Osum Oil Sands Corp.

Q3 2017 Interim Report to Shareholders

Dated November 8, 2017

Q3 2017 Interim Report **Page**

Review and Outlook

Q3 2017 Review

Osum had a transformative third quarter that was highlighted by the completion of its Orion Phase 2A expansion, the sanctioning of its Orion's Phase 2B expansion, and the closing of a significant royalty sale. In addition, third quarter operating results were strong and Osum recognized substantial reserve additions.

The Phase 2A expansion was completed on time and on budget and is expected to add 1,500 bbl/d of production over the next twelve months. Steam circulation on the three Phase 2A well pairs continued in the third quarter and all three well pairs are currently in SAGD production, though full ramp-up of the wells will continue into 2018. The waste crystallizer unit was completed in the third quarter and its commissioning continued in the fourth quarter.

Work on the Phase 2B expansion has commenced and will build on the successful execution of Phase 2A. The Phase 2B expansion, which will add a third evaporator tower, five growth well pairs, three sustaining well pairs and additional oil processing and other equipment, is projected to be completed in mid-2018 and is expected to increase production progressively through mid-2019 by an additional 3,000 bbl/d.

Concurrent with the sanctioning of Phase 2B, Osum, through its wholly-owned subsidiary, Osum Production Corp., completed the sale of a 4 percent gross overriding royalty interest ("GORR") on Orion to an unrelated third party for cash proceeds of $92.5 million, before transaction costs. The GORR sale closed on September 29, 2017. Under the terms of the agreement, effective September 1, 2017, the GORR purchaser is entitled to a monthly royalty on bitumen sales from the Orion project, including from any future development phases.

Also during the third quarter, Osum engaged its independent reserve evaluators to update its reserves and resource assessment, taking into consideration the results of a delineation well drilled during the period and project performance since its last assessment effective December 31, 2016. As a result of the update, the Company's gross proved (1P) bitumen reserves at September 1, 2017 increased by 12.5 MMbbls or 26% from December 31, 2016, and total proved plus probable (2P) reserves increased by 29.9 MMbbls or 6% over the same period. Further details are provided in the "Bitumen Reserves" section of this report.

With the proceeds of the GORR sale, Osum significantly strengthened its liquidity position with $236.8 million of cash on hand at September 30, 2017 and net working capital (excluding net unrealized hedging liabilities) of $233.8 million.

Production

Average production at Orion in the quarter of 7,946 bbl/d was higher than the forecast average for the year of 7,700 bbl/d and up 6% from the prior quarter's average of 7,478 bbl/d. The increase from the prior quarter's average was mainly due to the positive impact of workovers completed on the pilot wells in the third quarter, and to the initial contribution from the Phase 2A well pairs.

Operating netback

Osum generated an operating netback in the period of $14.7 million or $20.10/bbl, compared with $12.1 million or $17.73/bbl in the prior quarter. Including realized net financial hedging losses, the netback in the third quarter was $13.3 million or $18.24/bbl, compared with $10.5 million or $15.41/bbl in the second quarter. The following positive and negative factors contributed to the higher overall total and per unit netbacks:

- While the average index price of US-dollar West Texas Intermediate oil was substantially the same as for the prior quarter, the benefit of a decrease in heavy oil differentials was more than offset by the strengthening of the Canadian dollar, leading to the average index price of Cold Lake Blend in Canadian dollars being $2.09 or 4% lower than the prior quarter. Mitigating some of the impact of that decrease, Osum's realized bitumen price on a barrel of production basis was positively impacted by a lower seasonal blending ratio. As a result, the average realized bitumen price of $38.64/bbl was lower than the prior quarter, down $0.84/bbl or 2%.
- Average royalties of $0.61/bbl or 2.5% of bitumen sales decreased from $0.98/bbl or 2.9% of bitumen sales in the prior quarter. The decline was attributable to differences between the timing of bitumen production and blended bitumen sales, as well as a decrease in the calculated Canadian dollar oil price. Royalties in the third quarter included $0.04/bbl of the GORR, which represents the two days of royalties on and after the closing date of September 29, 2017.
- Average total operating costs of $17.93/bbl were 14% or $2.84/bbl lower than the prior quarter.
    - Average non-fuel operating costs of $15.06/bbl were 4% or $0.68/bbl lower than the second quarter. The decrease in unit costs was primarily due to lower average fixed costs as a result of higher production and the absence of evaporator washing costs incurred in the second quarter, partially offset by workover costs on the pilot wells completed in the third quarter.
    - Average fuel costs of $2.87/bbl were 43% or $2.16/bbl lower than the prior quarter due to a 48% decrease in the average AECO gas price, slightly offset by higher steam volumes.
- Realized net losses on financial hedges totaled $1.4 million or $1.86/bbl, compared with $1.6 million or $2.32/bbl in the prior quarter.

Other noteworthy items

- Capital expenditures in the quarter were $8.3 million, of which $5.8 million related to the Orion expansion projects.
- Net general and administrative expenses were $3.0 million, consistent with $2.9 million in the prior quarter.
- Net unrealized hedging liabilities totaled $1.0 million at September 30, 2017, due mainly to the narrowing of future quality differentials, partially offset by the weakening of West Texas Intermediate future oil prices, since the time that the outstanding hedges were put in place.

Outlook

With Orion Phase 2A complete, Osum is beginning to see the positive impacts of these projects on production and operating costs. Year-to-date average production of 7,694 bbl/d is on track with the full-year target average of 7,700 bbl/d, and the contributions from the three new well pairs in the fourth quarter should allow Osum to meet or exceed its annual production target.

The success in managing costs and maintaining schedule in the execution of Phase 2A demonstrated the effectiveness of Osum's disciplined execution strategy. The Phase 2B expansion will utilize the same approach and will be funded with cash on hand plus the proceeds from the GORR sale. Combined, Phases 2A and 2B are expected to add 4,500 bbl/d to production though mid-2019, moving Osum closer to its goal of producing 20,000 bbl/d from Orion.

Finally, in September Osum welcomed John Lee to its Board of Directors as one of the Blackstone Group's nominees, replacing Gary Levin. Osum thanks Mr. Levin for his contributions to the Board over the past three years.

