MANAGEMENT'S DISCUSSION AND ANALYSIS

For the three and nine months ended September 30, 2021

This management's discussion and analysis of financial condition and results of operations ("MD&A") of Obsidian Energy Ltd. ("Obsidian Energy", the "Company", "we", "us", "our") should be read in conjunction with the Company's unaudited interim condensed consolidated financial statements for the three and nine months ended September 30, 2021 and the Company's audited consolidated financial statements and MD&A for the year ended December 31, 2020. The date of this MD&A is November 5, 2021. All dollar amounts contained in this MD&A are expressed in millions of Canadian dollars unless noted otherwise.

Certain financial measures such as funds flow from operations, funds flow from operations per share-basic, funds flow from operations per share-diluted, free cash flow, netback, net operating costs, gross revenues and net debt included in this MD&A do not have a standardized meaning prescribed by International Financial Reporting Standards ("IFRS") and therefore are considered non-GAAP measures; accordingly, they may not be comparable to similar measures provided by other issuers. This MD&A also contains oil and natural gas information and forward-looking statements. Please see the Company's disclosure under the headings "Non-GAAP Measures", "Oil and Gas Information", and "Forward-Looking Statements" included at the end of this MD&A.

Within this MD&A the Company has updated the presentation of our financial figures to disclose dollar figures rounded to the nearest hundred thousand. This may result in immaterial differences in the comparative figures.

Quarterly Financial Summary

(millions, except per share and production amounts) (unaudited)

Three months ended	**Sep. 30 2021**	June 30 2021	Mar. 31 2021	Dec. 31 2020	Sep. 30 2020	June 30 2020	Mar. 31 2020	Dec. 31 2019
Production revenues	**$ 124.5**	$ 111.0	$ 92.2	$ 72.8	$ 75.4	$ 48.2	$ 79.0	$ 111.6
Cash flow from operations	**65.5**	42.2	28.1	11.1	34.8	2.1	31.4	49.5
Basic per share	**0.88**	0.57	0.38	0.15	0.47	0.03	0.43	0.68
Diluted per share	**0.85**	0.55	0.37	0.15	0.47	0.03	0.43	0.68
Funds flow from operations (1)	**59.3**	42.3	36.3	26.4	30.4	24.7	36.3	54.2
Basic per share	**0.79**	0.57	0.49	0.36	0.41	0.34	0.50	0.74
Diluted per share	**0.77**	0.55	0.48	0.36	0.41	0.34	0.50	0.74
Net income (loss)	**46.6**	322.5	23.2	0.2	(3.2)	(21.1)	(747.6)	(543.2)
Basic per share	**0.62**	4.33	0.32	0.01	(0.04)	(0.29)	(10.24)	(7.44)
Diluted per share	**$ 0.60**	$ 4.23	$ 0.31	$ 0.01	$ (0.04)	$ (0.29)	$ (10.24)	$ (7.44)
Production								
Light oil (bbls/d)	**10,314**	10,836	10,014	10,055	10,952	12,800	12,512	12,246
Heavy oil (bbls/d)	**2,688**	2,660	2,788	2,895	2,823	1,966	3,644	3,718
NGLs (bbls/d)	**2,213**	2,162	2,056	2,087	2,244	2,278	2,239	2,095
Natural gas (mmcf/d)	**54**	54	50	52	54	53	52	52
Total (boe/d)	**24,164**	24,651	23,225	23,644	25,031	25,872	27,092	26,639

(1) Please refer to our prior quarterly filings for reconciliations of cash flow from operations to funds flow from operations.

Cash flow from Operations and Funds Flow from Operations

(millions, except per share amounts)	Three months ended September 30 2021	2020	Nine months ended September 30 2021	2020
Cash flow from operating activities	**$ 65.5**	$ 34.8	**$ 135.8**	$ 68.3
Change in non-cash working capital	**(9.1)**	(11.1)	**(1.1)**	(1.0)
Decommissioning expenditures	**1.6**	0.6	**5.4**	8.8
Onerous office lease settlements	**2.3**	2.4	**7.0**	7.4
Deferred financing costs	**(1.7)**	-	**(4.4)**	-
Financing fees paid	**-**	-	**4.4**	-
Realized foreign exchange loss – debt maturities	**-**	-	**0.3**	-
Restructuring charges (1)	**0.1**	-	**(1.8)**	0.3
Transaction costs	**-**	2.9	**-**	2.9
Other expenses (1)	**0.6**	0.8	**(7.7)**	4.7
Funds flow from operations	**$ 59.3**	$ 30.4	**$ 137.9**	$ 91.4
Per share – funds flow from operations				
Basic per share	**$ 0.79**	$ 0.41	**$ 1.86**	$ 1.25
Diluted per share	**$ 0.77**	$ 0.41	**$ 1.81**	$ 1.25

(1) Excludes the non-cash portion of restructuring and other expenses.

Both cash flow from operations and funds flow from operations were higher in Q3 2021 and for the first nine months of 2021 than the comparable periods mainly due to higher revenues as a result of higher commodity prices. This was partially offset by lower production levels as base production declines were not replaced by development activity as commencing in March 2020, the Company restricted capital spending in response to the COVID-19 pandemic and resultant volatile commodity price market. The Company re-started development activities in late 2020 with the first wells brought on production in March 2021. Additionally, in 2021, the Company recorded significant share-based compensation charges which reduced funds flow from operations and cash flow from operations, which was predominately due to the significant increase in the Company's share price in Q2 2021.

Business Strategy

We believe our plan to primarily focus on our industry leading Cardium position offers a predictable, liquids weighted, production profile that is capable of generating sustainable value for all stakeholders. Favourable weather and ground conditions allowed us to start our second half development program early, and in light of higher commodity prices and strong production results, we modestly increased our 2021 capital budget and increased our production guidance. With strong results thus far from our 2021 development program, we expect to generate higher fourth quarter and exit 2021 production rates than that achieved in 2020, while still meaningfully reducing debt levels. With a continued constructive pricing environment, our program further positions us for additional production growth that generates even higher free cash flow in 2022.

During our second half 2021 development program we have been utilizing a two-rig continuous drilling program and plan to drill 27 wells (25.7 net), predominantly in our Willesden Green and Pembina Cardium assets, resulting in a total program of 36 wells (34.7 net) for full year 2021 plus 1 well (1.0 net) that was rig released in December 2020. We expect to bring 26 wells (25.0 net) on production in 2021, with the remaining 10 wells (9.7 net) expected to be on production early in Q1 2022. In addition, our successful optimization program continues with approximately $11 million allocated for 2021 to capture further highly attractive capital efficiencies. The Company has significant capability to scale our development drilling in response to changes in commodity prices.

In Q3 2021, we continued our participation in the Alberta Site Restoration Program ("ASRP") and Area-Based Closure ("ABC") program, focusing on inactive fields in Northern Alberta. Our decommissioning activity in 2021 and 2022 will benefit from over $35 million (gross) of ASRP grants, of which approximately $11 million (net) have been utilized since inception through Q3 2021.

Peace River Oil Partnership ("PROP) acquisition

Subsequent to September 30, 2021, the Company announced that we have entered into a purchase and sale agreement to acquire the remaining 45 percent partnership interest in PROP from our joint venture partner, through a wholly-owned subsidiary. Total consideration paid will be $43.5 million prior to closing adjustments with an effective date of July 1, 2021. The acquisition will be funded by a combination of cash and, if necessary, Obsidian Energy common shares issued to our joint venture partner. Closing adjustments are expected to reduce the total consideration paid at closing by approximately $7.2 - $7.5 million to $36.0 - $36.3 million, assuming the acquisition closes in mid-November 2021.

