, regulations and industry standards; however, these regulations are subject to intervention by governments that can affect future exploration, production and abandonment of fields and licenses. Rights and licenses can be cancelled, may expire or be expropriated and regulations can change. Certain licenses have restrictions which may not be removed on a timely basis. Due to the nature of emerging markets and changing regulations, regulatory changes can have a material adverse effect on operations in a way beyond what can be forecast.

Litigation

The Company is not involved in any proceedings before a court, relevant arbitration body or public administrative authority concerning payables or debt of the Company whose value, individually or in aggregate, would be equal to or greater than 10% of the Company's equity.

Critical Accounting Estimates

The preparation of financial statements in conformity with IFRS requires management to make judgements, estimates and assumptions based on currently available information that affect the application of accounting policies and the reported amounts of assets, liabilities, income and expenses. Estimates and judgements are evaluated and are based on managements' experience and other factors, including expectations of future events that are believed to be reasonable under the circumstances. However actual results could differ from these estimates. By their very nature, these estimates are subject to measurement uncertainty and the effect on the financial statements of future periods could be material. Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the period in which the estimates are revised and in any future periods affected.

Significant estimates and judgments made by management in the consolidated financial statements are described below:

Oil and gas reserves

Measurements of depletion, depreciation, impairment, ARO and business acquisitions are determined in part based on the company's estimate of oil and gas reserves and resources. The process of determining reserves is complex and involves the exercise of professional judgement. All reserves have been evaluated at December 31, 2017 by independent qualified reserves evaluators. All significant judgments are based on available geological, geophysical, engineering, and economic data. These judgments are based on estimates and assumptions that may change substantially as additional data from ongoing development activities and production performance becomes available and as economic conditions impacting oil and gas prices and costs change. The reserve estimates are based on current production forecasts, prices and economic conditions. As circumstances change and additional data becomes available, reserve estimates also change. Estimates made are reviewed and revised, either upward or downward, as warranted by the new information. Revisions are often required due to changes in well performance, prices and economic conditions. Although every reasonable effort is made to ensure that reserve estimates are accurate, reserve estimation is an inferential science. As a result, subjective decisions, new geological or production information and a changing environment may impact these estimates. Revisions to reserve estimates can arise from changes in year-end oil and gas prices and reservoir performance. Such revisions could be material and result in either positive or negative amounts.

The cash flow model used to value oil and gas properties incorporates estimates of future commodity prices. Generally, the pricing assumptions used are those of the external reserve engineer adjusted for differentials specific to the Company. Commodity prices can fluctuate for a variety of external reasons including supply and demand fundamentals, inventory levels, exchange rates, weather, and economic and geopolitical factors as well as internal reasons including quality differentials.

Oil and gas activities

The Company is required to apply judgment when designating the nature of oil and gas activities as exploration, evaluation, development or production, and when determining whether the initial costs of these activities are capitalized and reclassified. The Company is required to make judgments about future events and circumstances and applies estimates to assess the economic viability of extracting the underlying resources.

Cash generating units

The determination of CGUs requires judgment in defining a group of assets that generate cash inflows that are largely independent of the cash inflows from other assets or groups of assets. CGUs are determined by similar geological structure, shared infrastructure, geographical proximity, commodity type, similar exposure to market risks and materiality.

Impairment and reversals

Judgment in assessing the existence of impairment and impairment reversal indicators is based on various internal and external factors. The recoverable amount of CGUs and individual assets is determined on the higher of fair value less cost of disposal or value in use. Key estimates in determining the recoverable amount normally include proved and probable reserves, forecasted commodity prices, expected production, future operating and development costs, discount rates and tax rates. In determining the recoverable amount, management may also need to make assumptions regarding the likelihood of an event. Changes to these estimates and judgements will impact the recoverable amounts of CGUs and individual assets and may require a material adjustment to their carrying value.

Asset retirement obligations

The Company recognizes liabilities for the future decommissioning and restoration of exploration and evaluation assets and property, plant and equipment. Management applies judgment in assessing the existence and extent as well as the expected method of reclamation of the Company's decommissioning and restoration obligations at the end of each reporting period. Management also uses judgment to determine whether the nature of the activities performed is related to decommissioning and restoration activities or normal operating activities. In addition, these provisions are based on estimated costs, which take into account the anticipated method and extent of restoration and the possible future use of the site. Actual costs are uncertain and estimates can vary as a result of changes to relevant laws and regulations, the emergence of new technology, operating experience, prices and closure plans. The estimated timing of future decommissioning and restoration may change due to certain factors, including reserve life. Changes to estimates related to future expected costs, discount rates and timing could result in a significant adjustment to the provisions established which would affect future financial results.