Financial and Operational Summary

Estimates and Judgments

The preparation of the financial and operational summary below and the interim consolidated financial statements on which they are based require management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the reported amounts of revenues and expenses during the period. Actual results may differ from these estimates. In preparing these figures, the significant judgments made by management in applying the Company's accounting policies and the key sources of estimation uncertainty were the same as those applied to and described in the audited consolidated financial statements for the year ended December 31, 2016 and supplemented in note 4 of the accompanying interim consolidated financial statements for the three and nine months ended September 30, 2017.

	Three months ended			Nine months ended	
	September 30, 2017	June 30, 2017	September 30, 2016	September 30, 2017	September 30, 2016
Business Environment [1]					
West Texas Intermediate (WTI) – US$/bbl	48.19	48.29	44.94	49.44	41.37
Cold Lake Blend (CLB) – US$/bbl	37.36	36.35	30.59	36.69	26.77
Differential – WTI less CLB – US$/bbl	10.83	11.94	14.35	12.75	14.60
Differential – CLB % of WTI	22.5%	24.7%	31.9%	25.8%	35.3%
Foreign exchange rate – C$/US$	1.2527	1.3449	1.3049	1.3067	1.3228
CLB – $/bbl	46.80	48.89	39.92	47.94	35.41
AECO – $/mcf	1.37	2.65	2.32	2.23	1.96
Operational [1] [2]					
Bitumen production – bbl/d	7,946	7,478	7,287	7,694	6,972
Blended bitumen sales [3] – bbl/d	10,402	10,201	9,348	10,389	9,441
Blended bitumen sales less diluent and transportation costs [3] – $/bbl	38.64	39.48	31.57	38.05	26.22
Royalties – $/bbl	(0.61)	(0.98)	(0.55)	(0.88)	(0.37)
Non-fuel operating costs – $/bbl	(15.06)	(15.74)	(16.31)	(14.82)	(15.43)
Fuel costs – $/bbl	(2.87)	(5.03)	(4.11)	(4.36)	(3.51)
Netback [3] [4] – $/bbl	20.10	17.73	10.60	17.99	6.91
Realized gain (loss) on financial risk management contracts – $/bbl	(1.86)	(2.32)	(2.13)	(2.22)	9.58
Adjusted netback [3] [4] – $/bbl	18.24	15.41	8.47	15.77	16.49
Financial					
Netback [3] [4]	14,695	12,061	7,110	37,792	13,198
Adjusted netback [3] [4]	13,339	10,481	5,681	33,138	31,493
Funds flow [5]	5,961	3,135	(2,846)	9,843	3,373
Cash flows from operating activities	6,040	1,211	2,508	9,159	5,773
Net and comprehensive income (loss)	11,929	7,108	(130,781)	22,635	(147,814)
Net income (loss) per share (basic and diluted) – $	0.09	0.05	(1.07)	0.17	(1.21)
Capital investment [6]	8,265	18,439	8,149	42,598	15,656
General and administrative expenses (net) [7]	2,961	2,933	3,558	9,777	13,746
Cash and cash equivalents [8]	236,798	154,589	95,252	236,798	95,252
Adjusted working capital [9]	233,753	144,698	84,479	233,753	84,479
Adjusted working capital plus available capital from outstanding callable warrants [9][10]	233,753	144,698	184,479	233,753	184,479
Outstanding principal – long-term debt [11]	251,415	262,075	267,458	251,415	267,458
Shareholders' equity	507,887	495,499	283,477	507,887	283,477
Weighted average common shares outstanding	130,927	130,915	122,444	129,834	122,420

See footnotes on the next page.

(1) Business environment and operational metrics are averages for the period.
(2) Dollar per barrel metrics are calculated based on bitumen production volumes. Quarter-over-quarter per barrel metrics may be affected by differences between the timing of bitumen production and blended bitumen sales.
(3) Blended bitumen sales, blended bitumen sales less diluent and transportation costs, netback and adjusted netback include $267 of realized losses and $22 of realized losses on physical risk management contracts for the three and nine month periods ended September 30, 2016, respectively.
(4) Netback is calculated by deducting the related diluent, transportation, royalties and field operating costs from blend sales revenue. Adjusted netback is calculated by adjusting the netback to include realized gains and losses on financial risk management contracts.
(5) Funds flow is calculated as cash flows from (used in) operating activities before changes in non-cash operating working capital, which is presented on the consolidated statement of cash flows.
(6) Capital investment includes capitalized general and administrative expenses and excludes capitalized stock based compensation.
(7) General and administrative expenses (net) is calculated after reductions for capitalized salaries and benefits, onerous lease payments and exploration costs.
(8) Cash and cash equivalents include restricted cash of $11,205 at September 30, 2017 (June 30, 2017 – $11,220, September 30, 2016 – $11,162).
(9) Adjusted working capital is calculated as working capital adjusted to exclude risk management contracts, which are fair value estimates of unrealized gains and losses and are subject to a high degree of volatility prior to ultimate settlement.
(10) At September 30, 2016, adjusted working capital plus available capital from outstanding callable warrants included $100,000 associated with the aggregate exercise value of the 8,000,000 then outstanding callable common share purchase warrants. On December 1, 2016, the Company called all of the outstanding callable common share purchase warrants and proceeds were received in February of 2017.
(11) Outstanding principal of long-term debt consists of the non-current portion of the outstanding principal balance of the US$210,000 term loan and any amounts outstanding under the US$15,000 revolving loan, translated to C$ at the period-end foreign exchange rate of 1.2471 (June 30, 2017 – 1.2966, September 30, 2016 – 1.3130), and presented before unamortized transaction costs.

Bitumen Reserves

The Company's bitumen reserves related to its Orion project were evaluated and its reserves for its Taiga project updated by independent third-party engineers, GLJ Petroleum Consultants Ltd. ("GLJ") in its reports effective September 1, 2017. Bitumen reserves estimates were prepared in accordance with definitions, standards and procedures contained in the Canadian Oil and Gas Evaluation Handbook.

Future net revenue was estimated using forecast prices and costs arising from the anticipated development and production of reserves, net of the associated royalties (inclusive of the GORR), operating costs, development costs and abandonment and reclamation costs, but before corporate overhead or other indirect costs, including interest and income taxes. Future net revenue disclosed does not represent fair market value. Also, estimations of reserves and future net revenue discussed in this section constitute forward looking information. See "Forward-Looking Statements" in Management's Discussion and Analysis for the year ended December 31, 2016.