The cash consideration for the acquisition will be funded by a $16.3 million limited-recourse loan secured by the 45 percent interest in PROP, which will be acquired pursuant to the acquisition and proceeds from a new equity offering. The Company has filed and been receipted for an amended and restated preliminary short form prospectus with the securities commissions in each of the provinces of Canada, other than Québec, in connection with a "best efforts" marketed equity offering of subscription receipts for minimum gross proceeds of $12.5 million and maximum gross proceeds of $22.5 million.

In connection with the Company's acquisition of the 45 percent interest in PROP, we have agreed to reduce our aggregate syndicated credit facility commitment amount by $25 million to $415 million at closing of the transaction. The $25 million reduction will be applied against the non-revolving term loan. Also, upon closing of the acquisition, the Company will repay approximately $3.3 million of the outstanding senior notes.

Business Environment

The following table outlines quarterly averages for benchmark prices and Obsidian Energy's realized prices for the previous eight quarters.

	Q3 2021	Q2 2021	Q1 2021	Q4 2020	Q3 2020	Q2 2020	Q1 2020	Q4 2019
Benchmark prices								
WTI oil ($US/bbl)	**$ 70.56**	$ 66.07	$ 57.84	$ 42.66	$ 40.93	$ 27.85	$ 46.17	$ 56.96
Edm mixed sweet par price (CAD$/bbl)	**83.77**	77.30	66.61	50.29	49.83	29.55	51.62	67.99
Western Canada Select (CAD$/bbl)	**71.80**	67.01	57.45	43.46	42.41	22.42	34.11	54.29
NYMEX Henry Hub ($US/mmbtu)	**4.01**	2.83	3.56	2.53	2.00	1.72	1.95	2.50
AECO Index (CAD$/mcf)	**3.60**	3.09	3.15	2.77	2.24	1.99	2.22	2.48
Foreign exchange rate (CAD$/$US)	**1.260**	1.228	1.266	1.303	1.332	1.386	1.345	1.320
Benchmark differentials								
WTI - Edm Light Sweet ($US/bbl)	**(4.08)**	(3.11)	(5.24)	(4.07)	(3.51)	(6.14)	(7.58)	(5.37)
WTI - WCS Heavy ($US/bbl)	**(13.58)**	(11.49)	(12.47)	(9.31)	(9.08)	(11.47)	(20.53)	(15.83)
Average sales price (1)								
Light oil (CAD$/bbl)	**84.27**	76.97	67.34	50.76	50.84	29.20	50.59	70.57
Heavy oil (CAD$/bbl)	**60.87**	48.58	40.48	30.00	29.54	5.98	20.07	41.80
NGLs (CAD$/bbl)	**52.79**	39.31	38.20	24.61	22.11	11.65	22.52	31.42
Total liquids (CAD$/bbl)	**75.55**	66.95	58.27	43.14	43.06	24.18	41.13	60.10
Natural gas (CAD$/mcf)	**$ 3.89**	$ 3.21	$ 3.21	$ 2.81	$ 2.40	$ 2.14	$ 2.20	$ 2.55

(1) Excludes the impact of realized hedging gains or losses.

Oil

WTI averaged US$70.56 per barrel during Q3 2021. WTI prices started the quarter at approximately US$75.00 per barrel but decreased throughout July and August as concerns over rising COVID-19 cases, specifically due to the Delta variant, and uncertainty over OPEC's curtailment plan led to demand uncertainty. In September, OPEC provided more clarity regarding their plan to maintain previously announced production increases and inventory levels showed positive draws which resulted in WTI increasing to approximately US$75.00 per barrel.

In Q3 2021, the MSW differential averaged US$4.08 per barrel and the WCS differential averaged US$13.58 per barrel. Differentials for Q3 2021 were marginally wider than Q2 2021, however, they tightened throughout the quarter as various operational issues led to less supply out of Western Canada.

The Company currently has the following financial oil contracts in place on a weighted average basis:

Term	Notional volume	Pricing
October 2021	7,750 bbl/d	$92.59/bbl
November 2021	6,500 bbl/d	$100.39/bbl
December 2021	500 bbl/d	$100.00/bbl

Additionally, the Company currently has the following physical contracts in place:

	Notional volume	Term	Pricing
Heavy Oil Differential – USD (1)			
	550 bbl/d	Oct – Dec 2021	US$26.00/bbl

(1) Hedged on a USD basis and inclusive of WCS differential, quality and transportation charges.

Natural Gas

NYMEX Henry Hub gas prices started the quarter at US$3.79 per mmbtu, reducing to a low of US$3.56 per mmbtu in early July and then gradually increased throughout the period reaching a high of US$5.73 per mmbtu in late September due to extremely warm weather in the U.S. and Canada and increased demand for US exported LNG. For Q3 2021, the average price was US$4.01 per mmbtu.

In Alberta, AECO 5A prices followed a similar pattern, starting the quarter at $4.35 per mcf due to an early summer heat wave, then decreasing to a low of $1.25 per mcf in early August as pipeline border restrictions restricted egress out of Alberta. Natural gas prices then increased over the remainder of the quarter, reaching a high of $5.06 per mcf in late September. The AECO 5A price for Q3 2021 averaged $3.60 per mcf.

The Company currently has the following financial natural gas contracts in place on a weighted average basis:

Term	Notional volume	Pricing
October 2021	23,695 mcf/d	$2.70/mcf
November 2021 – March 2022	25,591 mcf/d	$4.63/mcf

Average Sales Prices

	Three months ended September 30			Nine months ended September 30		
	2021	2020	% change	**2021**	2020	% change
Light oil (per bbl)	**$ 84.27**	$ 50.84	66	**$ 76.35**	$ 43.14	77
Heavy oil (per bbl)	**60.87**	29.54	>100	**49.94**	19.99	>100
NGL (per bbl)	**52.79**	22.11	>100	**43.64**	18.73	>100
Total liquids (per bbl)	**75.55**	43.06	75	**67.05**	36.14	86
Risk management gain (loss) (per bbl)	**(0.13)**	-	n/a	**(1.50)**	4.79	n/a
Total liquids price, net (per bbl)	**75.42**	43.06	75	**65.55**	40.93	60
Natural gas (per mcf)	**3.89**	2.40	62	**3.44**	2.25	53
Risk management gain (loss) (per mcf)	**(0.38)**	(0.19)	100	**(0.14)**	(0.09)	56
Natural gas net (per mcf)	**3.51**	2.21	59	**3.30**	2.16	53
Weighted average (per boe)	**56.21**	32.74	72	**50.11**	28.43	76
Risk management gain (loss) (per boe)	**(0.93)**	(0.42)	>100	**(1.27)**	2.98	n/a
Weighted average net (per boe)	**$ 55.28**	$ 32.32	71	**$ 48.84**	$ 31.41	55

RESULTS OF OPERATIONS

Production

	Three months ended September 30			Nine months ended September 30		
Daily production	**2021**	2020	% change	**2021**	2020	% change
Light oil (bbls/d)	**10,314**	10,952	(6)	**10,389**	12,084	(14)
Heavy oil (bbls/d)	**2,688**	2,823	(5)	**2,712**	2,811	(4)
NGL (bbls/d)	**2,213**	2,244	(1)	**2,144**	2,254	(5)
Natural gas (mmcf/d)	**54**	54	-	**53**	53	-
Total production (boe/d)	**24,164**	25,031	(3)	**24,017**	25,995	(8)

During 2020, the Company postponed virtually all development activity from late March to early December, in response to the COVID-19 pandemic and the low commodity price environment, which led to lower production levels throughout the year and in the first nine months of 2021 due to base declines.