Deferred income taxes

Estimates and assumptions are used in the calculation of deferred income taxes. Judgments include assessing whether tax assets can be recognized is based on expectations of future cash flows from operations and the application of existing tax laws and terms of concession agreements. To the extent that future cash flows and taxable income differ significantly from estimates, the ability of the Company to realize the deferred tax assets and liabilities recorded at the balance sheet date could be impacted by a material amount. Additionally, changes in tax laws could limit the ability of the Company to obtain tax deductions in the future.

The determination of the Company's taxable income and other tax liabilities requires interpretation of complex laws and regulations often involving multiple jurisdictions. Estimates that require significant judgments are also made with respect to the timing of temporary difference reversals, the realizability of tax assets and in circumstances where the transaction and calculations for which the ultimate tax determination are uncertain. All tax filings are subject to audit and potential reassessment after the lapse of considerable time. Accordingly, the actual income tax liability may differ significantly from that estimated and recorded by management.

Share-based compensation

Stock options issued by the Company are recorded at fair value using the Black-Scholes option pricing model. The calculation of share-based payment expense requires estimates which involve assumptions about the share price volatility, forfeiture rates, option life, dividend yield and risk-free rate at the initial grant date. Changes to these estimates impact the stock based compensation expense and contributed surplus and may have a material impact on the amounts presented.

Future Changes in Accounting Policies

For the three months and year ended December 31, 2017, the Company did not adopt any new IFRS standards nor were any applicable pronouncements announced.

<u>*Revenue from Contracts with Customers*</u>

In April 2016, the IASB issued its final amendments to IFRS 15 "*Revenue from Contracts with Customers*", which will replace IAS 11 "*Construction Contracts*" and IAS 18 "*Revenue*" and the related interpretations on revenue recognition. IFRS 15 establishes a single revenue recognition framework that applies to contracts with customers. The new standard moves away from a revenue recognition model based on an earnings process to an approach that is based on transfer of control of a good or service to a customer. The standard requires an entity to recognize revenue to reflect the transfer of goods and services for the amount it expects to receive, when control is transferred to the purchaser. Disclosure requirements have also been expanded to include the nature, amount, timing and uncertainty of revenues and cash flows arising from contracts with customers.

The new standard is effective for annual periods beginning on or after January 1, 2018 with early adoption permitted. The standard is required to be adopted retrospectively to each period presented or retrospectively using a modified approach as a cumulative-effect adjustment as of the date of adoption. The Company will adopt the standard on January 1, 2018 using the modified retrospective approach, which requires recognizing the cumulative impact of adoption, if any, in retained earnings as of January 1, 2018. Comparative periods will not be restated. The Company has completed reviewing its numerous revenue and underlying revenue contracts and has concluded that the adoption of IFRS 15 will not have a material impact on the Company's consolidated financial statements. Under IFRS 15 revenue will be recognized once volumes are delivered for lifting rather than the current requirement to recognize upon lifting. This will impact the presentation in the statement of operations as the amount recorded currently as "change in oil inventory" will be recognized as "petroleum and natural gas revenues". This has no impact on net earnings. Likewise, on the statement of financial position, commodity inventory under the current standard net of advances for crude oil sales, will under the new standard be recorded as a trade receivable. The Company will expand the disclosure in the notes to the consolidated financial statements as prescribed by IFRS in Q1 2018.

Financial Instruments
In July 2014, the IASB issued the last version of IFRS 9 "*Financial Instruments" ("IFRS 9") to* replace IAS 39 "*Financial Instruments: Recognition and Measurement" ("IAS 39")*.

The new standard replaces the current multiple classification and measurement models for financial assets and liabilities with a single approach to determine whether a financial asset is measured at amortized cost or fair value. The approach is based on how an entity manages it financial instruments in the context of its business model and the contractual cash flow characteristics of the financial assets. The IAS 39 measurement categories for financial assets will be replaced by fair value through profit or loss, fair value through other comprehensive income ("FVOCI") and amortized cost. The standard eliminates the existing IAS 39 categories of held-to-maturity, loans and receivable and available for sale.

IFRS 9 retains most of the IAS 39 requirements for financial liabilities. However, where fair value option is applied to financial liabilities, the change in fair value resulting from an entity's own credit risk is recorded through other comprehensive income rather than net earnings. Serinus currently does not designate any financial liabilities as fair value through profit or loss; therefore, there will be no impact on the accounting for financial liabilities.