The following table compares bitumen reserves and the net present value of future net revenue at a 10% discount rate as at September 1, 2017 and December 31, 2016:

	Bitumen Reserves – Gross (Mbbl)			Net Present Value of Future Net Revenue at 10% – Before Taxes ($ millions)		
	2017(1)	2016(2)	%	2017(1)	2016(2)	%
Total proved (3)	60,138	47,650	26%	471	436	8%
Total probable (4)	477,272	459,896	4%	1,540	1,437	7%
Total proved plus probable	537,410	507,546	6%	2,011	1,873	7%

(1) GLJ reserve estimates based on forecast prices and costs as of July 1, 2017, effective September 1, 2017.

(2) GLJ reserve estimates based on forecast prices and costs as of January 1, 2017, effective December 31, 2016.

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

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

The increases in gross bitumen reserves reflect the results of a delineation well drilled in the third quarter of 2017 and continued strong project performance.

The increases in the net present values of future net revenue resulted from the increases in reserves, partially offset by lower forecast prices at July 1, 2017 compared with January 1, 2017.

The following table displays gross bitumen reserves and bitumen reserves net of forecast royalties (inclusive of the GORR), along with the present values of estimated future net revenue using a range of discount rates at September 1, 2017:

	Bitumen Reserves [1] – (Mbbl)		Net Present Value of Future Net Revenue – Before Taxes ($millions) Forecast Prices and Costs				
	Gross	Net	0%	5%	10%	15%	20%
Total proved [2] (1P)	60,138	49,697	1,064	690	471	336	250
Total probable [3]	477,272	391,715	10,011	3,768	1,540	622	198
Total proved plus probable (2P)	537,410	441,412	11,075	4,458	2,011	958	448

(1) GLJ reserve estimates based on forecast prices and costs as of July 1, 2017, effective September 1, 2017.

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

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

GLJ's pricing assumptions dated July 1, 2017 used in its September 1, 2017 evaluation are summarized below:

Year	Western Canadian Select (C$/bbl)	WTI at Cushing (US$/bbl)	Diluent (condensate) (C$/bbl)	AECO gas (C$/mmbtu)	Exchange rate (US$/C$)
H2 2017	47.83	49.00	65.63	2.83	0.750
2018	48.68	52.00	67.02	2.93	0.775
2019	53.17	57.00	70.89	3.05	0.800
2020	57.65	62.00	74.52	3.22	0.825
2021	60.54	66.00	77.32	3.39	0.850
2022	64.08	69.00	81.06	3.58	0.850
2023	67.60	72.00	83.60	3.76	0.850
2024	71.17	75.00	87.29	3.95	0.850
2025	74.61	78.00	90.98	4.03	0.850
2026	78.47	81.27	94.04	4.11	0.850
Remainder	+2.0% per year	+2.0% per year	+2.0% per year	+2.0% per year	0.850

Auditor Review

The accompanying unaudited interim consolidated financial statements of Osum Oil Sands Corp. ("the Company") have been prepared by and are the responsibility of the Company's management. The Company's independent auditor has not performed a review of these unaudited interim consolidated financial statements in accordance with standards established by the Chartered Professional Accountants of Canada for a review of interim financial statements by an entity's auditor.

Osum Oil Sands Corp.

Consolidated Statements of Financial Position

(Unaudited, expressed in thousands of Canadian dollars)

	September 30, 2017	December 31, 2016
Assets		
Current assets:		
Cash and cash equivalents	225,593	72,333
Restricted cash	11,205	11,192
Accounts receivable	17,821	16,957
Financial risk management contracts (note 5)	9,187	3,215
Prepaid expenses and other assets	1,447	1,037
Total current assets	265,253	104,734
Non-current assets:		
Property, plant and equipment (note 7)	510,584	507,423
Exploration, evaluation and other intangible assets (note 8)	75,977	78,510
Deferred tax asset	30,207	33,548
Financial risk management contracts (note 5)	2,105	—
Abandonment deposits	335	322
Total assets	**884,461**	**724,537**
Liabilities		
Current liabilities:		
Accounts payable, accrued liabilities and provision (note 9)	18,291	21,897
Financial risk management contracts (note 5)	11,060	13,768
Current portion of long-term debt (note 10)	2,619	2,823
Current portion of deferred consideration (note 6)	1,277	—
Share unit liabilities (note 12)	126	113
Total current liabilities	33,373	38,601
Non-current liabilities:		
Long-term debt (note 10)	245,617	265,945
Deferred consideration (note 6)	63,123	—
Decommissioning liabilities (note 11)	30,022	31,861
Share unit liabilities (note 12)	2,535	1,180
Financial risk management contracts (note 5)	1,192	1,752
Provision (note 9)	712	1,848
Total non-current liabilities	343,201	302,586
Shareholders' equity		
Common shares (note 12)	1,032,188	932,094
Contributed surplus (note 12)	63,462	61,654
Cumulative deficit	(587,763)	(610,398)
Total shareholders' equity	507,887	383,350
Total liabilities and shareholders' equity	**884,461**	**724,537**

Contractual obligations and commitments (note 14)

The accompanying condensed notes are an integral part of these interim consolidated financial statements.

Vincent Chahley
Director

George Crookshank
Director

Osum Oil Sands Corp.