Our decision to defer development spending for the majority of 2020 reduced production levels across all areas in the second half of 2020 and in the first three quarters of 2021. Heavy oil production volumes in Peace River were also impacted by our decision to temporarily shut-in certain heavy oil production which remained partially in effect until early Q3 2021. The Company re-started development activity in late 2020 and brought 12 wells on production in the first nine months of 2021, which has partially mitigated base declines. Through further development activities, we expect to generate higher fourth quarter and exit 2021 production rates than achieved in 2020.

Average production within the Company's key development areas and within the Company's Legacy asset area was as follows:

Daily production (boe/d) [1]	Three months ended September 30 2021	2020	% change	Nine months ended September 30 2021	2020	% change
Cardium	**19,807**	20,661	(4)	**19,753**	21,615	(9)
Peace River	**2,974**	3,196	(7)	**2,960**	3,123	(5)
Alberta Viking	**822**	825	-	**810**	845	(4)
Legacy	**561**	349	61	**494**	412	20
Total	**24,164**	25,031	(3)	**24,017**	25,995	(8)

(1) Refer to "Supplemental Production Disclosure" for details by product type.

Netbacks

Three months ended September 30	2021 Liquids (bbl)	2021 Natural Gas (mcf)	**2021 Combined (boe)**	2020 Combined (boe)
Sales price [1]	$ 75.55	$ 3.89	**$ 56.21**	$ 32.74
Risk management gain (loss) [2]	(0.13)	(0.38)	**(0.93)**	(0.42)
Royalties	(8.79)	(0.21)	**(5.99)**	(1.42)
Transportation	(3.21)	(0.18)	**(2.41)**	(2.13)
Net operating costs	(18.01)	(0.87)	**(13.28)**	(11.36)
Netback	$ 45.41	$ 2.25	**$ 33.60**	$ 17.41
	(bbls/d)	(mmcf/d)	**(boe/d)**	(boe/d)
Production	15,215	54	**24,164**	25,031

(1) Includes the impact of commodities purchased and sold to/from third parties - $0.4 million (2020 – nil).
(2) Realized risk management gains and losses on commodity contracts.

Nine months ended September 30	2021 Liquids (bbl)	2021 Natural Gas (mcf)	**2021 Combined (boe)**	2020 Combined (boe)
Sales price [1]	$ 67.05	$ 3.44	**$ 50.11**	$ 28.43
Risk management gain (loss) [2]	(1.50)	(0.14)	**(1.27)**	2.98
Royalties	(6.54)	(0.19)	**(4.56)**	(1.48)
Transportation	(2.60)	(0.18)	**(2.05)**	(2.01)
Net operating costs	(18.17)	(0.90)	**(13.50)**	(10.65)
Netback	$ 38.24	$ 2.03	**$ 28.73**	$ 17.27
	(bbls/d)	(mmcf/d)	**(boe/d)**	(boe/d)
Production	15,245	53	**24,017**	25,995

(1) Includes the impact of commodities purchased and sold to/from third parties - $0.8 million (2020 – ($0.1) million).
(2) Realized risk management gains and losses on commodity contracts.

In 2021, netbacks were higher than the comparable periods due to higher commodity prices as product demand increased with the easing of COVID-19 restrictions and the roll-out of vaccines. This was partially offset by minor realized hedging losses and higher royalties due to stronger oil prices, as well as higher operating costs due to increased activity levels and higher power prices. Note that in Q2 2020 and for a portion of Q3 2020, the Company delayed discretionary operating cost spending in response to the low commodity price environment at that time.

Production Revenues

A reconciliation from production revenues to gross revenues is as follows:

	Three months ended September 30		Nine months ended September 30	
(millions)	**2021**	2020	**2021**	2020
Production revenues	**$ 124.5**	$ 75.4	**$ 327.7**	$ 202.6
Realized risk management gain (loss) [1]	**(2.0)**	(1.0)	**(8.3)**	21.2
Sales of commodities purchased	**2.8**	0.8	**6.7**	2.8
Less: Commodities purchased	**(2.4)**	(0.8)	**(5.9)**	(2.9)
Gross revenues	**$ 122.9**	$ 74.4	**$ 320.2**	$ 223.7

(1) Relates to realized risk management gains and losses on commodity contracts

Production revenues and gross revenues were higher in 2021 due to increases in commodity prices, which was partially offset by lower production volumes and realized risk management losses versus realized risk management gains in 2020 for the first nine months of the year.

Change in Gross Revenues

(millions)	
Gross revenues – January 1 – September 30, 2020	$ 223.7
Decrease in liquids production	(20.5)
Increase in liquids prices	129.8
Decrease in natural gas production	(0.4)
Increase in natural gas prices	17.2
Decrease in realized oil risk management	(28.8)
Decrease in realized natural gas risk management	(0.8)
Gross revenues – January 1 – September 30, 2021 [1]	$ 320.2

(1) Excludes processing fees and other income.

Royalties

	Three months ended September 30		Nine months ended September 30	
	2021	2020	**2021**	2020
Royalties (millions)	**$ 13.3**	$ 3.3	**$ 29.9**	$ 10.6
Average royalty rate [1]	**11%**	4%	**9%**	5%
$/boe	**$ 5.99**	$ 1.42	**$ 4.56**	$ 1.48

(1) Excludes effects of risk management activities and other income.

For 2021, royalties, including the average royalty rate and per boe metrics, increased from the comparable periods largely due to higher commodity prices.

Expenses

(millions)	Three months ended September 30		Nine months ended September 30	
	2021	2020	**2021**	2020
Net Operating	**$ 29.5**	$ 26.2	**$ 88.5**	$ 75.9
Transportation	**5.4**	4.9	**13.5**	14.3
Financing	**8.7**	7.3	**27.4**	28.4
Share-based compensation	**$ 3.0**	$ 0.7	**$ 15.4**	$ 1.7

(per boe)	Three months ended September 30		Nine months ended September 30	
	2021	2020	**2021**	2020
Net Operating	**$ 13.28**	$ 11.36	**$ 13.50**	$ 10.65
Transportation	**2.41**	2.13	**2.05**	2.01
Financing	**3.84**	3.18	**4.16**	3.99
Share-based compensation	**$ 1.41**	$ 0.30	**$ 2.36**	$ 0.24

Operating

A reconciliation of operating costs to net operating costs is as follows:

(millions)	Three months ended September 30		Nine months ended September 30	
	2021	2020	**2021**	2020
Operating costs	**$ 32.3**	$ 28.0	**$ 97.1**	$ 83.9
Less processing fees	**(1.6)**	(1.3)	**(4.9)**	(4.6)
Less road use recoveries	**(1.2)**	(0.5)	**(3.7)**	(3.4)
Net Operating costs	**$ 29.5**	$ 26.2	**$ 88.5**	$ 75.9

In 2021, the Company returned to normal activity levels compared to 2020 where the Company restricted discretionary spending beginning in March 2020 and into Q3 2020 as a result of the low commodity price environment. During 2021, the Company was impacted by high power prices particularly in the first half of 2021, mostly due to extreme weather (cold in Q1 and heat in Q2) in several parts of North America which increased demand and, when combined with higher natural gas prices (power input cost), led to an increase in operating costs. The increase in power costs was more than offset by the increase in our natural gas revenue.