The new standard also changes how debt modifications are treated. Under IAS 39, debt modifications did not have an impact on profit and loss. However, under IFRS 9, the difference between the carrying amount of the financial liability, and the present value of the estimated future contractual cash flows discounted at the original effective interest rate, must be recognized in profit and loss. As the Company renegotiated the repayment terms on its long-term debt, effective October 31, 2017, the impact of IFRS 9 will be to recognize a modification loss of $0.4 million on the Senior Loan, and a modification gain of $1.4 million on the Convertible Loan. The net impact will be a $1.0 million modification gain which will decrease long-term debt and increase opening retained earnings as at January 1, 2018.

The new standard also introduces an expected credit loss model for evaluating impairment of financial assets. The new model will result in more timely recognition of expected credit losses. The Company does not expect the change in the impairment model to have a material impact on the consolidated financial statements.

In addition, IFRS 9 provides a simplified hedge accounting model, aligning hedge accounting more closely with risk management activities. The Company currently does not apply hedge accounting.

IFRS 9 is effective for years beginning on or after January 1, 2018 with early adoption permitted. The Company will apply the new standard retrospectively. Comparative periods will not be restated.

Leases
In January 2016, the IASB issued IFRS 16 "*Leases" ("IFRS 16"),* which requires entities to recognize assets and lease obligations on the balance sheet. For lessees, IFRS 16 removes the classification of leases as either operating leases or finance leases, effectively treating all leases as finance leases. Certain short-term leases (less than 12 months) and leases of low-value assets are exempt from the requirements, and may continue to be treated as operating leases. Lessors will continue with a dual lease classification model. Classification will determine how and when a lessor will recognize lease revenue and what assets would be recorded.

IFRS 16 is effective for years beginning on or after January 1, 2019 with early adoption permitted if IFRS 15 "*Revenue From Contracts With Customers*" has been adopted. The standard shall be applied retrospectively to each period presented or using a modified retrospectively approach where the Company recognizes the cumulative effect as an adjustment to the opening retained earnings and applies the standard prospectively. The Company is currently in the process of identifying, gathering, and analyzing contracts that fall into the scope of the standard. The extent of the impact of the adoption of the standard has not yet been determined. The Company plans to apply IFRS 16 effective January 1, 2019. The Company intends to adopt the standard using the modified retrospective approach recognizing the cumulative impact of adoption in retained earnings as of January 1, 2019 and apply several of the practical expedients available such as low-value and short-term exemptions.

Disclosure Controls and Procedures and Internal Controls Over Financial Reporting

The preparation of this MD&A is supported by a set of disclosure controls and procedures ("DC&P") and internal controls over financial reporting ("ICFR") as at December 31, 2017.

Disclosure controls and procedures as defined in National Instrument 52-109 means controls and other procedures of an issuer that are designed to provide reasonable assurance that information required to be disclosed by the issuer in its annual filings, interim filings or other reports filed or submitted by it under securities legislation is recorded, processed, summarized and reported within the time periods specified in the securities legislation and include controls and procedures designed to ensure that information required to be disclosed by an issuer in its annual filings, interim filings or other reports filed or submitted under securities legislation is accumulated and communicated to the issuer's management, including its certifying officers, as appropriate to allow timely decisions regarding required disclosure;

Internal control over financial reporting means a process designed by, or under the supervision of, an issuer's certifying officers, and effected by the issuer's board of directors, management and other personnel, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with the issuer's Generally Accepted Accounting Principles ("GAAP") and includes those policies and procedures that:

(a) Pertain to the maintenance of records that in reasonable detail accurately and fairly reflect the transactions and dispositions of the assets of the issuer;

(b) are designed to provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with the issuer's GAAP, and that receipts and expenditures of the issuer are being made only in accordance with authorizations of management and directors of the issuer; and

(c) are designed to provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the issuer's assets that could have a material effect on the annual financial statements or interim financial statements.

The Company's Chief Executive Officer and Chief Financial Officer of the Company have designed DC&P and ICFR, or caused them to be designed under their supervision, to provide reasonable assurance that all material information required to be disclosed by Serinus in its annual filings and interim filings are recorded, processed, summarized and reported within the time periods specified in applicable securities legislation, and to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes, in accordance with IFRS. The ICFR is based on criteria established in "Internal Control – Integrated Framework" issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO") in 2013.

The board of directors, through its Audit Committee, is responsible for ensuring that management fulfils its responsibilities for financial reporting and internal control. The Audit Committee meets at least annually with the Company's external auditors to review accounting, internal control, financial reporting, and audit matters.

There have been no material changes to the Company's internal controls over financial reporting during the period beginning January 1, 2017 and ending December 31, 2017. Under the supervision of the Company's Chief Executive Officer and Chief Financial Officer, Serinus conducted an evaluation of the effectiveness of its DC&P and ICFR as at December 31, 2017. Based on this evaluation, management concluded that DC&P and ICFR were effective as of December 31, 2017.