Consolidated Statements of Net and Comprehensive Income

(Unaudited, expressed in thousands of Canadian dollars, except share and per share amounts)

	Three months ended September 30,		Nine months ended September 30,	
	2017	**2016**	**2017**	**2016**
Revenue:				
Blended bitumen sales	44,626	33,941	135,397	90,708
Royalties	(445)	(366)	(1,845)	(713)
	44,181	33,575	133,552	89,995
Gain (loss) on financial risk management contracts (note 5)	(8,627)	2,155	6,691	(6,799)
Revenue net of gain or loss on financial risk management contracts	35,554	35,730	140,243	83,196
Expenses:				
Diluent and transportation	16,381	12,776	55,470	40,613
Operating expenses	13,105	13,689	40,290	36,184
Depletion, depreciation and impairment (notes 7, 8)	7,437	126,955	26,638	146,723
General and administrative expenses	2,961	3,558	9,777	13,746
Share-based compensation expense (note 12)	828	1,057	2,930	4,542
Exploration costs	3	36	17	93
Onerous contract expense (recovery) (note 9)	(148)	726	(156)	3,129
	40,567	158,797	134,966	245,030
Other expenses (income):				
Net finance costs (note 13)	4,429	4,617	13,589	14,119
Unrealized foreign exchange loss (gain) on long-term debt (note 10)	(10,109)	4,230	(19,862)	(14,717)
Gain on disposition of property, plant and equipment (note 6)	(14,922)	—	(14,922)	—
Accretion (notes 9, 11)	162	130	496	420
Total other expenses (income)	(20,440)	8,977	(20,699)	(178)
Net income (loss) before taxes	**15,427**	**(132,044)**	**25,976**	**(161,656)**
Deferred income tax recovery (expense)	(3,498)	1,263	(3,341)	13,842
Net and comprehensive income (loss)	**11,929**	**(130,781)**	**22,635**	**(147,814)**
Net income (loss) per share, basic and diluted (note 12)	$0.09	($1.07)	$0.17	($1.21)
Weighted average number of common shares outstanding (thousands):				
Basic	130,927	122,444	129,834	122,420
Diluted	132,543	123,757	131,256	123,575

The accompanying condensed notes are an integral part of these interim consolidated financial statements.

Osum Oil Sands Corp.

Consolidated Statements of Changes in Equity
(Unaudited, expressed in thousands of Canadian dollars)

	Number of common shares (thousands)	Share capital	Contributed surplus	Cumulative deficit	Total equity
Balance – January 1, 2017	122,914	932,094	61,654	(610,398)	383,350
Net income for the period	—	—	—	22,635	22,635
Share-based compensation	—	—	1,902	—	1,902
Share issuance on exercise of callable common share purchase warrants	8,000	100,000	—	—	100,000
Share issuance on vesting of share units	20	—	—	—	—
Reallocation on vesting of share units	—	94	(94)	—	—
Balance – September 30, 2017	**130,934**	**1,032,188**	**63,462**	**(587,763)**	**507,887**
Balance – January 1, 2016	122,401	929,927	58,975	(561,781)	427,121
Net loss for the period	—	—	—	(147,814)	(147,814)
Share-based compensation	—	—	4,156	—	4,156
Share issuance on vesting of share units	100	(1)	—	—	(1)
Share issuance on exercise of stock options	15	15	—	—	15
Reallocation on exercise of stock options	—	12	(12)	—	—
Reallocation on vesting of share units	—	1,667	(1,667)	—	—
Balance – September 30, 2016	**122,516**	**931,620**	**61,452**	**(709,595)**	**283,477**

The accompanying condensed notes are an integral part of these interim consolidated financial statements. Refer to note 12 for further details on share capital.

Osum Oil Sands Corp.

Consolidated Statements of Cash Flows
(Unaudited, expressed in thousands of Canadian dollars)

	Three months ended September 30,		Nine months ended September 30,	
	2017	2016	2017	2016
Cash provided by (used in)				
Operating activities:				
Net income (loss) for the period	11,929	(130,781)	22,635	(147,814)
Items not involving cash:				
Depletion and depreciation (notes 7, 8)	7,437	126,955	26,638	146,723
Unrealized foreign exchange loss (gain) on long-term debt (note 10)	(10,109)	4,230	(19,862)	(14,717)
Shared-based compensation expense (note 12)	828	1,057	2,930	4,542
Amortization of deferred transaction costs (note 10)	466	437	1,365	1,281
Accretion (notes 9,11)	162	130	496	420
Change in fair value of financial risk management contracts (note 5)	7,271	(3,584)	(11,345)	24,482
Onerous contract expense (recovery) (note 9)	(148)	726	(156)	3,129
Gain on disposition of property, plant and equipment (note 6)	(14,922)	—	(14,922)	—
Deferred income tax recovery (expense)	3,498	(1,263)	3,341	(13,842)
Settlements of onerous contract (note 9)	(312)	(151)	(849)	(229)
Settlements of share unit liabilities (note 12)	(75)	(556)	(75)	(556)
Settlements of decommissioning liabilities (note 11)	(64)	(46)	(353)	(46)
Funds flow from (used in) operating activities before changes in non-cash working capital	5,961	(2,846)	9,843	3,373
Change in non-cash operating working capital (note 15)	79	5,354	(684)	2,400
Total cash flows from operating activities	**6,040**	**2,508**	**9,159**	**5,773**
Investing activities:				
Property, plant and equipment expenditures (note 7)	(8,511)	(7,812)	(42,704)	(14,175)
Net investment (recovery) of exploration, evaluation and other intangible assets (note 8)	246	(337)	106	(1,480)
Disposition of property, plant and equipment (note 6)	90,993	—	90,993	—
Disposition of exploration, evaluation and other intangible assets (note 8)	2,114	—	2,114	—
Change in abandonment deposits	(6)	(7)	(13)	(12)
Change in non-cash investing working capital (note 15)	(8,012)	2,566	(4,347)	(2,255)
Total cash from (used in) investing activities	**76,824**	**(5,590)**	**46,149**	**(17,922)**
Financing activities:				
Proceeds from share issuance (net of costs) (note 12)	—	(1)	100,000	14
Principal repayments of long-term debt (note 10)	(655)	(690)	(2,035)	(2,054)
Total cash flows from (used in) financing activities	**(655)**	**(691)**	**97,965**	**(2,040)**
Increase (decrease) in cash in period	82,209	(3,773)	153,273	(14,189)
Cash and cash equivalents – beginning of period	143,369	87,920	72,333	98,258
Restricted cash – beginning of period	11,220	11,105	11,192	11,183
Cash and cash equivalents – end of period	**225,593**	**84,090**	**225,593**	**84,090**
Restricted cash – end of period	**11,205**	**11,162**	**11,205**	**11,162**

The accompanying condensed notes are an integral part of these interim consolidated financial statements.