For the first nine months of 2021 the Canadian Emergency Wage Subsidy ("CEWS") program reduced operating costs by $0.3 million.

Transportation

The Company continues to utilize multiple sales points in the Peace River area to increase realized prices. The increase in realized prices is partially offset by additional transportation costs. In 2020, the Company had certain take-or-pay contracts terminate which led to a reduction in transportation costs in the first nine months of 2021. Additionally, in the comparable period of Q3 2020, temporarily shut in production at various properties in the Peace River area (due to low commodity prices) resulted in lower transportation costs in 2020. The majority of the shut in production was brought back on-line late in Q3 2020.

Financing

Financing expense consists of the following:

(millions)	Three months ended September 30				Nine months ended September 30			
		2021		2020		**2021**		2020
Interest on bank debt and senior notes	**$**	**6.8**	$	5.5	**$**	**19.5**	$	19.0
Advisor fees		**0.4**		1.6		**1.4**		8.1
Deferred financing costs		**1.7**		-		**4.4**		-
Unwinding of discount on lease liabilities		**0.2**		0.2		**0.5**		1.3
Loss (gain) on debt modification		**(0.4)**		-		**1.6**		-
Financing	**$**	**8.7**	$	7.3	**$**	**27.4**	$	28.4

Obsidian Energy's debt structure includes short-term borrowings under our syndicated credit facility and term financing through our senior notes. In Q3 2021, financing charges increased mainly due to higher interest rates under the Company's current banking agreements which was partially offset by lower drawn balances under our syndicated credit facility. For the first nine months of 2021, lower advisor costs primarily contributed to lower financing costs which was partially offset by the before mentioned higher interest rates.

The interest rates on the Company's syndicated credit facility are subject to fluctuations in short-term money market rates as advances on the syndicated credit facility are generally made under short-term instruments. As at September 30, 2021, 85 percent (December 31, 2020 – 87 percent) of the Company's outstanding debt instruments were exposed to changes in short-term interest rates.

The Company has a reserve-based syndicated credit facility which is subject to a semi-annual borrowing base redetermination typically in May and November of each year. The aggregate amount available under the syndicated credit facility is $440 million which consists of a $225 million revolving syndicated credit facility and a $215 million non-revolving term loan. The revolving period under the syndicated credit facility is set at May 31, 2022, with the maturity date of both the syndicated credit facility and non-revolving term loan of November 30, 2022. Additionally, the Company has a revolving period reconfirmation date on January 17, 2022, whereby, on or prior to such date, the lenders may accelerate the end date of the revolving period to February 1, 2022. In this case, the end date of the term period would remain unchanged at November 30, 2022. Furthermore, the Company's revolving credit facility will have a one-time adjustment to reduce our undrawn availability to $35 million at December 31, 2021. Any borrowing availability at this time in excess of that amount will be used to reduce amounts outstanding on the non-revolving term loan and senior notes.

In connection with our announced acquisition of the 45 percent interest in PROP, we have agreed with our lenders to reduce the syndicated credit facility commitment amount by $25 million to $415 million at closing of the acquisition. The $25 million reduction will be applied against the non-revolving term loan. We will also repay $3.3 million of senior notes upon close of the acquisition.

At September 30, 2021, the carrying value of the Company's US dollar denominated senior notes was $58.9 million (December 31, 2020 – $60.3 million). In Q1 2021, the Company repaid senior notes in the amount of US$1.1 million (CAD $1.4 million) which resulted in a decrease in the carrying value. Additionally, a stronger Canadian dollar against the US dollar at the comparable balance sheet dates contributed to a lower carrying value. Summary information on the Company's senior notes outstanding as at September 30, 2021 is as follows:

	Amount (millions)	Maturity date	Average interest rate	Weighted average remaining term (years)
2008 Notes	US$4.0	November 30, 2022	8.52%	1.2
2010 Q1 Notes	US$9.5	November 30, 2022	7.97%	1.2
2010 Q4 Notes	US$20.8	November 30, 2022	7.06%	1.2
2011 Notes	US$12.0	November 30, 2022	6.91%	1.2

Share-Based Compensation

Share-based compensation expense relates to the Company's Stock Option Plan (the "Option Plan"), restricted shares units ("RSUs") granted under the Restricted and Performance Share Unit Plan ("RPSU plan"), restricted awards granted under the Non-Treasury Incentive Award Plan ("NTIP"), Deferred Share Unit Plan ("DSU plan") and performance share units ("PSUs") granted under the RPSU plan.

Share-based compensation expense consisted of the following:

	Three months ended September 30		Nine months ended September 30	
(millions)	**2021**	2020	**2021**	2020
RSU grants	**$ 0.2**	$ 0.7	**$ 0.9**	$ 1.5
PSU grants	**0.8**	-	**3.6**	-
DSU plan	**0.8**	-	**8.7**	0.2
Options	**0.4**	-	**0.8**	-
NTIP	**0.8**	-	**1.4**	-
Share-based compensation	**$ 3.0**	$ 0.7	**$ 15.4**	$ 1.7

In 2021, the increase in share-based compensation is largely attributed to the significant increase in the Company's share price which closed at $4.51 per share at September 30, 2021 compared to $0.87 per share at December 31, 2020 and $4.24 per share at June 30, 2021. The majority of the increase occurred in Q2 2021. During Q3 2021, approximately $1.5 million of DSUs vested and were consequently exercised and will no longer be included in future share-based compensation changes.

The share price at September 30, 2021 of $4.51 (2020 – $0.49) was used in the fair value calculation of the RPSU, DSU and NTIP plan obligations.

General and Administrative Expenses ("G&A")

	Three months ended September 30		Nine months ended September 30	
(millions, except per boe amounts)	**2021**	2020	**2021**	2020
Gross	**$ 7.5**	$ 5.3	**$ 20.5**	$ 17.1
Per boe	**3.36**	2.29	**3.13**	2.41
Net	**4.1**	3.2	**11.4**	10.4
Per boe	**$ 1.82**	$ 1.40	**$ 1.73**	$ 1.47

Beginning in Q2 2020, the Company implemented a number of temporary measures to reduce costs, specifically lower salaries and staff benefits in response to the low commodity price environment. Most of these temporary reductions were eliminated prior to Q2 2021 which led to the increase in G&A in 2021 compared to 2020.

Our decision to defer development spending for the majority of 2020 reduced production levels and partially contributed to higher per boe costs in 2021 compared to 2020.

Restructuring and other expenses

(millions, except per boe amounts)	Three months ended September 30 2021	2020	Nine months ended September 30 2021	2020
Restructuring	**$ 0.1**	$ 0.1	**$ (1.8)**	$ 0.4
Per boe	**0.07**	0.05	**(0.27)**	0.07
Other	**0.6**	0.8	**(7.7)**	5.8
Per boe	**$ 0.27**	$ 0.36	**$ (1.17)**	$ 0.81

In 2021, restructuring expenses include a settlement benefit of a prior cancelled office lease that resulted in a $2.0 million recovery of previously accrued costs recorded in Q1 2021.

In 2018, the Company fully utilized available insurance coverage relating to ongoing claims against former Penn West employees arising from the Company's 2014 restatement of certain financial results when we were known as Penn West. A claim brought by the United States Securities and Exchange Commission ("SEC") against Penn West was previously settled. The Company had been indemnifying two former employees pursuant to indemnity agreements in connection with the claims brought by the SEC arising out of the same restatement. In 2020, the SEC reached a settlement with the two former employees.