Non-IFRS Measures

The financial information presented in this MD&A has been prepared in accordance with IFRS except for the terms "netback" and "working capital" which are not recognized measures under IFRS and do not have standardized meanings prescribed by IFRS. These non-IFRS measures are presented for information purposes only and should not be considered an alternative to, or more meaningful than information presented in accordance with IFRS. Management believes netback and working capital may be useful supplemental measures as they are used by the Company to measure operating performance and to evaluate the timing and amount of capital required to fund future operations. The Company's method of calculating these measures may differ from those of other companies and, accordingly, they may not be comparable to measures used by other companies.

Serinus calculates "netback" and "working capital" as presented earlier in this document.

Forward-Looking Statements

This MD&A contains forward-looking statements. These statements relate to future events or future performance of the Company. When used in this MD&A, the words "may", "would", "could", "will", "intend", "plan", "anticipate", "believe", "estimate", "predict", "seek", "propose", "expect", "potential", "continue", and similar expressions, are intended to identify forward-looking statements. These statements involve known and unknown risks, uncertainties, and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements. Such statements reflect the Company's current views with respect to certain events, and are subject to certain risks, uncertainties and assumptions. Many factors could cause the Company's actual results, performance, or achievements to vary from those described in this MD&A. Should one or more of these risks or uncertainties materialize, or should assumptions underlying forward-looking statements prove incorrect, actual results may vary materially from those described in this MD&A as intended, planned, anticipated, believed, estimated, or expected.

Specific forward-looking statements in this MD&A, among others, include statements pertaining to the following:

- factors upon which the Company will decide whether or not to undertake a specific course of action;
- world-wide supply and demand for petroleum products;
- expectations regarding the Company's ability to raise capital;
- treatment under governmental regulatory regimes; and
- commodity prices.

With respect to forward-looking statements in this MD&A, the Company has made assumptions, regarding, among other things:

- the impact of increasing competition;
- the ability of partners to satisfy their obligations;
- the Company's ability to obtain additional financing on satisfactory terms; and
- the Company's ability to attract and retain qualified personnel.

The Company's actual results could differ materially from those anticipated in these forward-looking statements as a result of the risk factors set forth below and elsewhere in this MD&A:

- general economic conditions;
- volatility in global market prices for oil and natural gas;
- competition;
- liabilities and risks, including environmental liability and risks, inherent in oil and gas operations;
- the availability of capital;
- geopolitical volatility in the countries of operations; and
- alternatives to and changing demand for petroleum products.

Furthermore, statements relating to "reserves" or "resources" are deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the resources and reserves described can be profitable in the future.

The forward–looking statements contained in this MD&A are expressly qualified in their entirety by this cautionary statement. These statements speak only as of the date of this MD&A.

Abbreviations

The following abbreviations may be used throughout this MD&A document:

bbl	Barrel(s)	bbl/d	Barrels per day
boe	Barrels of Oil Equivalent	boe/d	Barrels of Oil Equivalent per day
mcf	Thousand Cubic Feet	mcf/d	Thousand Cubic Feet per day
mmcf	Million Cubic Feet	mmcf/d	Million Cubic Feet per day
mcfe	Thousand Cubic Feet Equivalent	mcfe/d	Thousand Cubic Feet Equivalent per day
mmcfe	Million Cubic Feet Equivalent	mmcfe/d	Million Cubic Feet Equivalent per day

mboe	Thousand boe	Bcf	Billion Cubic Feet
mmboe	Million boe	mcm	Thousand Cubic Metres
CAD	Canadian Dollar	USD	U.S. Dollar
$M	Thousands of Dollars	UAH	Ukrainian Hryvnia
$MM	Millions of Dollars	TND	Tunisian Dinar

Measurement Conversions

Certain crude oil and natural gas liquids volumes have been converted to mcfe or mmcfe on the basis of one bbl to six mcf. Also, certain natural gas volumes have been converted to boe or mboe on the same basis. Any figure presented in mcfe, mmcfe, boe or mboe may be misleading, particularly if used in isolation. A conversion ratio of one bbl of crude oil or natural gas liquids to six mcf of natural gas is based on an energy equivalency conversion method primarily applicable at the burner tip and does not necessarily represent value equivalency at the wellhead.

Investor Information

Additional information regarding Serinus and its business and operations is available at www.sedar.com. Information is also accessible on the Company's website at www.serinusenergy.com.

We welcome questions from interested parties. Contact should be directed to the head office of Serinus via address: Suite 1500, 700 – 4th Avenue S.W., Calgary, Alberta T2P 3J4 Canada, phone: +1 403 264-8877 or e-mail: info@serinusenergy.com.