1. The Company

Osum Oil Sands Corp. (“Osum” or the "Company”) is a private company formed under the Alberta Business Corporations Act on June 24, 2005. The Company’s primary activities are the operation and development of its in-situ bitumen properties in Alberta, Canada. These unaudited interim consolidated financial statements encompass the Company and its wholly-owned subsidiaries, Osum Production Corp. (“OPC”) and Osum Holdings Corp. ("OHC").

The address of the Company’s head office is Suite 1900, 255-5th Avenue SW, Calgary, Alberta, Canada, T2P 3G6.

2. Basis of Preparation

These unaudited interim consolidated financial statements are in compliance with International Accounting Standard 34, Interim Financial Reporting ("IAS 34"). These interim consolidated financial statements do not include the information and disclosures required in annual audited financial statements and therefore should be read in conjunction with the Company's annual audited consolidated financial statements for the year ended December 31, 2016.

The timely preparation of interim consolidated financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the reported amounts of revenues and expenses during the period. Actual results may differ from these estimates.

These interim consolidated financial statements are presented in Canadian dollars ("C$"), the Company's functional currency, and all financial information is reported in thousands of dollars unless otherwise noted.

These interim consolidated financial statements reflect the activities of the Company and its wholly-owned subsidiaries. All intercompany transactions, balances, income and expenses have been eliminated on consolidation.

These interim consolidated financial statements were authorized for issue by the Board of Directors on November 8, 2017.

3. Significant Accounting Policies

These interim consolidated financial statements have been prepared using the same significant accounting policies outlined in the Company's annual audited consolidated financial statements for the year ended December 31, 2016.

Future Accounting Policies

(a) IFRS 15 – Revenue from contracts with customers

IFRS 15 – *Revenue from contracts with customers*, intended to replace IAS 18 – *Revenue*, IAS 11 – *Construction Contracts*, and related interpretations, specifies how and when an IFRS reporter will recognize revenue as well as requiring more informative, relevant disclosures. The standard provides a single, principles-based five-step model to be applied to all contracts with customers. IFRS 15 was issued in May 2014 and applies to annual reporting periods beginning on or after January 1, 2018, with early adoption permitted. The Company intends to adopt IFRS 15 in its financial statements for the annual period beginning on January 1, 2018. The Company is currently assessing and evaluating the impact of the standard on the consolidated financial statements. Adoption of the standard is not expected to have a material impact on the Company's consolidated financial statements. The Company anticipates there will be additional enhanced disclosures upon adoption.

(b) IFRS 9 – Financial instruments

IFRS 9 – *Financial Instruments,* intended to replace IAS 39 – *Financial Instruments: Recognition and Measurement*, uses a single approach to determine whether a financial asset is measured at amortized cost or fair value, replacing the multiple rules in IAS 39. The new standard also requires a single impairment method to be used, replacing the multiple impairment methods in IAS 39, and incorporates a substantially reformed approach to hedge accounting. IFRS 9 is effective for annual periods beginning on or after January 1, 2018, with early adoption permitted. The Company intends to adopt IFRS 9 in its financial statements for the annual period beginning on January 1, 2018. The Company is currently assessing and evaluating the impact of the standard on the consolidated financial statements.

(c) IFRS 16 – Leases

IFRS 16 – *Leases*, intended to replace IAS 17 – *Leases,* brings most leases on-balance sheet for lessees under a single model, eliminating the distinction between operating and finance leases. Lessor accounting however remains largely unchanged and the distinction between operating and finance leases is retained. IFRS 16 is effective for annual periods beginning on or after January 1, 2019 and the Company intends to adopt IFRS 16 in its financial statements for the annual period beginning on January 1, 2019. The extent of the impact of adoption of the standard has not yet been determined.

4. Critical Accounting Estimates

These interim consolidated financial statements have been prepared using the same critical accounting estimates outlined in the Company's annual audited consolidated financial statements for the year ended December 31, 2016 with the exception of the following:

<u>Sale of a Royalty Interest</u>

When the Company sells a royalty interest linked to production at a specific property, judgment is required in assessing the appropriate accounting treatment of the transaction on the closing date and in future periods. The Company considers the specific terms of each arrangement to determine whether it has disposed of an interest in the reserves of the respective property. This assessment considers what the counterparty is entitled to and the associated risks and rewards attributable to it over the life of the property including the contractual terms related to production over the life of the property, the holder of the royalty having the option of either being paid in cash or in kind and the associated commitments, if any, to develop future expansions or projects at the property.

(Unaudited, Expressed in thousands of Canadian dollars)

5. Risk Management Contracts

Financial risk management contracts

The Company recorded the following net gains (losses) related to its financial risk management contracts:

	Three months ended September 30,		Nine months ended September 30,	
	2017	2016	2017	2016
Realized gain (loss)	(1,356)	(1,429)	(4,654)	18,295
Change in fair value	(7,271)	3,584	11,345	(24,482)
Premiums paid	—	—	—	(612)
Gain (loss) on financial risk management contracts	(8,627)	2,155	6,691	(6,799)

The following financial risk management contracts were in place as at September 30, 2017, and the related fair values were recorded on the consolidated statement of financial position:

Contract	Notional	Price	Remaining Term	Fair Value
Swap – WTI	4,300 bbl/d	$70.80	Oct 1/17 - Dec 31/17	2,449
Swap – WTI	2,025 bbl/d	$70.15	Jan 1/18 - Mar 31/18	960
Swap – WTI	2,375 bbl/d	$73.50	Jan 1/18 - Dec 31/18	7,859
Swap – WTI/WCS differential	1,341 bbl/d	$(19.25)	Jan 1/19 - Mar 31/19	24
Total unrealized financial risk management assets				11,292

Contract	Notional	Price	Remaining Term	Fair Value
Swap – WTI/WCS differential	5,800 bbl/d	$(21.88)	Oct 1/17 - Dec 31/17	(3,828)
Swap – WTI/WCS differential	2,700 bbl/d	$(21.39)	Jan 1/18 - Mar 31/18	(1,091)
Swap – WTI/WCS differential	3,240 bbl/d	$(22.70)	Jan 1/18 - Dec 31/18	(5,749)
Swap – WTI/WCS differential	3,060 bbl/d	$(19.64)	Apr 1/18 - Jun 30/18	(555)
Swap – WTI	2,325 bbl/d	$60.85	Apr 1/18 - Jun 30/18	(799)
Swap – WTI/WCS differential	963 bbl/d	$(17.95)	Jul 1/18 - Sep 30/18	(22)
Swap – WTI	1,096 bbl/d	$63.31	Jul 1/18 - Sep 30/18	(96)
Swap – WTI	1,493 bbl/d	$62.82	Jan 1/19 - Mar 31/19	(112)
Total unrealized financial risk management liabilities				(12,252)

The fair market value measurements are categorized as level 2 as they are based on quoted WTI and WCS differential prices from independent pricing services in active markets for similar assets or liabilities.