The Company continued to accrue for, but not pay, defense costs incurred on behalf of the two former employees and in Q1 2021 agreed to a settlement to pay $6.4 million of the defense costs equally over a 30-month period beginning in April 2021. As a result of the settlement, the Company recorded a recovery of previously accrued costs in Q1 2021 within Other in the Consolidated Statements of Income (Loss).

Depletion, Depreciation, Impairment and Accretion

(millions, except per boe amounts)	Three months ended September 30 2021	2020	Nine months ended September 30 2021	2020
Depletion and depreciation ("D&D")	**$ 32.4**	$ 27.6	**$ 83.8**	$ 103.9
D&D expense per boe	**14.60**	12.00	**12.78**	14.58
PP&E Impairment (reversal)	**(22.3)**	-	**(333.7)**	762.3
PP&E Impairment (reversal) per boe	**(10.02)**	-	**(50.89)**	107.02
Accretion	**2.0**	1.9	**6.0**	6.5
Accretion expense per boe	**$ 0.89**	$ 0.81	**$ 0.92**	$ 0.90

The Company's D&D expense has increased in Q3 2021 due to a non-cash impairment reversal recorded in Q2 2021 due to the higher commodity price environment and capital additions within our Cardium Cash Generating Unit ("CGU").

The decrease in D&D expense from the comparable period for the first nine months of 2021 is primarily due to non-cash impairment charges recorded in Q1 2020. These impairment charges were recorded mainly due to lower forecasted commodity prices and higher discount rates due to continued commodity price and market value volatility within the oil and natural gas industry.

During Q3 2021, as a result of the Company entering into an agreement to purchase the 45 percent interest of our partner in PROP, the Company concluded that an indicator of impairment reversal was present within our Peace River CGU. The Company followed the fair value less costs of disposal method using the estimated purchase price of the acquisition which resulted in a $26.5 million impairment reversal. The reversal was partially offset by a $4.2 million impairment charge on our Legacy CGU.

In Q2 2021, as a result of recent improvements in forecasted commodity prices and continued positive drilling results, the Company recorded a $311.5 million impairment reversal in our Cardium CGU.

In 2020, the Company completed impairment tests across all of our CGU's as a result of the low commodity price environment, primarily due to the impact of the COVID-19 pandemic and concerns regarding potential supply and demand implications. This led to the Company recording $762.9 million of non-cash impairments in Q1 2020.

Taxes

As at September 30, 2021, the Company was in a net unrecognized deferred tax asset position of approximately $357.9 million (December 31, 2020 - $448.6 million). Since the Company has not recognized the benefit of deductible timing differences in excess of taxable timing differences, deferred tax expense (recovery) for the quarter is nil.

Foreign Exchange

Obsidian Energy records unrealized foreign exchange gains or losses to translate U.S. denominated senior notes and the related accrued interest to Canadian dollars using the exchange rates in effect on the balance sheet date. Realized foreign exchange gains or losses are recorded upon repayment of the senior notes.

The split between realized and unrealized foreign exchange gain or loss is as follows:

	Three months ended September 30		Nine months ended September 30	
(millions)	**2021**	2020	**2021**	2020
Realized foreign exchange loss	**$ -**	$ -	**$ 0.3**	$ -
Unrealized foreign exchange (gain)/loss	**1.6**	(1.3)	**(0.3)**	1.5
Foreign exchange (gain)/loss	**$ 1.6**	$ (1.3)	**$ -**	$ 1.5

In Q1 2021, the Company repaid senior notes in the amount of US$1.1 million which resulted in the realized foreign exchange loss.

Net Income/(Loss)

	Three months ended September 30		Nine months ended September 30	
(millions, except per share amounts)	**2021**	2020	**2021**	2020
Net income/(loss)	**$ 46.6**	$ (3.2)	**$ 392.3**	$ (771.9)
Basic per share	**0.62**	(0.04)	**5.28**	(10.55)
Diluted per share	**$ 0.60**	$ (0.04)	**$ 5.14**	$ (10.55)

In 2021, net income was associated with the Company's strong netback which was supported by higher oil prices. Additionally, during Q3 2021, the Company recorded a $26.5 million impairment reversal in our Peace River CGU.

For the first nine months of 2021, the Company recorded a $311.5 million impairment reversal in Q2 2021 in our Cardium CGU due to higher forecasted commodity prices and strong drilling results. In Q1 2021, the Company recorded a recovery within Other in the Consolidated Statements of Income (Loss) as a result of a settlement on a previously accrued provision.

In 2020, the net loss was mainly due to non-cash, PP&E impairment charges as a result of lower forecasted commodity prices due to the impact of the COVID-19 pandemic and potential supply and demand implications.

Capital Expenditures

	Three months ended September 30		Nine months ended September 30	
(millions)	**2021**	2020	**2021**	2020
Drilling and completions	**$ 30.8**	$ 2.3	**$ 64.4**	$ 32.9
Well equipping and facilities	**14.4**	2.2	**30.6**	12.2
Land and geological/geophysical	**(0.3)**	-	**0.6**	0.3
Corporate	**0.2**	0.1	**0.5**	0.2
Capital expenditures	**45.1**	4.6	**96.1**	45.6
Property dispositions, net	**-**	-	**-**	(0.1)
Total capital expenditures	**$ 45.1**	$ 4.6	**$ 96.1**	$ 45.5

The Company began drilling our second half 2021 program in our Willesden Green and Pembina plays in the Cardium in June 2021 which includes 25 wells. A total of 11 gross (10.2 net) wells were rig-released during Q3 2021 with three gross (3.0 net) brought on production.

The remainder of our second half 2021 drilling program includes 16 gross (15.5 net) additional wells to be drilled and 14 gross (13.0 net) operated wells expected to be brought on production in Q4 2021.

Drilling

	Nine months ended September 30			
	2021		2020	
(number of wells)	**Gross**	**Net**	Gross	Net
Oil	**23**	**19**	12	10
Gas	**1**	**1**	-	-
Injectors, stratigraphic and service	**3**	**1**	1	-
Total	**27**	**21**	13	10
Success rate (1)		**100%**		100%

(1) Success rate is calculated excluding stratigraphic and service wells.

The Company rig released 20 wells relating to our 2021 development program between December 2020 and September 2021. In addition to this, the Company had a minor non-operated working interest on four oil wells and three injector wells that were drilled by a partner during the period.

Environmental and Climate Change

The oil and natural gas industry has a number of environmental risks and hazards and is subject to regulation by all levels of government. Environmental legislation includes, but is not limited to, operational controls, site restoration requirements and restrictions on emissions of various substances produced in association with oil and natural gas operations. Compliance with such legislation could require additional expenditures and a failure to comply may result in fines and penalties which could, in the aggregate and under certain assumptions, become material.

Obsidian Energy is dedicated to managing the environmental impact from our operations through our environmental programs which include resource conservation, water management and site abandonment/reclamation/remediation. Obsidian Energy has voluntarily entered into the Government of Alberta's Area Based Closure program (the "ABC program") which has allowed the Company to accelerate abandonment activities, specifically on inactive properties, in a more cost-effective manner. The Company is committed to remaining in the ABC program for at least 2021 and 2022. The Alberta Government announced the suspension of spending requirements for the ABC program for 2020 and the $11 million incurred by the Company in 2020 will be applied to our 2021 program target. Additionally, operations are continuously monitored to minimize both environmental and climate change impacts and allocate sufficient capital to reclamation and other activities to mitigate the impact on the areas in which the Company operates.