(Unaudited, Expressed in thousands of Canadian dollars)

The following table sets out the impact of changes in forward commodity prices on net income before taxes related to changes in the fair value of financial risk management contracts in place as at September 30, 2017:

Price or rate	Change	Impact on net income before taxes
WTI	$1.00/bbl	1,814
WTI/WCS differential	$1.00/bbl	2,447

Subsequent to September 30, 2017, the Company entered into financial risk management contracts with the following terms:

Contract	Notional	Price	Term
Swap – WTI	1,050 bbl/d	$64.55	Jul 1/18 - Sep 30/18
Swap – WTI/WCS differential	1,900 bbl/d	$(18.76)	Jul 1/18 - Sep 30/18
Swap – WTI/WCS differential	1,146 bbl/d	$(20.60)	Oct 1/18 - Dec 31/18
Swap – WTI	846 bbl/d	$67.35	Oct 1/18 - Dec 31/18
Swap – WTI	1,500 bbl/d	$63.70	Jan 1/19 - Mar 31/19
Swap – WTI/WCS differential	2,700 bbl/d	$(20.40)	Jan 1/19 - Mar 31/19
Swap – WTI	800 bbl/d	$65.75	Apr 1/19 - Jun 30/19
Swap – WTI/WCS differential	1,116 bbl/d	$(21.05)	Apr 1/19 - Jun 30/19

Credit and counterparty concentration risks related to the financial risk management contracts are considered acceptable due to the size and financial strength of the counterparties.

Physical risk management contracts

For the three and nine month periods ended September 30, 2017, the Company did not have any physical risk management contracts in place. For the three months ended September 30, 2016, the Company recorded a realized loss of $267 within blended bitumen sales related to its physical risk management contracts. For the nine months ended September 30, 2016, the Company recorded a realized loss of $22.

6. Sale of a Royalty Interest

On September 29, 2017, the Company sold a 4.0% gross overriding royalty interest on its Orion property for cash proceeds of $92,500, before transaction costs. The sale has an effective date of September 1, 2017. The royalty interest applies to all current and future production from the Orion property and the owner of the royalty has the option of being paid either in cash or in kind. As part of the sale agreement, the proceeds are to be used for the development of the Orion property.

The Company applied judgment in concluding that the proceeds from the sale of the royalty interest comprised two components: (1) a payment for partial disposal of an interest in property, plant and equipment; and (2) an upfront payment received for costs expected to be incurred by the Company in relation to future production of the royalty owner's 4.0% share of proved plus probable reserves.

The Company recorded deferred consideration of $64,400, representing the present value of estimated future costs at the time of the sale. The remaining net proceeds of $26,593 were compared to the carrying value attributable to the partial disposal of property, plant and equipment, and resulted in the recognition of a gain on sale of $14,922.

(Unaudited, Expressed in thousands of Canadian dollars)

At September 30, 2017, the current portion of deferred consideration was $1,277. Deferred consideration will be recognized in income based on the ratio of production in relation to then estimated proved plus probable reserves, and therefore may fluctuate in future periods with production levels and to the extent there are changes in estimated reserves.

7. Property, Plant and Equipment

	Development and production assets	Corporate assets	Total
Cost			
Balance – December 31, 2016	611,794	5,238	617,032
Additions	39,882	130	40,012
Capitalized general and administrative expenses	2,692	—	2,692
Capitalized share-based compensation	411	—	411
Disposition (note 6)	(11,671)	—	(11,671)
Changes to decommissioning assets	(1,660)	—	(1,660)
Balance – September 30, 2017	**641,448**	**5,368**	**646,816**
Accumulated depletion and depreciation			
Balance – December 31, 2016	(104,731)	(4,878)	(109,609)
Depletion and depreciation	(26,421)	(202)	(26,623)
Balance – September 30, 2017	**(131,152)**	**(5,080)**	**(136,232)**
Carrying amounts			
Balance – December 31, 2016	507,063	360	507,423
Balance – September 30, 2017	**510,296**	**288**	**510,584**

During the nine months ended September 30, 2017, the Company recorded $26,077 (2016 – $28,568) of depletion and $344 (2016 – $1,048) of depreciation related to its Orion oil sands project. The Company included $1,289,730 of future development costs associated with proved plus probable reserves in its depletion calculation for the three months ended September 30, 2017 (2016 – $1,558,397).

(Unaudited, Expressed in thousands of Canadian dollars)

8. Exploration, Evaluation and Other Intangible Assets

	Exploration and evaluation assets	Other Intangible assets	Total
Cost			
Balance – December 31, 2016	482,157	416	482,573
Additions (recoveries)	(151)	—	(151)
Capitalized depreciation	1,149	—	1,149
Capitalized general and administrative expenses	45	—	45
Capitalized share-based compensation	5	—	5
Changes to decommissioning assets	(302)	—	(302)
Disposition	(2,114)	—	(2,114)
Balance – September 30, 2017	**480,789**	**416**	**481,205**
Accumulated depletion, depreciation and impairment			
Balance – December 31, 2016	(403,812)	(251)	(404,063)
Depletion and depreciation	(1,149)	(16)	(1,165)
Balance – September 30, 2017	**(404,961)**	**(267)**	**(405,228)**
Carrying amounts			
Balance – December 31, 2016	78,345	165	78,510
Balance – September 30, 2017	**75,828**	**149**	**75,977**

During the three months ended September 30, 2017, the Company's partner and operator of the Saleski joint venture disposed of certain assets of the joint venture. The net proceeds attributable to the Company's 40% working interest in the assets were $2.1 million, which approximated the assets' carrying value.

(Unaudited, Expressed in thousands of Canadian dollars)

9. Provision

Provision for onerous contract

At September 30, 2017, the total provision for an onerous lease contract related to the Company's Calgary head office lease was $2,020 (December 31, 2016 – $3,005), of which $1,308 (December 31, 2016 – $1,157) was recorded within accounts payable, accrued liabilities and provision, and $712 (December 31, 2016 – $1,848) as a non-current provision.

	Nine months ended September 30, 2017
Balance – beginning of period	3,005
Change in estimated future cash flows	(156)
Liabilities settled	(849)
Accretion	20
Balance – end of period	2,020
Less: current portion of provision	1,308
Non-current portion of provision	712

The provision represented the present value of the difference between the estimated minimum future lease payments that the Company is obligated to make under the lease until its expiry on March 31, 2019, less estimated sublease recoveries. At September 30, 2017, these cashflows were discounted using a risk-free discount rate of 1.58% (December 31, 2016 – 0.84%). This estimate may fluctuate in future periods as a result of changes in estimated sublease recoveries and actual lease payments.

10. Long-term Debt

	September 30, 2017	December 31, 2016
Senior secured term loan – US$	203,700	205,275
Period end exchange rate – US$1 = C$	1.2471	1.3442
Senior secured term loan – C$	254,034	275,931
Less: unamortized deferred debt issue costs	(5,798)	(7,163)
	248,236	268,768
Less: current portion of long-term debt	(2,619)	(2,823)
Long-term debt	245,617	265,945

During the nine months ended September 30, 2017 and 2016, the Company made scheduled principal repayments totaling US$1,575 (2017 – C$2,035, 2016 – C$2,054) on the term loan. During the nine months ended September 30, 2017, $1,365 (2016 – $1,281) of deferred debt issue costs were amortized against the loan balance.

The fair market value of the Company's long-term debt as at September 30, 2017 was approximately $228,173 (December 31, 2016 – $208,889), compared with a carrying amount of $254,034 (December 31, 2016 – $275,931). The fair market value measurement is categorized as level 2 as it is based on quoted prices in inactive markets.

(Unaudited, Expressed in thousands of Canadian dollars)

As at September 30, 2017 and December 31, 2016, the revolving loan was undrawn. The senior secured credit facilities are subject to certain covenants by OPC, including maintaining minimum ratios of asset values to net senior secured debt. OPC was in compliance with all loan covenants as at September 30, 2017 and December 31, 2016.

11. Decommissioning Liabilities

	Nine months ended September 30, 2017
Balance – beginning of period	31,861
Liabilities incurred	400
Liabilities settled	(353)
Changes to discount rates	(778)
Changes in estimates	(1,584)
Accretion	476
Balance – end of period	30,022

As at September 30, 2017, the Company estimated that the expenditures required to settle the decommissioning liabilities will be made over the next 38 years with the majority of payments being made around 2045. As at September 30, 2017, the Company used discount rates ranging from 1.5% to 2.4% (December 31, 2016 – 0.7% to 2.3%) based on the Bank of Canada's long-term risk-free bond rate and an inflation rate of 1.6% (December 31, 2016 – 1.8%) to calculate the present value of the decommissioning liabilities.

12. Share Capital

(a) Authorized

Unlimited number of voting common shares without nominal or par value.

(b) Callable common share purchase warrants

In connection with previous equity financings, the Company issued callable common share purchase warrants to investors who concurrently subscribed for an equivalent number of common shares.

On December 1, 2016, the Company called all of the 8,000,000 then outstanding common share purchase warrants with an exercise price of $12.50 per warrant and the related proceeds of $100,000 were received in February of 2017.

(Unaudited, Expressed in thousands of Canadian dollars)

(c) Stock options

During the second quarter of 2017, the Company's Board of Directors approved the issuance of 555,500 stock options to employees and directors at an exercise price of $2.25 per share with an effective grant date of March 30, 2017. The stock options expire six years from the grant date and vest in four equal tranches: 25% on the grant date and 25% on each of the three subsequent anniversary dates. A fair value of $0.99 per stock option was estimated on the date of the grant based on the following assumptions:

Assumption	March 30, 2017
Share price on grant date	$ 2.25
Exercise price	$ 2.25
Expected volatility	50%
Expected life	5 years
Risk-free interest rate	1.10%
Expected forfeiture rate	12%

During the three months ended September 30, 2017, the Company granted 6,700 stock options using the same assumptions noted above with the exception of a risk free interest rate of 1.43% and a fair value of $1.00 per stock option.

A summary of the changes in options outstanding under the stock option plan is as follows:

	Nine months ended September 30, 2017	
	Number of options (thousands)	Weighted average exercise price
Balance – beginning of period	5,578	3.02
Granted	562	2.25
Forfeited	(242)	2.30
Balance – end of period	5,898	2.98

The following is a summary of the number of stock options outstanding and exercisable as at September 30, 2017:

Exercise price	Number outstanding (thousands)	Exercisable (thousands)	Weighted average remaining life
$0.15	75	75	3.3 years
$1.00	25	25	3.3 years
$2.25	4,611	2,216	4.6 years
$3.00	564	564	3.3 years
$8.11	170	170	1.6 years
$9.00	453	440	3.4 years
	5,898	3,490	4.3 years

(Unaudited, Expressed in thousands of Canadian dollars)

(d) Performance warrants

At September 30, 2017 and December 31, 2016, the Company had 11,895 vested and exercisable performance warrants outstanding at an exercise price of $0.15 per performance warrant. All unexercised performance warrants expire in October 2018.

(e) Restricted Share Units ("RSUs") and Performance Share Units ("PSUs")

During the nine months ended September 30, 2017, the Company's Board of Directors approved the issuance of 789,100 RSUs and 1,154,350 PSUs to employees and directors of the Company. The RSUs and PSUs granted vest all at once on the third anniversary date. The number of PSUs that ultimately vest is subject to the Company satisfying certain performance criteria within a target range set by the Company's Board of Directors. A multiplier (ranging from 0.5 to 2.0) will be applied to any vested PSUs to the extent such performance criteria are satisfied. The performance factor for the PSUs granted in the period was assumed to be 1.0.