The Company has received ASRP grants and allocations to date of over $35 million on a gross basis, a portion of which was received in allocation eligibility as an ABC program participant. Total grant support will be determined by final project costs. These awards have allowed the Company to expand our abandonment activities for wells, pipelines, facilities, and related site reclamation and thus reduce our decommissioning liability. We began utilizing the ASRP grants in Q4 2020 and continued this work in 2021. We will continue to utilize these grants for the remainder of 2021 and throughout 2022.

Liquidity and Capital Resources

Net Debt

Net debt is the total of long-term debt and working capital deficiency as follows:

		As at
(millions)	**September 30, 2021**	December 31, 2020
Long-term debt		
Syndicated credit facility	**$ 340.0**	$ 395.0
Senior secured notes	**58.9**	60.3
Deferred interest	**1.6**	-
Deferred financing costs	**(3.5)**	(3.5)
Total	**397.0**	451.8
Working capital deficiency		
Cash	**(4.0)**	(8.1)
Accounts receivable	**(56.5)**	(40.8)
Prepaid expenses and other	**(12.0)**	(9.2)
Accounts payable and accrued liabilities	**103.6**	74.1
Total	**31.1**	16.0
Net debt	**$ 428.1**	$ 467.8

Net debt decreased compared to December 31, 2020, as a result of free cash flow generation due to higher commodity prices and strong production performance which led to higher netbacks and lower drawings on the syndicated credit facility, which has been reduced by $55 million since December 31, 2020.

The Company's credit facility was classified as a long-term liability at September 30, 2021 as the term-out date is November 30, 2022, which is beyond 12 months from the reporting date.

Liquidity

The Company has a reserve-based syndicated credit facility with a borrowing limit of $440.0 million with $340.0 million drawn at September 30, 2021. For further details on the Company's debt instruments and our recent bank amendment, please refer to the "Financing" section of this MD&A.

The Company actively manages our debt portfolio and considers opportunities to reduce or diversify our debt capital structure. Management contemplates both operating and financial risks and takes action as appropriate to limit the Company's exposure to certain risks. Management maintains close relationships with the Company's lenders and agents to monitor credit market developments. These actions and plans aim to increase the likelihood of maintaining the Company's financial flexibility and appropriate capital program, supporting the Company's ongoing operations and ability to execute longer-term business strategies.

On September 30, 2021, the Company was in compliance with all of our financial covenants which consisted of the following:

	Limit	**September 30, 2021**
Senior debt to capitalization	Less than 75%	**36.0%**
Total debt to capitalization	Less than 75%	**36.0%**

Financial Instruments

Obsidian Energy had the following financial instruments outstanding as at September 30, 2021. Fair values are determined using external counterparty information, which is compared to observable market data. The Company limits our credit risk by executing counterparty risk procedures which include transacting only with institutions within our syndicated credit facility or companies with high credit ratings, and by obtaining financial security in certain circumstances.

	Notional volume	**Remaining term**	**Pricing**		**Fair value (millions)**
Oil					
WTI Swaps	6,750 bbl/d	October 2021	$91.54/bbl	$	(0.7)
AECO Swaps					
AECO Swaps	23,695 mcf/d	October 2021	$2.70/mcf		(1.1)
AECO Swaps	21,325 mcf/d	November/21 – March/22	$4.46/mcf		(2.4)
Total				**$**	**(4.2)**

Refer to the Business Environment section above for a full list of hedges currently outstanding including trades that were entered into subsequent to September 30, 2021.

Based on commodity prices and contracts in place at September 30, 2021, a $1.00 change in the price per barrel of liquids of WTI would change pre-tax unrealized risk management by $0.2 million and a $0.10 change in the price per mcf of natural gas would change pre-tax unrealized risk management by $0.4 million.

The components of risk management on the Consolidated Statements of Income (Loss) are as follows:

	Three months ended September 30		Nine months ended September 30	
(millions)	**2021**	2020	**2021**	2020
Realized				
Settlement of commodity contracts	**$ (2.0)**	$ (1.0)	**$ (8.3)**	$ 21.2
Total realized risk management gain (loss)	**$ (2.0)**	$ (1.0)	**$ (8.3)**	$ 21.2
Unrealized				
Commodity contracts	**$ (0.9)**	$ 0.2	**$ (4.4)**	$ 0.4
Total unrealized risk management gain (loss)	**(0.9)**	0.2	**(4.4)**	0.4
Risk management gain (loss)	**$ (2.9)**	$ (0.8)	**$ (12.7)**	$ 21.6

Refer to the Business Environment section above for a full list of physical hedges currently outstanding including trades that were entered into subsequent to September 30, 2021.

Sensitivity Analysis

Estimated sensitivities to selected key assumptions on funds flow from operations for the 12 months subsequent to the date of this MD&A, including risk management contracts entered into to date, are based on forecasted results (before giving effect to the proposed acquisition of the remaining 45% interest in PROP).

		Impact on funds flow	
Change of:	Change	$ millions	$/share
Price per barrel of liquids	WTI US$1.00	5	0.07
Liquids production	1,000 bbls/day	25	0.34
Price per mcf of natural gas	AECO $0.10	1	0.02
Natural gas production	10 mmcf/day	14	0.18
Effective interest rate	1%	3	0.04
Exchange rate ($US per $CAD)	$0.01	3	0.05

Contractual Obligations and Commitments

Obsidian Energy is committed to certain payments over the next five calendar years and thereafter as follows:

	2021	2022	2023	2024	2025	Thereafter	Total
Long-term debt (1)	**$ -**	$ 389.9	$ -	$ -	$ -	$ -	$ 389.9
Transportation	**1.5**	6.0	5.0	2.6	2.1	6.0	23.2
Interest obligations	**7.4**	27.2	-	-	-	-	34.6
Office lease	**2.5**	10.0	10.0	10.0	0.8	-	33.3
Lease liability	**1.1**	4.1	2.9	0.3	0.1	5.2	13.7
Decommissioning liability (2)	**2.6**	13.6	3.5	3.3	3.1	39.3	65.4
Total	**$ 15.1**	$ 450.8	$ 21.4	$ 16.2	$ 6.1	$ 50.5	$ 560.1

(1) The 2022 figure includes $340.0 million related to the syndicated credit facility and non-revolving term loan that is due for renewal in 2022 and $58.9 million of senior notes set to mature in 2022; refer to the Financing section above for further details. Historically, the Company has successfully renewed its syndicated credit facility.
(2) These amounts represent the inflated, discounted future reclamation and abandonment costs that are expected to be incurred over the life of the Company's properties.

The revolving period of our syndicated credit facility continues to May 31, 2022, with a term out period to November 30, 2022, provided that if the lenders do not reconfirm the revolving period on January 17, 2022 the revolving period will accelerate to February 1, 2022 and the end date of the term period will continue to be November 30, 2022. In addition, the Company has an aggregate of US$46.3 million in senior notes maturing November 30, 2022. If the Company is unsuccessful in renewing or replacing the syndicated credit facility or obtaining alternate funding for some or all of the maturing amounts of the senior notes, it is possible that we could be required to seek to obtain other sources of financing, including other forms of debt or equity arrangements if available. Please see the Financing section of this MD&A for further details regarding our syndicated credit facility and senior notes.

The Company is involved in various litigation and claims in the normal course of business and records provisions for claims as required.