Notwithstanding the Board's discretion to settle vested units in cash or with shares, according to the terms of the share unit plan, a unitholder may elect to receive up to 50 percent of their vested units in the form of a cash payment. The Company therefore treats the share units 50% equity-settled and 50% cash-settled.

A summary of the changes in RSUs and PSUs outstanding is as follows:

For the nine months ended September 30, 2017

(thousands)	RSUs	PSUs
Balance – beginning of period	1,237	1,956
Granted	789	1,154
Forfeited	(62)	(62)
Vested and settled	(68)	(31)
Balance – end of period	1,896	3,017

As at September 30, 2017, the Company's share unit liabilities for those RSUs and PSUs expected to be settled in cash were recorded using an estimated fair value of $2.25 per share unit (December 31, 2016 – $2.25) and a performance factor for the PSUs of 1.0 (2016 – 1.0).

As at September 30, 2017, $126 of the Company's share unit liabilities were classified as current (December 31, 2016 – $113), relating to those RSUs and PSUs scheduled to vest in the next twelve months, while $2,535 (December 31, 2016 – $1,180) were classified as non-current.

(Unaudited, Expressed in thousands of Canadian dollars)

(f) Contributed surplus

The table below summarizes activity in the contributed surplus account (excludes share-based compensation associated with share units expected to be settled in cash, which is reported as a liability on the consolidated statement of financial position):

	For the nine months ended September 30, 2017
Balance – beginning of period	61,654
Share-based compensation	1,902
Share units vested	(94)
Balance – end of period	63,462

(g) Per share amounts

The table below summarizes the weighted average number of common shares outstanding used in the calculation of basic and diluted income (loss) per common share:

(thousands)	Three months ended September 30, 2017	Nine months ended September 30, 2017
Weighted average common shares outstanding	130,927	129,834
Effect of dilutive securities	1,616	1,422
Weighted average common shares outstanding, diluted	132,543	131,256

Basic net income (loss) per share was calculated using the weighted average number of shares outstanding for the period. The Company uses the treasury stock method to calculate net income (loss) per share. The calculation of diluted weighted average common shares excludes shares related to stock options and warrants that are anti-dilutive. For the three and nine month periods ended September 30, 2017 and 2016, the Company's net income (loss) per share did not differ from diluted earnings per share.

13. Net Finance Costs

	Three months ended September 30,		Nine months ended September 30,	
	2017	2016	2017	2016
Interest expense, long-term debt (note 10)	4,357	4,522	13,459	13,684
Amortization of deferred transaction costs (note 10)	466	437	1,365	1,281
Interest income	(580)	(264)	(1,466)	(794)
Realized foreign exchange loss (gain)	186	(78)	231	(52)
Net finance costs	4,429	4,617	13,589	14,119

(Unaudited, Expressed in thousands of Canadian dollars)

14. Contractual Obligations and Commitments

The information presented in the table below reflects management's estimate of the contractual maturities of the Company's obligations for its oil sands properties and its general corporate activities as at September 30, 2017.

	Total	2017	2018	2019	2020+
Contracts and purchase orders (1)	18,464	3,936	14,465	43	20
Transportation agreements (2)	32,187	2,269	6,826	6,449	16,643
Operating leases (3)	3,354	552	2,029	636	137
Outstanding share units (4)	4,741	1	20	2,220	2,500
Interest and fees on term loan (5)	47,309	4,316	16,778	16,605	9,610
Repayment of term loan (5)	254,034	655	2,619	2,619	248,141
Total	360,089	11,729	42,737	28,572	277,051

(1) Contracts and purchase orders including commitments relating to the Orion expansion projects and costs for the storage of the evaporators procured for use at Taiga.
(2) Firm service gas and bitumen blend transportation commitments.
(3) Future commitments for the head office leases and field vehicles. The amounts reported are net of expected settlements of the onerous lease provision on the consolidated statement of financial position.
(4) Unaccrued fair value of outstanding share units expected to be settled for cash.
(5) Minimum obligations under the term loan using the foreign exchange and interest rates in effect at September 30, 2017.

15. Supplemental Cash Flow Information

	Three months ended September 30,		Nine months ended September 30,	
	2017	2016	2017	2016
Changes in non-cash operating working capital				
Accounts receivable	(2,541)	5,316	(64)	2,713
Prepaid expenses and other assets	1,075	544	(410)	123
Accounts payable and accrued liabilities	1,545	(506)	(210)	(436)
	79	5,354	(684)	2,400
Changes in non-cash investing working capital				
Accounts receivable	(400)	—	(800)	—
Accounts payable and accrued liabilities	(7,612)	2,566	(3,547)	(2,255)
	(8,012)	2,566	(4,347)	(2,255)
Supplemental cash flow information				
Cash interest earned	562	247	1,423	736

Corporate Information

Directors

William A. Friley – Interim Chairman
Independent Businessman

Angelo Acconcia
Senior Managing Director, Blackstone Capital Partners and Blackstone Energy Partners

Vincent Chahley
Independent Businessman

George Crookshank
Independent Businessman

David Krieger
Managing Director, Warburg Pincus LLC

John Lee
Associate, Blackstone Capital Partners and Blackstone Energy Partners

Francesco Mele
Partner, Azimuth Capital Management

Brian Reinsborough
President and Chief Executive Officer, Venari Resources LLC

Steve Spence
President and Chief Executive Officer, Osum Oil Sands Corp.

Officers

Steve Spence, P.Eng.
President and CEO

Victor Roskey
Chief Financial Officer

Rick K. Walsh, P.Eng.
Chief Operating Officer

Dr. Peter Putnam, P.Geol.
Sr. Vice President, Geoscience

Dr. Jen Russel-Houston, P.Geol
Vice President, Geoscience

Auditor

PricewaterhouseCoopers LLP
Calgary, Alberta

Independent Engineers

GLJ Petroleum Consultants Ltd.
Calgary, Alberta

Legal Counsel

McCarthy Tetrault LLP
Calgary, Alberta

Registrar and Transfer Agent

Alliance Trust Company
Calgary, Alberta

Financial Institution

ATB Financial
Calgary, Alberta

1900, 255 - 5th Ave S.W.
Calgary, AB. T2P 3G6
T(403)283.3224 F(403)283.3970
osumcorp.com