Equity Instruments

Common shares issued:	
As at September 30, 2021 and November 5, 2021	74,852,877
Options outstanding:	
As at September 30, 2021 and November 5, 2021	3,033,610
RSUs	
As at September 30, 2021	1,183,538
Forfeited	(8,167)
As at November 5, 2021	1,175,371

Supplemental Production Disclosure

Outlined below is production by product type for each area as follows for the periods indicated:

	Three months ended September 30		Nine months ended September 30	
Daily production (boe/d)	**2021**	2020	**2021**	2020
Cardium				
Light oil (bbls/d)	**9,988**	10,695	**10,098**	11,793
Heavy oil (bbls/d)	**60**	43	**52**	38
NGLs (bbls/d)	**2,127**	2,175	**2,067**	2,184
Natural gas (mmcf/d)	**46**	46	**45**	46
Total production (boe/d)	**19,807**	20,661	**19,753**	21,615
Peace River				
Light oil (bbls/d)	**-**	-	**-**	-
Heavy oil (bbls/d)	**2,449**	2,701	**2,481**	2,647
NGLs (bbls/d)	**2**	-	**3**	2
Natural gas (mmcf/d)	**3**	3	**3**	3
Total production (boe/d)	**2,974**	3,196	**2,960**	3,123
Viking				
Light oil (bbls/d)	**177**	202	**168**	215
Heavy oil (bbls/d)	**122**	62	**118**	47
NGLs (bbls/d)	**49**	41	**43**	38
Natural gas (mmcf/d)	**3**	4	**3**	3
Total production (boe/d)	**822**	825	**810**	845
Legacy				
Light oil (bbls/d)	**149**	55	**123**	76
Heavy oil (bbls/d)	**57**	17	**61**	79
NGLs (bbls/d)	**35**	28	**31**	30
Natural gas (mmcf/d)	**2**	1	**2**	1
Total production (boe/d)	**561**	349	**494**	412
Total				
Light oil (bbls/d)	**10,314**	10,952	**10,389**	12,084
Heavy oil (bbls/d)	**2,688**	2,823	**2,712**	2,811
NGLs (bbls/d)	**2,213**	2,244	**2,144**	2,254
Natural gas (mmcf/d)	**54**	54	**53**	53
Total production (boe/d)	**24,164**	25,031	**24,017**	25,995

Changes in Internal Control Over Financial Reporting (“ICFR”)

Obsidian Energy’s senior management has evaluated whether there were any changes in the Company's ICFR that occurred during the period beginning on July 1, 2021 and ending on September 30, 2021 that have materially affected, or are reasonably likely to materially affect, the Company's ICFR. No changes to the Company’s ICFR were made during the quarter.

Off-Balance-Sheet Financing

Obsidian Energy has off-balance-sheet financing arrangements consisting of operating leases. The operating lease payments are summarized in the Contractual Obligations and Commitments section.

Non-GAAP Measures

Certain financial measures including funds flow from operations, funds flow from operations per share-basic, funds flow from operations per share-diluted, free cash flow, netback, net operating costs, gross revenues and net debt, included in this MD&A do not have a standardized meaning prescribed by IFRS and therefore are considered non-GAAP measures; accordingly, they may not be comparable to similar measures provided by other issuers. Funds flow from operations is cash flow from operating activities before changes in non-cash working capital, decommissioning expenditures, onerous office lease settlements, the effects of financing related transactions from foreign exchange contracts and debt repayments, restructuring charges, transaction costs and certain other expenses and is representative of cash related to continuing operations. Funds flow from operations is used to assess the Company’s ability to fund our planned capital programs. See “Cash flow from Operations and Funds Flow from Operations” above for a reconciliation of funds flow from operations to cash flow from operating activities, being our nearest measure prescribed by IFRS. Free cash flow is funds flow from operations less both capital and decommissioning expenditures. Netback is the per unit of production amount of revenue less royalties, net operating costs, transportation expenses and realized risk management gains and losses, and is used in capital allocation decisions and to economically rank projects. See "Results of Operations – Netbacks" above for our calculation of netbacks. Net operating costs are calculated by deducting processing income and road use recoveries from operating costs and is used to assess the Company’s cost position. Processing fees are primarily generated by processing third party volumes at the Company’s facilities. In situations where the Company has excess capacity at a facility, it may agree with third parties to process their volumes as a means to reduce the cost of operating/owning the facility. Road use recoveries are a cost recovery for the Company as we operate and maintain roads that are also used by third parties. See "Expenses – Operating" above for a reconciliation of operating costs to net operating costs. Gross revenues are production revenues including realized risk management gains and losses on commodity contracts and adjusted for commodities purchased and sales of commodities purchased and is used to assess the cash realizations on commodity sales. See "Production Revenues" above for a reconciliation of gross revenues to production revenues, being our nearest measure prescribed by IFRS. Net debt is the total of long-term debt and working capital deficiency and is used by the Company to assess our liquidity. See "Liquidity and Capital Resources – Net Debt" above for a calculation of the Company’s net debt.

Oil and Natural Gas Information

Barrels of oil equivalent ("boe") may be misleading, particularly if used in isolation. A boe conversion ratio of six thousand cubic feet of natural gas to one barrel of oil is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Given that the value ratio based on the current price of oil as compared to natural gas is significantly different from the energy equivalency conversion ratio of 6:1, utilizing a conversion on a 6:1 basis is misleading as an indication of value.

Forward-Looking Statements

Certain statements contained in this document constitute forward-looking statements or information (collectively "forward-looking statements") within the meaning of the "safe harbour" provisions of applicable securities legislation. In particular, this document contains forward-looking statements pertaining to, without limitation, the following: our belief that our plan to primarily focus on our industry leading Cardium position offers a predictable, liquids weighted, production profile that is capable of generating sustainable value for all stakeholders; that we expect to generate higher fourth quarter and exit 2021 production rates than achieved in 2020, while still meaningfully reducing debt levels; that with a constructive pricing environment, our program further positions us for additional production growth that generates even greater free cash flow in 2022; expectations regarding our 2021 and second half 2021 drilling program, locations, completion and on production dates, optimization program and significant capability to scale our development drilling in response to changes in commodity prices; that our decommissioning activity will benefit in 2021 and 2022 from our ASRP grants; all matters relating to our proposed acquisition of the remaining 45% interest in PROP, including the purchase price, amount of estimated closing adjustments, nature of the consideration, proposed closing date, funding sources, and related agreement to reduce the amount of our credit facility commitment amount and to repay a portion of the principal amount of our senior notes; all matters relating to our proposal to obtain a limited-recourse loan and to complete a prospectus offering of new equity to fund the proposed acquisition; the expected re-confirmation and term out dates, as applicable, in connection with our reserve-based syndicated credit facility, the lender option date to complete a borrowing base redetermination on the credit facility, the available revolving capacity at the end of the year depending on the amount drawn under the credit facility, and the maturity dates and interest rates on the senior notes; the use of borrowing availability to reduce amounts outstanding on the non-revolving term loan and senior notes; that the compliance with certain environmental legislation could require additional expenditures and a failure to comply may result in fines and penalties which could, in the aggregate and under certain assumptions, become material; that the Company continuously monitors operations to minimize environmental and climate change impacts and allocate sufficient capital to reclamation and other activities to mitigate the impact on the areas in which the Company operates; that we are dedicated to managing the environmental impact from our operations through our environmental programs which include resource conservation, water management and site abandonment / reclamation / remediation; that we will remain in the ABC program for 2021 and 2022; how the ASRP will allow the Company to expand the abandonment activities, the timing thereof and staying actively engaged in these types of programs; that amounts spent in 2020 under the ABC program can be applied to our 2021 target; the continued use of ASRP grants in 2021 and 2022; the information disclosed under "Sensitivity Analysis"; our future payment obligations as disclosed under "Contractual Obligations and Commitments"; that management contemplates both operating and financial risks and takes action as appropriate to limit the Company’s exposure to certain risks and that management maintains close relationships with the Company's lenders and agents to monitor credit market developments, and these actions and plans aim to increase the likelihood of maintaining the Company's financial flexibility and capital program, supporting the Company's ongoing operations and ability to execute longer-term business strategies; and the Company's need to require additional sources of financing in certain circumstances.

With respect to forward-looking statements contained in this document, the Company has made assumptions regarding, among other things: that the Company does not dispose of or acquire material producing properties or royalties or other interests therein other than as stated herein in respect of our proposed acquisition of the remaining 45% interest in PROP; that the Government of Alberta will not impose oil and bitumen production quotas under its curtailment rules again in the future; the impact of regional and/or global health related events, including the ongoing COVID-19 pandemic, on energy demand and commodity prices; that the Company's operations and production will not be disrupted by circumstances attributable to the COVID-19 pandemic and the responses of governments and the public to the pandemic; global energy policies going forward, including the continued ability and willingness of members of OPEC, Russia and other nations to agree on and adhere to production quotas from time to time; our ability to qualify for (or continue to qualify for) new or existing government programs created as a result of the COVID-19 pandemic (including the CEWS and ASRP) or otherwise, and obtain financial assistance therefrom, and the impact of those programs on our financial condition; our ability to execute our plans as described herein and in our other disclosure documents and the impact that the successful execution of such plans will have on our Company and our stakeholders; future capital expenditure and decommissioning expenditure levels; future operating costs and G&A costs; future oil, natural gas liquids and natural gas prices and differentials between light, medium and heavy oil prices and Canadian, WTI and world oil and natural gas prices; future hedging activities; future oil, natural gas liquids and natural gas production levels, including that we will not be required to shut-in production due to a deterioration of commodity prices; future exchange rates and interest rates; future debt levels; our ability to execute our capital programs as planned without significant adverse impacts from various factors beyond our control, including extreme weather events such as wild fires and flooding, infrastructure access and delays in obtaining regulatory approvals and third party consents; our ability to obtain equipment in a timely manner to carry out development activities and the costs thereof; our ability to market our oil and natural gas successfully to current and new customers; our ability to obtain financing on acceptable terms, including our ability (if necessary) to continue to extend the revolving period and term out period of our credit facility, our ability to maintain the existing borrowing base under our credit facility, our ability to renew or replace our syndicated bank facility and our ability to finance the repayment of our senior notes on maturity; our ability to add production and reserves through our development and exploitation activities; and our ability to complete the proposed acquisition of the remaining 45% interest in PROP, including our ability to secure the necessary financing to pay the purchase price and satisfy all of the conditions precedent to closing the acquisition including the related financing matters in respect thereof.

Although the Company believes that the expectations reflected in the forward-looking statements contained in this document, and the assumptions on which such forward-looking statements are made, are reasonable, there can be no assurance that such expectations will prove to be correct. Readers are cautioned not to place undue reliance on forward-looking statements included in this document, as there can be no assurance that the plans, intentions or expectations upon which the forward-looking statements are based will occur. By their nature, forward-looking statements involve numerous assumptions, known and unknown risks and uncertainties that contribute to the possibility that the forward-looking statements contained herein will not be correct, which may cause our actual performance and financial results in future periods to differ materially from any estimates or projections of future performance or results expressed or implied by such forward-looking statements. These risks and uncertainties include, among other things: the possibility that the Company will not be able to continue to successfully execute our business plans and strategies in part or in full, and the possibility that some or all of the benefits that the Company anticipates will accrue to our Company and our stakeholders as a result of the successful execution of such plans and strategies do not materialize; the possibility that the Company ceases to qualify for, or does not qualify for, one or more existing or new government assistance programs implemented in connection with the COVID-19 pandemic and other regional and/or global health related events or otherwise, that the impact of such programs falls below our expectations, that the benefits under one or more of such programs is decreased, or that one or more of such programs is discontinued; the impact on energy demand and commodity prices of regional and/or global health related events, including the ongoing COVID-19 pandemic, and the responses of governments and the public to the pandemic, including the risk that the amount of energy demand destruction and/or the length of the decreased demand exceeds our expectations; the risk that the significant decrease in the valuation of oil and natural gas companies and their securities and the decrease in confidence in the oil and natural gas industry generally that has been caused by, among other things, the COVID-19 pandemic and the worldwide transition towards less reliance on fossil fuels persists or worsens; the risk that the COVID-19 pandemic adversely affects the financial capacity of the Company's contractual counterparties and potentially their ability to perform their contractual obligations; the possibility that the revolving period and/or term out period of our credit facility and the maturity date of our senior notes is not further extended (if necessary), that the borrowing base under our credit facility is reduced, that the Company is unable to renew our credit facilities on acceptable terms or at all and/or finance the repayment of our senior notes when they mature on acceptable terms or at all and/or obtain new debt and/or equity financing to replace one or both of our credit facilities and senior notes; the possibility that we breach one or more of the financial covenants pursuant to our agreements with our lenders and the holders of our senior notes; the possibility that we are forced to shut-in production, whether due to commodity prices decreasing or the Alberta government reactivating its curtailment program; the risk that OPEC, Russia and other nations fail to agree on and/or adhere to production quotas from time to time that are sufficient to balance supply and demand fundamentals for oil; general economic and political conditions in Canada, the U.S. and globally, and in particular, the effect that those conditions have on commodity prices and our access to capital; industry conditions, including fluctuations in the price of oil, natural gas liquids and natural gas, price differentials for oil and natural gas produced in Canada as compared to other markets, and transportation restrictions, including pipeline and railway capacity constraints; fluctuations in foreign exchange or interest rates; unanticipated operating events or environmental events that can reduce production or cause production to be shut-in or delayed (including extreme cold during winter months, wild fires and flooding); the possibility that fuel conservation measures, alternative fuel requirements, increasing consumer demand for alternatives to hydrocarbons and technological advances in fuel economy and renewable energy generation systems could permanently reduce the demand for oil and natural gas and/or permanently impair the Company's ability to obtain financing and/or insurance on acceptable terms or at all, and the possibility that some or all of these risks are heightened as a result of the response of governments, financial institutions and consumers to the ongoing COVID-19 pandemic and/or public opinion and/or special interest groups; the risk that we are unable to complete our proposed acquisition of the remaining 45% interest in PROP due to an inability to raise financing on acceptable terms or at all or satisfy one or more of the conditions precedent to closing such acquisition; and the other factors described under "Risk Factors" in our Annual Information Form and described in our public filings, available in Canada at www.sedar.com and in the United States at www.sec.gov. Readers are cautioned that this list of risk factors should not be construed as exhaustive.

The forward-looking statements contained in this document speak only as of the date of this document. Except as expressly required by applicable securities laws, the Company does not undertake any obligation to publicly update any forward-looking statements. The forward-looking statements contained in this document are expressly qualified by this cautionary statement.

Additional Information

Additional information relating to Obsidian Energy, including Obsidian Energy's Annual Information Form, is available on the Company's website at www.obsidianenergy.com, on SEDAR at www.sedar.com and on EDGAR at www.sec.gov.